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FINAL REPORT

California Class II Underground Injection Control Program Review

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USEPA Region 9

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FIGURES

TABLES

ACRONYMS

AI	Air Injection
AOR	Area of Review
API	American Petroleum Institute
APM	Annulus Pressure Monitoring
Bbl	Barrel
BFW	Base of Fresh Water
CalEMA	California Emergency Management Agency
CalWIMS	California Well Information Management System
CBL	Cement Bond Log
CDOGGR	California Division of Oil and Gas and Geothermal Resources
CS	Cyclic Steam
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
FOT	Fall-Off Test
GS	Gas Storage
MASP	Maximum Allowable Surface Pressure
mg/L	Milligrams per Liter
MI	Mechanical Integrity
MIT	Mechanical Integrity Test
MOI	Manual of Instructions
NOV	Notice of Violation
P&A	Plugging and Abandonment
PM	Pressure Maintenance
psi	Pounds per Square Inch
RAT	Radioactive Tracer
RWQB	Regional Water Quality Board
SAPT	Standard Annulus Pressure Test
SF	Steamflood
SNC	Significant Non-Compliance
SRT	Step-Rate Test
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
TA	Temporary Abandonment
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
WD	Water Disposal
WF	Waterflood
ZEI	Zone of Endangering Influence

EXECUTIVE SUMMARY

The United States Environmental Protection Agency (EPA) Region 9 requested a review and evaluation of the California Division of Oil and Gas and Geothermal Resources (CDOGGR, or the Division) Class II Underground Injection Control (UIC) Program for compliance with the CDOGGR Program Description and Memorandum of Agreement (Appendix A1) that were submitted in connection with the State of California application for primacy (the Primacy Application) that was approved by EPA in 1983. The review focuses on the following topics:

- Definitions of Underground Sources of Drinking Water (USDWs) and Base of Fresh Water (BFW);
- Area of Review (AOR)/Zone of Endangering Influence (ZEI) considerations, including corrective action requirements, well construction practices, and status of wells located within the AOR;
- CDOGGR annual project reviews;
- Monitoring program, including procedures for establishing Maximum Allowable Surface Pressures (MASPs);
- Inspections and compliance/enforcement procedures;
- Idle well planning and testing;
- Financial responsibility requirements;
- Plugging and abandonment requirements; and
- UIC staff qualifications.

The review was conducted as a third-party endeavor by the Horsley Witten Group, Inc. (HW) and Mr. James D. Walker, subcontractor to HW, and with initial guidance from EPA Region 9 on the process, format, and content of the review and of this final report. The conclusions, recommendations, and expressions of opinion provided in this report are solely those of HW and Mr. Walker.

The evaluation process of the CDOGGR Class II UIC Program started with a review of a number of critical documents and field data. A questionnaire was then developed (the EPA Questionnaire - available in Appendix A2) as a tool to gather critical information in the areas listed above from each of the six CDOGGR district offices. A district specific follow-up questionnaire was then submitted for clarification on certain district responses. Following these responses, Mr. Walker visited each district office to discuss any additional information, and collect information on representative samples of injection well projects and other data that would provide further insight into the areas of focus listed above.

A map of California showing the boundaries of each of the six districts, as well as district office locations is provided in Figure ES-1. In addition, a summary of injection well numbers by district is provided in Table ES-1. Well numbers are provided for both active and inactive wells of the following types: gas storage (GS), pressure maintenance (PM), cyclic steam (CS), steamflood (SF), waterflood (WF), air injection (AI), and water disposal (WD).

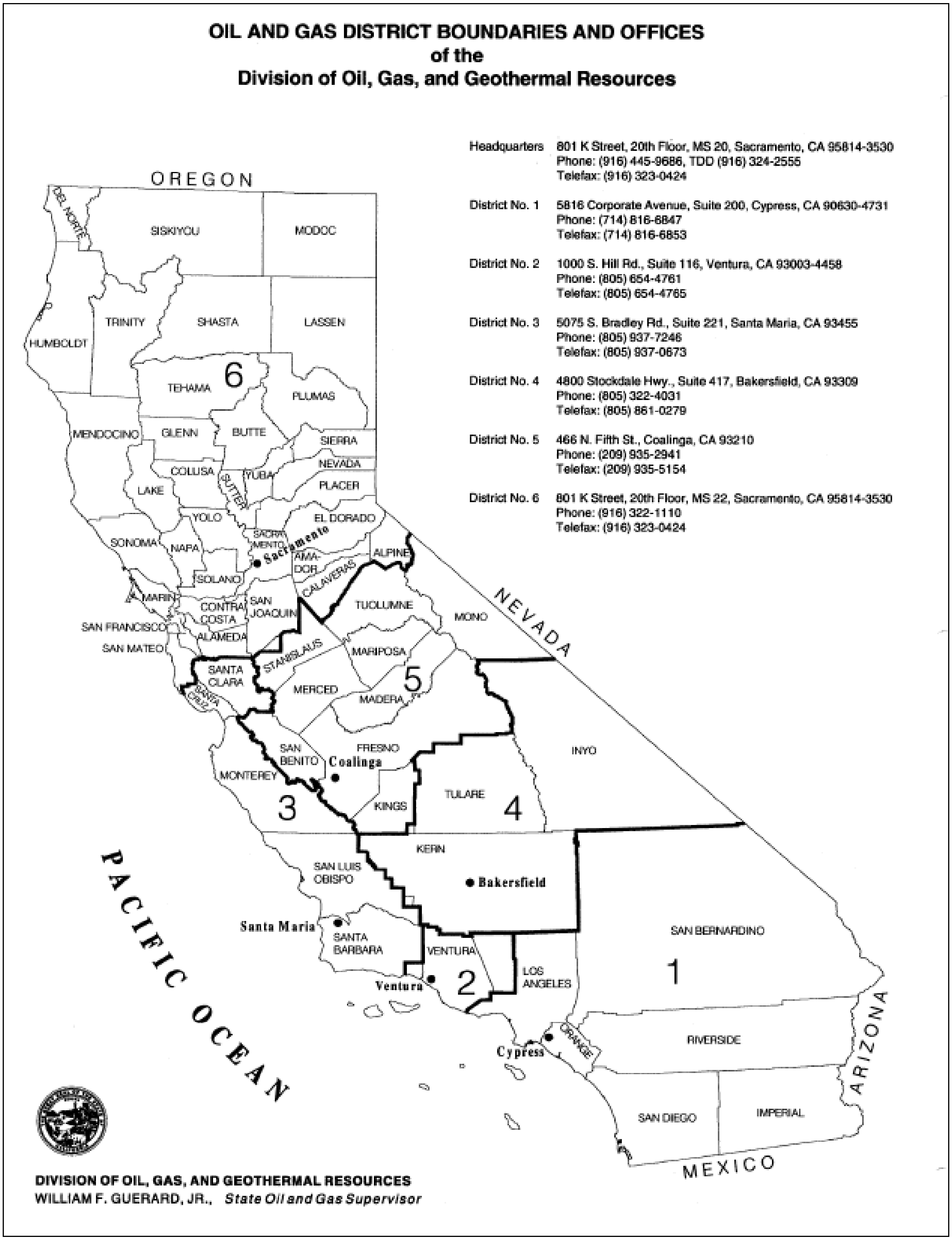


Figure ES-1. Map of CDOGGR Districts and District Offices

Table ES-1. Summary of Injection Well Numbers by District and Well Type

District	Injection Well Type	GS	PM	CS	SF	WF	AI	WD	Total	% of State Wells
1	Active	24	1	-	2	1,397	-	16	**1,440**	**6.14%**
	Inactive	53	1	-	9	411	2	26	**502**	
	Total	**77**	**2**	**-**	**11**	**1,808**	**2**	**42**	**1,942**	
2	Active	86	-	66	45	326	-	64	**587**	**3.19%**
	Inactive	48	1	-	31	278	-	65	**423**	
	Total	**134**	**1**	**66**	**76**	**604**	**-**	**129**	**1,010**	
3	Active	17	8	203	120	87	-	87	**522**	**2.83%**
	Inactive	4	8	-	124	142	4	90	**372**	
	Total	**21**	**16**	**203**	**244**	**229**	**4**	**177**	**894**	
4	Active	-	63	14,310	3,380	2,893	-	604	**21,250**	**80.8%**
	Inactive	-	16	-	3,064	851	12	377	**4,320**	
	Total	**-**	**79**	**14,310**	**6,444**	**3,744**	**12**	**981**	**25,570**	
5	Active	-	-	369	276	136	-	29	**810**	**6.45%**
	Inactive	1	-	-	694	501	-	36	**1,232**	
	Total	**1**	**-**	**369**	**970**	**637**	**-**	**65**	**2,042**	
6	Active	104	-	-	-	-	-	26	**130**	**0.57%**
	Inactive	41	-	-	-	-	-	10	**51**	
	Total	**145**	**-**	**-**	**-**	**-**	**-**	**36**	**181**	
State Totals	Active	231	72	14,948	3,823	4,839	-	826	**24,739**	**100%**
	Inactive	147	26	-	3,922	2,183	18	604	**6,900**	
	Total	**378**	**98**	**14,948**	**7,745**	**7,022**	**18**	**1,430**	**31,639**	

This report summarizes the results of the evaluation, and provides third-party conclusions and recommendations to EPA on potential improvements to the CDOGGR Class II UIC Program related to each of the topics identified above.

USDW DEFINITION AND PROTECTION

The CDOGGR Program Description submitted with the Primacy Application refers to protection of fresh water, and historically that term has been used to describe groundwater that contains 3,000 milligrams per liter (mg/L) or less total dissolved solids (TDS) in California. That is inconsistent with the federal definition of a USDW at 40 CFR §144.3, which defines USDWs as containing less than 10,000 mg/L TDS. In addition, there are apparently no provisions in California statutes or UIC regulations for exemption of an aquifer as an USDW containing between 3,000 and 10,000 mg/L TDS. The term commonly applied to identify the depth to which groundwater is protected is the BFW not the base of USDWs, and fresh water in California is defined as containing 3,000 mg/L or less TDS. Consequently, it would appear that USDWs containing more than 3,000 mg/L TDS are not fully protected under the California UIC regulations.

The Manual of Instructions (MOI) for the administration of the CDOGGR program, however, has a provision for the protection of USDWs containing 3,000 to 10,000 mg/L TDS. That provision clearly defines a USDW as containing fewer than 10,000 mg/L TDS, but that provision refers primarily to the aquifer exemption requirements, not to the more stringent protections in well construction and plugging abandonment requirements applied to fresh water zones. The description of the aquifer exemption process in the MOI includes requirements for an aquifer exemption in new injection projects if the proposed aquifer contains less than 10,000 mg/L TDS. Essentially all existing hydrocarbon bearing formations were exempted in the approval of the original Primacy Application in 1983, regardless of TDS concentrations. In addition, existing nonhydrocarbon bearing formations that were used for oil field wastewater disposal were identified and exempted at that time. There have been very few aquifer exemptions requested and approved since then.

Based on our review, the actual practices employed in UIC operations provide protection of fresh water from movement of fluids, but not necessarily for other USDWs. Annular cement is required at the BFW, but not at the base of other USDWs in injection wells. Zonal isolation of saline aquifers from USDWs by cement placement is not required and isolation from hydrocarbon bearing zones open to the uncemented wellbore is not assured without cement placement at the base of USDWs. That leaves those USDWs exposed to fluid movement due to improperly plugged wells and/or lack of cement in the casing/wellbore annulus, notwithstanding the presence of drilling mud that may restrict fluid flow. We believe that CDOGGR should address the lack of clarity regarding USDW protection and ensure that all USDWs are fully protected from fluid movement and resulting degradation. USDWs containing more than 3,000 mg/L TDS should be protected as much as fresh water aquifers are protected in the permitting, construction, operation, and abandonment of injection wells.

AREA OF REVIEW/ZONE OF ENDANGERING INFLUENCE

District staff indicated that the quarter-mile fixed radius AOR standard has been applied historically with very few exceptions. The ZEI calculation has rarely been applied to the AOR determination. The quarter-mile fixed radius for determination of the AOR applies to both water disposal wells and to multi-well projects in enhanced recovery projects.

The CDOGGR MOI states that, "(a)s a general rule, disposal into a nonhydrocarbon-producing zone should not be allowed to raise the zone pressure above that of hydrostatic pressure; however, exceptions may be made under certain conditions." District staff members indicated that surface shut-in pressures are monitored or fall-off tests are performed in wells of concern to ensure that the pressure falls to zero over a reasonable period of time. If the pressure does not fall to zero, the permit to inject into that zone is usually terminated or otherwise limited to avoid fluid movement in defective wells in the quarter-mile AOR.

District staff statements and a review of selected project files indicate most disposal wells inject into abandoned or producing zones, either in the field or at the flanks below the oil-water contact. Since the zone pressure is usually reduced well below hydrostatic pressure due to fluid withdrawals in those fields, it can be maintained at a pressure below hydrostatic as produced water is injected into the producing reservoir. Disposal of produced water into nonhydrocarbon bearing zones and normally pressured hydrocarbon bearing zones should be carefully monitored for reservoir pressure increases above hydrostatic, and the AOR should be determined by the ZEI calculation to ensure that corrective action requirements are fully addressed in all wells within the expanded AOR. Generally, the ZEI calculation is not necessary in Enhanced Oil Recovery (EOR) projects unless fluid volumes injected exceed the volumes withdrawn and static reservoir pressure exceeds hydrostatic pressure for an extended period of time, which is usually not the case.

Well construction practices and status of wells located within the AOR were reviewed in each district for consistency with the MOI, CDOGGR Program Description, UIC regulations, and adequate protection of USDWs. The review indicated that all defective wells in the AOR must meet those requirements for project approval, but that USDWs containing more than 3,000 mg/L TDS do not require as much protection as fresh water aquifers in terms of annular cement and plug placement in those wells. Sufficient volumes of cement in the annulus of unplugged wells are required at the BFW and above the injection/production zones to protect fresh water zones, but cement is not required at the base of USDWS in any well. Only “heavy” drilling mud between the injection zone and BFW annular cement is required for protection of USDWs from fluid movement in unplugged wells. Plugged wells require similar confinement in the annulus plus heavy mud inside the casing or open hole between cement plugs. The result of that practice is that fluid movement in the uncemented casing/wellbore annulus can occur, especially in older wells wherein the mud has likely deteriorated and may no longer be capable of preventing fluid movement.

Project approvals for recent applications generally satisfy corrective action requirements, but historical projects do not always meet current standards. In the May 2010 memorandum to the district offices (the Division Expectations Memorandum - available in Appendix A3), the Division provides directives (the Division directives) that require existing injection projects to comply with corrective action standards for wells within the AOR, in addition to new injection projects. The overriding mandate is that “injection fluid must be confined to the permitted zone of injection” whether or not a USDW is present.

The recent Division requirement that the ZEI be calculated for existing injection projects and all new Class II injection well project applications should result in a substantial improvement in the protection of USDWs when fully implemented at the district level. It will require a significant increase in the number of qualified staff members in the district offices, and we were informed that those increases have been authorized at the State level.

CDOGGR ANNUAL PROJECT REVIEW

Records of well activity, pressures, inactive well and non-compliance data and CDOGGR actions taken to correct non-compliance were reviewed in each district. All existing projects are required to have an annual review, in accordance with the MOI and the recent Division directives from the Division Expectations Memorandum to the district offices. The adherence to the annual project review standards varies from district to district. Most projects are reviewed at least on the basis of the CDOGGR Project Review Questionnaire (Appendix A4) responses, inspection reports, and other data in the monthly reports submitted by operators. Annual meetings with project operators are prioritized on the basis of the numbers of wells, activity, and levels of non-compliance associated with the operator. Actions taken to correct non-compliance include informal contacts, deficiency notices, shut-ins, notices of deficiency, civil orders, plugging and abandonment, and fines.

Comprehensive project reviews should be conducted annually for all active injection well projects, especially with those operators that are negligent in maintaining compliance with UIC regulations. Based on district responses, that may not be the case in the largest districts, due to the large number of injection wells and lack of manpower in those districts. That situation should improve with the hiring and training of several additional UIC personnel that was reportedly authorized by the Division. In addition, the requirement for monthly reports from the operators, mechanical integrity tests (MITs), periodic inspections, and other sources of project information provides data on wells that support the objectives of the annual project reviews.

MONITORING PROGRAM

Mechanical Integrity Testing surveys/reports were examined for compliance with UIC requirements and consistency with actual MIT results in each district. Radioactive tracer (RAT) surveys are required annually in water disposal wells, every two years in waterflood wells, and every five years in steamflood wells. Standard annulus pressure tests (SAPTs) are required in all Class II injection wells every five years. Our review of the well records indicates that schedule is followed with a few exceptions for variances approved by CDOGGR.

CDOGGR inspectors witness a large percentage of the SAPTs, but only a few of the RAT surveys. The percentages vary widely from district to district depending largely on the number of wells to test and the availability of inspectors to witness a test. Examination of MIT reports in district files indicates that they are generally consistent with historic UIC requirements as described above. Few of the RAT surveys are witnessed in the largest districts, but most of the SAPTS are witnessed in all districts. In our view, the percentage of RATs witnessed should be increased to at least 25 percent per year and the goal for SAPTs should be 100 percent, which would include witnessing MITs on all wells in a five-year cycle.

The requirement for pressure testing wells to at least 200 pounds per square inch (psi) for 15 minutes in the approved SAPT procedure is inconsistent with the standards applied to Class II injection wells in many of the other state and federal UIC programs. Those programs require testing to the maximum allowable surface injection pressure or at a minimum pressure higher than 200 psi, and for more than 15 minutes in some cases.

The Division directives modify the SAPT procedure to require testing at the approved MASP for a well where there is only a single string of cemented casing across a USDW (10,000 mg/L TDS). Comments received by the districts indicate that this standard is undergoing further review at the Division level and may be modified to allow for consideration of the age and condition of the casing in a well.

We support the Division directive to test the casing/tubing annulus to the maximum allowable surface injection pressure, if that will not expose the casing to a pressure that could cause a rupture, which can be a significant risk in older wells. The recently modified SAPT procedure described above is a substantial improvement, but we would recommend it be applied regardless of the number of cemented casing strings across USDWs.

Procedures for establishing MASPs and monitoring for compliance were reviewed in each district. Historically, MASPs were based largely on assumptions or estimates of the formation fracture gradient of the injection formation. Fracture gradients applied in the MASP determination vary from 0.6 to 1.0 psi/foot. In some wells, the fracture gradients were based on results of step-rate testing or calculations from other data. Estimates of fracture pressures based on generalized relationships between fracture pressure and depth to the formation or other means are not always a reliable method for that determination. Step-rate tests (SRTs) provide a more reliable and accurate measure of formation fracture pressures in the injection zone.

A review of selected SRT reports in each district indicated that the methodology and validity of the tests were generally in accordance with accepted industry standards, although most were based on surface pressure rather than bottom- hole pressure measurements. The estimation of friction losses would be avoided and the accuracy of the test results would therefore increase if the test analyses were based on bottom hole in addition to surface pressure measurements.

It is our view that the fracture pressure of the injection zone should be determined on the basis of an SRT unless SRTs have been performed on a sufficient number of wells in the area to ascertain the fracture gradient within acceptable confidence limits. Also, the SRT should include a pressure gauge to measure bottom-hole pressures directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates.

In its Division directives, CDOGGR has recently initiated steps to ensure the accuracy of fracture gradients and MASP determinations in all districts. New and existing projects will require approved SRTs to determine the fracture gradient in injection wells, and that injection pressure will be maintained below fracture pressure as determined by approved SRTs. Implementation of that directive should improve the accuracy of the fracture pressure determination and reduce the potential for fracturing the injection zone. We support that directive to the fullest extent.

We also support the requirement for a wellhead inspection at least once every two years to ensure that the injection pressure is below the MASP and the requirement to immediately reduce the injection pressure if it exceeds the MASP. Annual inspections are required according to the MOI, but that may not be possible in the largest districts with current staffing levels. In our view, wells that inject at or near the MASP should be inspected annually. In addition, we endorse the requirement that a database or records must be maintained that lists the MASP for all injection wells and is easily accessible to field personnel to verify that the MASP is not being exceeded.

The databases used in each district office vary, but the districts are in the process of replacing those with the California Well Information Management System (CalWIMS) database statewide. CalWIMS is more user-friendly and more up-to-date in its applications than the existing systems at the district level

INSPECTIONS AND COMPLIANCE/ENFORCEMENT PRACTICES AND TOOLS

Injection wells are required to be inspected annually in accordance with the Division MOI guidelines. Injection pressures are compared with the MASP for a well to ensure that the MASP or 90 percent of the fracture gradient is not exceeded. If exceeded, the well is considered in violation of the project approval letter and the operator is required to reduce the pressure immediately. If USDWs are endangered, the violation is considered a significant non-compliance (SNC). An enforcement action may ensue at the district level if the operator fails to comply with the order to maintain the pressure below the MASP and/or correct other deficiencies

A MIT is described as either a RAT, temperature, or spinner survey. The initial MIT is usually witnessed and subsequent MITs may be witnessed depending on the availability of an inspector and the priority for witnessing the MIT. Water disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years. Less than five percent of RATs are witnessed in the largest districts and they are not a priority in most districts. However, essentially all tests are reviewed and documented by district personnel.

An SAPT is required for all water disposal wells and waterflood wells every five years. Most of the SAPTs are witnessed by district personnel. When a MIT is not witnessed, the results of the tests are reviewed in the office. Inspections are also carried out in cases of noncompliance and in response to citizen complaints. Plugging and abandonment operations are witnessed for plug depth and hardness, squeeze cementing operations, and surface plug location, but witnessing cement placement in a well is not a requirement. An SRT for the determination of the formation fracture gradient and pressure is usually witnessed, but is rarely required by CDOGGR. Most MASP limits are set on the basis of fracture pressures estimated from statistical data on fracture gradients in the oil producing basins of California. However, SRTs are required for establishment of the MASP in new and existing projects under the Division directives of May 20, 2010. We fully support that directive, and recommend that the fracture pressure be based on bottom-hole pressures rather than surface pressures corrected for estimated friction losses.

Compliance assurance and enforcement tools utilized are as follows: informal contact, well shut-in, notice of deficiency, notice of violations, rescission of approval to inject, project suspension, civil order and penalty. Orders can be issued to repair or plug and abandon wells and "undertake such action as is necessary to protect life, health, property, or natural resources." Generally, an order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. If an emergency exists, district deputies can obtain authorization from the Division headquarters to repair or plug wells or eliminate hazardous conditions without issuing a formal order or seeking bids. Civil penalty procedures are described in Section 137 of the MOI and are limited to $25,000 per violation.

Inspections are not necessarily prioritized for wells where fresh water is present, and residential areas are not a consideration for the many wells that are located in rural areas, which is the case in most districts. In our view, those areas should receive a higher priority for inspections than is apparently the case in some districts.

According to the MOI, annual inspections are required for all injection wells, but not all wells are inspected annually in all districts. However, the recent Division Expectations Memorandum to the districts states that inspections at least every two years are acceptable. Most plugging and abandonment (P&A) operations are witnessed, but witnessing cement placement is not required, and that is one of our concerns. We believe it is important to witness cement placement operations to ensure the correct volumes and quality of cement are pumped into a well.

In general, inspections and monitoring are conducted in accordance with the general outline in the CDOGGR Program Description, but not in rigid adherence to the CDOGGR UIC regulations and MOI guidelines in all districts. The Division Expectations Memorandum requires inspections of all injection wells at least every two years and annual project reviews, which is consistent with the CDOGGR Program Description, but not with the annual inspection standard in the MOI. Historically, the MOI standards have not always been met in most districts. The hiring of additional staff members that was recently authorized by the Division should alleviate the lack of personnel to meet the Division standards.

Violation of a formal enforcement action is a significant noncompliance. Most (13) of the civil penalties issued in the past ten years were initiated by District 4 with fines ranging from $250 to $25,000 for each violation. Most of these actions were related to unauthorized injection violations.

In general, the CDOGGR enforcement program is apparently conducted in accordance with the general outline in the CDOGGR Program Description. Most districts indicated that they do not have enough resources and personnel to initiate adequate numbers of compliance/enforcement actions. That is also our assessment from our review of the district level inspection activity and formal enforcement actions. The hiring of additional personnel that was recently authorized by the Division, however, should alleviate the lack of staff to initiate and carry out UIC compliance/enforcement actions when violations occur.

IDLE WELL PLANNING AND TESTING PROGRAM

The stated objective of the idle well program is to eliminate idle wells by requiring operators to return idle wells to production/injection, or to plug and abandon their idle wells. The description of the program is found in Section 138 of the MOI. The definition of an idle well is “any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last five or more years.” The definition of long-term idle is “any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last ten or more years.”

Idle wells must have the fluid level determined as prescribed in the Idle Well Planning and Testing Program. The tests are required to verify fresh water is protected and that reservoir damage is not occurring. The program states that if the fluid level of a well is above the BFW, a casing pressure test should be run. If the casing lacks mechanical integrity and fresh water is threatened, the program recommends that the operator be ordered to perform remedial work. If an injection well is inactive for two or more years, the program recommends that approval for injection be rescinded.

Idle injection wells are not subject to the normal MIT schedule, but are subject to the idle well testing guidelines. In areas with fresh water, a two-year test cycle applies after five years of inactivity. Testing procedures for wells in areas with no fresh water are identical to those in fresh water areas except the testing cycle is five years instead of two years and references to BFW are excluded.

Plans for future use of idle wells are required for wells idle for ten years or longer. An approved Idle Well Management Plan satisfies this requirement. Otherwise, the plan for future use must include what is planned for the well and when it will be done. Wells idle for 15 years or longer must have an engineering study prepared and submitted detailing the future plans for the well(s).

The idle well testing guidelines for District 4 vary significantly from the statewide program. Districts are allowed to modify the general guidelines to address specific district conditions. The emphasis of the District 4 Idle Well Program is testing ten-year and 15-year idle wells for mechanical integrity (MI). District 4 wells that are idle for longer than ten years in areas where fresh water is present must be tested every two years. If located in a non-fresh water area, ten and 15-year idle wells must be tested every five years." The MIT for idle wells consists of a fluid level survey, and/or a casing pressure test if the fluid level is found above the BFW.

This program is a comprehensive monitoring program except that remedial work or plugging is not required for wells that lack MI unless there is evidence of a threat to fresh water zones while in idle status. Also, idle wells with apparent casing integrity are not required to be reactivated or plugged and abandoned before 15 years in that status. Only a small fraction of long-term idle wells are plugged and abandoned on a yearly basis, resulting in long-term temporary abandonment of most idle wells. The option for an operator to submit an Idle Well Management Plan provides some assurance that idle wells will be reactivated or plugged and abandoned on a specific timetable after ten years in idle status. However, it is optional and the other options provide insufficient assurance that the operator will comply with the requirement to reactivate or P&A a long-term idle well. In our view, the idle well fee amounts imposed on operators are too small to incentivize operators to reactivate or plug their idle wells and idle well bond or escrow amounts are insufficient to cover P&A costs.

Monitoring the fluid levels in idle wells every two years in fresh water areas is not consistent with adequate protection of other USDWs penetrated by an idle well. A pressure test is required if the fluid level rises above the BFW, but not the base of USDWs. In non-fresh water areas, testing requirements are on a five-year cycle and are otherwise less rigorous. If USDWs containing more than 3,000 mg/L TDS are present, those USDWs are not protected as well as they would be in a fresh water area. A pressure test would be more definitive of a casing or bridge plug leak and the potential for fluid movement into USDWs as fluid levels rise in a well, especially where USDW heads are drawn down by pumping for drinking water, agricultural, and/or other uses. Well integrity should be maintained while a well is in idle status, as it is in active status, unless the permittee can satisfactorily demonstrate that fluid movement will not occur into or between USDWs. Consideration should be given to modification of the CDOGGR Program to strengthen the protection of all USDWs penetrated by a well.

Field rules for District 4 allow less rigorous monitoring and testing of idle wells, probably because of the large number of idle wells in that district. In our view, consideration should be given to strengthening the idle well requirements in District 4 to make them more consistent with the statewide program and more protective of USDWs.

FINANCIAL RESPONSIBILITY REQUIREMENTS

These are applied on a statewide basis. The districts are fairly consistent in their responses regarding financial responsibility requirements for operators, as noted in Section 4.

An operator may demonstrate financial responsibility by filing an individual indemnity or cash bond for each well drilled or a blanket bond covering all well operations. Individual bonds are normally released after a noncommercial injection well has injected fluids for a six-month continuous period if the Division is satisfied that a well is mechanically sound. Blanket bonds are normally not released until all of the operator's wells are abandoned or until the operator specifically requests the release of a well from bond coverage. After the release of a bond, the Division still has the authority to order an operator to perform remedial or corrective work on a well. The Division may also order the abandonment of any well that has been deserted whether or not any damage is occurring or threatening to occur.

The individual bond amount for a Class II commercial disposal well is $50,000 per well if not covered by a blanket bond. The bond must be retained until the well is plugged and abandoned to the satisfaction of the Division.

The CDOGGR Program Description states that "(a) special well abandonment allotment is also available in California for the purpose of abandoning deserted wells when the last known operator is deceased, defunct, or no longer in business in California and the present surface and mineral estate owners did not receive a substantial financial gain from the wells."

The current bond amount of $50,000 per well may not be adequate to cover the full cost to plug and abandon some commercial Class II injection wells. Bond amounts for non-commercial wells are much less and are based on well depth. Basing the bond amount on third-party estimates of P&A costs for individual wells and periodic review and adjustment of those amounts would increase the probability that adequate funds would be available to P&A a deserted well. The individual well bond amounts were increased in 1999, but have apparently not been updated since then and are probably not adequate to cover the full cost to plug and abandon a well when that becomes necessary.

PLUGGING AND ABANDONMENT REQUIREMENTS

Procedures for P&A are standardized at the state level, with special requirements at the field level as described in field rules issued for special circumstances (see the *Bentonite Plugging Guidelines* discussed below for an example of the field rules that apply in the Bakersfield and Coalinga Districts). In general, cement plugs are placed across specified intervals to protect oil and gas zones, to prevent degradation of "useable" waters, to protect surface conditions, and for public health and safety purposes. Cement may be mixed with or replaced by other substances with adequate physical properties, subject to approval by the supervisor and application to particular wells at the discretion of the district deputy.

Plugging an open hole requires a cement plug from at least 100 feet below the bottom to at least 100 feet above the top of each oil or gas zone. A minimum 200-foot cement plug must be placed across all fresh-saltwater interfaces or within a thick shale if the shale separates the fresh water sands from the brackish or saltwater sands. Plugging in a cased hole requires that all perforations be plugged with cement, and that the plug extend at least 100 feet above the top of the upper most perforations, a landed liner, the casing cementing point, the water shut-off holes, or the hydrocarbon zone, whichever is highest. If there is cement behind the casing across the fresh-saltwater interface, a 100-foot cement plug must be placed inside the casing across the interface. If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the fresh water aquifers. Surface plugs require at least a 25-foot cement plug placed in the casing and the annuli of all casing strings at the surface.

The regulations specify that some P&A operations **may** require witnessing by a Division employee, at the discretion of the district deputy, and that some operations require witnessing. Witnessing the placement of cement plugs is optional. Operations that require witnessing include the location and hardness of cement plugs, cementing through perforations, and environmental inspection after completion of plugging operations. The operator is required to submit a detailed P&A report to the district within 60 days of the completion of P&A operations.

Each district has special abandonment requirements, resulting from unique geology and/or operational practices in certain fields. Field rules or field practice guidelines are issued for those special requirements that vary from the regulations and general P&A requirements described in the regulations and MOI. For example, Field Rules in the Bakersfield and Coalinga Districts, allow the use of sodium bentonite in well plugging operations with certain conditions and restrictions. Use of bentonite plugs is contrary to the federal UIC regulations at 40 CFR 146.10(a) regarding the requirement for the use of cement in plugging Class II injection wells. Additional information on the basis for those field rules were requested, but has not yet been provided by CDOGGR (as of June 23,2011).

Procedures for P&A are intended to isolate fresh water zones from the injection zone and hydrocarbon bearing formations, poor quality surface waters, and water zones of varying quality. Those objectives are generally met in wells plugged in recent decades. They are not always met in older wells due to plugging practices that were not as rigorous or protective of fresh water aquifers and other USDWs. However, deficient wells located within the AOR must be re-plugged or otherwise eliminated as a pathway for fluid movement, as a condition of approval of an injection well project.

In addition, USDWs containing more than 3,000 mg/L TDS are not protected to the extent that fresh water aquifers are protected from inflow of lesser quality waters. Placement of cement plugs is required at the BFW, but not at the base of other USDWs unless those depths happen to be coincident in a well. Protection from fluid movement into and between USDWs below the BFW depends partially on the presence of “heavy mud” in the casing/wellbore annulus and between cement plugs in the open-hole or inside casing strings. However, USDWs must be isolated from fluid movement exiting the injection zone and hydrocarbon bearing zones, by placement of sufficient cement volumes in the annular space and cement plugs above those zones. The presence of drilling mud may not prevent fluid movement between zones in the uncemented annulus, especially in the older wells within the AOR since the mud will degrade over time and not retain the density and other properties necessary to suppress fluid movement.

The requirements for witnessing P&A operations are somewhat flexible in that the district deputy in each district has the discretion to require witnessing or not for some plugging operations. Placement of cement plugs does not require the presence of a CDOGGR inspector, for example. Witnessing the tagging of cement plugs for proper placement and hardness, and the final site inspection for environmental compliance are requirements, and those are high priorities in the districts. However, in our view, the mixing and pumping of cement for placement of plugs is a critical step in the plugging operation that warrants the presence and monitoring of a CDOGGR inspector and should be witnessed whenever possible.

The option to use bentonite as a replacement for cement in plugging some wells in Districts 4 and 5 is contrary to federal UIC regulations which specify the use of cement in plugging Class II injection wells. The basis for that option is not clear from a review of the CDOGGR regulations, MOI, EPA Questionnaire responses, and other references to P&A requirements. CDOGGR should provide the basis for the use of bentonite instead of cement in plugging operations in those districts. District 4 was requested to provide that information and the district deputy agreed to that request, but that had not been received as of June 23, 2011.

UIC STAFF QUALIFICATIONS

The district offices provided organization charts and position descriptions for district level staff positions, which are included in Section 4 and in the appendices to this report (Appendix A5 for the overall CDOGGR organization chart, Appendix B1 for District 4, and Appendix B2 for District 2). Based on a review of staff qualifications and responses to the EPA Questionnaire and questions raised during the on-site visits, most district personnel appear to possess the necessary qualifications for the positions they hold. A general assessment of staff qualifications was based primarily on discussions with district management and staff.

Additional UIC specific training for the less experienced staff members would be beneficial to the CDOGGR UIC Program. Some have not attended the EPA sponsored UIC Inspector Training Course offered in nine EPA regional offices annually on a rotational basis between EPA offices. Attendance at that training course by new hires and the less experienced staff members would enhance staff qualifications and should be a priority for the districts.

The overriding concern with regard to staff qualification is that the districts lack sufficient personnel to adequately manage and implement the Class II UIC Program, especially with regard to the standards set forth by Division management in the Division Expectations Memorandum. As a result of implementation of these new standards and expectations, completion of reviews for UIC project applications has been delayed, especially in the largest districts. However, some districts have not yet fully implemented those standards, and are awaiting further clarification and/or modification before acting on the new Division directives from that memorandum.

Comprehensive annual UIC project reviews have also been limited to the most critical projects in some districts. Additionally, more MITs and P&A operations could be witnessed and more annual inspections could be performed if there were sufficient numbers of qualified staff in the district offices. However, we were informed by district management that authorization has been given to hire several additional personnel for implementation of the UIC Program. That authorization should substantially improve the quality of the CDOGGR UIC program at the district level when the new positions are filled and the new hires complete the CDOGGR UIC training program.

1.0 INTRODUCTION

In April 2010, the U.S. Environmental Protection Agency (EPA) Region 9 requested a review and evaluation of the California Division of Oil and Gas and Geothermal Resources (CDOGGR, or the Division) Class II Underground Injection Control (UIC) Program. The goal of the review was to evaluate compliance with the CDOGGR Program Description and Memorandum of Agreement (Appendix A1) that were submitted in connection with the State of California Application for Primacy (the Primacy Application). State primacy for the program was approved by EPA in March 1983. The review focuses on the following topics:

- Definitions of Underground Sources of Drinking Water (USDWs) and Base of Fresh Water (BFW);
- Area of Review (AOR)/Zone of Endangering Influence (ZEI) considerations, including corrective action requirements, well construction practices, and status of wells located within the AOR;
- CDOGGR annual project reviews;
- Monitoring program, including procedures for establishing Maximum Allowable Surface Pressures (MASPs);
- Inspections and compliance/enforcement procedures;
- Idle well planning and testing;
- Financial responsibility requirements;
- Plugging and abandonment (P&A) requirements; and
- UIC staff qualifications.

The review was conducted as a third-party endeavor by Mr. James D. Walker and the Horsley Witten Group, Inc. (HW) with initial guidance from EPA Region 9 on the process, format, and content of the review and of this final report. James Walker, subcontractor to HW, was contracted to conduct the review, with the support of HW staff and EPA Region 9 Ground Water Office staff. The conclusions, recommendations, and expressions of opinion provided in this report are solely those of HW and Mr. Walker.

Mr. Walker has over 45 years of experience as an engineer, worked in reservoir and production engineering for over 25 years, and served as an environmental engineer for EPA's UIC Program for over 20 years until his retirement in 2008. While at EPA, Mr. Walker was initially responsible for UIC permit determinations and enforcement at EPA Region 9, before he was assigned as a UIC Project and Enforcement Officer in EPA Region 8 where he provided oversight to delegated Class II UIC programs in various states. After a temporary intergovernmental assignment to the Navajo Nation EPA during which Mr. Walker was responsible for the development and implementation of the Navajo UIC Program, he returned to the EPA Region 9 office where he resumed his responsibility for UIC permit determinations and enforcement and was promoted to the General Schedule (GS)-13 level. Finally, during the last nine years of his EPA career and until his 2008 retirement, Mr. Walker was place-based to the Navajo Nation for the primary purpose of managing and implementing the EPA Navajo UIC Program and assisting in the development of the Navajo Nation Class II UIC Program. The Navajo Nation EPA received approval from EPA in 2008 for primacy of the Class II UIC Program.

The evaluation process of the CDOGGR Class II UIC Program started with a review of a number of critical documents and field data. Documents reviewed as part of this project include CDOGGR UIC regulations, CDOGGR Manual of Instructions (MOI), and other documents applicable to the implementation of the UIC Program. A full list of references, data, and documents reviewed for the purposes of this report is provided in the References Section of this report. The CDOGGR publication *California Oil and Gas Fields* provided valuable geological and production information on the oil and gas fields in California. The CDOGGR Annual Reports for 2008 and 2009 were also utilized to identify fields with Class II injection wells, the number of injection wells in each field, and the volumes of fluids injected in each field. A copy of form 7520 from the 2009 CDOGGR Annual Report is available in Appendix A6.

Table 1 provides a summary of injection well numbers by district. Well numbers are provided for both active and inactive wells of the following types: gas storage (GS), pressure maintenance (PM), cyclic steam (CS), steamflood (SF), waterflood (WF), air injection (AI), and water disposal (WD).

Table 1. Summary of Injection Well Numbers by District and Well Type

District	Injection Well Type	GS	PM	CS	SF	WF	AI	WD	Total	% of State Wells
1	Active	24	1	-	2	1,397	-	16	**1,440**	**6.14%**
	Inactive	53	1	-	9	411	2	26	**502**	
	Total	**77**	**2**	**-**	**11**	**1,808**	**2**	**42**	**1,942**	
2	Active	86	-	66	45	326	-	64	**587**	**3.19%**
	Inactive	48	1	-	31	278	-	65	**423**	
	Total	**134**	**1**	**66**	**76**	**604**	**-**	**129**	**1,010**	
3	Active	17	8	203	120	87	-	87	**522**	**2.83%**
	Inactive	4	8	-	124	142	4	90	**372**	
	Total	**21**	**16**	**203**	**244**	**229**	**4**	**177**	**894**	
4	Active	-	63	14,310	3,380	2,893	-	604	**21,250**	**80.8%**
	Inactive	-	16	-	3,064	851	12	377	**4,320**	
	Total	**-**	**79**	**14,310**	**6,444**	**3,744**	**12**	**981**	**25,570**	
5	Active	-	-	369	276	136	-	29	**810**	**6.45%**
	Inactive	1	-	-	694	501	-	36	**1,232**	
	Total	**1**	**-**	**369**	**970**	**637**	**-**	**65**	**2,042**	
6	Active	104	-	-	-	-	-	26	**130**	**0.57%**
	Inactive	41	-	-	-	-	-	10	**51**	
	Total	**145**	**-**	**-**	**-**	**-**	**-**	**36**	**181**	
State Totals	Active	231	72	14,948	3,823	4,839	-	826	**24,739**	**100%**
	Inactive	147	26	-	3,922	2,183	18	604	**6,900**	
	Total	**378**	**98**	**14,948**	**7,745**	**7,022**	**18**	**1,430**	**31,639**	

Data from the annual reports were used to screen for fields with the largest number of injection wells and the largest volumes of fluids injected on an annual and cumulative basis. A summary of field data collected during this review process is provided in Appendix B3. The CDOGGR online database was accessed to search for injection wells that were injecting at the highest pressures on a sustained basis. Those injecting at the highest pressures were reviewed more closely for possibly exceeding the MASP or the hydrostatic pressure of the injection zone. Water disposal wells were given a priority for review of high injection pressures and shut-in pressures that failed to fall to zero after an extended period of inactivity. Field data were examined for the BFW depths, formation water salinities, initial reservoir pressures, age, depths to the production/injection formations, etc. Those data were utilized to screen for fields and reservoirs that could be problematic in terms of potential endangerment of USDWs.

A questionnaire was then developed as a tool to gather critical information in the areas listed above from each of the six CDOGGR district offices. For purposes of this report, the questionnaire submitted to district offices will be called the EPA Questionnaire to avoid confusion with the CDOGGR Project Review Questionnaire, both available in Appendix A. The EPA Questionnaire was distributed to each of the six district offices in May 2010 as the first step in the review process. District responses were received and reviewed a few weeks later. Following Mr. Walker's review of district responses, he added requests for clarification to the EPA Questionnaire for responses that required clarification or additional information, and returned the follow-up EPA Questionnaires to each of the district offices. When those were returned by the district offices, Mr. Walker reviewed the follow-up responses and identified areas that would be discussed further during district office visits planned for October and November 2010. During the district office visits, Mr. Walker focused on additional follow-up to the EPA Questionnaire responses and on collecting information on representative samples of injection well projects and other data that would provide further insight into the areas of focus listed above.

This report summarizes the results of the evaluation, and provides third-party conclusions and recommendations to EPA on potential improvements to the CDOGGR Class II UIC Program. District-level implementation is based on common standards and requirements set at the state level, which are discussed on a statewide basis in Section 2. This is followed by state-level conclusions in Section 3, and district-level discussions of Program implementation in Section 4. Overall recommendations are provided in the last Section of the report (Section 5). The district-level discussion is presented in a question and answer format, followed by conclusions and/or comments on the district responses to the questions and requests for clarification. Questions and district responses were summarized from the EPA Questionnaire and district responses with minimal editing. They are essentially verbatim as written or spoken by district level personnel, either in response to the EPA Questionnaire or during the district office visits. Some individual district discussions and conclusions are duplicative across districts in several areas because districts were asked the same questions and provided similar responses. In summary, there are far more similarities than differences between the districts in their implementation of the UIC Program.

2.0 STATE-LEVEL ANALYSIS

District-level implementation is based on common standards and requirements set at the state level. This section summarizes these standards and requirements based on information gathered from state-level document and guidance review, and from district-level responses to the EPA Questionnaire. It is organized by topic of interest, as outlined in the introduction.

2.1. USDW DEFINITION AND PROTECTION

The frequent response by district staff to the question of what constitutes groundwater that is protectable for drinking water purposes by California regulations is “fresh water” that contains 3,000 milligrams per liter (mg/L) or less total dissolved solids (TDS). The CDOGGR Program Description submitted with the Primacy Application refers to protection of fresh water, and historically that term has been used to describe groundwater that contains 3,000 mg/L or less TDS in California. That is inconsistent with the federal definition of a USDW at 40 CFR §144.3, which defines USDWs as containing less than 10,000 mg/L TDS. In addition, there apparently are no provisions in California statutes or UIC regulations for exemption of an aquifer as an USDW containing between 3,000 and 10,000 mg/L TDS equivalent to the federal UIC regulations for aquifers that are not reasonably expected to supply a public water system. The term commonly applied to identify the depth to which groundwater is protected is the BFW, not the base of USDWs, and fresh water in California is defined as containing 3,000 mg/L or less TDS. Consequently, it would appear that USDWs containing more than 3,000 mg/L TDS are not fully protected under the California UIC regulations.

The MOI for the administration of the CDOGGR program, however, has a provision for the protection of USDWs containing 3,000 to 10,000 mg/L TDS. The provision is in Section 170, beginning on page 370, and it clearly defines USDW as containing fewer than 10,000 mg/L TDS on page 371. Section 170 is dated April 1999. That provision refers primarily to the aquifer exemption requirements, but not to the more stringent protections in well construction and P&A requirements applied to fresh water zones. The description of the aquifer exemption process in Section 170 includes requirements for an aquifer exemption in new injection projects if the proposed aquifer contains less than 10,000 mg/L TDS. Essentially all existing hydrocarbon bearing formations were exempted in the approval of the original 1983 Primacy Application, regardless of TDS concentrations.

In addition, existing nonhydrocarbon bearing formations that were used for oil field wastewater disposal were identified and exempted at that time. There have been very few aquifer exemptions requested and approved since primacy was approved for the CDOGGR UIC Program on March 14, 1983. One exemption was approved in the Asphalto Field and two others are currently pending approval. All are located in District 4. The Asphalto Field exemption was based on the 3,000 to 10,000 mg/L TDS criterion described in the MOI. Another exemption was reported by District 3 near the San Ardo Field, but it is located in an oil producing zone outside of the field boundary.

Based on UIC regulations and responses to the EPA Questionnaire, the actual practices employed for permitting, construction, operations, and P&A of wells provide adequate protection of fresh water from movement of fluids from hydrocarbon bearing and injection zones, but not necessarily for USDWs containing more than 3,000 mg/L TDS. For example, annular cement and cement plugs are required at the BFW, but not at the base of USDWs as defined by EPA. It is unclear whether project approvals by CDOGGR fully address the requirement for protection of USDWs exceeding 3,000 mg/L TDS, since the project approval letter template in the MOI refers to protection of fresh water zones, but not USDWs.

2.2. AREA OF REVIEW/ZONE OF ENDANGERING INFLUENCE

The CDOGGR Program Description in the original Primacy Application for the Class II UIC Program states in Section J that "The Division of Oil and Gas will utilize the one-quarter (¼) - mile fixed radius as set forth in 40 CFR 146.06(b); and if the appropriate data are available, a radial flow equation as shown in Section 40 CFR 146.06(a) may also be used to determine the zone of endangering influence (ZEI)." It also states that "Additionally, to provide the areas of review concept a degree of flexibility, specifically known and documented geological features may limit the need to review all the wells within a quarter-mile radius. This concept will be utilized in conjunction with the fixed radius method."

Responses to the EPA Questionnaire and follow-up interviews with district staff indicated that the quarter-mile fixed radius AOR standard has been the standard applied historically with very few exceptions. The ZEI calculation has rarely been applied to the AOR determination. The quarter-mile fixed radius for determination of the AOR applies to both single water disposal wells and to multi-well projects in enhanced recovery projects.

The MOI states that "(a)s a general rule, disposal into a nonhydrocarbon-producing zone should not be allowed to raise the zone pressure above that of hydrostatic pressure; however, exceptions may be made under certain conditions." The exceptions are: "(1) the depth and areal extent of the zone; (2) the competency of the cap rock; (3) the condition of wells in the area; and (4) the absence of fresh water zones. However, an appropriate monitoring program must be required to ensure that no damage to adjacent properties will occur, either in the subsurface or at the surface." Staff members in most districts indicated that surface shut-in pressures are monitored in wells of concern to ensure that the pressure falls to zero over a reasonable period of time. If the pressure does not fall to zero, the permit to inject into that zone is usually terminated or otherwise limited to avoid fluid movement in defective wells in the quarter-mile AOR.

A review of selected project files indicates that most disposal wells inject into producing zones, either in the field or at the flanks below the oil-water contact. Since the zone pressure is usually reduced well below hydrostatic pressure due to fluid withdrawals, it can be maintained at a pressure below hydrostatic as produced water is injected into the producing reservoir. Disposal of produced water into nonhydrocarbon bearing zones should be carefully monitored for reservoir pressure increases above hydrostatic, and the AOR should be determined by the ZEI calculation to ensure that corrective action requirements are fully addressed in all wells within the expanded AOR. Generally, the ZEI calculation is not necessary in Enhanced Oil Recovery (EOR) projects unless fluid volumes injected exceed the volumes withdrawn and static reservoir pressure exceeds hydrostatic pressure for an extended period of time, which is usually not the case.

Representative samples of Class II UIC projects/wells were reviewed to examine the methodology and results of the AOR/ZEI determination in each district. These examinations and results are discussed in Section 4. Generally, the review of the selected projects/wells and responses to the EPA Questionnaire at the district level indicated that the ZEI calculation has been applied only in a few instances, and most often to project applications received within the past year. The Bernard equation and/or modified Theis equations were applied in those project reviews.

District staff indicated that in most disposal well projects, injection is into abandoned or hydrocarbon producing formations within an existing field. The reservoir pressures in those formations are usually well below the normal hydrostatic pressure of USDWs overlying the injection zone in those areas. That would tend to reduce the ZEI and mitigate the risk of movement of fluids into USDWs as long as the hydrostatic pressure in the USDWs is not exceeded during injection over the active life of the disposal well. To ensure that it does not occur, it would be necessary to monitor the static reservoir pressure on a periodic basis and cease injection into the receiving zone if and when the hydrostatic pressure were exceeded. District staff stated that monitoring of surface shut-in pressures and fall-off testing is performed in wells of concern to ensure that static pressure is zero or less at the surface. If it is greater than zero, the permit to inject into that formation is usually terminated or otherwise limited to avoid potential fluid movement in defective wells within the AOR.

Well construction practices and status of wells located within the AOR were reviewed in each district for consistency with the CDOGGR Program Description, UIC regulations, and adequate protection of USDWs. Post-1978 wells require at least 500 feet of cemented casing above the injection and hydrocarbon bearing zones and a minimum of 100 feet of cemented casing at the BFW. Pre-1978 wells required only 100 feet of annular cement above the injection and hydrocarbon bearing zones. In general, plugged wells with installed casing require 100-foot cement plugs at the top of the injection and hydrocarbon zones and across the BFW, and a 25-foot plug at the surface in addition to adequate volumes of cement in the casing/wellbore annulus to isolate the injection zone from fresh water zones. Plugging requirements in open-hole are similar, but require a minimum 200-foot cement plug across all fresh-salt water interfaces. Plugging and abandonment requirements are described in greater detail below.

The regulations state that, as a general guideline, surface casing shall be set at ten percent of the total well depth or at least to 200 feet and a maximum of 1,500 feet in prospect wells and cemented to surface in all wells. In development wells, surface casing depth is determined on the basis of "known field conditions." The district deputy may vary these general surface casing requirements, including the adoption of field rules, to provide adequate protection for fresh water zones and blowout control. Intermediate casing may be required for protection of hydrocarbon and fresh water zones and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The regulations require that production casing be set to or through the production or injection intervals and cemented with sufficient cement to fill the annular space to at least 500 feet above those zones. Sufficient cement is required to fill the annular space to at least 100 feet above the BFW zones, if not cemented to surface, either lifted or cemented through perforations at or below the BFW. Proper distribution and bonding of cement in the annular spaces must be ensured, which may require a cement bond log, temperature survey, or other survey to determine cement fill behind casing. Tubing and packers are required in all injection wells unless no fresh water is present and/or in some cases where steam is injected for EOR purposes.

Idle, plugged and abandoned, or deeper-zone producing wells located within the area affected by the project (AOR) require a review of construction and/or P&A records to ensure that those wells "will not have an adverse effect on the project or cause damage to life, health, property, or natural resources" (CCR Section 1724,7(a)(4)). Presumably, this includes fresh water aquifers and other USDWs, but that is not stated explicitly in these regulations or in the CDOGGR Program Description.

The review of regulations and practices at the district level indicates that defective wells in the AOR must meet injection zone isolation requirements for project approval, but cement at the BFW or base of USDWs is not required in those wells. Sufficient volumes of cement in the annulus are required at the BFW and above the injection/production zones to protect fresh water zones of injection wells. However, protection of other USDWs requires confinement of the injection/production zones with sufficient cement, but only "heavy" drilling mud in the annulus for isolation of USDWs in unplugged wells. Plugged wells require similar confinement in the annulus in addition to heavy mud inside the casing or open hole between cement plugs. Heavy mud is wellbore fluid with a density capable of preventing fluid flow from any overpressured zone exposed to the wellbore. It must also have properties that will restrict or prevent fluid flow into an underpressured zone. Achieving those dual objectives is not always possible, and the result can be fluid movement in the uncemented casing/wellbore annuli, especially in older wells wherein the mud has likely deteriorated and is no longer capable of preventing fluid movement.

Corrective action requirements were reviewed in selected project files for each district. The older wells in most fields do not always meet well construction requirements, but deficiencies in construction must be addressed in wells within the AOR of a Class II injection well before sustained injection is authorized for a project. Defective wells must be remediated and/or monitored so that fresh water zones are isolated from hydrocarbon bearing and injection zones, and fluid movement into a fresh water aquifer from those zones does not occur. The injection and hydrocarbon bearing zones in an injection well must be isolated from fresh water zones penetrated in the well by cemented casing, as described above. Project approvals for recent applications generally satisfy those requirements, but historical projects do not always meet current standards for corrective action, based on district staff responses and a review of relevant files and documents. In the May 2010 memorandum to the district offices (the Division Expectations Memorandum - available in Appendix A3), the Division provides directives (the Division directives) that require existing injection projects to comply with corrective action standards for wells within the AOR, in addition to new injection projects. The overriding mandate is that "injection fluid must be confined to the permitted zone of injection" whether or not a USDW is present.

2.3. CDOGGR ANNUAL PROJECT REVIEW

Records of well activity, pressures, inactive well and non-compliance data and CDOGGR actions taken to correct non-compliance were reviewed in each district. CDOGGR uses a Project Review Questionnaire in the review process to address project performance and injection data. A copy of the CDOGGR Project Review Questionnaire is provided in Appendix A4 to this report. Injection data include the following information:

- Number of active, shut-in, and idle wells in water disposal projects;
- Injection rates and pressures;
- Produced and injected water analysis;
- Source of injection fluid;
- Anticipated project changes;
- Problem wells;
- Workovers;
- Well testing information;
- Non-compliance issues; and
- Other relevant information about a project.

All existing projects are required to have an annual review, in accordance with the MOI and the recent Division directives stated to the district offices. The adherence to the annual project review standards varies from district to district and is discussed at length in Section 4 of this report. Most projects are reviewed at least on the basis of Project Review Questionnaire responses and other data in the monthly reports submitted by operators. Each well in a project is reviewed for compliance when mechanical integrity tests (MITs) and other inspections are performed. In the largest districts, projects are apparently selected for a comprehensive review based on size and activity. Large and active projects are a priority, while smaller and less active projects are not unless issues arise from reviewing MITs and other well data. Annual meetings with project operators appear to be prioritized on the same basis. Actions taken at the district level to correct non-compliance are discussed in the Section 4 of this report.

Individual well records and data were reviewed by accessing the CDOGGR online database and project/well files in each district office. For example, wells injecting at seemingly excessive pressures were selected for compliance with the MASP for those wells. Idle well shut-in pressures were reviewed for exceeding the zero pressure limitation imposed on most injection wells to avoid exceeding the quarter-mile AOR radius for a well. According to district staff responses, most wells that fit this description are required to cease injection and be disconnected, and it appears from reviewing online pressure and other data that shut-ins for that purpose are fairly common.

2.4. MONITORING PROGRAM

Surveys/reports of MIT were examined for compliance with UIC requirements and consistency with actual MIT results in each district. Radioactive tracer (RAT) surveys are required annually in water disposal wells, every two years in waterflood wells, and every five years in steamflood wells. Standard annulus pressure tests (SAPTs) are required in all Class II injection wells every five years. A review of well records indicates that schedule is followed with a few exceptions for variances approved by the Division.

The SAPT procedure requires testing the casing/tubing annulus at a minimum of 200 pounds per square inch (psi), with less than a ten percent decrease in pressure within 15 minutes for a well to pass the MIT. Tubingless completions require running a packer in the well to test the casing or an Ada test as an alternative to the SAPT.

CDOGGR inspectors witness a large percentage of the SAPTs, but only a few of the RAT surveys. The percentages vary widely from district to district depending largely on the number of wells to test and the availability of inspectors to witness a test. MITs that are not witnessed require that the operator submit documentation of the MITs in the form of a written report and a copy of the RAT survey log. Copies of the MIT reports and surveys are retained in a project or well file and the results are entered into the district database to track MIT results and due dates for running them.

A recent Division initiative modifies the SAPT procedure to require testing at the approved MASP for a well where there is only a single string of cemented casing across a USDW (10,000 mg/L TDS). Comments received by the districts indicate that this standard is undergoing further review at the Division level and may be modified to allow for consideration of the age and condition of a well casing.

The databases used in each district office vary, but districts are in the process of switching to the California Well Information Management System (CalWIMS) database statewide. CalWIMS is apparently more user-friendly and more up-to-date in its applications than certain existing systems at the district level. District 4 has converted to the CalWIMS system, and it appears to be superior to the other databases in use at the other district offices. Well records and data are also available to view through the CDOGGR online database, although not all districts have completed scanning and entering their records into the online system. Most well data reported by operators on a monthly basis are available for online viewing by the public, including monthly injection pressures and volumes. Electric and other well logs in some districts are accessible online as well. Eventually, most logs, well records, and other related data will be accessible through the CDOGGR website on a statewide basis.

Procedures for establishing MASPs and monitoring for compliance were reviewed in each district. Historically, MASPs were based largely on assumptions or estimates of the formation fracture gradient for the injection formation. Fracture gradients applied in the MASP determination vary from 0.6 to 1.0 psi/foot. In a few wells, the fracture gradients were based on results of step-rate testing or calculations of the formation parting pressure from other data. Most were based on assumptions and estimates derived from formation lithology, depth, and petrophysical properties. CDOGGR Publication M13 titled *Evaluation and Surveillance of Water Injection Projects*, contains average breakdown gradient data for oil fields located in the major basins in Central and Southern California (Table 4, page 12), and has reportedly been the primary source for estimates of fracture gradients by CDOGGR district offices. It should be noted that the fracture gradient is somewhat less than the breakdown gradient. The MASP is typically set at five to ten percent less than the estimated or calculated fracture pressure.

Injection well pressure and volume data were reviewed through the online CDOGGR database for the largest and oldest active fields for compliance with MASPs and limitation on static surface pressures. The highest pressures in the largest fields were flagged for further review to verify whether those pressures exceeded the MASP. Well pressures that exceed the MASP must be curtailed by reducing the injection rate or other means. Wells for which shut-in pressures fail to fall to zero over a reasonable period of time are usually required to cease injection, and the permit to inject in the existing injection zone is rescinded to avoid exceeding hydrostatic pressure in the well.

Examples of Step-Rate Tests (SRTs) conducted in each district were obtained and reviewed to assess the tests' methods and validity and the resulting MASPs assigned to the tested wells. A review of the SRT reports for those wells indicated that the methodology and validity of the tests were overall in accordance with generally accepted industry standards. Most SRTs in California are based on surface pressures corrected for friction losses in downhole tubulars. The preferred approach is to also use bottom-hole gauges to measure downhole injection pressures directly, without corrections for friction losses, because measured bottom-hole pressures yield a more accurate measure of the formation fracture gradient. Several samples SRT reports are provided in Appendix B4.

The Division Expectations Memorandum takes initial steps to ensure the accuracy of fracture gradients and MASP determinations in all districts. In accordance with that memorandum and UIC regulations at §1724.10(i), new and existing projects will require approved SRTs to determine the fracture gradient in injection wells and will require that injection pressure be maintained below fracture pressure as determined by the approved SRTs.

2.5. INSPECTIONS AND COMPLIANCE/ENFORCEMENT PRACTICES AND TOOLS

Injection wells are required to be inspected annually in accordance with MOI guidelines. Wellhead and injection line conditions, and compliance with injection pressure and rate limitations are the most important elements of the annual inspection. Injection pressures are compared with the MASP for a well to ensure that neither the MASP nor 90 percent of the fracture gradient are exceeded. If exceeded, the well is considered in violation of the project approval letter and the operator is required to reduce the pressure immediately. If USDWs are endangered, the well is considered to be in Significant Non-Compliance (SNC). An enforcement action may ensue at the district level if the operator fails to comply with the order to maintain the pressure below the MASP and/or correct other deficiencies. A listing of deficiencies is prepared and sent to the operator for correction within the time allowed, as verified by a reinspection of the well. A legal notice with the uncorrected deficiencies listed as violations is sent to the operator if the deficiencies are not corrected when the well is reinspected. Additional legal action may be taken to correct violations. When corrected, a compliance letter is sent to the operator (MOI Section 170.13.5).

A MIT is described as either an RAT, temperature, or spinner survey. The initial MIT is usually witnessed, but subsequent MITs may be witnessed depending on the availability of an inspector and the priority for witnessing the MIT. Water disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years. An SAPT is required for all water disposal wells and waterflood wells every five years. Most SAPTs are witnessed by district personnel. Witnessing MITs on disposal wells is emphasized. When a MIT is not witnessed, the results of the test must be reviewed in the office. Inspections are also carried out in cases of non-compliance and in response to citizen complaints. Plugging and abandonment operations are witnessed for plug depth and hardness, squeeze cementing operations, and surface plug location, but witnessing cement placement in a well is not a requirement. An SRT for the determination of the formation fracture gradient and pressure is usually witnessed, but it is rarely required by the Division. Most MASP limits are apparently set on the basis of fracture pressures estimated from statistical data on fracture gradients in the oil producing basins of California.

Compliance assurance and enforcement tools utilized by CDOGGR districts include the following:

- Well shut-ins;
- Notice of deficiency;
- Notice of violations;
- Rescission of approval to inject;
- Project suspension; and
- Civil orders and penalties.

According to Section 137 of the MOI, a deficiency means a "failure to meet Division requirements, brought about through unintentional, inadvertent, or negligent actions;" and a violation means a "purposeful, negligent, or fraudulent action contrary to the laws or regulations of the Division and for which a formal order, civil penalty, notice of violation, or a formal letter has been issued." Civil order procedures are described in Section 136 of the MOI. They can be issued to repair or plug and abandon wells, and to "undertake such action as is necessary to protect life, health, property, or natural resources." Generally, an order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. If an emergency exists, district deputies can obtain authorization from Division headquarters to repair or plug wells, or to eliminate hazardous conditions without issuing a formal order or seeking bids. Civil penalty procedures are described at Section 137 of the MOI and are limited to $25,000 per violation.

The implementation of compliance assurance and enforcement policies, practices, and tools are discussed in greater detail in Section 4 of the report.

2.6. IDLE WELL PLANNING AND TESTING PROGRAM

The stated objective of the idle well program is to eliminate idle wells by requiring operators to return idle wells to production/injection, or to plug and abandon their idle wells. The description of the program is found in Section 138 of the MOI. The definition of an idle well is "any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last five or more years. A long-term idle well is defined as "any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last ten or more years." This does not include active observation wells.

The requirements for idle-well testing are described in CCR Section 1723.9 and are paraphrased as follows. Idle wells must have the fluid level determined as prescribed in the Idle Well Planning and Testing Program. Acceptable methods are "acoustical, mechanical, or other reliable methods, or other diagnostic tests as approved by the Supervisor." The tests are required to verify fresh water is protected and that reservoir damage is not occurring. If the fluid level of a well is above the BFW, a casing pressure test should be run. If the casing lacks mechanical integrity (MI), the operator should be ordered to perform remedial work. If an injection well is idle for two or more years, the approval for injection should be rescinded (MOI Section 170.7.2).

Idle injection wells are not subject to the normal MIT schedule, but are subject to the idle-well testing guidelines. In areas with fresh water, a two-year test cycle applies. Possible alternatives to the initial fluid level survey include a casing-inspection log, a static temperature survey, and a bridge plug above the injection zone. A pressure test is required when a bridge plug is used. If it is questionable whether the annular cement lift of a well is above the BFW, a static temperature survey should be run since a casing-pressure test would not detect fluid movement behind pipe and a bridge plug would not prevent such fluid movement.

Testing procedures for wells in areas with no fresh water are identical to those in fresh water areas except the testing cycle is five years instead of two years and references to the BFW are excluded. Fresh water is defined as containing 3,000 mg/L or less TDS in the MOI.

Operators have the following five options for compliance with the idle-well planning and testing requirements for unbonded idle wells:

- Pay a fee based on the length of time the well has been idle ($100 for five years, $250 for ten years, and $500 for 15 or more years idle);
- Fund a $5,000 escrow account per idle well;
- File a $5,000 bond per idle well;
- File an Idle-Well Management Plan that eliminates a specified number of long-term idle wells annually; or
- Obtain a $1 million blanket bond.

Plans for future use of idle wells are required for wells idle for ten years or longer. An approved Idle Well Management Plan satisfies this requirement. Otherwise, the plan for future use must describe what is planned for the well and when it will be done. If a well is incapable of use in its present condition, it must be prepared for the planned future use by remedial operations that make it capable for the future use. The Division requires a detailed, specific, written engineering evaluation for wells that are idle for 15 years and longer. The evaluation must outline the well condition, recompletion potential in other zones, and how the well integrates into the overall production plan for the project. The evaluation must also include a specific plan and timetable for abandonment or for returning the well to active status.

The idle well testing guidelines for District 4 vary significantly from the other districts and are described in detail in Section 138.3 of the MOI. Modifications to the Division level guidelines are apparently due to the large number of idle wells (over 13,000) in District 4 and the ages of many of those wells. The emphasis of the District 4 Idle Well Program is testing ten-year and 15-year idle wells for MI. However, all five-year idle wells must be tested with a fluid level survey. Another test is not required until the well has been idle for ten years unless the well is located in a sensitive area, or there is evidence of damage that could threaten groundwater or the environment.

District 4 wells that are idle for longer than ten years in areas where fresh water is present must be tested every two years. If located in a non-fresh water area, ten and 15-year idle wells must be tested every five years. "All repairs or abandonment of 15-year idle wells must be performed within one year of the original test due date unless a Division approved work schedule is in place." If located in fresh water areas, "(t)he Division may require a period shorter than one year if evidence indicates formation damage or contamination is occurring."

2.7. FINANCIAL RESPONSIBILITY REQUIREMENTS

Financial responsibility requirements are applied on a statewide basis. The districts are fairly consistent in their responses regarding financial responsibility requirements for operators, as noted in Section 4 of the report. This discussion of Division-level requirements is based primarily on a review of the CDOGGR Program Description, UIC regulations, and the MOI.

An operator may demonstrate financial responsibility by filing either an individual indemnity or cash bond for each well drilled, or a blanket bond covering all well operations. Individual bonds are normally released after a noncommercial injection well has injected fluids for a six-month continuous period if the Division is satisfied that the well is mechanically sound. Blanket bonds are not normally released until all the operator's wells are abandoned or until the operator specifically requests the release of a well from bond coverage. However, this release can only occur after the well is demonstrated to be mechanically sound following six months of continuous injection.

After the release of a bond, the Division still has the authority to order an operator to perform remedial or corrective work on a well. If the operator fails to perform the required work, the Division can enter the property and perform the necessary work. The expenditures constitute a lien against the owner or operator's real or personal property. The Division may also order the abandonment of any well that has been deserted whether or not any damage is occurring or threatening to occur.

Individual bond amounts were increased in 1999 by California Senate Bill (SB) 1763 and are as follows:

- $15,000 for wells up to 5,000 feet deep;
- $20,000 for wells greater than 5,000 feet but less than 10,000 feet deep; and
- $30,000 for wells 10,000 feet deep or greater.

The individual bond amount for a Class II commercial disposal well is $50,000 per well if not covered by a blanket bond. The bond must be retained until the well is plugged and abandoned to the satisfaction of the Division.

Blanket bond amounts were also changed by SB 1763 in 1999 as follows:

- If an operator has 50 or fewer total onshore wells, the blanket bond amount is $100,000;
- If an operator has more than 50 total onshore wells, the blanket bond amount is $250,000;
- The above two blanket bond amounts do not provide idle-well coverage, which is $5,000 per well if the operator has no approved Idle Well Management Plan or escrow account, and opts not to pay the idle-well fees described under Section 2.6 of this report; and
- A $1 million blanket bond can be filed to cover all onshore operations, including idle wells.

The bonding requirements are fully described in Section 120 of the MOI.

The CDOGGR Program Description states that "(a) special well abandonment allotment is also available in California for the purpose of abandoning deserted wells when the last known operator is deceased, defunct, or no longer in business in California and the present surface and mineral estate owners did not receive a substantial financial gain from the wells." The abandonment requirements and process for deserted wells are described in Section 180.8 of the MOI.

2.8. PLUGGING AND ABANDONMENT REQUIREMENTS

Procedures for P&A are standardized at the state level and described in detail in the MOI Section 180 and CCR Section 1723, with special requirements at the field level as described in field rules issued for those special circumstances (see the *Bentonite Plugging Guidelines* discussed below for an example of the field rules that apply in the Bakersfield and Coalinga Districts). In general, cement plugs are placed across specified intervals to protect oil and gas zones, to prevent degradation of useable waters, to protect surface conditions, and for public health and safety purposes. Cement may be mixed with or replaced by other substances with adequate physical properties, subject to approval by the supervisor and application to particular wells at the discretion of the district deputy.

Plugging an open hole requires a cement plug from at least 100 feet below the bottom to at least 100 feet above the top of each oil or gas zone. A minimum 200-foot cement plug must be placed across all fresh-saltwater interfaces or within a thick shale if the shale separates the fresh water sands from the brackish or saltwater sands. Special requirements may be applied for fractured shale or schist, massive sand intervals, depleted productive intervals, and multiple hydrocarbon zones completed in a well. These special requirements include a cement plug extending from at least 100 feet below the top of hydrocarbon zones to at least 100 feet above the top those zones.

Plugging in cased hole requires that all perforations be plugged with cement, and that the plug extend at least 100 feet above the top of the uppermost perforations, a landed liner, the casing cementing point, the water shut-off holes, or the hydrocarbon zone, whichever is highest. If there is cement behind the casing across the fresh-saltwater interface, a 100-foot cement plug must be placed inside the casing across the interface. If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the fresh water aquifers. A special requirement may be applied for hydrocarbon zones in fractured shale or schist, massive sand intervals, depleted productive intervals, and multiple hydrocarbon zones completed in a well. That includes placing a cement plug extending from at least 25 feet below the top of the uppermost perforated interval to at least 100 feet above the top of the perforations, the top of the landed liner, the casing cementing point, the water shut off holes, or the zone, whichever is highest.

Other special plugging procedures may be specified to prevent contamination of useable waters where geologic or groundwater conditions dictate variations from the standard plugging procedures. Those include prevention of downward percolation of poor quality surface waters, separating water zones of varying quality, and isolating dry sands that are in hydraulic continuity with groundwater aquifers.

Surface plugs require at least a 25-foot cement plug placed in the casing and the annuli of all casing strings at the surface. The district deputy may require that inner strings of uncemented casing be removed to at least the base of the surface plug prior to placement of the plug. All casing must be cut off at least five feet but no more than ten feet below the surface of the ground, and a steel plate must be welded at the top of the casing showing the identification of the well, indicated by the last five digits of the American Petroleum Institute (API) well number.

The regulations specify that some P&A operations may require witnessing by a Division employee, at the discretion of the district deputy, and that some operations require witnessing. Witnessing the placement of cement plugs is optional. Operations that require witnessing include the location and hardness of cement plugs, cementing through perforations, and environmental inspection after completion of plugging operations. The operator is required to submit a detailed P&A report to the district within 60 days of the completion of P&A operations. The P&A report is reviewed by district staff for compliance with the approved P&A plan/procedures.

Each district has special abandonment requirements, resulting from unique geology and/or operational practices in certain fields. Field rules or field practice guidelines are issued for those special requirements that vary from the regulations and general P&A requirements described in the regulations and MOI. For example, Field Rules in the Bakersfield and Coalinga Districts, allow the use of sodium bentonite in well plugging operations with certain conditions and restrictions (see *Bentonite Plugging Guidelines* in Exhibit 180.3.4 of the MOI dated November 15, 2004). The basis for those rules and the use of compressed bentonite rather than cement for P&A operation are not explained in the Guidelines. Use of bentonite plugs is contrary to the federal UIC regulations at 40 CFR 146.10(a) regarding the requirement for the use of cement in plugging Class II injection wells. District 4 was contacted for clarification on that issue, but a complete response had not been received as of June 20, 2011.

The state regulations at Section 1723.8 and the Program Description at Section G state, however, that the Division may set forth other P&A requirements or may establish field rules for the P&A

of wells. The CDOGGR Program Description states: "(w)hen sufficient geologic and engineering information is available from previous drilling or operating history, P&A requirements and operating conditions that differ from those prescribed by regulation can be established as field rules for any oil or gas pool or zone in the field."

2.9. UIC STAFF QUALIFICATIONS

The district offices provided organization charts and position descriptions for district level staff positions, which are provided in Section 4. A general organization chart for CDOGGR is also provided in Appendix B to this report. Qualification requirements are described in detail for each position. Based on a review of staff qualifications and responses to the EPA Questionnaire and questions raised during the on-site visits, most district personnel appear to possess the necessary qualifications for the positions they hold. The general assessment of staff qualifications was based primarily on discussions with district management.

Additional UIC-specific training for the less experienced staff members would be beneficial to the entire UIC program. Some have not attended the EPA-sponsored UIC Inspector Training Course offered annually by nine EPA regional offices on a rotational basis across EPA Regions. Attendance by new hires and the less experienced staff members in that course should enhance staff qualifications and be highly beneficial to the district level UIC program. The individual district responses are summarized in Section 4.

The CDOGGR UIC Program appears to lack sufficient manpower and other resources to implement the Program at a satisfactory level, especially in the largest districts. The Division directives issued in the Division Expectations Memorandum will increase the workload substantially in the district offices. The districts will need to hire a significant number of qualified personnel to manage the added workload. The review of new project applications and other important UIC functions are being delayed or sometimes omitted in some districts as a result of the deficiency in the number of qualified personnel in those districts. These issues are discussed at greater length in Section 4.

3.0 STATE-LEVEL CONCLUSIONS

This section provides state-level conclusions for each topic of interest. It follows the same structure as Section 2, and is organized following the topics of interest identified in the introduction.

3.1. USDW DEFINITION AND PROTECTION

The MOI refers to the EPA definition of a USDW, but it is unclear whether USDWs containing less than 10,000 mg/L and more than 3,000 mg/L TDS are fully protected in all Class II injection projects. The BFW is the term most often used to define protectable groundwater in the UIC regulations and the MOI, and fresh water is defined as containing 3,000 mg/L or less TDS. Provisions for exemption of aquifers refer to the EPA definition for USDWs, and essentially all producing formations and several nonhydrocarbon bearing formations that were used for produced water disposal in existing fields were exempted in the Primacy Application approval in 1983. That approval, however, does not apply to USDWs that were not listed in the Primacy Application at the time. Since then, only two exemptions have been approved and two others are pending.

Permitting, well construction, and plugging requirements are written to protect fresh water zones, but are less protective of USDWs containing more than 3,000 mg/L TDS. The regulations require that the injection zone be isolated and that injection fluids be confined to the injection zone, which is protective of USDWs and fresh water zones as long as the injection fluid is confined to the permitted injection zone. Without cement at their base, however, USDWs are not fully protected from possible fluid movement in the uncemented portion of the annulus and from eventual failure of the casing and cement above the injection zone in a well. Cement is required at the BFW but not at the base of USDWs in well construction and plugging requirements, which is less protective of USDWs containing more than 3,000 m/L TDS than of fresh water zones. That leaves those USDWs exposed to fluid movement due to improperly plugged wells and/or lack of cement in the casing/wellbore annulus, notwithstanding the presence of drilling mud that may restrict fluid flow in an uncemented annulus.

CDOGGR should address the lack of clarity regarding USDW protection and ensure that all USDWs are fully protected from fluid movement and resulting degradation. USDWs containing more than 3,000 mg/L TDS should be protected as much as fresh water aquifers are protected in the permitting, construction, operation, and abandonment of injection wells.

3.2. AREA OF REVIEW/ZONE OF ENDANGERING INFLUENCE

This section provides state-level conclusions on the determination of AOR/ZEI, on well construction practices, on the status of wells located in the AOR, and on corrective action requirements.

AOR/ZEI Determinations

CDOGGR has historically applied the quarter-mile fixed radius rather than the ZEI option for determination of the AOR for individual wells and for each injection well in a project area, with very few exceptions. Recently, CDOGGR management initiated a requirement that the ZEI be calculated for existing injection projects and all new Class II injection well project applications. Heretofore, the ZEI calculation was an option "if appropriate data are available," as stated in the Primacy Application. That new requirement should result in a substantial improvement in the protection of USDWs when fully implemented at the district level. It will require a significant increase in the number of qualified staff members in the district offices, and Mr. Walker was informed that staff increases have been authorized at the State level.

The use of the quarter-mile fixed radius AOR may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project and pressure buildup in the reservoir is not likely beyond the AOR and the boundaries of the project. Use of the quarter-mile fixed radius AOR for disposal well projects may be inappropriate where injection into a nonhydrocarbon bearing formation is permitted and/or where groundwater is pumped and hydrostatic pressure is reduced in an aquifer located above the injection zone. In most disposal well projects, however, injection is permitted for Class II fluids into a hydrocarbon bearing formation in which the reservoir pressure has been reduced to a level substantially below the normal hydrostatic pressure. The quarter-mile fixed radius AOR is appropriate for those projects as long as the reservoir pressure is not allowed to exceed the normal hydrostatic pressure during the life of the disposal wells and the hydrostatic pressures of USDWs are not subnormal within the AOR.

The MOI states that disposal into a nonhydrocarbon producing zone should not be allowed to raise the zone pressure above that of hydrostatic pressure except under certain conditions listed in the MOI, including the absence of fresh water zones. In any event, the ZEI should be calculated, especially for disposal wells, with an accurate representation or reasonable estimate of all the relevant parameters that determine the ZEI, including the static pressures of the injection zone and USDWs in the project area. Generally, the ZEI calculation is not necessary in EOR projects. Disposal into nonhydrocarbon producing zones should be carefully monitored for reservoir pressure increases that could cause the ZEI to increase beyond the AOR over time. Also, a fall-off pressure test to determine the static reservoir pressure would be a useful tool to evaluate reservoir pressure behavior of wells in which shut-in pressures do not fall to zero.

Well Construction Practices and Status of Wells Located within the AOR

Current well construction regulations and practices are adequately protective of fresh water aquifers for the most part. That was not necessarily the case for wells drilled before 1978 when annular cementing requirements provided for only a minimum of 100 feet of annular cement above the injection and hydrocarbon bearing zones. Protection of other USDWs is not as rigorous as the well construction and plugging practices for fresh water zones in injection wells. Cement is not required at the base of USDWs in the casing/wellbore annulus or as a plug inside the casing at abandonment of a well within the AOR of an injection well. Cement placement at the BFW appears to be required in AOR wells when those wells are plugged and abandoned, but not for injection project approval. It can be argued that heavy mud, especially in older wells, is not an effective deterrent to fluid movement into or between USDWs in the uncemented portion of a casing/wellbore annulus. USDWs are therefore not fully protected by the construction and abandonment requirements for wells within the AOR.

The status of wells located within the AOR is reviewed by district staff, and deficiencies in the construction and plugging of those wells are identified in the project application review process. The applicant is required to remediate deficiencies that may threaten fresh water zones as a condition of project approval. This requirement for new projects also applies to existing projects and wells, as described in the Division Expectations Memorandum (Appendix A3). However, the review process should require more consideration for protection of other USDWs, and require cement placement at the base of USDWs in injection wells and AOR wells when they are plugged and abandoned, if not as a condition for injection project approvals.

Corrective Action Requirements

Project approvals for recent applications generally satisfy current CDOGGR requirements for corrective action, but historical projects do not always meet those standards. The historical and current requirements fail to adequately address the protection of all USDWs because the cementing standards are less protective of USDWs containing more than 3,000 mg/L TDS. The recent CDOGGR initiative to review the AORs of existing projects and require corrective action in wells that fail to meet current standards will require additional staff and training to perform these reviews on a timely basis. The hiring of a substantial number of qualified personnel has been authorized to attain that goal. Consideration should also be given to modification of the standards to provide adequate protection of all USDWs. A discussion of corrective action requirements implemented at the district level is provided for each district in Section 4.

3.3. CDOGGR ANNUAL PROJECT REVIEW

This section provides state-level conclusions on the records of well activity, pressures, inactive well and non-compliance data. The MOI and the Division Expectations Memorandum state that injection projects must be reviewed with the operator at least once a year. That requirement is consistent with the CDOGGR Program Description of Project Review requirements. Project Review Questionnaires (Appendix A4) are sent to operators yearly for the required information on each project, but it is unclear whether that is done in all districts and whether adequate responses are provided by the operators for all projects.

Comprehensive project reviews should be conducted annually for all active injection well projects. Based on district responses, that may not be the case in the largest districts, due to the large number of injection wells and lack of personnel in those districts. That situation should improve with the hiring and training of several additional UIC personnel reportedly authorized by the Division. In addition, the requirement for monthly reports from the operators, MITs, periodic inspections, and other sources of project information provides data on wells that support the objectives of the annual project reviews. Annual project reviews and related actions at the district level are discussed for each district in Section 4.

3.4. MONITORING PROGRAM

This section provides state-level conclusions on the MITs and MASPs, based on responses to the district-level EPA Questionnaires, and interviews with district staff.

Mechanical Integrity Tests

Based on a review of district files and interviews with staff members, MITs are performed as scheduled and described in the CDOGGR Program Description and MOI with very few exceptions. RAT surveys are performed annually in disposal wells and every two years in waterflood wells, which is more frequent than federal UIC regulations require. RAT surveys are quite effective in demonstrating that injected fluids are confined to the injection zone or in identifying non-confinement of injected fluids. SAPTs are performed on a five-year cycle and whenever major workover operations are performed in injection wells, or at the discretion of the deputy director in each district, which is consistent with federal UIC regulations. The requirement for pressure testing wells to at least 200 psi for 15 minutes in the approved SAPT procedure is inconsistent with the standards applied to Class II injection wells in many of the other state and federal UIC programs. Those programs require testing to the maximum allowable surface injection pressure or at a minimum pressure higher than 200 psi, for more than 15 minutes in some cases.

A more conservative approach is to test the casing/tubing annulus to the maximum allowable surface injection pressure if that will not expose the casing to a pressure that could cause a rupture, which can be a significant risk in older wells. However, the newer wells should be able to withstand the MASP, and they could be exposed to that pressure whenever a tubing leak or packer failure occurs. The Division recently modified the SAPT procedure to require testing at the approved MASP for a well in which there is only a single string of cemented casing across a USDW, which is a substantial improvement to the procedure. Some of the district staff indicated, however, that this standard may be further modified at the Division level to allow for the consideration of well age and condition.

Examination of MIT reports in district files indicates that they are generally consistent with historic UIC requirements as described above. Few of the RAT surveys are witnessed in the largest districts, but most SAPTs are witnessed in all districts. The CDOGGR Program Description states that, if circumstances warrant, CDOGGR will witness surveys that are conducted annually, which would seem to indicate that more than just a few should be witnessed. The specifics of those statistics are discussed in Section 4. With the Division authorization to add UIC staff in the district offices, those statistics should improve over time.

Maximum Allowable Surface Injection Pressures

Maximum allowable surface injection pressures must be less than the fracture pressure of the injection zone, as prescribed by the UIC regulations at 1724.10(i). The regulations require an SRT to determine the fracture pressure, but allow the district deputy to waive or modify that requirement if he or she determines that the surface injection pressure for a particular well will be maintained considerably below the estimated fracture pressure. Historically, fracture pressures and MASPs were based mostly on estimates of the formation fracture gradient of the injection zone. These estimates were apparently based on empirical relationships between fracture gradient and lithology, depth, and petrophysical properties of the injection zone. Estimates of fracture pressures based on generalized relationships between fracture pressure and depth to the formation or other means are not always a reliable method for that determination. An SRT provides a more reliable and accurate measure of formation fracture pressures in the injection zone.

Division management recently issued a directive to require that the injection pressure be maintained below fracture pressure in all new and existing projects, as determined by approved SRTs, and SRTs must be run in new wells to determine the fracture pressure of the injection zone. Implementation of that directive should improve the accuracy of the fracture pressure determination and reduce the potential for fracturing the injection and confining zones. We support that directive to the fullest extent. We also support the Division directive for a wellhead inspection at least once every two years to ensure that the injection pressure is below the MASP and for the requirement to immediately reduce the injection pressure if it exceeds the MASP. However, the MOI states that injection well inspections should be conducted annually, and we support that standard, but it may not be possible in the largest districts without additional inspectors in the field. In addition, we endorse the requirement that a database or records must be maintained that lists the MASP for all injection wells and is easily accessible to field personnel to verify that the MASP is not being exceeded.

A review of selected SRT reports in each district indicated that the methodology and validity of the tests were overall in accordance with generally accepted industry standards, although most were based on surface pressure rather than bottom-hole pressure measurements. The estimation of friction losses would be avoided and the accuracy of the test results would therefore increase if the test analyses were based on bottom hole in addition to surface pressure measurements.

It is our view that the fracture pressure of the injection zone should be determined on the basis of an SRT unless SRTs have been performed on a sufficient number of wells in the area to ascertain the fracture gradient within acceptable confidence limits. Also, the SRT should include a pressure gauge to measure bottom-hole pressures directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates.

3.5. INSPECTIONS AND COMPLIANCE/ENFORCEMENT PRACTICES AND TOOLS

Inspections are not necessarily prioritized for wells where fresh water is present, and residential areas are not a consideration for the many wells that are located in rural areas, which is the case in most districts. In our view, those areas should receive a higher priority for inspections than is apparently the case in some districts. Injection wells in areas with fresh water receive more scrutiny for project approvals, permits, testing, monitoring, and compliance assurance. Disposal wells are given a higher priority for MIT witnessing and monitoring than are enhanced recovery wells. For example, RAT surveys are required annually for disposal wells versus two years for waterflood wells and five years for steamflood wells. SAPTs are required once every five years and whenever a packer is re-seated in a well after a workover operation. Most SAPTs are witnessed, while most RAT surveys are not witnessed in the largest districts.

Annual inspections are required for all injection wells, according to the MOI, but not all wells are inspected annually in all districts. The Division Expectations Memorandum states that inspections at least every two years are acceptable. Most P&A operations are witnessed to confirm the location and hardness of cement plugs and most cement squeeze operations are witnessed, according to district responses to the EPA Questionnaire and follow-up comments. Witnessing cement placement is not required, however, and that is one of our concerns. We believe it is important to witness cement placement operations to ensure the correct volumes and quality of cement are pumped into a well.

In general, inspections and monitoring are conducted in accordance with the general outline in the CDOGGR Program Description, but are not in rigid adherence to the CDOGGR UIC regulations and MOI guidelines in all districts. The Division Expectations Memorandum requires inspections of all injection wells at least every two years and annual project reviews, which is consistent with the CDOGGR Program Description. Historically, those standards have not always been met in most districts. The hiring of additional staff members that was recently authorized by the Division should alleviate the lack of personnel to meet those standards.

The enforcement procedures available to the districts are highlighted above and are described in detail in the CDOGGR laws and regulations that apply to the UIC Program and in the MOI guidelines. Notices of Violation (NOV), rescind letters, project suspension, civil orders, and penalties can be issued if the informal actions do not result in compliance. Violation of a formal enforcement action is a SNC. Most of the civil penalties (13) issued in the past ten years were initiated by District 4 with fines ranging from $250 to $25,000 for each violation. Most of those actions were related to unauthorized injection violations. The Civil Penalty Amount Guidelines are listed for various types of violations in Exhibit 136.1.1 Part 5 of the MOI and were apparently updated in January 2009 from a maximum of $5,000 to $25,000 per violation.

In general, the CDOGGR enforcement program appears to be conducted in accordance with the general outline in the CDOGGR Program Description and the recent review and update of procedures and penalty amounts listed in the MOI. Most districts indicated that they do not have enough resources and personnel to initiate adequate numbers of compliance/enforcement actions. That is also our assessment from our review of the district level inspection activity and formal enforcement actions. The hiring of additional staff members that was recently authorized by the Division should alleviate the lack of personnel to initiate and carry out UIC compliance/ enforcement actions when violations occur.

3.6. IDLE WELL PLANNING AND TESTING PROGRAM

This monitoring and testing program for idle wells is comprehensive, but remedial work or plugging is not required for wells that lack MI unless there is evidence of a threat to fresh water zones while in idle status. Also, idle wells with apparent casing integrity (pass a fluid level survey) are not required to be reactivated or plugged and abandoned before 15 years in that status and many wells have been idle for much longer than 15 years. Less than five percent of long-term idle wells are typically plugged and abandoned on a yearly basis, resulting in long-term temporary abandonment of most idle wells. The option for an operator to submit an Idle Well

Management Plan provides some assurance that idle wells will be reactivated or plugged and abandoned on a specific timetable after ten years in idle status. However, it is optional and the other options provide insufficient assurance that the operator will comply with the requirement to reactivate or P&A a long-term idle well. In our opinion, the idle well fee amounts imposed on operators are too small to incentivize operators to reactivate or plug their idle wells, and idle well bond or escrow amounts are insufficient to cover P&A costs.

Monitoring the fluid levels in idle wells every two years in fresh water areas is not consistent with adequate protection of other USDWs penetrated by an idle well. A pressure test is required if the fluid level rises above the BFW, but not if it rises above the base of USDWs. In non-fresh water areas, testing requirements are on a five-year cycle and are otherwise less rigorous, but if USDWs containing more than 3,000 mg/L TDS are present, those USDWs are not protected as well as they would be in a fresh water area.

A pressure test would be more definitive of a casing or bridge plug leak and potential for fluid movement into USDWs as fluid levels rise in a well, especially where USDW heads are drawn down by pumping for drinking water, agricultural, and/or other uses. Mechanical integrity should be maintained while a well is in idle status, as it is in active status, unless the permittee can satisfactorily demonstrate that fluid movement will not occur into or between USDWs. We believe that consideration should be given to modifying the Program to strengthen the protection of USDWs.

Field rules for District 4 allow somewhat less rigorous monitoring and testing of idle wells. That may be due to the large number of idle wells in a rural area and limited resources to monitor and test the wells on the same schedule that other districts require. We urge that consideration be given to strengthening the idle well requirements in District 4 to make them more consistent with the statewide program and more protective of USDWs, as the additional personnel authorized by the Division are hired in the district.

3.7. FINANCIAL RESPONSIBILITY REQUIREMENTS

Individual non-commercial well bonds and non-commercial injection wells under blanket bonds are normally released after a well has injected fluids for a six-month continuous period and the well is demonstrated to be mechanically sound. That is inconsistent with federal UIC regulations which require a well to be properly plugged and abandoned before the bond, letter of credit, or trust funds are released. State funds are available, however, to plug wells that are improperly plugged or eventually deserted by the operator in the absence of a bond. Operators are required to fund the state account through fees paid into the account. There are no similar funds available to EPA for plugging deserted Class II injection wells. EPA must rely on surety bonds and other financial assurance instruments provided by the operator to plug improperly abandoned and deserted Class II injection wells. The disadvantage to the CDOGGR process is that only a small percentage of deserted wells are plugged in a given year, leaving wells with MIT problems unplugged for an extended period wherein USDWs could be at risk of degradation.

Bonds for commercial Class II disposal wells are not released until the well is properly plugged and abandoned by the operator. The current bond amount of $50,000 per well may not be adequate to cover the full cost to P&A some commercial wells, however. Basing the bond amount on third-party estimates of P&A costs for individual wells and periodic review and adjustment of those amounts would increase the probability that adequate funds will be available to P&A a deserted well.

The individual well bond amounts were increased in 1999, but the amounts have apparently not been updated since then and are probably not adequate to cover the full cost to plug and abandon a well when that becomes necessary.

3.8. PLUGGING AND ABANDONMENT REQUIREMENTS

Procedures for P&A are described in detail in the CDOGGR regulations and MOI. They are intended to isolate fresh water zones from the injection zone and hydrocarbon bearing formations, poor quality surface waters, and water zones of varying quality. Those objectives are generally met in wells plugged in recent decades. They are not always met in older wells due to plugging practices that were not as rigorous or protective of fresh water aquifers and other USDWs. However, deficient wells located within the AOR must be re-plugged or otherwise eliminated as a pathway for fluid movement, as a condition of approval of an injection well project.

In addition, USDWs containing more than 3,000 mg/L TDS are not protected to the extent that fresh water aquifers are protected from inflow of lesser quality waters. Placement of cement plugs is required at the BFW, but not at the base of other USDWs unless those depths happen to be coincident in a well. Protection from fluid movement into and between USDWs below the BFW depends partially on the presence of heavy mud in the casing/wellbore annulus and between cement plugs in the open-hole or inside casing strings. However, USDWs must be isolated from fluid movement exiting the injection zone and hydrocarbon bearing zones, by placement of sufficient cement volumes in the annular space and cement plugs above those zones. The presence of drilling mud may not prevent fluid movement between zones in the uncemented annulus, especially in the older wells within the AOR since the mud will degrade over time and not retain the density and other properties necessary to suppress fluid movement. In our view, cement should be placed at the base of USDWS as it is for the BFW to ensure long-term protection from fluid movement into or between USDWs.

The requirements for witnessing P&A operations are somewhat flexible in that the district deputy in each district has the discretion to require witnessing or not for some plugging operations. Placement of cement plugs does not require the presence of a CDOGGR inspector, for example. However, witnessing the tagging of cement plugs for proper placement and hardness, and the final site inspection for environmental compliance are requirements and are priorities in the districts. The variation in those inspections at the district level is discussed Section 4. In our view, the mixing and pumping of cement for placement of plugs is a critical step in the plugging operation that warrants the presence and monitoring of a government inspector and should be witnessed whenever possible.

The option to use compressed bentonite as a replacement for cement in plugging certain wells in Districts 4 and 5 is contrary to federal UIC regulations which specify the use of cement in plugging Class II injection wells. The basis for that option is not clear from a review of the CDOGGR regulations, MOI, EPA Questionnaire responses, and other references to P&A requirements. We requested that the Bakersfield CDOGGR office explain the basis for the use of bentonite instead of cement in plugging operations in those districts, but had not received a response as of June 20, 2011.

3.9. UIC STAFF QUALIFICATIONS

Most district UIC staff members appear to have the necessary qualifications to meet the requirements of the positions they hold. The most recent staff additions to the Program will enhance their qualifications with more experience in the field and could benefit from UIC specific training, such as the EPA sponsored UIC Inspector Training Course.

The overriding concern with regard to staff qualification is that the districts lack sufficient personnel to adequately manage and implement the Class II UIC Program, especially with regard to the standards set forth by CDOGGR management in the Division Expectations Memorandum. As a result of those new standards and expectations, completion of reviews for UIC project applications has been delayed, especially in the largest districts. Annual UIC project reviews have also been limited to the most critical projects in those districts. Additionally, more routine inspections could be performed and more MITs and P&A operations could be witnessed if there were sufficient numbers of qualified staff in the district offices.

We were informed by district management that authorization has been given to hire several additional staff for implementation of the UIC Program. That authorization should substantially improve the quality of the CDOGGR UIC Program at the district level when the new positions are filled and the new hires complete the CDOGGR UIC training program. Staff qualifications are discussed at greater length in Section 4.

4.0 DISTRICT-LEVEL DISCUSSIONS AND CONCLUSIONS

Six CDOGGR districts cover the State of California. A map of California showing the boundaries of each of the six districts, as well as district office locations is provided in Figure 1. In addition, a summary of injection well numbers by district is provided in Table 2. Well numbers are provided for both active and inactive wells of the following types: gas storage (GS), pressure maintenance (PM), cyclic steam (CS), steamflood (SF), waterflood (WF), air injection (AI), and water disposal (WD).

Table 2. Summary of Injection Well Numbers by District and Well Type

District	Injection Well Type	GS	PM	CS	SF	WF	AI	WD	Total	% of State Wells
1	Active	24	1	-	2	1,397	-	16	**1,440**	**6.14%**
	Inactive	53	1	-	9	411	2	26	**502**	
	Total	**77**	**2**	**-**	**11**	**1,808**	**2**	**42**	**1,942**	
2	Active	86	-	66	45	326	-	64	**587**	**3.19%**
	Inactive	48	1	-	31	278	-	65	**423**	
	Total	**134**	**1**	**66**	**76**	**604**	**-**	**129**	**1,010**	
3	Active	17	8	203	120	87	-	87	**522**	**2.83%**
	Inactive	4	8	-	124	142	4	90	**372**	
	Total	**21**	**16**	**203**	**244**	**229**	**4**	**177**	**894**	
4	Active	-	63	14,310	3,380	2,893	-	604	**21,250**	**80.8%**
	Inactive	-	16	-	3,064	851	12	377	**4,320**	
	Total	**-**	**79**	**14,310**	**6,444**	**3,744**	**12**	**981**	**25,570**	
5	Active	-	-	369	276	136	-	29	**810**	**6.45%**
	Inactive	1	-	-	694	501	-	36	**1,232**	
	Total	**1**	**-**	**369**	**970**	**637**	**-**	**65**	**2,042**	
6	Active	104	-	-	-	-	-	26	**130**	**0.57%**
	Inactive	41	-	-	-	-	-	10	**51**	
	Total	**145**	**-**	**-**	**-**	**-**	**-**	**36**	**181**	
State Totals	Active	231	72	14,948	3,823	4,839	-	826	**24,739**	**100%**
	Inactive	147	26	-	3,922	2,183	18	604	**6,900**	
	Total	**378**	**98**	**14,948**	**7,745**	**7,022**	**18**	**1,430**	**31,639**	

This district-level discussion is presented in a question and answer format, followed by conclusions and/or comments on the district responses to the questions and requests for clarification. Questions and district responses were summarized from the EPA Questionnaire and district responses with a minimum of editing for this report. The district responses are essentially verbatim as written or spoken by district level personnel, either in response to the EPA Questionnaire or during the district office visits. Our questions and comments are italicized, while the district responses are in plain text.

The individual district discussions and conclusions are duplicative of other district discussions in several areas since the same questions were asked to all districts, and the district responses were similar in many respects. There are significant differences in a few areas, and those differences are discussed in detail in the conclusions that follow each stated objective in the EPA Questionnaire. In summary, there are far more similarities than differences between the districts in their implementation of the UIC Program.

Figure 1. CDOGGR District Office Boundaries and Office Locations

4.1. DISTRICT 1

This section is organized in six parts to address questions and responses from District 1. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. Each of the six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 1 has a total of 1,942 active and inactive injection wells, which represent approximately 6.1% of state injection wells. Table 3 provides numbers of wells by well type for both active and inactive wells.

Table 3. District 1 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	CS	SF	WF	AI	WD	Total	% of State Wells
Active	24	1	-	2	1,397	-	16	**1,440**	
Inactive	53	1	-	9	411	2	26	**502**	**6.14%**
Total	**77**	**2**	**-**	**11**	**1,808**	**2**	**42**	**1,942**	

PART I: General

This part addresses UIC program organization for District 1, and interagency coordination and changes to the UIC Program.

UIC Program Organization:

Organization chart for District 1 is inserted below (Figure 2).

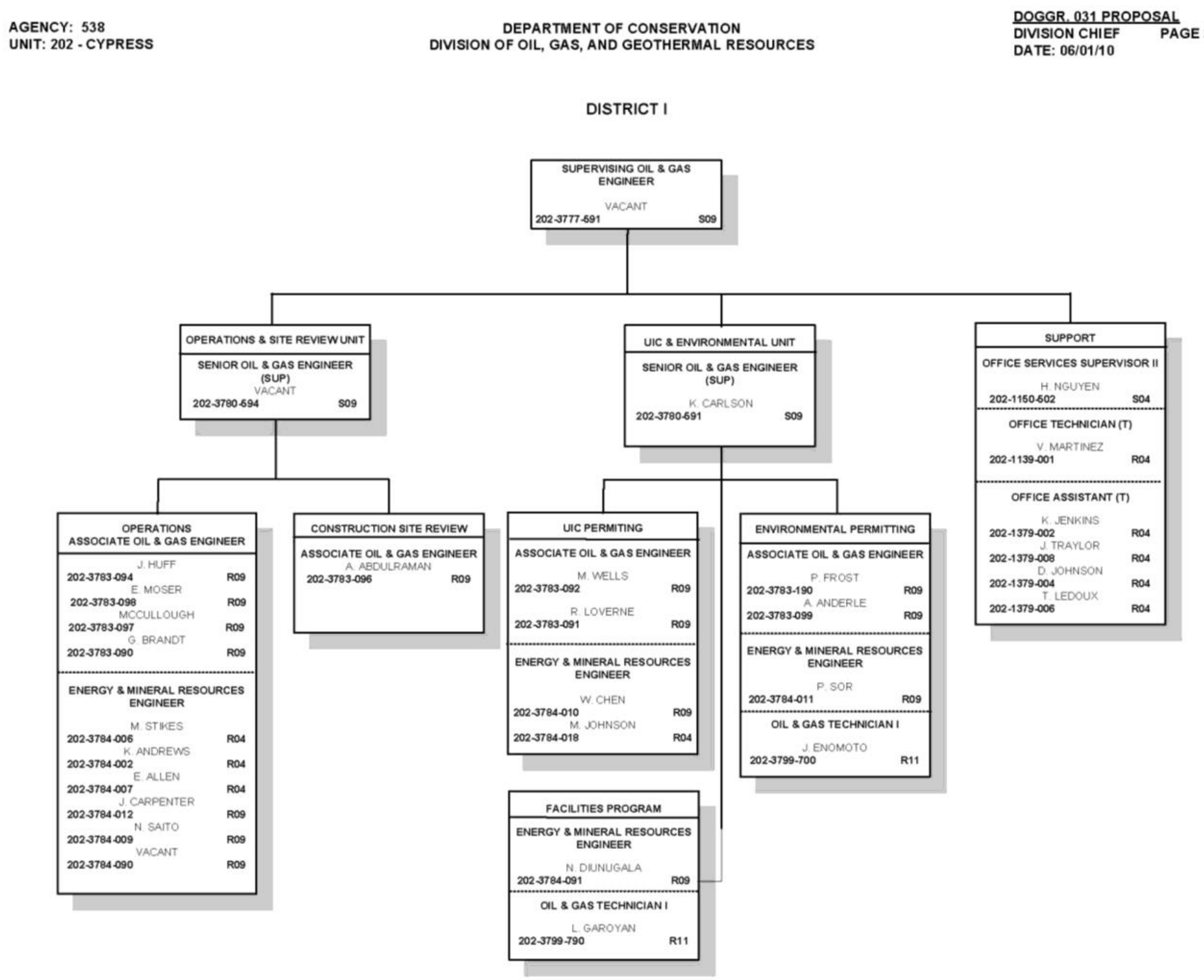


Figure 2. District 1 Organizational Chart

The inserted Organizational Chart provides a good visual overview of the District's staff structure. However, please provide more details on the qualifications and responsibilities of each UIC staff position/functions with regards to the activities listed in question 1 above. The Duty statement for UIC Supervisor was provided and the Duty statement for UIC Associate Engineer will be forthcoming. Please see attachments with email.

Interagency Coordination and Changes to the UIC Program

Please list any memoranda of agreement or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available.

1. Memorandum of Agreement between the US EPA Region 9 and DOGGR September 29, 1982

2. Memorandum of Agreement between the State Water Resources Board and the DOGGR May 19, 1988
3. State Water Resources Control Board Resolution No. 88-63

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes.

There have been two new directives from HQ Sacramento that have significantly changed how District 1 regulates the UIC program:

1. Historically, District 1 did not put a big emphasis on keeping injected fluids to the intended zone of injection; the primary focus of the District 1 UIC program was to protect USDWs. As long as USDWs were protected, then District 1 wasn't too concerned about injection fluids migrating out of intended zones of injection (again, as long as these fluids did not migrate into a USDW). Recently, HQ Sacramento issued a directive to all Districts that the UIC program will keep all injected fluid confined to the intended zone of injection. This new directive has significantly changed the way District 1 has historically regulated the UIC program (this new directive has also changed the regulation of other areas in District 1 such as P&A of wells and the Construction Site Review Program).

2. District 1 has been regulating underground injection in the LA basin since the 1940s. Most injection projects in District 1 were up and running before the Memorandum of Understanding (MOU) between the EPA and DOGGR in 1982. These projects that were up and running before the EPA MOU are called legacy projects. Most of these legacy projects have never had an AOR as defined by DOGGR regulations. Historically, District 1 has assumed that the legacy projects have had an adequate review at one time, and no further review would be necessary. Recently HQ Sacramento issued a directive that all injection projects will have an AOR as defined by DOGGR regulations regardless of the age of the project. This new directive has significantly changed the way District 1 has historically regulated the UIC program.

When was the directive issued by HQ regarding confinement of all injected fluid to the intended zone of injection? Please provide a copy of that document. Also, please elaborate on how this directive has changed the regulation of other areas in District 1 such as P&A of wells and the Construction Site Review Program. Please elaborate on how this directive has significantly changed the way District 1 regulates the UIC program. A copy of the UIC Program expectations letter issued on May 20, 2010 was provided. It should be noted that this expectation letter is a work in progress, and that a revised UIC Program expectation letter is expected to be issued in the near future.

The directives in the UIC Program expectations letter have initiated significant changes that have propagated throughout the District's various programs. Below are three examples:

1. The plugging and abandonment of wells now includes zonal isolation plugs. Zonal isolation plugs are now required for all oil and gas zones, regardless if the zones have active injection. The zonal isolation plugs for zones with active injection must be 100 linear feet verified (minimum), or 150 linear feet calculated (minimum), above the approved zone of injection. All wells that do not have zonal isolation plugs are not abandoned to current standards.

2. The Construction Site Review Program reviews oil and gas wells associated with surface development projects. The purpose of the program is to ensure wells are abandoned to current standards prior to the development project. There is an ongoing development project in Santa Fe Springs that was started in 2008. The first part of the project has development over wells that were reviewed in 2008/2009. According to the standards that were in place in 2008/2009, all of the oil and gas wells located in this ongoing development project were abandoned to current standards at that time. Now that the abandonment standards have changed, we find that all of the oil and gas wells located in this ongoing development project are NOT abandoned to current standards, including the oil and gas wells in the first part of the project that now have surface development over them.

3. The District 1 UIC program now must ensure that all injection projects have an AOR as defined by DOGGR regulations. This requirement has substantially increased the work load on the District 1 UIC unit. In order to meet this requirement, D1 now performs AORs on all injection wells within existing injection projects that are new drills, redrills, convert from production to injection, and return to injection. This way the AORs of existing injection projects will eventually be completed in a piece meal fashion. Historically, D1 probably did not perform AORs on wells located in existing injection projects. AORs were only done on new injection projects. This new requirement has created a substantial backlog of work for the UIC unit.

PART II: Permitting and Compliance Review

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program

Applications are sent directly to the District 1 office and are initially screened for completeness by an Associate Engineer

Associate UIC Engineer using DOGGR regulations as a guide. If the application is found to be incomplete, the UIC engineer will contact the applicant by phone and will follow up with a letter or email to the applicant. It is preferred that all UIC engineers have a college degree in Geology, Petroleum Engineering, or another related degree. Currently, all Associate UIC Engineers and other UIC staff in District 1 have college degrees. Additional training would be beneficial in step rate testing, pressure fall-off testing, reservoir engineering, and design and management of injection projects.

District 1 UIC Engineers utilize the following tools to review project applications: step rate test data, reservoir characteristics/data, injection fluid characteristics/data, casing diagrams, cross sections, structure maps, isopachous maps, and pressure profiles and behavior in the injection zone. District 1 would benefit from having access to appropriate computer modeling software.

District 1 has never permitted a commercial Class II well or a CO2 EOR project, but the permitting process would be similar to other projects except for bonding requirements for a commercial well ($50,000 bond for life of well) and more attention to the corrosivity of and mobility of CO2 associated with a CO2 EOR project.

OBJECTIVE: Understand the current compliance/file review process.

An injection well is selected for a file review in District 1 for the following reasons:

1. The operator proposes to rework a well and needs a DOGGR permit to be issued.
2. In connection with a required MIT on an injection well
3. An injection well is in the AOR of another injection well.
4. A public complaint is received or an incident occurs concerning an injection well.

Selection for a file review is not based on residential areas or where USDWs are present since the vast majority of wells are located in urban areas where fresh water and/or USDWs are present.

The injection well file review is usually performed by a UIC Associate Engineer, but at times by field staff under the supervision of a UIC Associate Engineer. The percentage of file reviews done in the past year is 56% of the 1876 injection wells in the District. The quality of a file review is assured by reviewing the well data in the well record and the District database (PARADOX) and is documented by entering the review data into the database. The operator is notified when deficiencies are found, and corrective actions are required and tracked by the responsible Associate UIC Engineer to ensure they are resolved in a timely manner.

Project reviews differ from well file reviews in that the entire project is reviewed as a whole, and may include review of specific well information such as the MASP for each well in the project. An annual face to face meeting with all operators would be the ideal, but not possible in District 1 because of the large number of wells and lack of manpower. Currently, annual meetings are held only for approximately 1% of active injection projects due to lack of resources. This should improve when the authorized additions to the UIC staff are hired and trained. Project reviews are not a high priority at this time because District staff is focused on reviewing AORs and new permit applications.

Conclusions

Project reviews should be performed at least annually to be in compliance with the CDOGGR Program Description and the MOI requirements described at Section 170.13.3.1. Annual meetings with operators to review active projects is an important element of the UIC Program, especially for those projects that have ongoing compliance issues that go unresolved within acceptable timelines. The lack of a project review is somewhat alleviated by the fact that individual wells in disposal projects are reviewed by means of the required annual RAT survey. However, that does not fully apply to enhanced recovery wells because waterflood wells are tested only on a two-year cycle and steamflood wells on a five-year cycle. Also, RATs will not detect a casing leak up hole from the injection zone.

OBJECTIVE: Understand the technical review and related aspect of the permit/file review process.

See the UIC regulations and MOI for a description of adequate casing and cementing requirements for a new well. All new wells need adequate cement to protect the BFW (3,000 mg/L TDS). Other USDWs (TDS = 3,000 to 10,000 mg/L) are protected in a new well by confining the injection fluid to intended injection zone. Casing and cement are not required through all USDWS in new wells, only the BFW requires cemented casing. District 1 has historically picked the fresh water zone in established oil fields from oil field e-logs. The pick is made based on a rapid decrease in resistivity at the base of a porous interval. Heavy mud is considered sufficient protection for other USDWs by the standards described in the May 20, 2010 Division expectations memo. Heavy mud is typically 72 pounds per cubic feet (lbs/cf) or greater. Cement is not required at the base of other USDWs as long as the injection zone and other hydrocarbon bearing zones are isolated by casing and cement from USDWs with adequate cement above those zones.

Converted wells need to have adequate zonal isolation outside all casings. In addition, a packer and tubing must be set in cemented casing immediately above the approved injection zone. The well must pass a pressure test on the backside of the packer to demonstrate casing, packer, and tubing integrity. "There may be a new directive from HQ Sacramento that requires all injection wells to have adequate cement outside casing to protect the BFW. But historically, District 1 never had that requirement for conversions." District 1 is awaiting a decision from HQ Sacramento as to the casing and cement requirements in regards to the BFW for converted wells, return to injection wells, and the general reworking of injection wells. Historically, District 1 never required BFW cementing for those wells. It was assumed that if the injection fluid was confined to the injection zone, then the BFW was protected. The Division expectations memo states that all injection wells must have cement across the BFW with at least 100 feet above the BFW interface.

At the injection well, surveys are run, pressure tests are conducted, and tubing/casing pressures are reviewed to assure that fluids are confined to the intended zone of injection. Throughout the field, all well casing diagrams in the area affected by the injection well are reviewed to assure adequate zonal isolation. In cases where there is not adequate zonal isolation, monitoring and twining have been allowed in the past to assure zonal confinement. However, in the future, HQ

Sacramento will only allow monitoring and twinning as a means to assure zonal confinement if DOGGR has the staff to properly regulate monitoring and twinning in injection projects

Twinning is the placement of a producing well between an injection well and a potential problem well in an injection project. The theory is that the producing well will act as a pressure “sink”, thus preventing pressures from the injection well to adversely affect the problem well.

The requirements for remedial cementing are described in the UIC Program expectations letter, page 2. If there are not 100 feet of cement above the injection interval, remedial cementing would be required for wells completed before 1978, and remedial cementing would be required for wells completed in 1978 and later if there are not 500 feet above the injection interval.

Packer and tubing are used in all injection wells in District 1. If packer and tubing are not used, then an alternative to the annular pressure test could be an ADA[1] test. Dual completions are permitted in District 1 as either a single string with mandrels isolated by two packers, or two or more tubing strings in a single well. The requirements are the same as single completions. *Is injection allowed above a packer in a dual well?* No

USDWs are determined from well e-logs, and the historic base of fresh water information in a given field. Occasionally, District 1 will consult with other state and federal agencies regarding USDW information.

Geologic information of the area is used to determine the adequacy of the confining zone/system. This would include structure maps and cross sections. Other data that can be used to determine the adequacy of the confining system include reservoir pressure data within the approved zone of injection and above the approved zone of injection, oil/water contacts on either side of a fault, pressure differences on either side of a fault, and log data.

DOGGR regulations state that an accurate pressure gauge or recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. Operators of injection wells are required to report injection volumes, number of days on injection, tubing pressure, and casing pressure for each well to DOGGR every month.

In order to calculate the maximum injection pressure of a well, the approved injection gradient, TVD of the confining depth, and the injection fluid density need to be known for the well. Sometimes District 1 will also consider friction drop in the injection string in calculating maximum injection pressure. Historically, District 1 has assumed a fracture gradient of approximately 1.0 psi/foot for the LA basin. Thus, new injection projects were usually assigned an injection gradient of 0.8 psi/foot. There have been some exceptions to this rule, but most injection projects in District 1 have approved injection gradients of 0.8 psi/foot. Recently, HQ Sacramento directed District 1 to start requesting step rate tests for injection projects so it can be verified that approved injection gradients are below fracture gradients. If a project has been reviewed by applying Bernards Pressure Buildup Equation or Theis Modified Equation, then a maximum flow rate will be established.

[1] The ADA test is a mechanical integrity test developed by the EPA lab in Ada, Oklahoma.

Historically, District 1 assumed that the fracture gradient was equivalent to the overburden gradient. The overburden gradient in the LA Basin has been assumed to be 1.0 psi/foot from various sources. See CDOGGR Publication M 13, pg. 10.

District 1 has very few historic step rate tests. Recently, D1 started requesting some operators to run step rate tests. In the last year, D1 asked operators to conduct 13 step rate tests: One in the Huntington Beach field, one in the Wilmington field, three in the Las Cienegas field, and eight in the Inglewood field. Based on recent SRT data, the gradient is less than 1.0 psi/foot, SRT procedures and requirements are undergoing review. MASPs are based on 95% of the fracture pressure or the highest pressure achieved in the SRT if fracture pressure was not reached. Use of BHP gauges in SRTs is under consideration.

Conclusions

USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance for total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement. CDOGGR should consider modification of cementing requirements to require placement of cement at the base of all USDWs penetrated by a well, and not just at the BFW (3,000 mg/L or less TDS) zones, above the injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells and wells located within the AOR of an injection well when casing repairs occur or when the AOR wells are plugged and abandoned. Monitoring and twinning to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.

The historical fracture gradient assumption of 1.0 psi/foot for the Los Angeles Basin is not based on SRT data in specific wells and is believed to be considerably higher than the actual gradient, based on recent SRT data and the other data presented in CDOGGR Publication M13. District 1 has required very few SRTs in the past. We understand that SRTs will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives from the May 20, 2010 Division Expectations Memorandum are fully implemented at the district level. We support that directive with the recommendation that bottom hole as well as surface pressure gauges be used in SRTs. Bottom hole pressure measurements remove the uncertainty of friction losses during a test and provide a more accurate measure of formation fracture gradient.

Maximum allowable surface injection pressures are set at 95% of the fracture pressure or the highest pressure achieved if fracture pressure was not reached during a SRT. Where the SRT data and the fracture pressure determined from those data are not 95% reliable, the MASP should be set at a more conservative value.

OBJECTIVE: Understand the Area of Review/Zone of Endangering Influence considerations and procedures

Usually, District 1 uses the ¼-mile fixed radius method to determine the AOR for EOR injection wells. Occasionally, other methods have been used such as the Theis Modified Equation. Historically, District 1 used the ¼mile fixed radius method to determine the AOR for each disposal well. The new method now used by District 1 is the Theis Modified Equation or the Bernards Pressure Buildup Equation and then compare it to the ¼-mile fixed radius method.

The Theis Modified Equation and/or the Bernard's Pressure Buildup Equation are used to determine the pressure profile from an injection well in a given reservoir. This pressure profile is a graph of either pressure vs. distance from the injection well, or it can be feet of fluid rise vs. distance from the injection well. Next, the minimum pressure (or minimum feet of fluid rise) is determined to push zonal fluid to the base of the area's USDW. Once these two items are determined, then the ZEI can be calculated by finding the maximum radius from the injection well where the injection profile has pressures at or above the minimum pressure required to push zonal fluid to the base of the USDW. This maximum radius from the injection well is the ZEI. The ZEI is then compared to the ¼ mile radius. This procedure was begun in District 1 within the last year to provide some assurance that the ¼ mile radius is adequate for AORs. An example calculation was provided. It applies to all injection wells, but with emphasis on new wells at this point. More staff is needed to review the existing wells, and a request has been made.

How is the AOR determined for a commercial disposal well and for CO2 EOR wells? Current District 1 UIC staff has never permitted a commercial injection well or a CO2 EOR well. The AOR of a multi-well project or area permit is determined by creating an envelope of ¼-mile fixed radius around the bottom hole location of all the injection wells in the project or area.

Neither ZEI nor computer modeling are performed routinely for EOR projects. Some type of ZEI calculation will now be performed routinely for disposal projects; however this has not always been the case for District 1. Less than 5% of EOR projects and disposal projects have been subjected to ZEI calculations.

Shut-in pressures are reported monthly for all active slurry wells. In the past, pressure falloff tests were rarely performed in the district. The UIC program in District 1 plans to start routinely performing Pressure Fall Off Tests for all disposal projects in the district.

The shut-in and fall-off pressure data are not reviewed for pressure buildup over time. Currently in District 1, the ZEI is only determined at the beginning of an injection project, or during the initial AOR. It is not routinely determined over the life of an injection project. This is because the vast majority of District 1 injection projects are waterflood projects, thus it is assumed that over the life of an injection project, there is a net loss of reservoir fluid. The exception to this is the Wilmington Oil Field. Because of subsidence issues associated with the field, operators within the Wilmington Oil Field are required by law to inject 102% - 105% of the total volume extracted from the reservoirs within the field.

Does this response also apply to SWD wells and the Wilmington Field? Yes, but fall-off testing and shut-in pressure monitoring may be required in the future. This will be considered during the AOR reviews of new conversions to injection and annual reviews of existing wells, but more resources are needed to perform the necessary AOR reviews.

Recently HQ Sacramento issued a directive that all injection projects will have an AOR as defined by DOGGR regulations regardless of the age of the project. District 1 has started doing AORs for all new drills, redrills, conversions, and return to injection permits in existing projects. Many problem wells have been found throughout the district. The problem wells need to be resolved before a permit is issued. Corrective actions that were required include remedial cementing operations, and looking at the formation around the problem wells to see if there is adequate shale to provide zonal isolation. Examples were discussed and the shale issue was explained. A shale zone above the injection zone provides confinement when the well is open to flow above the permitted injection interval in wells with uncemented liners through the injection zone.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? If the defective well is not resolved, then the project will be modified or rescinded.

Conclusions

ZEI determinations were usually not performed for District 1 injection wells in past years. AORs were usually based on a quarter-mile fixed radius from the injection well, even for disposal wells. That may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project and reservoir pressure is maintained at a level that does not cause the position of the pressure front to expand beyond the quarter-mile AOR boundary. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. Where injection is into a depleted or producing zone, the fixed radius quarter-mile AOR may be appropriate, as is the case in some of the District 1 disposal wells. However, a ZEI analysis should be performed for all disposal wells to determine whether the quarter-mile AOR is appropriate. This also applies to EOR projects if injected fluid volumes will exceed produced fluid volumes for an extended period, allowing reservoir pressures to increase and the pressure front to potentially expand beyond the quarter-mile AOR.

District 1 recently began to evaluate the ZEI for all injection wells, with emphasis on new disposal wells at this point. This was in response to the Division directives issued in the Division Expectations Memorandum. District 1 uses the modified Theis equation or the Bernard pressure buildup equation in this evaluation. We strongly support this change in the determination of AORs.

Problem wells outside of the quarter-mile AOR but within the ZEI were not addressed in the past. With the full implementation of this procedure, those wells will be subject to corrective action considerations, and protection of USDWs will be significantly improved. Many problem *wells have been found since the recent District implementation of the requirement to review ZEI/AORs and require corrective action as a condition for issuing permits for new drills, redrills, conversions, and return to injection operations.*

Pressure fall-off tests were rarely performed in the past, but will now be performed routinely for all disposal projects in the District, according to District staff responses to the EPA Questionnaire. That will provide the necessary reservoir pressure data to monitor pressure buildup and should ensure that the pressure front is contained within the AOR over the life of a well. We fully support that initiative.

OBJECTIVE: Understand the administrative permit application components

Describe the public notification and participation process for applications. DOGGR places a legal notice in a local newspaper to run three consecutive days, then waits 15 calendar days, from the last date the legal notice appeared, for public comments. If comments are serious, DOGGR will hold a public hearing. Most District 1 UIC staff have never gone through the hearing process.

The financial assurance mechanisms used in connection with UIC applications are stated in the California Laws for Conservation of Petroleum & Gas, PRC01, sections 3204 – 3207. See the discussion of statewide Financial Responsibility requirements above for details.

Conclusions

See Section 3.0 for additional information.

OBJECTIVE: Understand the process for aquifer exemptions

District 1 has never gone through the process for an aquifer exemption. See the discussion of the statewide aquifer exemption process in the MOI and Program Description in the Primacy Application for details.

Conclusions

See Section 3.0 for additional information.

<u>PART III: Inspections</u>

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District

Inspections are prioritized by considering several factors, which include:

1. Time since the last inspection;
2. Past history of the well;
3. Past history of the operator; and
4. Area in which the well is located.

District 1 does not prioritize inspections based on residential areas, and areas where BFWs and/or USDWs are present because the vast majority of UIC wells in D1 are located in residential areas where BFWs and/or USDWs are present. Division map #100 lists all oil and gas fields in District 1. A copy of a map depicting the location and size of oil fields in the District is included in the Appendix

What professional qualifications and/or experience are required by DOGGR to be an inspector? DOGGR would like a field inspector to have a four year degree in Geology, Petroleum Engineering, or a related field. DOGGR will accept people without a four year degree if they can demonstrate adequate work experience. DOGGR provides field inspectors with a combination of formal training and on-the-job training. UIC field staff can use more formal training in witnessing RAT surveys. At the present time, District 1 has a relatively new group of field engineers/inspectors. Average on-the-job experience for District1 field engineers/inspectors is about one year. Due to the complexities of the job, it usually takes two to three years before a field engineer/inspector is fully trained.

The tools utilized by field inspectors include: writing material, calculator, reference material, personal safety equipment, cell phone, and camera. An additional tool that would be very useful would be a laptop computer with internet access. There is a standard inspection form listing MASPs, tubing pressure, casing pressure, and flow rate. An example form was provided and is included in the Appendix.

Field inspectors play a major role in the documentation phase of an enforcement case. Field inspectors may be involved in the hearing or judicial process, usually to testify as to what they witnessed.

Conclusions

The professional qualification and/or work experience requirements for District 1 UIC inspectors are similar if not identical to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. However, more training may be needed in witnessing and analyzing RAT surveys in addition to other UIC operations. Currently, the District has a relatively new group of engineers/inspectors and the average length of experience is only about one year. Those employees will need several more years of training and experience before they are fully qualified for the positions they hold. We were informed that the Division has authorized the employment of several additional UIC staff members statewide. That increase in staff should significantly improve the District's ability to process new project applications and perform the other UIC functions on a more timely basis.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District

The goal is to inspect each UIC permitted well at least once a year. The inspector records tubing pressure, casing pressure, and any evidence of leaks. The inspections are stored in the District 1 Paradox database.

As of 9/8/2010 there were 1,775 active, idle, and shut-in injection wells in District 1, according to the D1 database. Below is the total number of injection wells inspected per year, according to the D1 database:

- 2009 – 1,234 injection wells were inspected
- 2008 – 888 injection wells were inspected
- 2007 – 1,030 injection wells were inspected
- 2006 – 883 injection wells were inspected
- 2005 – 492 injection wells were inspected
- 2004 – 1,147 injection wells were inspected
- 2003 – 680 injection wells were inspected
- 2002 – 245 injection wells were inspected
- 2001 – 613 injection wells were inspected
- 2000 – 1,053 injection wells were inspected

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plant which are an integral part of production operations. Class II injection wells are defined by the EPA in 40 CFR 146.5. Wells which inject fluids:

1. Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with wastewater from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection;
2. For enhanced recovery of oil or natural gas; and
3. For storage of hydrocarbons which are liquid at standard temperature and pressure.

In addition, the EPA Final Policy for Class II wells dated July 31, 1987, allows, aside from the use in enhanced oil recovery operations, the injection of the following four kinds of fluids in Class II wells:

1. Wastewater (regardless of their sources) from gas plants, which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection;
2. Brines or other fluids brought to the surface in connection with oil or natural gas production or natural gas storage operations;
3. Brines of other fluids described in # 2 above that, prior to injection, have been:

   a. Used on-site for purposes associated integrally with oil and gas production or storage.
   b. Chemically treated or altered to the extent necessary to make them usable for purposes related to oil or gas production or storage; or
   c. Commingled with fluids wastes resulting from the treatment in (b); and
4. Fresh water (less than 10,000 ppm) from groundwater or surface sources added to or substituted for the brine, as long as the only use of the water is for purposes associated integrally with oil and gas production or storage.

Please elaborate on 3b and 3c responses above. Chemically treated or altered how and with what? Commingled with what fluid wastes? Nonhazardous? Only Class II fluids are allowed to be injected as described in the MOI. Examples are biocides, scavengers, scale inhibitors, and corrosion inhibitors.

Aside from produced brines, the Oil and Gas Supervisor has determined that a Class II water disposal injection well may accept the following nonhazardous fluids that originate from oilfield brines:

1. Diatomaceous earth filter backwash;
2. Thermally enhanced oil recovery (TEOR) cogeneration plant fluid;
3. Water-softener regeneration brines;
4. Air scrubber waste;
5. Drilling mud filtrate;
6. Tank bottoms;
7. Slurrified crude oil saturated soils; and
8. NORM wasted. (Prior to approving NORM waste as a Class II fluid, Headquarters must be consulted.) This also requires EPA approval.

Are these fluids acceptable to EPA for disposal in Class II wells? How is nonhazardous defined and determined? Yes. In accordance with EPA requirements.

The operator is usually given advance notice of an inspection. The operator will receive a letter listing all deficiencies and violations. The operator is usually given 30 days to resolve any violations. It is the responsibility of the appropriate UIC Associate Engineer to ensure any violations are resolved. *Is the resolution of violations treated as an enforcement action with the issuance of a N.O.V.?* Yes, an example NOV document will be provided.

In the event of an emergency situation regarding Class II wells and related incidents such as spills, District 1 is usually notified by the operator of the well, local emergency response units, and/or the California Emergency Management Agency. Recent emergency situations that have been reported involving UIC wells include an injection line leak in the Long Beach Field, City of Signal Hill; a casing failure due to an over pressure zone in the Santa Fe Springs Field, City of Santa Fe Springs; and injection water surfacing in the Downtown Los Angeles Field, Los Angeles City.

Please elaborate on the response and remedial operation for the three incidents described in your response. Santa Fe Springs Field: An injection well had water in the cellar. Well was shut in and the pressure was bled off. Operator plans to abandon the well in the near future. Groundwater impacts are uncertain, but groundwater was likely impacted. Referred to RWQB for further enforcement actions. There are no water wells in the area, however. *More information was requested on the Long Beach and Signal Hill incidents regarding the response and remedial operation, and that information was provided on June 6, 2011.* The Santa Fe Springs problem well will be abandoned by the operator. DOGGR issued the abandonment permit in May, 2011. The Long Beach (Signal Hill) problem well was remediated by the operator in July, 2006. The remediation consisted of replacing the injection line to the well. The Downtown Los Angeles problem well was abandoned by the operator in 2006.

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. The PARADOX database is utilized for those purposes at present, but all districts will convert to the CalWIMS database in the near future. CalWIMS has been adopted in District 4 and a description of that system may be seen under the District 4 discussion.

How are the injections pressures on the wellhead compared with the approved MASP? The field inspector is given a list of MASPs for all wells to be inspected; the inspector can then compare observed readings with the list. All injection wells have approved MASP values in an accessible database. The PARADOX database could be more user friendly. Tubing pressure is also checked against the well's MASP whenever RAT surveys are reviewed.

Conclusions

The goal of inspecting each permitted injection well as least once a year has not been attained in the past ten years, according to District 1 inspection numbers for those years. There were 1,775 active, idle, and shut-in injection wells in the district, as of September 8, 2010. The peak year for the number of inspections was 2009 when 1,234 wells were inspected. That represents a substantial increase over the previous ten years, but is still far short of 1,775. The MOI states that injection wells must be inspected annually (Section 170.13.2.1).

The operator is usually given advance notice of an inspection and receives a letter listing all deficiencies and violations. The operator usually has 30 days to resolve any violations. The appropriate UIC Associate Engineer is responsible for ensuring that any violations are resolved. Notices of Violation letters may be issued as an enforcement action in some cases. Monetary penalties are associated with a civil enforcement action, which can be initiated if the operator fails to comply with less formal actions to resolve a major violation. Most deficiencies and minor violations are resolved on an informal basis involving phone calls, emails, and Notices of Deficiencies after deficiencies or violations have been observed and/or reported. No information was provided on the percentage or number of inspections conducted without advance notice. That procedure could be an effective means to reveal hidden deficiencies and violations and perhaps should be employed more often than indicated in the District response.

Emergency situations involving injection wells and related surface facilities are usually reported by the operator, local emergency response units, and/or the California Emergency Management Agency (CalEMA). After the initial response by CDOGGR and other agencies, remedial operations and enforcement is referred to the Regional Water Quality Board (RWQB). Information on three recent incidents involving Class II injection wells in the District was provided. Those occurred in the Santa Fe Springs Field, Long Beach Field, and the Downtown Los Angeles Field. The Santa Fe Springs well had a casing failure and a surface discharge of fluid. The well was shut in and will be plugged. Possible groundwater impacts were referred to the RWQB for further enforcement actions. The Long Beach incident was an injection line leak and the Downtown LA incident was surfacing of injection water.

The PARADOX database is utilized for data management at the present, but will be replaced by the CalWIMS system in the near future. Field Inspectors have access to the database in conducting inspections and verifying that injection well pressures do not exceed the MASP and the well is in compliance with other UIC requirements. The CalWIMS database is more user-friendly and should be a significant improvement over the PARADOX system currently in use in the District.

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its implementation

Usually, the acceptable method for satisfying part 1 of a MIT is to pressure up the backside of the injection packer, from the top of the packer to surface. Other methods may be allowed, but they would have to be reviewed on a case by case basis. The standard MIT for District 1 is SAPTs and RAT surveys. Alternatives to the SAPT that may be allowed are ADA tests and temperature surveys. Noise surveys, temperature surveys, and oxygen activation surveys may be allowed as alternatives to the RAT survey.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? The following text and illustration describes the SAPT requirements:

Standard Annular Pressure Test (SAPT) Requirements

> A standard annular pressure test is required prior to injection, every time a packer is reset, and at least once every five years for both water disposal (WD) and waterflood (WF) wells.
>
> The Division requirements for an SAPT are a minimum final test pressure of 200 psi, a minimum stabilization time of 15 minutes, and a maximum pressure loss of ten percent of the initial test pressure. These standards are represented graphically below (*Figure 3*):

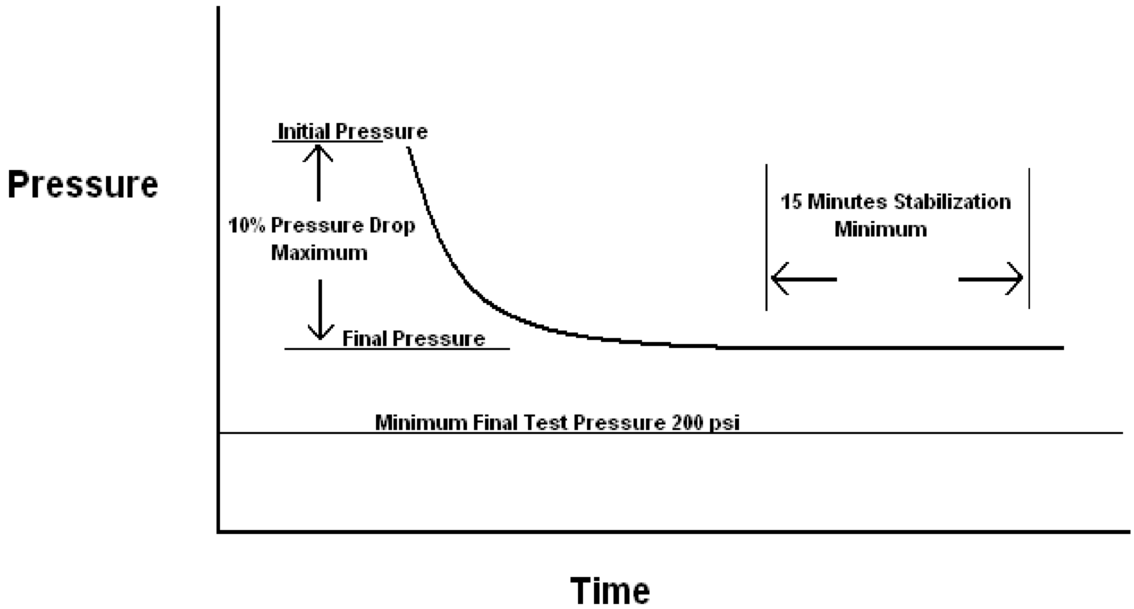
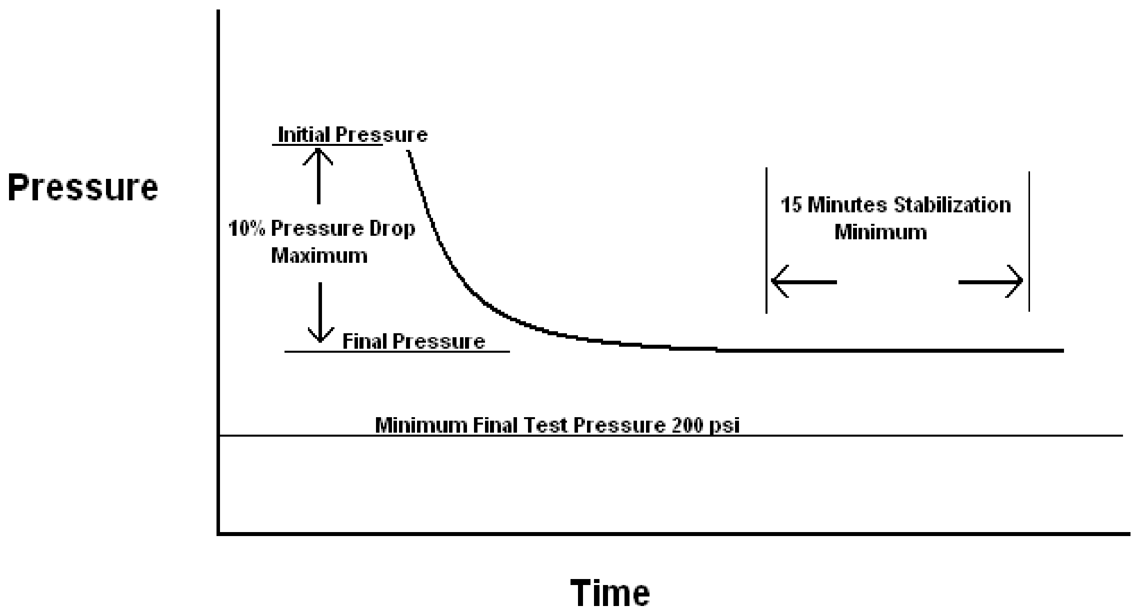


Figure 3. Graph of an SAPT - Pressure v. Time ***(as provided by District 1)***



Recently, there has been talk of changing the minimum final test pressure to the MASP of the well. Refer to the expectations memo, page 5. Testing to the MASP is under consideration. Older wells may be allowed to test at a lower pressure to avoid casing damage.

If annulus pressure monitoring (APM) is allowed to determine Mechanical Integrity (MI), how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM? District 1 (D1) does not allow annulus pressure monitoring to determine MI. APM has never been allowed in D1 as a means to remediate holes in the casing above the injection packer. D1 has never allowed holes above an injection packer because D1 has always wanted two levels of protection from the surface to the injection packer, competent tubing, and competent casing.

District 1 uses cement records and a survey to fulfill part 2 of a MIT. HQ Sacramento just developed the definition of adequate zonal isolation: either 100 linear feet of cement (minimum) verified by a survey (CBL, static temperature), or 150 linear feet of cement (minimum) calculated, above the approved injection zone. In addition, a packer and tubing must be set in cemented casing immediately above the approved injection zone (ideally within 100 feet).

How does this apply to post-1978 wells wherein 500 feet of cement are required above the injection zone as described on page 2 of the expectations memo? This applies to pre-1978 wells, but waivers may be allowed by the District Deputy.

Is there a requirement for annular cement at the base of USDWs and fresh water? Are remedial cementing operations required to place cement at those depths during casing repair or P&A operations? For P&A operations and new well completion operations, there is a requirement for annular cement at the base of the fresh water; however there is no requirement for annular cement at the base of the USDW. D1 is awaiting a decision from HQ Sacramento as to whether this annular cement requirement at the base of the fresh water is to be extended to all injection wells that undergo any type of Division permitted work.

Identify any logs used for the determination of MI and the limitations imposed on their use. District 1 usually uses a pressure test on the backside of the packer, a check for adequate cement, and an RAT survey to fulfill MIT requirements. Static temperature surveys can be run in idle wells, but that is not a common practice in District 1. Evidence of vertical fluid movement out of the permitted injection zone is indicative of MI failure in RAT surveys.

What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? Usually wells are tested on the same schedule. Tests can be prioritized by considering several factors, which include:

1. Time since the last inspection;
2. Past history of the well;
3. Past history of the operator; and
4. Area in which the well is located.

Some wells are tested more frequently than the standard cycle. The more frequent test cycle is required on all wells that deviate from standard completion standards. This more frequent test cycle is determined on a case by case basis. The standard test schedule is an RAT survey every two years for EOR wells, and an RAT survey every year for disposal wells. All wells need a pressure test at least once every five years.

In setting priorities, does the area consideration include residential or areas where fresh water and/or USDWs are present and in close proximity to the injection zone? Not necessarily. Fields in District 1 are located largely in residential areas, and USDWs are present in most fields, so there is no emphasis for setting priorities on that basis.

Describe the follow-up and typical enforcement actions for MIT failures. The typical enforcement action for MIT failures is to shut-in the well until the MIT failure is resolved. Repair is not usually required unless the fluid level rises above the BFW depth. The well remains shut-in until it is repaired and passes a MIT. If a well remains in idle status for two years, the permit to inject is rescinded.

Field staff witness MITs, but less than 5% of MITs are witnessed. Field staff document witnessed MITs on the appropriate DOGGR form – OG 109 for pressure tests, OGD 6 for RAT surveys. The operator is required to submit a description of the pressure test for all tests, witnessed or not, and a copy of the RAT survey, again, for all surveys, witnessed or not.

Please elaborate on the reasons for the low percentage of witnessed MITs. Lack of sufficient staff and other resources is the primary reason. Witnessing SAPTs is usually required for wells that are reworked. All MITs are reviewed by staff.

In the event of MIT failure, how is the operator notified to shut the well in. The appropriate UIC engineer will initially notify the operator by phone to shut-in the well, and will then follow up with a letter. The operator is required to report the MIT failure immediately or ASAP. The well must be shut in immediately, unless there are special circumstances. Operators are not required to institute corrective measures for failed MITs, but they cannot return the well to injection until the MIT failure is corrected. Also, if any injection well is shut-in for more than two years, then permission to inject into the well is rescinded.

Does this apply to casing leaks? If so, please elaborate. Please describe P&A or other requirements for wells shut in more than two years. P&A or repairs are not required for wells shut-in for two years or more, but the permit to inject is rescinded. Refer to idle well regulations and the management plan. *Apparently this applies to wells with casing leaks as well as other MIT failures.*

If work is required to repair an injection well, the operator must submit a proposal of the work to be done, then DOGGR will issue a permit for the proposed work. The permit will list specific operations that need to be witnessed by DOGGR. Sometimes the operations are not witnessed due to shortage of field staff. After the work is completed, the operator is required to submit a history of the work performed within 60 days after the completion of the work, or termination of the work.

What are the procedures/requirements for the operator to report a MIT failure discovered during routine operations and take corrective measures to restore MI. The operator must notify DOGGR immediately of any MI failures. The injection well is to be shut-in until the MI failure is corrected.

How much time is allowed for remedial action to be completed? Does if differ for casing failures versus tubing/packer failures and risk of endangerment to USDWs? Yes, MI failures that potentially endanger USDWs would require remedial action as soon as possible.

What are the current MI failure rates for enhanced recovery and disposal wells? According to the District 1 database, from 6/1/2008 to 6/1/2009:

1. Pressure Tests (SAPT): Good 152 Bad 4
2. RAT surveys: Good 616 Bad 82

How has the failure rate changed over time? This information has been provided in a subsequent email from the District office. No significant changes have occurred in recent years.

Describe the data management system used in the various components of the MIT program.

Procedure used to manage MITs:

1. Review and enter into the database all submitted MITs for a particular Operator;
2. Query the database for overdue MITs for that particular Operator;
3. Send the Operator a letter listing all overdue MITs;
4. The UIC Associate Engineer is responsible for ensuring overdue MITs are performed within a timely manner;
5. If MITs are not performed within a timely manner, then the UIC Associate Engineer is responsible for getting the operator to shut-in the injection well. The meaning of Timely is determined by the DOGGR engineer would determine what that means based on his/her professional judgment and possible threat to USDWs; and
6. If DOGGR becomes aware of any MIT failures, the operator must shut-in the injection well until the MIT failure is corrected.

Conclusions

The SAPT requirements as described above are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in Sections 2.4 and 3.4 of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure but with more frequent testing and/or monitoring of casing pressure.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. However, increasing that to 30 minutes would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes described above, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

The District states that less than five percent of MITs are witnessed, which is well below the federal UIC goal to witness at least 25 percent of MITs. Witnessing SAPTs in District 1 should be given a higher priority, in our view, especially since SAPTs are required only every five years or whenever the packer is reset during a workover operation or at the director's discretion.

Wells that fail a MIT are required to cease injection immediately, but are not required to be repaired unless USDWs are potentially endangered while the well is shut-in. That may be *acceptable if a well fails a MIT due to a packer or tubing leak and the casing pressure declines to zero after shut in, however, one cannot be certain that a casing leak does not exist concurrently with a tubing or packer leak. If USDWs are present in a well with a casing leak, there may be a risk for fluid movement into a USDW or other zones that lack cement in the casing/wellbore annulus between the leak and the USDWs or other zones. The risk increases with time in idle status, as the casing integrity becomes less certain over time without passing an annular pressure test*

A pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are required every five years, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. We believe that wells that lack MI should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area.

The requirement for sufficient volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of heavy mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

The recent Division directives to the district offices and the authorization to hire additional UIC staff should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

DOGGR has the following enforcement tools for the UIC program:

1. Notice of Deficiency;
2. Notice of Violation;
3. Formal Order;
4. Civil Penalties; and
5. Well shut-in and pipeline severance.

Please provide information on the numbers and types of enforcement actions taken in the past five years. The information requested will be provided. No information received as of, 2-28-2011.

What types of formal enforcement actions have been taken relative to UIC violations in the District? Wells have been Formal Ordered to be abandoned because of Significant Non-Compliances (SNCs). Civil Penalties have also been assessed.

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. Violations that potentially threaten USDWs would be processed faster: 60 days to correct paper violations versus 30 days or less for SNCs. HQ handles paper violations.

How many NOVs were issued by the District in the past year? Refer to 7520 report for 2009 NOVs. Please list and describe recent examples. None provided as of 2-28-2011.

Does the District issue Notices of Violation (NOVs) or similar notices to the operator and attach penalties? How many have you issued in the last five years? Please list these or the most recent examples. District 1 does issue Notices of Violations and Civil Penalties. Currently, the district does not keep track of these statistics.

What are the follow-up procedures to assure compliance and correction of the violation? It is the responsibility of each UIC Associate Engineer to assure Deficiencies and Violations are corrected. When the UIC unit in District 1 becomes aware of a deficiency or a violation the appropriate UIC Associate Engineers will call the operator and have the well shut-in, in the case of a major deficiency or a violation, or tell the operator he has 30-60 days to resolve the deficiency, in the case of a minor one. The UIC Associate Engineer will then follow up the phone call with a formal letter. Once the deficiency or violation is resolved, a follow-up reinspection by field staff is usually warranted.

Usually, an operator is given 30 days to correct a violation that could threaten a USDW. If the USDW is under an imminent threat, then the operator would have to correct the violation immediately. An operator has 30 days to correct a deficiency. If not corrected in 30 days, the deficiency becomes a violation. An operator then has 30 days to correct a violation. If not corrected within 30 days, the violation becomes a formal order and possibly a civil penalty.

What penalties have been assessed and collected on UIC violations in the past ten years? Currently, District 1 does not keep track of these statistics.

Please discuss the penalties assessed and collected in the past five years, and the past year. The information on the LA City leak to the surface is discussed below.

Please identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? The most prevalent UIC related problems faced by District 1 are to ensure operators run RAT surveys in a timely manner, to inspect each injection well at least once a year, and to verify injection pressures are below MASP. AORs for current and new injection projects are very slow due to inadequate staffing.

Is inadequate staffing also the reason for the low number of MITs witnessed? Yes. AOR reviews and implementation of the expectations memo have resulted in fewer MITs being witnessed. Additional staffing has been requested and has been authorized at Division HQ.

Conclusions

District 1 reported 11 wells with violations in 2009, including nine SNCs. Nine of those were unauthorized injection violations and two were operation and maintenance violations. Enforcement actions were reported for all 11 violations, including nine administrative orders for the SNCs and two well shut-ins. Two of the wells were returned to compliance in 2009, which were the shut-in wells. None of the SNC wells were returned to compliance in 2009, according to the 2009 annual report to EPA. We assume the wells were shut-in, but that was not confirmed.

A total of 60 MIT failures of the 658 MITs performed were reported in 2009. Four of the failures were SAPTs and 56 were RAT surveys. The number of MITs reported as witnessed in 2009 was 90, which is 14 percent of the total MITs performed. The percent of MIT violations resolved in 90 days was 18%. A total of 2,146 wells were reportedly inspected in 2009. That exceeds the number of injection wells (1,775 as of 9/8/2010) in the district, which must mean that some wells were inspected more than once. A total of 1,820 routine inspections were reported, which exceeds the number of injection wells in the district. Remedial operations were completed on 110 wells in 2009, according to the District 1 annual report submitted to EPA for 2009. That number exceeds the number of wells that failed MITs by a factor of almost 200 percent. The remedial operations must include wells other than those that failed MITs since only 60 wells failed MITs and only 18 percent of those were resolved in 90 days.

There were no P&A remedial operations reported in the 2009 report. We are not sure whether that means there were no P&A operations or not, since CDOGGR may not consider routine P&A operations as remedial operations. It would seem that some injection wells would require P&A in a given year, based on the number of long-term idle wells in the District and the requirement to plug at least a small percentage of idle wells each year described in the Idle Wells Planning and Testing Program. Allowing wells without MI to remain idle for so long without repairs or plugging is perceived as one of the weaknesses in the CDOGGR UIC Program on a statewide basis.

District 1 stated that the most prevalent UIC related problems faced by the District in providing adequate enforcement is ensuring that operators run RAT surveys in a timely manner, inspecting each well at least once a year, and verifying that injection pressures are below MASP. The reasons given were inadequate staffing to address both the increased emphasis on AOR reviews and the Division compliance objectives.

Those deficiencies should be at least partially alleviated by the authorization to hire additional staff members in the district offices.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public.

Policy for handing complaints from Operators and the Public:

1. Investigate the complaint by talking with all parties involved;
2. Document the complaint by writing a report; and
3. Confer with supervisor and/or HQ Sacramento as to next course of action.

Please provide the number of alleged USDW contamination incidents reported to the District in the past five years. What were the causes of the contamination? Currently, District 1 does not keep track of these statistics. See discussion below in subsequent responses.

What actions are taken by the District when an alleged contamination report is received? DOGGR investigates the report, and then notifies the US EPA and the California Regional Water Control Board.

Please describe how these are reported to EPA and provide a copy of such a report. District 1 sends all annual and semi-annual EPA reports to Division HQ in Sacramento. The current HQ contact person for UIC is Tim Kustic. A copy of the 2009 report was provided.

How many such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? District 1 reported thirteen cases of alleged USDW contamination to the EPA over the last ten years. Twelve of the cases are for an ongoing incident of illegal injection from one operator in the Huntington Beach field, and one case was for injection water surfacing in the Downtown Los Angeles field. The twelve cases in the Huntington Beach Oil Field are for illegal injection by an operator. Enforcement action is currently an ongoing legal affair with the attorneys. The one case in the Downtown Los Angeles Oil Field was for injection water surfacing. Enforcement action consisted of fining the responsible operator and abandoning the injection well.

The Huntington Beach problem centers on 12 improperly abandoned injection wells that may have impacted fresh water in a residential area. There is no direct evidence of that as yet, however. The wells were directionally drilled. The alleged contamination and enforcement issue is still in litigation at HQ

A Power Point presentation on the Huntington Beach incident was provided on June 6, 2011. It contains a DOGGR report on a proposed waterflood project titled "Angus Drill Site". It identifies three improperly abandoned wells within the AOR of the project that could impact fresh water penetrated by those wells, on the basis of injection pressure effects that would exceed hydrostatic pressure at the abandoned well locations.

A civil penalty of $20,000 was issued for the Downtown L.A. Oil Field violation, which was later reduced to $10,000 and that amount was collected.

Formal Order #1007 to cease injection was issued in October 2010 to the operator of the wells within the ¼ mile radius of the Inglewood Block #1 well, which was abandoned in1972, but flows water and gas to the surface outside the casing. A copy of the Order was provided *and is included in Appendix B. Fluid flows to the surface were significantly reduced after the operator* *shut in several of the nearby injection wells, indicating that the Block #1 well is the probable cause of the flow*.

Conclusions

The final resolution of the Inglewood case is unknown as it was still under investigation at the time this information was received. The Block #1 well should be re-plugged since the well is apparently defective and allows water and gas to flow to the surface from the operation of surrounding injection wells. The operator was ordered to shut in the injection wells within a quarter mile of the well pending final determination of the cause of the fluid flow to the surface and remediation of the leak.

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District

For plugging requirements, refer to the California Code of Regulations, PRC04, sections 1723 thru 1723.8 for onshore wells, and sections 1745 thru 1745.10 for offshore wells. Historically, for onshore wells, District 1 has focused on four major plugging requirements: 1) Bottom or Zone Plug (completed well interval), 2) Upper Hydrocarbon Plug, 3) Base of Fresh water Plug, and 4) Surface Plug. Recently, HQ Sacramento issued a directive that in addition to the above plugging requirements, all wells need to have an additional requirement 5); Zonal Isolation Plug, if the well is in the AOR of an active injection project. All UIC wells in District 1 have surface casing. A cement plug is not required at the base of USDWs, but is required at the BFW. The BFW coincides with the base of USDWs in some fields. The BFW depth is based on qualitative e-log picks for SP and resistivity responses.

In the past, DOGGR required a stub plug when casing was cut and pulled from a well, but it is currently no longer required for onshore wells. The reason for this change is unknown, but it may have been an inadvertent omission in the regulations for onshore wells.

Usually, all plug depths need to be verified by the operator by tagging the plugs with the tubing string after the cement plug sets up. Offshore wells are required to have the plugs verified by placing the total weight of the tubing string, or 10,000 pounds, whichever is less.

Usually, District 1 field staff witness some part of the plugging process for each well plugged and abandoned in the district. Unwitnessed plugging operations still need to follow the minimum requirements stated in the abandonment permit. In addition, all plugging and abandonment work needs to be documented and submitted to DOGGR when the work is completed.

Describe the process used to get an idled and an orphaned well plugged.

DOGGR needs to go through the following process:

1. Notice to Test the idle well;
2. Notice of Deficiency;
3. Notice of Violation;
4. Provisional Order Imposing Civil Penalty (skip to 5 if there is no viable operator);
5. Formal Order to Abandon the Well;
6. Prepare an Abandonment Contract;
7. Put Contract out for public bid; and
8. Sign Contract with contractor and abandon well.

If a responsible operator is found during the process, then a lien would be applied to the operator's property to recoup some or all of the abandonment cost.

Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund. DOGGR has the Hazardous Idle Well Abandonment Fund. It is funded by a small assessment on an operator's production and number of idle wells. This fund is to be used for idle wells that pose an immediate danger to life, health, property, or natural resources. *How many abandoned (orphan) wells are listed in the current inventory and how is this list organized for review and/or correlation purposes?* See the Division's Orphan wells list on our website at: http://www.conservation.ca.gov/dog/idle_well/Pages/idle_well.aspx. There currently are a total of 36 orphan wells in District 1, according to the website list of orphan wells in 2009. Wells are listed by district, county, operator, lease name, number, and location.

How are the current plugging requirements different from those of 40 years ago? Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project? As mentioned before, District 1 has focused on four major plugging requirements:

1. Bottom or Zone Plug (completed well interval);
2. Upper Hydrocarbon Plug;
3. Base of Fresh water Plug; and
4. Surface Plug.

Recently, HQ Sacramento issued a directive that in addition to the above plugging requirements, all wells need to have an additional requirement: 5. Zonal Isolation Plug, if the well is in the AOR of an active injection project. This new requirement has a major and significant impact on how District 1 conducts AORs for injection projects. For example, District 1 has issued letters, as recently as a year ago, stating that wells located near active injection projects were abandoned to current standards. But, these same wells would not pass AOR if done today.

Conclusions

Statewide P&A requirements are discussed in the foregoing state level portion of the report. District 1 applies those standards and is in the process of adopting the changes discussed above regarding the "zonal isolation plug," which is a new requirement for wells within the AOR of an *active injection project. That requirement applies to existing wells as well as new injection projects and has had a major impact on the District in reviewing AOR wells for corrective actions. We support that change, but have concerns about the lack of adequate protection of USDWs in approved P&A procedures. The lack of cement at the base of USDWs and reliance on heavy mud to restrict fluid movement into USDWs is the issue. Cement is required at the BFW but not at the base of USDWs where those are located at different depths in a well. We believe cement should be placed at the base of USDWs, instead of the BFW, in the plugging operations for all wells within the AOR of an injection well, in addition to the permitted injection well.*

Another concern is that idle wells are allowed to remain inactive for 15 years or longer without requirements for remedial or plugging operations in wells that lack MI. That issue is discussed in Sections 3.4 and 3.6 of the report.

Additional staff and other resources are needed to implement the changes in plugging and AOR requirements at the district level. We were informed that the hiring of additional personnel has been authorized; however, it will take some time to recruit and train qualified professionals for the new vacancies.

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District

Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well? District 1 treats TA wells as Idle or Orphaned wells. An idle well has a viable operator, an orphaned well does not.

Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well? All Temporary Abandoned wells are subject to idle well requirements. Any well in District 1 that is returned to injection will need a permit. The permit will list the MIT requirements. These MIT requirements are usually a pressure test on the backside of the injection packer before commencing injection, and an RAT survey submitted to DOGGR within 90 days of commencing injection.

Are TA wells subject to passing a SAPT for approval of TA/idle well status and while in TA/idle status? All TA wells are subject to passing idle well requirements. A pressure test is required if the fluid level in the TA well is above the BFW. Sonic signals are the most common method to measure fluid levels. Refer to the Idle Well Management Program for more information

Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. How long may a UIC well remain in TA status before being reactivated or P&A. District 1 treats Temporary Abandoned wells as Idle or Orphaned wells, all being subjected to the requirements of Idle or Orphaned wells.

How long are these wells allowed to remain inactive before the District requires P&A or takes enforcement action? These wells are allowed to remain inactive indefinitely, as long as the operator continues to fulfill the idle well requirements. Idle well requirements are listed in PRC01, section 3206 and the MOI in Section 138. They are summarized in the above discussion of statewide issues.

Conclusions

Temporary abandonment (TA) of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements are not as rigorous in terms of MIT, repair, and timely plugging requirements. District 1 applies the statewide standards for management of idle and orphan wells. USDWs are not adequately protected in idle wells in our view. Those concerns are discussed at length in the state level conclusions and at other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs.

4.2. DISTRICT 2

This section is organized in seven parts to address questions and responses from District 2. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. The last part is an opportunity for District 2 staff to provide their own comments. Each of the remaining six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 2 has a total of 1,010 active and inactive injection wells, which represent approximately 3.2% of state injection wells. Table 4 provides numbers of wells by well type for both active and inactive wells.

Table 4. District 2 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	SC	SF	WF	AI	WD	Total	% of State Wells
Active	86	-	66	45	326	-	64	**587**	
Inactive	48	1	-	31	278	-	65	**423**	**3.19%**
Total	**134**	**1**	**66**	**76**	**604**	**-**	**129**	**1,010**	

In their response to the EPA Questionnaire, District 2 provided the following statement, and attached a copy of the State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER) questionnaire:

> In 1990, under the auspices of the IOGCC (Interstate Oil and Gas Compact Commission), states were reviewed in order to improve the oil and gas regulatory program. In 2000, a non-profit corporation was established for the purposes of moving the State review process forward and creating balanced stakeholder control of the process. In 2000, the State Review of Oil and Natural Gas Environmental Regulations, Inc. (STRONGER) reviewed California. Prior to that review, a similar "questionnaire" was completed. In the effort to not duplicate that questionnaire, it has been attached. It should be noted that while attachments are noted in the STRONGER questionnaire, they have not been included. In answering questions, where differences have occurred since the 2000 review, they are noted in this document.

The STRONGER questionnaire was reviewed for comparison and duplication of the responses to the EPA questionnaire. Many of the responses to the latter questionnaire refer to the STRONGER document and are applicable on a statewide basis, but some are not specific to the District UIC operations or are thought to be out-of-date. We have attempted to elicit additional comments from the District where that is the case. Our review is focused more on the District level implementation of the CDOGGR Class II UIC Program, with emphasis on its performance in abiding by the standards set forth in the Program Description and Memorandum of Agreement with EPA that was approved as part of the CDOGGR application for primacy of the Program. None of the other District offices made any reference to the STRONGER questionnaire.

PART I: General

This part addresses UIC program organization for District 2, and interagency coordination and changes to the UIC Program.

UIC Program Organization

Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach. See Page 47 and page 48 of STRONGER Questionnaire.

A Division organization chart that includes District 2 is provided as a separate attachment. Office engineering staff consists of a District Deputy (Senior Engineer), Permitting Engineer (Associate Oil & Gas Engineer), and four Field Engineers (Energy & Mineral Resource Engineers). Each field engineer in the Ventura (D2) District is on-call one week out of four during which time they witness permitted field tests, including MIT's and SAPT's. Field engineers also conduct environmental inspections, which includes UIC wells. In addition to verifying compliance with DOGGR environmental regulations, inspectors also inspect UIC wells to determine if they are injecting above their established MASP. MASP data is printed out prior to conducting their inspections. If the injection pressure is above the MASP, they inform the Permitting Engineer who then follows-up with the operator. File review and data management is performed by the Permitting Engineer. Qualifications for staff are established during the hiring and promotional process and differ by classification

Comments

The position descriptions are discussed in more detail in subsequent sections.

Interagency Coordination and Changes to the UIC Program

Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available. See Page 4 and Page 8 of STRONGER Questionnaire.

Please provide the attachments referenced in the STRONGER document if available. The attachments unfortunately are not available in the copy we have. This District has no local written agreements that are not statewide. The statewide agreements are with Bureau of Land

Management in which they inspect cyclic steam wells, USEPA, and State Water Resources Control Board. Attached as PDF documents are copies of those agreements.

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. No changes have been made at a District level. All statues and regulatory changes are adopted on a State-wide basis and the District adheres to those changes. See page 8 of STRONGER Questionnaire.

Comments:

The attachments referenced in the STRONGER document were not provided, but are available in the responses of other district offices. The most significant changes in the UIC Program are described in the Division Expectations Memorandum, which was provided by the District 1 office in their response to the EPA questionnaire.

PART II: Permitting and Compliance Review

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program.

Who receives the application from the operator (District or Headquarters office)? See Page 10 of STRONGER Questionnaire. This District requires two copies of the application. One copy must be in a PDF format. This copy is placed on the Division's FTP site. While proceeding thru the approval process, the application is reviewed by California Regional Water Quality Control Board and by local agencies Ventura County Planning Department)

How and by whom are permit applications screened for completeness? See Page 10 of STRONGER Questionnaire. In District 2, the permit application is screened by Steve Fields. The AOR is reviewed based upon scanned images of the well files and comparison those with the data that the operator submitted.

What are the procedures or protocols if an application is found to be incomplete? See Page 10 of STRONGER Questionnaire.

What are the professional qualifications required for staff who conduct permitting and compliance activities? See Page 11 of STRONGER Questionnaire. Qualifications for staff are established during the hiring and promotional process and differ by classification. Do those staff members meet the minimum requirements? Yes

What types of training would staff like to access if funds were available? Industry training specific to UIC wells and UIC well testing that are applicable to California unique engineering and geological conditions. We have a designated individual that was recently made to oversee our training needs and expectations.

What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful? District 2 reviews well logs and records scanned and posted into the online database and other sources such as the California Oil and Gas Fields maps and data sheets and compares that data with that submitted by the operator.

Describe any differences between the processing and requirements of commercial and noncommercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal). See Page 12 of STRONGER Questionnaire. It is our understanding that the section on Commercial Class II injection wells in the "Stronger Report" was developed for a commercial disposal project (that no longer exists) located in rural area that was not easily monitored by Division staff. The operator of this site had a history of non-compliance which is reflected by the more stringent requirements of the Stronger Report.

District 2 currently has one commercial disposal project located in the Oxnard oil field, Ventura County, operated by Anterra Energy Services, Inc. The project is located in a highly visible area and located in close proximity to the Ventura office allowing more frequent inspections of the facilities and day-to-day operations. (The project approval for this operation is attached.) The operator of the facility provides monthly reports of the source, chemical analysis and volumes of materials/fluids accepted at their site. New sources of fluids accepted at the site must comply with requirements and testing procedures established in the project approval letter. Monthly reporting is necessary due to man-power requirements since the review and approval of every new source at the time of delivery would require a significant amount of time, some outside normal work hours. *The project approval letter for the Oxnard disposal well project was not attached to this supplemental response.*

Describe any differences between the processing of a waterflood project and a CO2 EOR project. N/A in this District

Conclusions

References to the STRONGER Questionnaire above were not particularly helpful in understanding the application flow process in District 2, but the overall response is sufficient and further discussion on this point would be of little value.

The responses we received from some of the districts were not entirely consistent with the description of the fairly rigorous requirements for commercial Class II injection wells in the STRONGER document. The district responses indicated a somewhat less rigorous monitoring of injected fluids and security requirements at a well site. This concern warrants further discussion and review at the district level to ascertain whether commercial Class II operations are monitored adequately to ensure that only Class II fluids are injected into those wells.

District 2 did not provide any specifics on requirements for commercial wells in the District during the initial review process, other than the reference to the STRONGER Questionnaire. Additional information was provided subsequent to the issuance of the draft Report on the CDOGGR program review that includes a description of the monitoring and reporting *requirements for the one commercial Class II well project in District 2. The project approval letter for that project was not found attached to the supplemental response, but is not considered essential to understanding the process.*

OBJECTIVE: Understand the current compliance/file review process.

The file review consists of determining whether the well is operating in accordance with regulations. The file reviews consists of periodically determining whether a mechanical integrity test has been performed, both internally and external as specified, whether the well is operating in accordance with specific approved injection pressure, and whether wells that permission to inject has been rescinded have indeed, stopped injection operations. The answers are found in performing database queries in several databases. Documentation of a file review is maintained in the District UIC database that includes the date that the file review was conducted and the person that conducted the file review. The file reviews are performed on a minimum of once a month and sometimes at greater time periods if time permits. The ease of the file report is facilitated by the use of a complex Access database linked to the Production/Injection Reporting system of the Division and the knowledge of running queries on the databases.

Is there a focus on compliance history and high priority areas such as residential or where UDSWs are present and at higher risk from injection well construction and/or operation? Division UIC regulations are the same for all areas and as a result the file review process is the same for all UIC wells. All District operators are required to comply with all Division regulations. We do, of course place increased emphasis on operators who have a history of non-compliance.

Who performs the file review and what are the qualifications of the reviewers? UIC Permitting Engineer and Field Engineers (See above). Over a one-year period, what percentage of total UIC permits/wells receives a review? 100% of all UIC wells are reviewed each year. The file reviews are done as indicated above at least monthly. The results are documented in the Access database if problems are found in the file review.

How is the quality of a file review assured and subsequently documented? The Districts UIC database maintains a date and the person whom conducted the reviewed. The queries used to review the UIC database and the injection statistics are pre-programmed to be user friendly.

When deficiencies are discovered during the review, what actions are taken to correct the deficiency? The operator is notified either by telephone, email or letter or a combination of any of them.

How much time is allowed for the operator to correct a deficiency; for a significant non-compliance versus other deficiencies? 30 days for SNCs and 60 days for other deficiencies, but not constrained by the 30-day limit if correction is an urgent matter. A formal order can be issued immediately when necessary.

How is the file review different from the annual project review? The difference between a project review and a file review is the same as the review for water-disposal projects. The differences for enhanced recovery projects are that a review of the project effectiveness is conducted. (i.e., is the injection enhancing oil production?) The percentage of projects reviewed using this method is less than 10% per year. Please note that 100% of the UIC wells are reviewed while a much lower number of the projects are reviewed.

Supplemental District Response:

The purpose of a Project Review is to:

- Determine if the injection project is still consistent with the permit conditions and is meeting its purpose.
- Ensure that all required testing has been performed.
- Determine if there have been any changes to the project, including if any wells within the AOR have been drilled.
- Confirm that the injection fluid is confined to the permitted zone of injection.
- Confirm that no damage is occurring as a result of the injection project.

The purpose of a File Review is similar with an emphasis on individual wells within the project.

At a minimum, the following items must be reviewed A (except #5 and #6) to be considered a **File Review:**

1. Query the District database to determine if wells are in compliance with MIT requirements.
2. Run a query of the UIC database maintained in Headquarters (Injection Reports) to determine if wells that are not currently allowed to be under injection are showing reported injection by the operator.
3. Query the District database to compare the reported injection pressure (Headquarters Database) versus the maximum allowable injection pressure in the District database.
4. Review and/or witness all mechanical integrity tests submitted by the operator to verify that fluid is confined to the permitted zone of injection.
5. Evaluate proposals to conduct operations on wells to determine that the well construction is in compliance and that the well work was properly completed in accordance with the permit.
6. Review results from inspections to determine the accuracy of items #2 and #3.

Conclusions

Project reviews should be performed at least annually to be in compliance with the CDOGGR Program Description, the MOI requirements described at Section 170.13.3.1 and the project approval letters. Annual meetings with operators to review active projects is an important element of the UIC Program, especially for those projects that have ongoing compliance issues that go unresolved within acceptable timelines. The lack of a project review is somewhat alleviated by the fact that individual wells in disposal projects are reviewed by means of the required annual RAT survey. However, that does not fully apply to enhanced recovery wells because waterflood wells are tested only on a two-year cycle and steamflood wells on a five-year cycle. Also, RATs will not detect a casing leak above the packer, which is normally set just above the injection zone.

The District response states that 100 percent of UIC wells are reviewed each year, which may compensate for the lack of a project review if it consists of a complete file review. However, we cannot be certain that every well receives a complete file review each year without a more in-depth review of the file review procedures in District 2. The District 2 Office has since provided a more complete description of the project review and file review processes in their supplemental response and has adequately addressed our concerns in that regard.

OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

The federal definition of USDWs (underground sources of drinking water) is found in the regulations at 40 CFR §144.3 which includes that an aquifer "...contains fewer than 10,000 mg/L total dissolved solids". Please distinguish when responses to questions pertaining to USDWs differ from the federal definition and describe how this difference is handled. This may apply to AOR/ZEI and MIT responses in other sections as well.

This complete section can be found on Page 14 of the STRONGER Questionnaire. A rough estimate is that over 75% are in fields in which no USDW is found.

What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Source of Drinking Water (USDWs)? If not, how are USDWs otherwise protected? **The answer is the same Statewide.**

Please describe adequate casing and cementing requirements for new injection wells or identify the reference and location where this information can be found. Is cement placement required through all USDWS penetrated by a well? No.

If not, how are USDWs otherwise protected? Division casing and cementing regulations are found in the California Code of Regulations (CCR) Sections 1722.2 (Casing Program), 1722.3 (Casing Requirements), and 1722.4 (Cementing Casing). USDW's are protected from the assumption that drilling mud will protect the USDW's from non-USDW when cement is not in the wellbore for protection. We at all times require cement to be placed immediately above the injection zone in all wells. Annular cement is required to at least 500 feet above the injection zone in all wells completed since 1978. Wells completed prior to 1978 are required to have at least 100 feet of cement if measured, or 150 feet if calculated, above the top of the injection zone.

What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected? **The answer is the same Statewide.**

P*lease describe adequate casing and cementing requirements for converted injection wells or identify the reference and location where this information can be found.* The requirements for new injection wells and converted injection wells are the same. CCR sections cited above apply to converted injection wells. When cement is not present at the base of USDW's, the USDW's are protected by ensuring that injection formation is confined to the permitted zone by having cement in the annulus immediately above the permitted zone. We use a rule-of-thumb of 100 feet if determined by a CBL or equivalent or 150 feet if calculated. Remedial cementing is required as a condition for conversion. This may mean reworking a well such as squeezing cementing to ensure that that is no annuli open (meaning no cement) above the permitted injection zone. This District does not allow the use of heavy weight drilling mud to be a deterrent to upward migration (contrary to other states). This Division requires cement to be immediately above the permitted injection zone. We may require a previously plugged and abandoned well to be re-enter and squeeze with cement to ensure that the annuli is covered with cement but we have not required a well to be plugged and abandoned. (just fix the problem) All these are done when an AOR reveals that a well exists that has a possible conduit from the permitted injection zone to a zone outside the permitted injection zone. Annular cement is required to at least 500 feet above the injection zone in all wells completed since 1978. Wells completed prior to 1978 are required to have at least 100 feet of cement if measured, or 150 feet if calculated, above the top of the injection zone.

Please discuss the implementation of the standards(expectations) described in the DOGGR memorandum of May 20, 2010 titled "Underground Injection Control (UIC) Program Expectations" as it applies to the above two questions regarding requirements for new and converted injection well. The HQ "Expectations" memorandum of May 20, 2010 is considered a draft document by District 2 at this point, subject to modification. Consequently, the standards have not yet been implemented

What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field? **The answer is the same Statewide.**

Packer and tubing requirements: Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? **The answer is the same Statewide.**

How does the District assure that fluids are confined to the permitted injection zone at the injection well and within the area of review? The District relies on a competent AOR in which there exists no potential for migration outside (meaning up or down) the permitted zone of injection. The District assures that fluids are confined to the permitted injection zone at the injection wells by ensuring that MITs are conducted in accordance with regulations. Beyond the wellbore, the Division assumes that if injection pressure is maintained below the fracture pressure of the injection zone or the fracture pressure of the cap rock overlying the injection zone, fluids will be confined to the permitted zone. In addition is the reservoir pressure is maintained below the original zone pressure, we are assuming the injection fluid is confined to the permitted zone. In non-hydrocarbon zones, we make an assumption the fluid will be confined to the permitted zone by the MITs, the competent AOR, the injection pressure is maintained below fracture pressure of the permitted zone and of the cap rock and maintaining the reservoir pressure to below hydrostatic pressure.

How is it possible to maintain reservoir pressure below hydrostatic pressure in a non-hydrocarbon bearing zone (disposal wells) when the initial reservoir pressure is the normal hydrostatic pressure? Disposal is not allowed if hydrostatic pressure is exceeded. Injection is permitted only into underpressured zones in District 2, such as depleted oil producing zones.

Packer and tubing requirements: Are packers and tubing routinely required for all newly completed and converted wells? Yes.

If there are exceptions, what criteria are used? See CCR Section 1724.10(g) below. What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? **The answer is the same Statewide.**

Please describe the alternative requirements for annular pressure testing in District 2. CCR Section 1724.10(g) requires that all injection wells, except steam, air, and pipeline quality gas injections wells, shall be equipped with tubing and packer…It goes on to say…exceptions may be made when there is:

1. No evidence of fresh water-bearing strata,
2. More than one string of casing cemented below the base of fresh water,
3. Other justification, as determined by the district deputy, based on documented evidence that fresh water and oil zones can be protected without the use of tubing and packer.

CCR Section 1724.10(j) (1) requires that each injection well must pass a pressure test of the casing tubing annulus. An alternative method (not a requirement) to verify casing integrity is a casing caliper casing inspection log. This log determines wall thickness of the casing and can identity holes.

This District only monitors the annuli between the packer and tubing and the casing, thus there is no alternative requirements for pressure testing casing annulus when tubing and packer do not exists as there is no tubing/casing annuli... However we do ensure, as stated in the answer to the question above, that monitoring of the casing annuli is not necessary. However, the casing can be pressure tested by use of setting a temporary bridge plug above the perforations or the use of the ADA test. This District does not have any tubingless configurations at this time.

Are dual (multiple) completions permitted? What requirements are different than single completions? What types? This District has no dual completions permitted.

How are the locations of USDWs determined? Does the District consult with other state and federal water resource agencies regarding USDW information? See Page 16 of STRONGER Questionnaire.

The STRONGER document discusses "fresh water" (3000 mg/L TDS or less) but ***not*** *USDWs specifically as far as I could discern. Please discuss how the location of USDWs is done in District 2.* USDW's are determined by a general knowledge of the formation waters in each of the fields. This is done either by direct measurements of the formation waters or by using direct measurements and correlating them with calculations using electric logs. State Regional Water Control Board and local water agencies do not maintain data of zones having water quality greater than 3000 mg/L TDS.

How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated? This office does not use the concept of a confining zone. We use the concept that injection is confined to the permitted zone only. Injection outside the permitted zone is not allowed at all.

Please clarify. The confining system within the AOR must be considered in permitting an injection well. If there is no confining system in the AOR, how is injection confined to the permitted injection zone? The concept of "confining zone" is a term that other States use. We use the more general term as "cap rock". Hydrocarbon zones are the result of oil migrating from the source rock to the reservoir rock with confinement resulting from (fault) traps or lithology (permeability) traps such as shale formations.(i.e., cap rock) Both can be verified by log and geologic interpretation. As part of the project application, the operator is required to provide reservoir characteristics for each injection zone (CCR Section 1724.7(a) (2), such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure. The original pressure is the result of confinement. In addition, step rate tests and leak-off tests can determine the fracture gradient for a formation. Limiting injection pressures below the fracture gradient will prevent vertical and horizontal fracture propagation. Limiting reservoir pressure to below original reservoir pressure will prevent fluid from exiting the intended zone.

Which two projects permit injection into undepleted reservoirs and have ZEIs been calculated for those wells? The response provided on June 6, 2011 indicated that static reservoir pressures are not above hydrostatic pressures in any injection projects in District 2 as of their last report. The question concerns injection into undepleted reservoirs. The District's ***verbal*** *response during the office visit was that disposal occurs in depleted reservoirs* <u>***in all but two projects in District 2***</u>***.*** *The District 2 office did not question that statement added to the final questionnaire sent to District 2 on October 21, 2010,* <u>*but it may have been overlooked or the question above may have been misunderstood*</u>*. The term "undepleted" should be replaced with "nonhydrocarbon bearing" or "normally pressured" for clarification purposes. The question should be rephrased as follows: Have static reservoir pressures exceeded the normal hydrostatic* *pressure in any wells and if so have they been shut in? Apparently, the response is that no wells were injecting under those conditions as the last report and earlier responses indicate that if that occurs, the well is required to cease injection. In fact, District 2 reported that three wells had been shut in due to reservoir pressures exceeding hydrostatic pressures.*

Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well. See Page 17 of STRONGER Questionnaire.

Is annulus pressure monitored and recorded at least weekly for SWD wells and monthly for ER wells? Is it reported to DOGGR monthly or annually? CCR Section 1724.10(c) requires operators to file an injection report to the Division on or before the 30th day of each month for the preceding month. Tubing pressure is recorded and provided with these injection reports. Casing pressure monitoring is more dependent on the operator. Unlike other states, this District does not allow a pressurized casing/tubing annulus. The casing/tubing annulus pressure may indicate that there is a problem. For example: Aera Energy LLC, who operates the over 450 waterflood wells (nearly 50% of the UIC wells in the District) monitors casing pressure daily with data fed to an operations control room. Other operators in the district monitor their injection wells by having their pumpers inspect them on a daily basis varying by operator. The district conducts annual inspections where we inspect both tubing and casing pressures.

How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose. See Page 17 of STRONGER Questionnaire. The current default fracture gradient in DO2 is 0.8 psi/foot if a SRT is not performed for a well. A gradient of 1.0 is the standard for deeper zones in the Ventura Field, but with monitoring in wells completed above the waterflood injection zone. These standards may change after the “Expectations” memo is finalized.

The memo states that SRTs will be required in new wells and injection pressure must be maintained below the fracture pressure in existing wells, as determined by approved SRTs, in accordance with CCR 1724.10(l). Step rate test reports were reviewed and examples were provided during the office visit

Conclusions

References to the STRONGER Questionnaire above were not particularly helpful in understanding the technical review and related aspects of the permit/file review process in District 2. The District 2 Office provided a more complete description of the permit/ file review processes in the follow-up response to this objective, which has provided the information needed for a complete review of those processes.

USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance of total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement.

In our view, CDOGGR should consider modification of cementing requirements to require placement of cement at base of all USDWs penetrated by a well, not just at the BFW (3,000 mg/L or less TDS) zones, above the injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells. Cement plugs should be placed at the base of USDWs during P&A or casing repair operations in wells located within the AOR of an injection well. Monitoring to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.

District 2 states that disposal is permitted only into underpressured zones, such as depleted oil producing zones, in all but two projects, and pressure is not allowed to exceed hydrostatic pressure whether in depleted oil zones or nonhydrocarbon bearing zones. We requested more information on the two projects that inject into the latter, but received none before the draft Report was submitted for EPA and DOGGR review. We received a written response on June 6, 2011 indicating possible confusion about the question. Nonetheless, injection is apparently not allowed if the static reservoir pressure exceeds hydrostatic pressure, whether in depleted oil zones or nonhydrocarbon zones or undepleted oil zones. Injection into depleted zones will minimize the risk of the ZEI exceeding the quarter-mile fixed radius AOR as long as the hydrostatic pressure of USDWs is not exceeded over the life of a well. The risk increases if the USDW is below the normal hydrostatic pressure. This can occur when the USDW is pumped and drawn down over a prolonged period of time. In any case, calculated ZEIs should be performed for disposal projects. Also, periodic monitoring of static reservoir pressure in disposal wells by means of pressure fall-off tests would be an effective deterrent to the ZEI exceeding the quarter-mile AOR. Enhanced recovery projects, however, are not likely to experience significant and/or long-term pressure increases unless cumulative injected fluid volumes exceed fluid withdrawals over the life of the project, which is usually not the case.

The historical fracture gradient assumption of 0.8 psi/foot for District 2 is believed to be considerably higher than the actual gradient in some wells, based on a review of available SRT data and the other data presented in CDOGGR Publication M13. District 2 has required very few SRTs in the past. We understand that SRTs will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives from the Division Expectations Memorandum are fully implemented at the District level. We support that directive with the recommendation that bottom hole as well as surface pressure gauges be used in SRTs. Bottom hole pressure measurements remove the uncertainty of friction loss estimates during a test and provide a more accurate measure of formation fracture gradient.

Maximum allowable surface injection pressures are usually set at 90 to 95% of the fracture pressure or the highest pressure achieved if fracture pressure was not reached during a SRT. Where the SRT data and the fracture pressure determined from those data are not 90 or 95% reliable, the MASP should be set at a more conservative value.

OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

How is the Area of Review (AOR) determined for enhanced recovery wells or projects? The AOR is determined by a fixed distance of ¼ mile from each injection well unless it can be easily determined that a greater distance is required based on the reservoir and geological conditions.

How is the AOR determined for saltwater disposal wells? **Same as above**

How is the AOR determined for commercial saltwater disposal wells? **Same as above**

How is the AOR determined for CO2 EOR wells? **N/A**

How are AORs determined for area permits and other multi-well projects? **N/A**

Please clarify. Are there no area or multi-well projects or permits in the District? Project approvals are issued for multi-well projects, but each well must be permitted before injection is authorized. That includes an AOR review and corrective action considerations in the ¼ mile radius from each well. ZEIs are not calculated for most projects and wells as explained in the foregoing.

Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? **No.** *If not, are they performed for all disposal well permits? What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved?* Since we do not use ZEI calculations, none in District 2. District staff stated that the complex geology in the Ventura District is not amenable to a meaningful calculation of the ZEI.

Please elaborate on the reasons for not performing ZEI calculations or modeling, especially for disposal wells. We feel that the fixed rate for an AOR of a "minimum of ¼ mile" far exceeds any ZEI calculations that have been submitted to us. Some project applications that have been submitted attempted to use calculated ZEI that we have reviewed and suggest that the ¼ mile is too great. We feel that these are in error and we stick to the ¼ mile unless geological knowledge suggests that ¼ mile is not great enough. *Has District 2 implemented the ZEI standards contained in the "expectations" memorandum of May 20, 2010?* No. See above responses to this question

Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects. This Division has a policy not to allow the static reservoir pressure to be above hydrostatic pressure. The requirements are that in a "poor boy" pressure-fall off test, the well is shut-in and if the well does not dropped to zero pressure, the operator is required to determine the cause. Injection may not be allowed to continue until the cause is determined.

Does this apply to disposal wells in which the initial pressure was at or near the normal hydrostatic pressure? **Yes.** *Are most disposal wells completed in depleted oil or gas zones? Please elaborate.* **Yes.** *What is the typical time interval for the pressure to fail to drop to zero* *that requires a well to be shut in?* It must drop to zero or the operator must determine the reasons for not dropping to zero before injection can continue. *Are standard pressure fall-off tests required in disposal wells on a regular basis or when the pressure does not drop to zero after a well is shut in?* We do not regularly require standard pressure fall-off tests because we have evidence that the current active disposal wells will drop to zero.

Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples. Based on previous responses, the AOR is not expanded, but when fall-off pressure fails to fall to zero after a reasonable time when a well is deactivated the well must cease injection until the cause is determined. Authorization to inject is rescinded if the final fall-off pressure is due to excessive static reservoir pressure. The following are examples of wells that were reportedly shut in for exceeding hydrostatic pressures.

- Vintage Production California LLC well “Ojai” 111, Ojai oil field.
- Arco Oil & Gas well “EP Clark” 15, Timber Canyon oil field.
- Ample Resources well “Snow” 5, Temescal oil field.

What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR? **N/A**

Describe any corrective action considerations or requirements associated with permits issued historically and for permits issued since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? Please list the most recent examples. During either a new project application or when a new well is proposed, an AOR is done. In the event that any remedial action is required then it is done at that time. This number is very low as operator determine that the remedial action is more costly than the project, (i.e., they will attempt to find an alternative well to be used). However we have required operators to plug and re-abandon wells in which the well determined to be a “possible” conduit of the injection zone to a zone outside the permitted zone.

Any historical or recent examples of wells that required plugging and abandonment? Please list examples. Aera Energy LLC, Ventura field, D&N “Deep Zone” waterflood project. Over 50 wells were either plugged-back out of the intended zone of injection or permanently plugged and abandoned. Currently we are undertaking a project in which there are 6 wells that are requiring remedial action. The operator is not be required to “plug and abandon” any wells but is being required to just “fix” the wells to ensure confinement of the injection fluid to the proposed zone. The District rarely requires a well to be plugged and abandoned but rather that a well be “fixed” to correct the problem.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? They are required to perform the work on any well that is deemed “defective”.

Conclusions

ZEI determinations are not performed for District 2 injection wells. AORs are based on a quarter-mile fixed radius from the injection well, even for disposal wells. That may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project, and reservoir pressure is maintained at a level that does not cause the position of the pressure front to expand beyond the quarter-mile AOR boundary. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. However, reservoir pressure will increase in depleted and other underpressured reservoirs if there are no withdrawals from the reservoir over the life of a disposal well. That increase could eventually cause the reservoir pressure to exceed the normal hydrostatic pressure of the USDWs and lead to the ZEI exceeding the fixed radius AOR.

Where injection is into a depleted or producing zone, the fixed radius quarter-mile AOR may be appropriate, as is apparently the case in most of the District 2 disposal wells. A ZEI analysis should be performed for all disposal wells, however, to determine whether the quarter-mile AOR is appropriate over the life of the project. This also applies to EOR projects if injected fluid volumes will exceed produced fluid volumes for an extended period, allowing reservoir pressures to increase and the pressure front to potentially expand beyond the quarter-mile AOR. The District 2 practice of monitoring static reservoir pressures to ensure that they do not exceed normal hydrostatic pressure should reduce the risk of exceeding the AOR. This may not be the case, however, where the static pressure of USDWs is less than the normal hydrostatic pressure, which can occur due to pumping the aquifer over a prolonged period and/or natural causes. District staff cited three examples of wells that were shut in for exceeding hydrostatic pressures.

The Division Expectations Memorandum (Appendix A3) is considered a draft document by District 2 at this point, and subject to modification. Consequently, the standards have not yet been implemented. Problem wells outside of the quarter-mile AOR but within the possibly larger ZEI were not addressed in the past. With the full implementation of this procedure, those wells will be subject to corrective action considerations, and protection of USDWs will be significantly improved. We fully support the Division requirement to review ZEI/AORs and require corrective action as a condition for issuing permits for new drills, redrills, conversions, and return to injection operations.

The District stated that standard fall-off tests are not usually required because the shut-in pressure falls to zero in most District 2 disposal wells. Monitoring shut-in pressures may provide the necessary reservoir pressure data to limit pressure buildup and ensure that the pressure front is contained within the AOR in those wells. Where shut-in pressure fails to fall to zero in a timely fashion, fall-off tests could be run to determine the static reservoir pressure. The MOI at section 170.7.1.1 states that, in most cases, a pressure fall-off test should be conducted periodically on water-disposal wells to ensure that the zone pressure is below hydrostatic. We concur with that statement, but recommend that bottom hole pressures be measured in addition to surface pressures during a fall-off test. Not exceeding the hydrostatic pressure in overlying USDWs should be the goal rather than the hydrostatic pressure in the injection zone since the

USDWs may be underpressured relative to the disposal zone. That can occur where the USDW hydrostatic head has been reduced due to pumping and/or natural causes.

OBJECTIVE: Understand the administrative permit application components.

Describe the public notification and participation process for applications under consideration by DOGGR. The public notification and participation process is the same statewide. *Where do we find this information as it applies to District 2?* Division Manual of Instruction (MOI) Section 170 for UIC projects. This is the same public notification system that is used statewide.

When and where is public hearing opportunity held on an application and how are they conducted? When was the last public hearing held in your District? No public hearing has ever been conducted in this District

What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed? See Page 19 of STRONGER Questionnaire.

Please clarify. If bonds are not required for the life of a well or project or until a well is plugged and abandoned, what determines when a bond can be released? Please provide examples, if any exist, of bonds that were collected to plug wells that were not plugged and abandoned by the permittee. Division onshore bonding requirements are found in the California Public Resources Codes, Sections 3204 and 3205. Bonding requirements do not change among the Districts. As part of the Division's formal order process, operators whose wells have been declared deserted can be abandoned with the operators existing bond coverage. A few examples for District 2 include GEO Petroleum ($250,000 blanket bond), Murray-Teague and Associates ($100,000 blanket bond), ITG (5 - $10,000 individual well bonds).

Conclusions

The administrative permit application components are essentially the same statewide and are described in the MOI. We express our concerns about the financial assurance requirements in Section 3.7.

OBJECTIVE: Understand the process for aquifer exemptions

No aquifer exemption has been done in this District but see Page 20 of STRONGER Questionnaire...

Conclusions

See Sections 2.0 and 3.0 for additional information on the aquifer exemption process at the state level.

PART III: Inspections

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District.

Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas where USDWS are present. Fresh water areas: Fillmore, Holser, Oxnard, Santa Clara Avenue, Saticoy, Sespe (Sections 20 & 21 of T4N, R19W), South Mountain (wells along the Santa Clara River), Ventura field ("RBU" leases), West Montalvo, all fields in Los Angeles County of District 2. Near (not within) residential areas: Part of the Ventura field along Highway 33, Placerita field is within the City of Santa Clarita, Cascade field is within the City of Los Angeles.

How are inspection priorities determined? The District attempts to witness all permitted tests. In the event a field engineer is not available, the lowest priority test is waived. In addition, the District policy is to conduct inspections on all wells on an annual basis, including UIC wells.

What professional qualifications and/or experience are required by DOGGR to be an inspector? Qualifications for the Energy & Mineral Resource Engineer are established by Human Resources and qualified candidates are then hired through a structured oral exam.

Does District staff have the necessary qualifications and/or experience? Only candidates meeting the minimum established qualifications are eligible to interview. Once hired, new-hires go through an employee orientation, including field training with experienced field staff. This training typically lasts three-to-four months before they go into the on-call field rotation (by themselves). Field engineers are instructed to contact the District Deputy or Permitting Engineer should they encounter any field situation they are not familiar with or if they have any questions/concerns.

What types of training do inspectors access or would like to access if funds were available? Industry training specific to California UIC wells and well testing in California. Additional data can be seen on Page 24 of STRONGER Questionnaire.

What tools do the inspectors utilize? To name a few of the basic tools, field equipment includes a state vehicle, safety equipment (including an H2S detector and cell phone), Trimble GPS to obtain lat/long readings, equipment to verify mud weight and gel strength on abandonments, and an office computer to input field data and generate inspection sheets prior to going into the field.

Are there additional tools that you can identify that would be useful? Hand-held GPS device, laptops with user-friendly program that could easily adapt for harsh environments in the field work with appropriate training.

Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training. As a new-hire they receive HQ orientation, district orientation, office training and actual field training with an experienced field staff. They only are placed in the on-call field rotation once the District Deputy has verified that they are adequately prepared. In addition, engineering staff attends industry training on a variety of subjects through the PTTC and during industry and professional organization conferences. A PowerPoint UIC training presentation has been prepared at the District level that all field staff have seen.

What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process? If a situation is becoming a compliance issue, the District Deputy assists them in collecting the necessary field data for enforcement cases, a potential formal order, and hearing. In general terms, the District Deputy prepares formal orders and coordinates these actions with HQ and Department and DOJ legal counsel.

Conclusions

Injection wells apparently are not prioritized for inspections based on proximity to residential areas or areas where USDWs are present. It is District policy to conduct inspections on all wells on an annual basis and the District attempts to witness all permitted tests.

The professional qualification and/or work experience requirements for District 2 UIC inspectors are similar if not identical to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. Training and qualifications of inspectors appears to be adequate in most areas, based on district responses and discussions with staff at the District 2 office. More training may be needed in witnessing and analyzing RAT surveys, however, in addition to other UIC operations, especially for new hires.

We were informed that the Division has authorized the employment of several additional UIC staff members statewide. That increase in staff should significantly improve the District's ability to process new project applications and perform the other UIC functions on a more timely basis.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District.

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations. Please refer to the attachment. *No attachment was found.*

How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database in which the inspection data is stored, or attach the inspection verification documentation. See above discussion and Page 25 of STRONGER Questionnaire. The District maintains an Access database.

Is the operator given advance notice of inspection and does the operator receive a copy of the report? See Page 26 of STRONGER Questionnaire.

Describe the reporting and follow-up procedures used in the inspection program when there are violations. When there are violations, they are followed-up by the individual creating the violations along with notification to the District Deputy that follow-up is due via a programmed email system.

Please elaborate on time limits for corrective action by the operator and follow-up inspections by District staff. See earlier responses regarding time limits for corrective action by the operator. Follow up inspections to ensure compliance are conducted by staff with Bruce in the lead for UIC violations and Steve in the lead for non-UIC violations.

How is the District notified of emergency situations regarding Class II wells and related incidents such as spills? See Page 28 of STRONGER Questionnaire. Update: OES was renamed as the California Emergency Management Agency after the STRONGER Questionnaire was completed in 2000.

What type(s) of emergency situations has/have been reported involving UIC permitted wells? None in last 5 years

Were any reported since inception of the UIC program? Please list and describe those incidents. In the early 1980's we had, because of an injection well, fluid appear at the surface. We did a thorough investigation as to whether a USDW existed at the site. We have data that a USDW existed some 2 miles away. After researching, contacting our local water District, and California Regional Water Quality Control Board, it was determined that no USDW or fresh water aquifer was found at the location of the well.

Also in the 1980's we again had a case of fluid surfacing as a result of injection. The fluid appeared near a water source well in which the formation was a USDW. By comparing the results of the analysis from the water source well, we concluded that while formation fluid containing less than 5,000 mg/L TD did enter the USDW, it was not detected in the nearby water source well. This incident was reported to California Regional Water Quality Control and they took no action. The RWQB is responsible for management of remedial operations where contamination has occurred due to a violation.

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. District Access database.

Please describe the database, its contents, and how it is utilized to ensure compliance. The Access database system was demonstrated during the visit to the District 2 office. *Samples of the database screens were printed and provided during the visit.*

How are the injection pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily *accessible database? If not, how does the District verify compliance with the MASP?* Yes, all injection wells have an approved MASP. Inspectors have an up-to-date list of the MASPs from the Access database when they perform inspections.

Conclusions

The District refers to the STRONGER questionnaire in many of their responses. Those references are helpful, but not necessarily representative of District level implementation of the UIC Program. The STRONGER document indicates the operators are usually not given advance notice of inspections, but do receive a copy of the report. Advance notice is necessary where pressure gauges need to be installed by the operator or when injection fluid samples are taken, but short notice is given in those cases to facilitate observation of violations, if present.

The District has developed and utilizes an Access database system for well data management. It was demonstrated during the on-site visit and appears to be more than adequate for the purpose of managing and tracking the voluminous amount of data received and gathered by the District. Maximum Allowed Surface Pressure for each well is recorded in the database and inspectors use those data when they perform inspections. The Access data management system will soon be replaced by the CalWIMS database, which is a system that will be utilized by all district offices when fully implemented at the district level later this year. CalWIMS is considered a substantial improvement to the various systems currently in use at the district offices, and it should improve coordination and reporting of well data on a more uniform basis statewide.

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and Implementation.

What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability. See Page 34 of STRONGER Questionnaire.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? See Page 35 of STRONGER Questionnaire. *Please explain why these criteria were selected. How is the actual test pressure in individual wells selected if not at the minimum of 200 psi?* This is the current standard statewide, but is under consideration to increase the test pressure to the MASP. The 200 psi minimum pressure may still apply if no USDWs are penetrated by a well.

If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM? Not allowed

If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail? Not used.

Please elaborate. Are cement bond logs acceptable for determination of Part 2 MI? No. Are they required in new injection wells? No. *Were CBLs commonly run in existing wells in District 2?* **Yes**, but they are not required. *Are cement records and/or CBLs reviewed during the technical review for issuance of a UIC permit?* **Yes.** *Is the absence of annular cement at the base of USDWs acceptable in new and converted injection wells?* **Yes**, as long as there is cement immediately above the zone of injection. *In existing wells?* **Yes.** We are assuming that the term "existing wells" is a USEPA term in that they are UIC wells that existed before primacy. We have an informal agreement with USEPA that since all of our existing wells have met post-primacy requirements, we do not maintain a listing of "existing" well anymore.

Existing wells are wells that were authorized to inject prior to primacy and other existing wells that were permitted post-primacy for disposal operations. Existing enhanced recovery wells do not require a UIC permit under federal UIC regulations unless the operator fails to maintain compliance and USDWs may be impacted by that failure.

Part 2 MIT requirement, "Injection wells shall pass a second demonstration of mechanical integrity. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer. By definition, cement records in our District do not satisfy the requirement to ensure the packer and tubing are not leaking. Cement bond logs can be used to evaluate the project wells during the AOR.

Part II MI relates to fluid movement in the casing/wellbore annulus, but not the tubing/casing annulus. It is unclear how Part II MI is determined from the response given above if cement records and CBLs are not acceptable. Are temperature or noise logs or other logs/surveys required? Very few static temperature logs or noise logs/surveys are run in District 2.

Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined? See Page 38 of STRONGER Questionnaire.

What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone? Every Year for SWD. Every other Year for Waterflood. Every 5 years for steamflood.

Does it vary depending on well conditions, such as in a well with only one string of casing and no annular cement at the base of USDWs or fresh water or in wells with no packer or tubing installed? The standard schedule doesn't vary in District 2. MITs are required whenever the packer is unseated, however.

Describe the follow-up and typical enforcement actions for MIT failures. Follow as per instruction that all Districts follow. *Please describe as it applies to District 2 or identify where* *that information can be found.* Division Manual of Instruction (MOI) Section 170 for UIC projects. The MOI for UIC projects will be updated in January, 2011.

Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed? See Page 40 of STRONGER Questionnaire.

What percentage of MITs is witnessed in District 2? While we witness less than 5% of all MIT's, all MIT's are reviewed. We emphasize the witnessing of SWD wells. It should be noted that while our requirements are to have EOR wells have a mechanical integrity test once every 2 years, our wells are surveyed far more than the requirement. For example we currently in one field, there are over 400 active waterflood wells in which in the last two years we have reviewed nearly 850 mechanical integrity tests on these wells.

Why are less than 5% of all MITs witnessed? This percent applies to RATs, not SAPTs. SAPTs and P&A operations are given a much higher priority to witness. BOP tests and spill response are given the highest priority. RATs are performed by operators more frequently than required and District 2 lacks the manpower to witness more of them.

In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate. See Page 41-44 of STRONGER Questionnaire.

Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures? See Page 45 of STRONGER Questionnaire.

If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work? The District will witness the repair operation. We do not witness operations that require a repair to tubing and/or packer. We do require copies of reports that document the repair work and a follow-up MIT test

What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time? This District has had very few failures in the last 20 years. The rate is about 5 per year and has not changed.

What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well? See Page 45 of STRONGER Questionnaire.

This question refers to MI failures discovered as a result of routine annulus pressure monitoring rather than MITs. The STRONGER document does not appear to address this question. Please describe the procedures/requirements and corrective measures applied in District 2. DO2 Written Response: If discovered as a result of a routine annulus pressure monitoring, the inspector notifies Steve Fields and the operator is contacted to prepare a reason for pressure on the annulus. However, in the event that the pressure is equal to the injection pressure, the operator is required to shut in the injection well and perform remedial action prior to putting the well back on injection. (As this sometimes may indicate a hole in the tubing or packer is leaking) A follow-up MIT survey, both a test of the casing/tubing annulus and a MIT would also be required. The same conditions would apply if the failure was reported by an operator as part of their routine inspections. If annulus pressure is less than injection pressure, an investigation is conducted. This may indicate holes (or even perforations) in casing above the packer, natural buildup of pressure to temperature changes, or several other reasons. At this time, the operator must determine the reason why there is pressure on the annuli. Injection is allowed.

Describe the data management system used in the various components of the MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure. Access Database that indicates when a next survey is due.

Please elaborate on how the system is used to manage follow-up on MI failures. Can the system be used to generate reports and notices? Yes. *A full demonstration of the system was provided during the office visit. The system appears more than adequate for District level operations, but will eventually be replaced by a statewide database named CALWIMs, which is still under development. Printouts of various screens were provided.*

Conclusions

The District refers to the STRONGER questionnaire in many of their responses. Those references are helpful, but not necessarily representative of District level implementation of the UIC Program. The SAPT requirements as described in the District 1 Discussions (Section 4.1) and the MOI are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in Sections 2.0, 3.0, and 4.1 of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure. More frequent testing and/or monitoring of casing pressure should be required, however, when a well is tested at less than the MASP.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. Increasing that to 30 minutes would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes described above, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

The District states that less than five percent of MITs are witnessed, which is well below the federal UIC guidelines to witness at least 25 percent of MITs. Witnessing SAPTS is given a much higher priority than RATs, however, especially for disposal wells. The District states that 70 percent of SAPTs are witnessed. RATs are required annually in disposal wells and every two years in waterflood wells, however, which is more often than the five year cycle prescribed for MITs in federal regulations. Witnessing a larger percentage of RATs, with a goal to witness RATs in all wells at least once every five years, would be more consistent with federal guidelines.

Witnessing SAPTs in District 2 should be given a high priority, especially since SAPTs are required only every five years or whenever the packer is reset during a workover operation or at *the Director's discretion. However, annual inspections of wells can reveal a MI failure if pressure is observed on the casing/tubing annulus, and the operator would be required to shut in the well if that were the case. If a pressure gauge is not installed on the annulus, however, there would be no way to observe pressure on the annulus, and permanent installation of a gauge on the annulus is not a requirement. If the operator is given advance notice of the inspection, a gauge could be installed, but the operator would be able to bleed off casing pressure before the inspection occurs. We would favor installation of a pressure gauge on the casing annulus as a permanent fixture on all injection wells so that the operator would not need to have advance notice of a routine inspection.*

Wells that fail a MIT are usually required to cease injection immediately, but are not required to be repaired unless USDWs are potentially endangered while the well is shut in. That may be acceptable if a well fails a MIT due to a packer or tubing leak and the casing pressure declines to zero after shut in. However, one cannot be certain that a casing leak does not exist concurrently with a tubing or packer leak. If USDWs are present in a well with a casing leak, there may be a risk for fluid movement into a USDW or other zones that lack cement in the casing/wellbore annulus between the leak and the USDWs or other zones. The risk increases with time in idle status and pressure on the casing, as the casing integrity becomes less certain over time without passing an annular pressure test. In our view, wells that fail MITs should be repaired or plugged and abandoned within a set time period (three to six months or sooner depending on the nature of the leak) unless no USDWS are penetrated by the well.

Injection is apparently allowed in a well that has pressure on the annulus but is less than injection pressure, which could be indicative of a casing leak. In our view, such a well should be shut in and repaired if the pressure on the casing is more than a nominal amount.

Our understanding of the idle well requirements is as follows: a pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are usually required on a two-year cycle after five years in idle status where fresh water is present, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. We believe that wells that lack mechanical integrity should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area. We also recommend a casing pressure test be performed in idle wells rather than fluid level surveys unless USDWs are known to be absent.

Assessment of Part 2 (external) MI in District 2 wells is not clearly described in the responses to the questionnaire and the responses are somewhat contradictory. Cement records and logging tools such as cement bond logs are not acceptable and static temperature surveys are rarely required, according to the District responses. However, UIC regulations require cement in the casing/wellbore annulus immediately above the injection zone, at the BFW, and behind surface casing. The presence of sufficient cement is determined by examination of cement records and Cement Bond Logs (CBLs). Those standards should satisfy Part 2 MI requirements at least in part, but cement should be present at the base of all USDWs (10,000 mg/L TDs or less) for complete protection of USDWs. In addition, we would recommend running CBLs in new and converted injection wells unless USDWs are known to be absent in the area.

The requirement for adequate volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of heavy mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

The recent Division directives to the district offices and the authorization to hire additional UIC staff should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

See Page 47-53 of STRONGER Questionnaire.

What types of enforcement tools and legal actions are available to the District for the UIC program? See Page 47 and page 48 of STRONGER Questionnaire.

How often in the last five years have you used them? Please list the most recent examples and elaborate. Again, I would like to explain our compliance tools when you visit as this process can involve a wide range of options available to the Division. These enforcement tools apply to all wells and with the recent passage of AB 1960, production facilities. Examples of a few of the enforcement activities in District 2 involving OG wells, UIC wells and facilities are listed in the foregoing discussion in Part II of this report.

Civil penalties can be assessed up to $25,000 per incident. Formal orders are issued with injunctive relief for corrective actions. Appeals are possible with 30 days to comply or appeal applies to wells and facilities. Judicial review occurs if orders are appealed. DOGGR can perform the necessary actions and use bond funds for reimbursement. Examples are described in Part II above.

What types of formal enforcement actions have been taken relative to UIC violations in the District? No formal enforcement action has been taken in the last five years. Enforcement action taken on reporting injection is handled by our Headquarter staff.

What actions were taken in the past ten years? Please elaborate. Examples cited in Part II were ordered shut-in which is their current condition. UIC wells associated with operators listed in Part II were abandoned.

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. See Page 50 of STRONGER Questionnaire.

Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties? Civil penalties would typically be issued following the "non-compliance" of a notice of violation.

How many have you issued in the last five years? Please list these or the most recent examples. None for injection wells.

What are the follow up procedures to assure compliance and correction of the violation? See Page 47 and page 48 of STRONGER Questionnaire.

How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? If threatening a USDW an operator can be ordered by the District to discontinue injection immediately. *How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV?* Again, if a paper violation is non-reporting of injection it is typically 90 days.

Please elaborate on the time allowed to complete repairs or P&A the well when a USDW is threatened. The STRONGER document seems to indicate 30 days for "paper" violation. Is it different for the District? Paper violations for non reporting are not handled at the District level. When a USDW is threatened, the well is shut-in immediately. However, if the problem continues to threaten the USDW, if nothing is done, then the operator is ordered to repair the cause immediately. In the event that the threat is only a threat then repairs must be done in order to use the well for injection. If the well actually causes injected fluid to enter a USDW, the well is immediately shut-in. Repair cannot be started until such time as California Regional Water Quality gives approval for repair. This is done to ensure that evidence is maintained to facilitate any possible cleanup operations required by California Regional Water Quality Control Board.

How and when do UIC violations escalate from non-compliance into formal enforcement actions? See Page 47-53 of STRONGER Questionnaire.

What penalties have been assessed and collected on UIC violations in the past ten years? The District has not issued any civil penalties for UIC wells.

Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? **N/A.** *Do you have the resources necessary to provide adequate enforcement? Are you able to witness most of the MITs and P&A operations and follow up with enforcement on all violations?* Yes, District 2 is up to full staff at present. Most SAPTs (70%) are witnessed.

Conclusions

The frequent reference to the STRONGER Questionnaire in the District responses is useful in understanding enforcement procedures at the state level, but not particularly helpful to understanding specific enforcement actions in District 2. It would be helpful to know how many shut-ins and rescissions were initiated over the past five or ten years, for example. A few examples of informal enforcement actions taken in the past are discussed in Section 4.2 Part II of *this report. No formal actions have been taken or NOVs issued in the last five years and no examples of formal actions were provided for earlier years.*

Based on the Districts' responses, our impression of UIC enforcement activity in the District is that it has been limited over the past five years. We lack the necessary information to make an informed judgment, but the District may need to put more of an emphasis on enforcement in the UIC Program. The District states that they have sufficient staff and other resources to witness most SAPTs and P&A operations that require CDOGGR presence, but state that fewer than ten percent of projects are reviewed each year. That is contrary to the requirement in the MOI and the commitment in the CDOGGR Program Description for annual project reviews. They also state that the District is up to full staff at present, however, that may not be the case when the Division directives from the Division Expectations Memorandum are fully implemented.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

No contamination/alleged contamination resulting from UIC well operations in the past 20 years.

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public. This is too general and will be explained upon site-visit. *Please describe the District policy for handling report or complaints of contamination if it should occur.* See the Division Manual of Instruction (MOU) Section 170 for UIC projects.

Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. None.

Any surface spills or releases of produced water or oil that could have impacted a USDW? None – Spill response requirements and procedures are outlined in the District Field Incident Plan.

What actions are taken by the District when an alleged contamination report is received? Please describe the actions that would be taken by the District if such a report were received. Same as above.

How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? No cases in last 20 years found to be actual. *Were any caused by failure of surface equipment or flow lines or release of fluids to surface impoundments.* Although none of the reported spills impacted a USDW, the district maintains a spill database, which among other things, lists the cause of the spill if determined.

Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to the above question. **N/A.** *Please describe incidents involving failure* *of surface equipment, flow lines, or surface impoundments, if any.* **Same as above.** *District response to spill incidents was discussed in general during the visit.*

Conclusions

No incidents of USDW contamination resulting from injection well operations or improperly abandoned wells were reported in the past twenty years, alleged or otherwise. The District maintains a spill database listing the cause of spills, if determined, but none of the reported spills impacted a USDW, according to responses to the EPA Questionnaire and on-site discussions. District policy for handling reports or complaints of contamination when they occur is described in the Division MOI at Section 170 for UIC projects.

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

See Page 55-60 of STRONGER Questionnaire.

Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.).

The District complies with existing DOGGR abandonment regulations. The rods/pump and tubing (packer if an injection well) are pulled prior to commencing cementing operations. The well must be cleaned out to at least 25 feet into the uppermost perforations and cemented to at least 100 feet above the uppermost perforation, liner top, WSO, whichever is highest. This plug is then tagged with tubing and witnessed by a district field engineer to verify it meets the minimum requirements. If it does not, this plug must be upgraded until it meets the minimum requirement. In areas of fresh water, a plug must be placed and be a minimum of 100 feet. Again, this plug is tagged to verify it meets the minimum requirements. If there is no cement behind casing, either a cavity shot or innovator shot is performed prior to cementing to ensure cement is outside the casing and across the BFW zone. A surface plug with a minimum length of 25 feet is placed last. In between these cement plugs abandonment mud must be pumped; however, the majority of the abandonments in District 2 over the last seven years have been conducted entirely with cement. Once the surface plug has been placed, the wellhead is cut-off between 5 and 10 feet below grade. If any annuli do not have cement, they are upgraded with cement. A metal ID plate is then welded to the largest string of casing and the site back-filled with clean dirt.

Are there any variances from Division level requirements or policy in the District? Yes. Variances are allowed. For instance, if an operator has made a diligent effort to retrieve junk (fish) and is still unable to recover it, the district can allow cementing from the top of the fish. CCR section 1745.2 specifies the cementing/squeezing requirements. D*oes this procedure apply to USDWs in addition to BFW zones?* No. Our regulations apply to BFW only, not to USDW's

Are there UIC wells without surface casing installed? No. If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed? If an inner string of casing is cut and pulled, a stub plug is placed from the stub to a minimum of 100 feet above the stub plug. *Are plug depths verified?* Yes. After the cement has hardened with coil tubing or a tubing workstring. *Are all plugs required to be tagged?* See Page 48-603 of STRONGER Questionnaire.

Are there any variances from Division level requirements or policy in the District? There are no significant variances. Cement retainers and bridge plugs are pressure tested but not tagged. Cement plugs are tagged and additional cement must be placed if the plug isn't at the required depth. The supplemental cement plugs are not tagged.

What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations? Plugs not witnessed would have to be waived by the district. The number of waived calls for abandonment operations is minimal since abandonment operations are our highest witnessing priorities.

What is meant by the term "waived" in this context? What situations would warrant a waiver? What are the procedures for ensuring compliance with P&A requirements when P&A operations are not witnessed? "Waived" means District staff are not available to witness a P&A operation due lack of manpower and staff conflicts with other priorities. Witnessing P&A operations is a high priority, however, and less than 5% are not witnessed. When not witnessed, District staff reviews the P&A report submitted by the operator to ensure compliance with the approved P&A plan.

Describe the process used to get an idled and an orphaned well plugged. The District has Idle Well Management Plan Agreements with three of the major operators who account for over 70% of the District's idle wells. We have annual project review meetings with these operators to ensure they are meeting their commitments. At these meetings we recommend idle wells that would be good candidates for abandonment based on our field observations (access issues, active slide areas, environmentally sensitive areas, etc.) Orphan wells are plugged by the Division using funding from the Hazardous Idle Deserted Well Fund (HIDWF) which is currently $2 million per year. (This fund will revert back to $1 million in FY 2012/13.) Each district identifies and proposes to HQ orphan wells they'd like to abandon. Once funding is allocated to the districts, a bid package is prepared and a contractor selected through the competitive bid process. Approval of the property owner is also required and normal abandonment procedures outlined above are required for orphan wells.

How is this managed for other operators? How much time is allowed for an idle well to remain inactive or require P&A? Refer to idle/orphan well requirements at section 3206 of the regulations. Idle wells may remain in that status indefinitely as long as they are in compliance with idle well regulations. Fees are charged to the operator at increasing rates for each well in idle status beyond 5, 10, and 15 years. See discussion below with regard to the fee amounts.

Does the District maintain an inventory of abandoned (orphaned) UIC wells? This District has no orphaned UIC wells.

Does the state maintain a well plugging fund that is used to plug idled (no) and orphaned wells? Yes. *Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund.* Currently 2 million/year until FY 2012/13 then reverts back to $1 million/year, unless extended. PRC section 3258 currently authorizes expenditure of up to two million/year. Money not spent this fund within that FY offsets the next year's assessment rate.

How are the current plugging requirements different from those of 40 years ago? Same Statewide. In early 1990's, an informal agreement was made with a local water agency in which we would plug and abandon the top portion of wells in accordance with water well standards. This was done in the Oxnard field.

The above question relates to the probability that wells plugged 40 or more years ago may not meet current standards. Please discuss how this might impact corrective action requirements in those situations. To begin with a well is not a problem just because it does not meet current standards. A well located in the AOR would only need to meet requirements that ensure that injection fluid is confined to the permitted zone for the project or in the case of permitting new wells to be approved. *Have any changes or improvements been adopted in the District since then, other than those related to the water well standards?* We do not associate water well requirements in our normal course of work. However since the approval of the Clean Water Act, Division and district requirements now require BFW plugs during plugging and abandonments.

Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project? The informal agreement plug has no affect on AOR.

Conclusions

District 2 applies the existing statewide P&A standards, which are discussed in the state level section of this report and are described in detail in the CDOGGR regulations and MOI. The recent Division directives require a zonal isolation plug for all wells within the AOR of an active injection project, which is a new and more rigorous requirement for protection of USDWs from migration of injection fluid out of zone in those wells. In addition, a cement plug is required at the BFW zones in plugged and abandoned injection wells, but not in other wells within the AOR of an injection well or at the base of USDWs in any well.

District 2 written responses are not clear about their adoption of the new requirement for a zonal isolation plug in AOR wells. Verbal responses provided during the office visit indicated that District 2 views the recent Division directives as not final and still subject to significant modification. We support the new Division directives and urge District 2 to adopt those for application in the District as soon as possible. However, the lack of a requirement for placement of cement plugs at the base of USDWs is a concern, and modification of P&A requirements in *that regard would greatly enhance the protection of USDWs containing more than 3,000 mg/L TDS. In our view, the USDW plugging requirement should apply to all wells within the AOR.*

District 2 states that less than five percent of P&A operations are not witnessed. That includes tagging cement plugs and cement squeezing operations, but does not include witnessing cement plug placement operations, as discussed Sections 2.0 and 3.0 of this report. When P&A operations are not witnessed, District staff review the P&A report submitted by the operator to ensure compliance with P&A requirements. We have concerns about the absence of a CDOGGR inspector during cement placement operations, as discussed Sections 2.0 and 3.0.

District 2 follows the statewide Idle Well Planning and Testing Program in managing P&A of idle and orphan wells. It has Idle Well Management Plan agreements with three of the major operators, which accounts for over 70 percent of the idle wells in the District. There are no orphan UIC wells in the District at this time. Our concerns regarding the management of idle wells are discussed below and at length in Sections 2.0 and 3.0 of the report.

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

See Page 63 of STRONGER Questionnaire.

Describe the District administrative program for TA/idle wells and how a TA/idle well is defined. How is a TA well/idle different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA/idle status has been approved by the District for a given well? See Page 63 of STRONGER Questionnaire.

Please note that "idle" has been inserted in items 1, 2 and 3 above as an alternative to TA well or status. Please modify your response accordingly. Attached is an SPE Paper detailing the Division's Idle and Orphan well programs which I think addresses the issues you raised as well as providing additional detail.

Does the District require a mechanical integrity test to be run on a TA/idle well before it is approved for TA/idle status, periodically while in TA/idle status, and before reactivation as an injection well? NA

Describe how TA/idle wells are tracked for compliance. How long may a UIC well remain in TA/idle status before being reactivated or P&A? NA

This Division does not use the term "TA".

The federal UIC program describes TA status as an injection well that has been inactive for more than two years and meets the requirements for notification and compliance with UIC regulations for active wells. If those requirements are not met, the well must be plugged and abandoned. The operator must demonstrate that the well has future utility and will not endanger USDWs while in TA status. Please describe any comparable requirements for idle wells that have been inactive for an extended period. Does the discussion of TA status in the STRONGER *document apply to the District?* Attached is an SPE Paper detailing the Division's Idle and Orphan well programs which I think addresses the issues you raised as well as providing additional detail.

Idle well fees are assessed at the rate of $100/year for wells idle for 5-10 years, $250 for 10-15 years and $500 for more than 15 years. Idle wells are defined as inactive for 5 years since last 6 months of continuous production or injection operations. Four percent of idle/orphan wells have to be removed from the inventory each year. 120 wells in District 2 have been abandoned since 2003 under the orphan well abandonment program.

Conclusions

Temporary abandonment of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements are not as rigorous in terms of MIT, repair, and timely plugging. District 2 applies the statewide standards for management of idle and orphan wells. In our view, USDWs are not adequately protected in idle wells. Those concerns are discussed at length in Section 3.0 and at other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs.

PART VII: Comments

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

Attached is the 2000 STRONGER Questionnaire

Conclusion

Reliance on references to the STRONGER Questionnaire by District 2 in many of their responses to the EPA Questionnaire was useful, but not always helpful. We would have preferred more discussion specific to District 2 UIC operations and implementation of UIC requirements.

4.3. DISTRICT 3

This section is organized in seven parts to address questions and responses from District 3. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. The last part is an opportunity for District 3 staff to provide their own comments. Each of the remaining six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 3 has a total of 894 active and inactive injection wells, which represent approximately 2.8% of state injection wells. Table 5 provides numbers of wells by well type for both active and inactive wells.

Table 5. District 3 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	SC	SF	WF	AI	WD	Total	% of State Wells
Active	17	8	203	120	87	-	87	**522**	**2.83%**
Inactive	4	8	-	124	142	4	90	**372**	
Total	**21**	**16**	**203**	**244**	**229**	**4**	**177**	**894**	

PART I: General

This part addresses UIC program organization for District 3, and interagency coordination and changes to the UIC Program.

UIC Program Organization

Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

See Attachment A

Interagency Coordination and Changes to the UIC Program

Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or *guidance) if available.* The Division has an MOU with the US Bureau of Land Management updated in 2010. It clearly identifies the roles of both agencies with regard to permitting, operation & inspection of Class II injection wells. Available on the DOGGR website for review.

Please list other MOUs or agreements with other state and federal agencies if applicable. We do have a delegation of authority with the US EPA with regard to our primacy agreement dated 1983. We also send our project application notices to the Regional Water Quality Control Board for comment. *MOUs are not attached, but are available in other District responses and on the DOGGR website*

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes? There have not been any changes in statute. There has been a revised interpretation of those statues/regulations over the years that has modified the way we conduct business. For instance we understood the importance of performing an AOR; however we did the reviews ourselves and provided the necessary information in table format. Today we require operators submit the information and require/accept only casing diagrams.

In the past many of our decisions were based on whether there were any fresh waters. For instance a monitoring program may have been acceptable in an area without any fresh water. Today we base decisions on whether or not injection is confined to the permitted injection zone, and do not modify requirements based on the presence or lack of fresh water.

No direct reference to the HQ "Expectations memo of 5/20/2010 was offered. Need to understand how AORs are performed and whether and how ZEIs are considered in the AOR determination. The "Expectations" memo is contained in "The Book", which also contains the MOI and DOGGR regulations. District 3 will follow "The Book" in the implementation of the UIC program, but the memo is under review for modification in some elements. There needs to consistency between the six district offices on how the new standards will be implemented, and a Notice to Operators should be issued to inform the operators of the new standards that apply to UIC operations. The injection Surveillance Committee (ISC) is considering changes to UIC regulations to make them more consistent with the new standards. ZEI determinations are required for new and existing projects, but that hasn't been the practice in the past.

Conclusions

We support the Division directives for changes in the UIC Program described in the Division Expectations Memorandum. We believe that it could be improved, however, by providing more protection for USDWs in the implementation of the UIC Program in California. Those concerns and suggested improvements are presented in the Conclusions sections under relevant Objective discussions found below.

PART II: Permitting and Compliance Review

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program.

Who receives the application from the operator? (District or Headquarters office) The district office receives the application.

How and by whom are permit applications screened for completeness? The project applications are usually screened by the Associate Oil & Gas Engineer or qualified Energy & Minerals Resources Engineer and may be reviewed by the district deputy.

What are the procedures or protocols if an application is found to be incomplete? A notice of incomplete submittal is sent to the operator and specifies the information that is required before the application can be processed.

What are the professional qualifications required for staff who conduct permitting and compliance activities? Do those staff members meet the minimum requirements? Professional qualifications include education, experience, and training in permitting and compliance activities. Staff members must demonstrate their ability and knowledge of permitting and compliance activities. *What types of training would staff like to access if funds were available?* Computer training for modeling software if provided.

Please be more specific. What are the specific educational, experience, and training requirements and do staff members meet those requirements?

In addition to what is listed below, see State Personnel Board listing for each position. Staff members include an Oil & Gas technician, Energy & Mineral Resources Engineer, Associate Oil & Gas Engineer, and Senior Oil & Gas Engineer. Employees are not hired unless they have the skills to meet the requirements. Annual performance reviews of each employee are conducted.

UIC Program Organization

District 3 – Santa Maria

District Deputy (1)

B.S. Degree in Geology – 27 yrs work experience

Permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach

Associate Oil & Gas Engineer (1)

Drilling & Wellsite Consultant – 48+ yrs work experience (26 yrs Industry/22 yrs DOGGR)

Permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach

Energy & Mineral Resources Engineer (EMRE) (4)

Degrees in Geology, Chemical Engineering, Mechanical Engineering, & On-The-Job-Training

35+ yrs combined work experience

File review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach with limited permitted by the senior most EMRE

Oil & Gas Technician (1)

3 yrs work experience

Inspections, compliance and enforcement, data management and limited mechanical integrity testing, and public outreach

* No single position is devoted entirely to UIC nor are any of the positions fully funded by EPA

What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful?

The statutes and regulations are used to evaluate the adequacy and completeness of the information submitted and review of reservoir conditions and parameters including review of electric logs, core and sidewall data, fluid analysis, reservoir pressure and temperature, injection systems, well construction, geologic information, and any other available information relevant to the application and project area.

Useful tools that could be provided would be a system that would take input data and construct a clear & concise casing diagram. Modeling software would also be beneficial in predicting fluid migration.

Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal). The processing of commercial Class II well applications must include review for adequate bonding. Otherwise the applications for both commercial and non-commercial wells have the same requirements. Class II SWD disposal wells require certification that the zone does not require an aquifer exemption, is in an exempted aquifer, or include a request for an aquifer exemption and must include supporting documentation for that certification or request.

Describe any differences between the processing of a waterflood project and a CO2 EOR project. The statutes and regulations have no specific requirements for processing applications for a waterflood vs. CO_2 EOR project. However, a more thorough review of the measures proposed to address and mitigate the corrosive nature of the CO_2 fluids would be in order in the CO_2 project. District 3 has not had any CO_2 EOR projects as of this date.

Conclusions

The application flow process is similar in all districts, and we have few additional comments or conclusions to offer beyond those included in the state level and other district sections of the report. Discussion of the staff qualifications and training requirement needs is satisfactory and is supplemented by further discussion under other Objectives listed below. The District identified software for constructing casing diagrams and predicting fluid migration as additional tools that would be beneficial to the Program. We agree with those comments and would recommend that the software be acquired or developed in-house for all district offices that lack those tools.

Requirements for commercial Class II disposal wells could be strengthened beyond the bonding requirement described above, if that description encompasses all of the requirements for those wells. Fluids to be injected should be analyzed to ensure that they qualify as Class II fluids (Appendix A7), and site security requirements should be described and enforced to ensure that access to the facility is not compromised.

OBJECTIVE: Understand the current compliance/file review process.

What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy. As the various field tests are conducted (Ra Tracer surveys, Static Temperature surveys, Pressure Falloff tests (PFO), Casing Pressure tests (SAPT), SRTs, the EMRE conducting the test not only completes a T-report and transfers information into our electronic tracking system, but is also encouraged to review the file at that time. The Associate in the preparation for a project review meeting with the operator also conducts a file review. Compliance history is not necessarily a component of file selection. It is more a factor of injection well type rather than a factor of where the surface location is.

Are areas with fresh water and/or USDWs present and/or are disposal wells given high priority? Please elaborate and identify those areas in the District. Yes and No. Water disposal wells are required to be tested annually and therefore would be reviewed more often than waterflood or steamflood wells by virtue of the testing frequency. A steamflood well in fresh water or non-fresh water bearing zones are tested/inspected the same. The Associate impacts his job function with file reviews based on program changes and project review meetings. The Technician bases field surveillance on when the lease was last inspected

Areas with fresh water and/or USDWs present are not identified. No fresh water is present in the Orcutt and Casmalia Fields. San Ardo steamflood project is a priority for review with the operator (Aera) on an annual basis.

Who performs the file review and what are the qualifications of the reviewers? File reviews are conducted by the District Deputy, the Associate & by the EMRE. Although each has a different educational background (see Attachment A), they have received DOGGR training from the Associate & District Deputy. There is also the DOGGR MOI 170 to use as reference.

Over a one-year period, what percentage of total UIC permits/wells receives a file review? At least 31 percent.

How is the quality of a file review assured and subsequently documented? A large percentage of the files reviewed are rechecked by the Associate prior to processing the reports. The file review is electronically tracked.

When deficiencies are discovered during the review, what actions are taken to correct the deficiency? It would depend on the deficiency. It may require a Notice of Records Due, or require a test, or require a reduction in injection pressure which would be partnered with additional inspections. If we spot a problem we work to resolve it and achieve compliance!

How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually? A File review can and is conducted by the EMRE's, the Associate, and by the District Deputy. It entails reviewing the file to ensure that all requirements are being met. If it is found that a test is needed then a letter/request is sent to the operator. There is a review of each injection well to assure compliance prior to the scheduled project review meeting. Any deficiencies are then brought up at the project review meeting. The project review process in this office has strictly been conducted by face-to-face meetings.

What percentage of projects is reviewed annually? This office conducted 10 project reviews in 2006, 31 project reviews in 2007, 10 project reviews in 2008, 8 project reviews in 2009, and 7 project reviews to date in 2010. Our project reviews consist of meeting face-to-face with the operator's engineering staff to discuss injection operations. This approach requires that the Associate review all of the well files prior to the meeting, and ensure that the operations are up-to-date. Any necessary tests or procedures are addressed in the meeting. Currently we have 44 projects however that number changes as projects are added and others are terminated.

Conclusions

Annual project reviews with the operator present are typically conducted for less than 25 percent of the projects. Project reviews should be performed at least annually to be in compliance with the CDOGGR Program Description and the MOI requirements described at Section 170.13.3.1. Annual meetings with operators to review active projects is an important element of the UIC Program, especially for those projects that have ongoing compliance issues that go unresolved within acceptable timelines. The lack of a project review with the operator is somewhat alleviated by the fact that individual wells in disposal projects are reviewed by means of the required annual RAT survey. However, that does not fully apply to enhanced recovery wells because waterflood wells are tested only on a two-year cycle and steamflood wells on a five-year cycle. Also, RATs will not detect a casing leak above the packer. The hiring of additional *professional staff could improve the District's ability to conduct more comprehensive project reviews with operators as well as increase the number of file and annual project reviews.*

The District indicates that fresh water is present in all but two fields but the presence of other USDWs is not discussed. The San Ardo steamflood project is a priority for review on an annual basis, apparently because of various compliance problems in that field, including injection line and tank spillage, which are discussed in later responses to this questionnaire.

OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected? The current cementing requirements for production & intermediate casing in all newly drilled wells, including injection wells, include annular cement lift to 500' above the completion zone or the uppermost hydrocarbon bearing zone and a minimum of 100' of annular cement lift above the base of fresh water (BFW). Surface casing must have the annulus cemented back to surface.

Fresh water containing 3,000 mg/L TDS or less? Does this also apply to USDWs containing less than 10,000 mg /L? If not, how are USDWs otherwise protected? Most likely 10,000 mg/L or less. The base of fresh water is determined in the office from an electric log not from sampling of the fluids during the drilling process.

Need a more definitive response and discussion regarding protection of USDWs. Is it a requirement that the long string or intermediate casing be cemented to 100' above the BFW if surface casing is not set and cemented from the BFW to surface? Yes, in the newer wells.

Where surface casing is set and cemented from the BFW to surface or cemented to at least 100' above the BFW, what are the cementing requirements for the long string or intermediate casing strings? Cement must be placed at least 500 feet above hydrocarbon bearing zones for zonal isolation since 1978. Prior to 1978, only 100 feet were required. Cement is not required at the base of USDWs. In the San Ardo Field o tubingless completions are allowed if two casing strings and cement are present at the BFW.

What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected? Wells converted to injection must have at least 100' of annular cement lift above the injection zone and casing with mechanical integrity set opposite the USDW. Converted wells must inject through tubing with a packer set as close as possible to the top of the injection zone.

Is cement placement required opposite the USDW or at least 100 ft. above the USDW base? If cement is absent, are remedial cementing operations required as a permit condition or later during conversion, casing repairs, or P&A operations? If not, how are the USDWs protected? 100 ft of cement is required across the saltwater-fresh water interface. Yes, operators are required to provide for adequate isolation of the fresh waters through perforating/squeezing/cementing operations. In some cases CBL's/temperature logs are required to ensure adequate isolation after cementing

Need a more definitive response and discussion regarding protection of USDWs. See above follow-up request for new wells. This response applies to the BFW but not USDWs, unless the base of USDWs is coincident with the BFW.

What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field? Mechanical integrity testing is conducted on the injection wells on a regularly scheduled basis prior to and after commencement of injection, and AOR's are conducted to ensure wells that may be influenced by the project are mechanically sound. Mechanically unsound wells are addressed prior to commencement of injection.

Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? All newly completed and converted injection wells except for steam, air, and pipeline quality gas injection wells are required to inject through tubing with the packer set as close to the top of the injection zone as possible. Additionally, wells with two strings of casing cemented through the fresh water zones may inject without tubing and packer or if there is no evidence of fresh water bearing strata, wells may inject without tubing and packer.

Does this also apply to USDWs? Annular pressure testing or internal casing integrity tests must be conducted every 5 years in all injection wells. An alternative for wells with no tubing or packer would be testing the casing with the ADA fluid level compression test. *I assume this does then apply also to USDWs, in terms of the two strings of casing cemented through USDWs?* Not necessarily.

Are dual (multiple) completions permitted? What requirements are different than single completions? What types? Dual or multiple zone completions are permitted and are usually EOR wells. Injection into the various permitted zones is achieved by cementing multiple strings of casing through the zones or by injection through tubing and packer configurations designed to regulate injection into the different zones.

What are the alternative requirements for annular pressure testing in wells with dual or multiple zone completions? The Arroyo Grande Field includes slim hole completions, but there is no fresh water present. Packers are set and SAPTs are run every five years in those wells. Annular injection is also allowed in steamflood wells where fresh water is absent. The ADA MIT is an alternative to the SAPT. There are perforations above the packer in some Orcutt wells, but there is no fresh water present. Increasing the frequency of RAT surveys to annual from five years in steamflood wells is otherwise an option. Operators are "getting away from slim hole injectors."

How are the locations of USDWs determined USDWs are determined by electric log evaluation, mud log review, analysis of fluids recovered from the zones, and other measurements made during the drilling, testing, and completion of wells. *Does the District consult with other state* *and federal water resource agencies regarding USDW information?* If we do, we contact the local Regional Water Quality Control Board for assistance.

How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated? The adequacy of the confining zone/system may be determined by a leak-off test at the shoe of the production/injection casing or by step rate tests conducted to determine the formation fracture gradient of the injection zone. Also static temperature and radioactive tracer tests are conducted on a regular basis typically as defined in regulation. If the confining system is in question, injection volumes and pressures may be limited and observation wells utilized to observe movement of injected fluids at various distances away from the injection well. Frequency of static temperature and radioactive tracer tests may also be increased to ensure that there is no vertical migration.

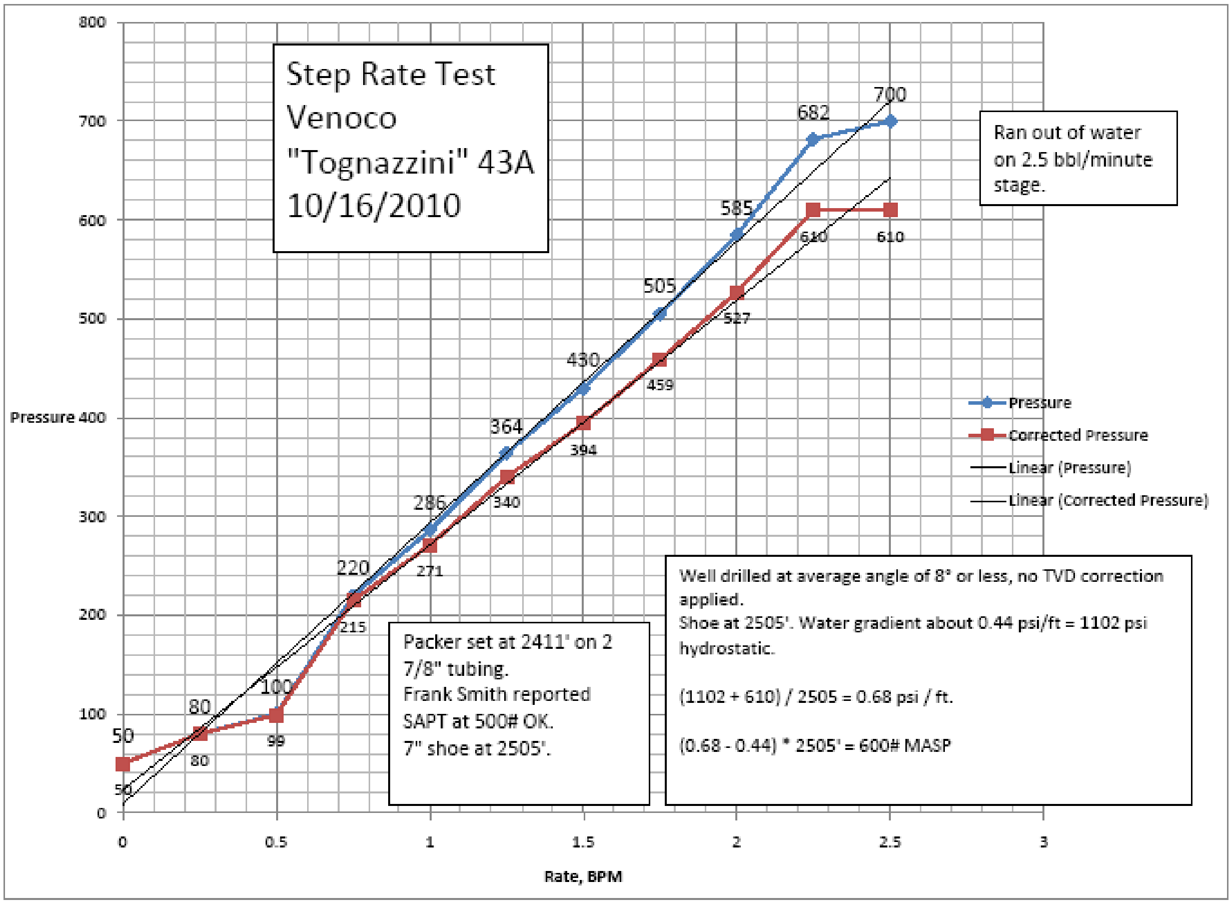
Please elaborate on how the adequacy of the confining zone in the AOR is evaluated in terms of geological considerations. Each wellbore within the AOR has the BFW, and the top of the injection zone reviewed. Electric logs are used to determine the depth of the top of the injection. If a log is not available, surrounding well information is used to extrapolate the depth. Log data is also used to determine if the zone has not been penetrated.

Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well. Most operators incorporate flow meters in the injection system or gauging methods to determine the flow rate into each injection well. The injection rate and maximum tubing pressure are required to be reported monthly to the division for each injection well. Cumulative injection may be obtained by adding the monthly reported volumes for a project or individual well. The casing pressure is usually verified by a gauge during well inspections, mechanical integrity testing, or the casing is vented to the atmosphere. In addition flow rates can be verified by the spinner and velocity checks conducted during a radioactive tracer survey.

How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose. Maximum injection pressures are established by step rate tests to determine the formation fracture gradient of the injection zone or until the maximum anticipated injection pressure is observed, whichever occurs first. Absent a step rate test, injection pressures are limited to an injection gradient estimated to be less than the gradient expected to fracture the formation.

Step rate tests have been conducted in several water disposal projects to establish the formation fracture gradient of the injection zone. Step rate tests include injecting fluids beginning at low rates with step rate increases until the anticipated maximum injection pressure is achieved or the formation fractures. Surface and down hole pressures are monitored, during most tests, and plotted to determine at what rate and pressure the formation fractures. Factors such as friction flow loss and fluid density are taken into account in these tests.

Please provide representative examples of step rate test performed in the District, including the evaluation of the tests. Please describe how injection gradients are estimated in the absence of a *step rate test.* The procedures used are outlined in the Division's Publication M13. Historically we have used the information in the Division's publication M13 to assign a fracture gradient in the absence of a SRT. We used .7 psi/foot as the breakdown gradient. If a well is in close proximity and is similar in geologic conditions to a well which has step-rate data on file, then we utilize that information in setting a fracture gradient.



What is the basis for the 0.7 psi/foot gradient? Are step rate tests required in all new wells per the 5/20/2010 memo from HQ? The frac gradient of 0.7 psi/foot is based on an internal DOGGR publication by Bill Gerard. The 5/20/10 HQ memo requires SRTs to establish the frac gradient and MASP in all new wells before commencement of injection unless SRTs have been performed in nearby wells in the target injection zone(s). Bottom hole pressure measurements are an operator option but are not required for SRTs. MASPs for steamflood wells are treated differently due to their less dense injection fluid. SRTs are required to be witnessed by DOGGR staff. A fall-off test is required within six months of the start of injection in new wells. The pressure must fall to zero during the test, which can take up to 30 days in some wells. Static reservoir pressure is limited to hydrostatic pressure. Boron in steamflood fluids is a concern since produced water is often used rather than the historical use of fresh water in steamfloods.

Conclusions

The technical review processes of permit application and related aspects of file reviews in District 3 follow the guidelines outlined in the MOI and are quite similar to those processes in other districts. As a result, we have concerns with District 3 technical review procedures similar to those expressed at the state and other district level sections of this report. We reiterate some of those concerns below.

USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance for total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement. CDOGGR should consider modification of cementing requirements to require placement of cement at base of all USDWs penetrated by a well, not just at the BFW (3,000 mg/L or less TDS) zones, above the injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells and wells located within the AOR of an injection well when casing repairs occur or when the AOR wells are plugged and abandoned. Monitoring to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.

Slimhole and multiwell completions are permitted in some fields in District 3 with special circumstances and/or requirements. For example, slimhole wells are allowed for steamflood, air, and pipeline quality gas injection. Packers and tubing are not required if there are two strings of casing cemented through the fresh water zones or there is no evidence of fresh water bearing strata. Also, annular injection is allowed in steamflood wells where fresh water is absent.

District 3 states that there are no fresh water zones present in some fields, although the presence of other USDWs in those fields is still possible. Tubingless or slimhole completions are not pressure tested for MI except during workover or plugging operations. The RAT survey substitutes for the SAPT in those wells, or the ADA test in some cases. Unless there are USDWs present, which is unknown at this time, there are no particular concerns about the construction and testing requirements for those wells. We would need to examine well logs and other data in those fields to assess the presence or absence of USDWs. If USDWs are present, tubingless completions would be a concern in those wells.

The historical fracture gradient assumption of 0.7 psi/foot reported for the District 3 area is apparently not based on SRT data and may be higher than the actual gradient in some injection formations, based on SRT data from District 3 wells and other data presented in CDOGGR Publication M13. We reviewed a few projects that had an approved gradient of 0.70 psi/foot and one with a 0.64 gradient, which was based on a SRT. District 3 has required very few SRTs in the past. We understand that SRTs will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives from the Division Expectations Memorandum are fully implemented at the district level. We support that directive with the recommendation that bottom hole as well as surface pressure gauges be used *in SRTs. Bottom hole pressure measurements remove the uncertainty of calculated friction losses during a test and provide a more accurate measure of formation fracture gradient.*

A sampling of wells were reviewed for exceeding the MASP (based on a 0.7 psi/foot fracture gradient assumption) and pressure failing to fall to zero when shut-in. Injection pressure in a few wells was suspiciously high, but whether the MASP was exceeded is unknown. Further review of those well records may be warranted. Shut-in pressures in two disposal wells in the Cat Canyon Field failed to fall to zero over at least two months, which could mean that hydrostatic pressure has been exceeded in those wells. Both are in active status and further review may be warranted. The API numbers for those wells are listed as 08621009 and 08301517.

OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

How is the Area of Review (AOR) determined for enhanced recovery wells or projects? Normally EOR injection well areas of review are a set ¼ mile radius around the proposed injection well. As the project expands, an area of review is conducted for each additional injection well on a ¼ mile radius basis. Areas of review may be expanded beyond the ¼ mile radius based on reservoir information and performance of surrounding wells.

How is the AOR determined for saltwater disposal wells? Reservoir information and other factors may be reviewed to include the area expected to be influenced by the proposed injection. Factors such as anticipated life of the project and volumes of water expected to be injected would affect the project area. Typically Individual wells in the project may have a set AOR such as ¼ mile radius. Project expansion and extended AORs may be required once the original area of influence has been reached by the injection.

Please describe how injection fluids and pressures reaching the original area of influence are determined. Cumulative fluid volumes injected, review of fluid distribution in the injection zone from RAT surveys, pressure observation wells, pressure falloff surveys, and pulse testing

What are the calculations involved in this determination? Theis or Bernard equations? Historically, a ¼ or ½ mile radius has been applied to the AOR, but static reservoir pressure was limited to hydrostatic pressure for the injection zone. Most wells were completed in underpressured or depleted zones and shut-in pressures are monitored by DOGGR inspectors to ensure that static pressure doesn't exceed zero. New wells will require a ZEI calculation per "The Book".

How is the AOR determined for commercial saltwater disposal wells? Basically the same as non-commercial disposal wells.

How is the AOR determined for CO2 EOR wells? District 3 has no CO2 EOR projects. I would expect the AOR would include all the wells located in the area expected to be influenced by injection.

How are AORs determined for area permits and other multi-well projects? Operators usually define the area included in the project in the project submittal application and regulations require submittal of reviews of all plugged and abandoned, idle, and deeper zone wells in the project area, including casing diagrams.

District 3 has historically conducted the area of reviews and maintained the data in tabular form. Currently, operators are required to submit updated AORs for new drills, conversions, and reactivation of all previously approved injection wells, including casing diagrams. District 3 reviews all the data for accuracy and completeness.

Please describe how the AOR and ZEI determinations are applied in setting the project area. Are the AORs based on a quarter-mile distance from the wells, or the project area? The operator comes to the Division with a project. We file a notice in the newspaper, submit the information to the RWQCB, and issue a project approval letter, once an operator has submitted a complete package. If the operator adds several wells one location away we typically don't consider that a major expansion. The well still goes through the AOR process but we do not refile with RWQCB and the newspaper. On the other hand if the operator is going beyond the originally proposed scope, then we do go back through the project approval process. Yes, the majority of our AOR's are based on ¼ mile radius. *¼ mile from the well or project area?* The standard is ¼ mile from each well as in multi-well projects.

Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? If not, are they performed for all disposal well permits? What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved? No, ZEI calculations are not routinely conducted. No they are not performed for water disposal wells. As an estimate, probably less than 2 percent of the wells permitted for injection have had calculations performed to determine the ZEI.

Why have so few disposal wells had ZEI calculations and what method was used to calculate the few that were calculated? It was never part of our process. We have analyzed and performed calculations in cases where we suspect there are bad wells outside of the ¼ mile radius.

Will it be part of the process for new injection well projects, in accordance with the 5/20/2010 HQ memo? Yes. *Do any disposal wells inject into undepleted (with normal hydrostatic pressures) zones in the District?* No, in most wells. *If so, why would ZEI calculations not be performed? Where have the calculations been performed?* See the Carragea 47-X WD well in Orcutt Field. Injection permitted with restrictions and subject to revision of injection zone thickness based on RAT profiles. *Orcutt Field is reported to lack fresh water, however, USDWs may be present.*

Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects. Operators are required to conduct pressure fall-off tests on some of their injection wells to demonstrate the injection zone is below hydrostatic pressure. Some operators use continuous pressure monitoring wells for this purpose. This information is usually reported on an annual basis.

Is this a requirement for all disposal wells? What factors determine this requirement for individual wells? Is this based on a normal fresh water gradient of 0.433 psi/foot? Yes, although it is not listed as a requirement in regulations. We also conduct the pressure fall-off tests on waterflood wells. It's a method of ensuring that wells meet the permit criteria on their project approval letter. The statement reads "Injection zone pressure, as determined by pressure fall-off surveys, is not to exceed hydrostatic pressure in the general area affected by the project". *Are disposal wells typically or always completed in reservoirs that are underpressured relative to normal hydrostatic pressure?* Yes.

*Are **all** disposal wells completed in depleted oil zones or other underpressured zones?* No. *Please identify any projects/wells that are injecting into undepleted zones.* See response to above regarding the Carragea 47-X project.

Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples. District 3 has not required pressure buildup tests on injection wells.

*The question is not about pressure buildup **tests**. To clarify: Does the District take action to increase the AOR if exceeded by the expanding ZEI? Where has that occurred? Please list examples.* In the past we would expand the AOR based on the fluid type, formation type, or if there were potentially bad wells that could potentially be an issue. It is only recently that we have implemented using a ZEI approach in addition to the traditional AOR and pressure fall-off.

What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR? Wells and reservoirs that have demonstrated significant reservoir pressure increases have had the permits to inject terminated. Once it has been determined that the reservoir pressure around an injection well is above hydrostatic pressure, the permit to inject at that location is rescinded. If an approved injection zone is determined to be above hydrostatic pressure, the project is terminated.

Please identify specific projects/wells that have had their permits terminated for these reasons. "Lloyd" 4 & 7, "United California" 84, "Tognazzini" 43A (Cat Canyon field); Aera & Chevron's North area Santa Margarita projects (San Ardo field); "Purisima" 59 & 84 (Lompoc Field).

Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? Please list the most recent examples. Yes, this district has found previously plugged and abandoned wells that require upgrading in order to approve injection. The most recent upgrades have occurred in the San Ardo field. Some of the upgrades are needed as a result of plugging that does not meet current standards as to depth of the cement plugs or cement material used, i.e. 18% gel in cement.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? This has rarely occurred. In the one instance both operators cooperated on applying corrective action.

Conclusions

ZEI determinations were usually not performed for District 3 injection wells in past years. AORs were based on a quarter-mile fixed radius from the injection well, even for disposal wells. That may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project and reservoir pressure is maintained at a level that does not cause the position of the pressure front to expand beyond the quarter-mile AOR boundary. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. Where injection is into a depleted or producing zone, the fixed radius quarter-mile AOR may be appropriate, as may be the case in most of the District 3 disposal wells. An initial ZEI analysis should be performed for all disposal wells, however, to determine whether the quarter-mile AOR is appropriate. This also applies to EOR projects if injected fluid volumes will exceed produced fluid volumes for an extended period, allowing reservoir pressures to increase and the pressure front to potentially expand beyond the quarter-mile AOR.

ZEI calculations were performed for one well in the Orcutt Field and the well was permitted for injection with restrictions and monitoring of the injection zone, as stated above, Less than two percent of wells have had calculations performed to determine ZEI, according to District responses above. The recent Division directives state that ZEI calculations will be required for determination of the appropriate AOR.

Problem wells outside of the quarter-mile AOR but within the theoretical ZEI were usually not addressed in the past. With the full implementation of the recent Division directives regarding ZEI/AOR procedures, those wells will be subject to corrective action considerations, and protection of USDWs should be significantly improved.

The District states that pressure fall-off tests are performed on some of their disposal wells, and also on waterflood wells, to demonstrate that the injection zone is below hydrostatic pressure. It appears that those tests are not standard fall-off tests wherein both surface and bottom hole pressure measurements are taken after a well is shut in and calculations are made for determination of static reservoir pressure, permeability, and other reservoir properties. A standard fall-off test (FOT) may not be necessary, however, when shut-in pressures fall to zero, and that is apparently the case in most District 3 injection wells.

The District confirmed that disposal wells are typically or always completed in underpressured reservoirs and the pressure is not allowed to exceed normal hydrostatic pressure in the injection zone. The static injection zone pressure should be limited to the hydrostatic pressure of overlying USDWs, rather than the injection zone hydrostatic pressure. The USDW hydrostatic pressure may be depressed below normal due to pumping wells in the USDW, which could possibly increase the ZEI to more than quarter-mile.

Standard fall-off tests may now be performed more often for disposal projects when the recent Division directives are fully implemented in the District. That should provide the necessary reservoir pressure data to monitor pressure buildup and ensure that the pressure front is contained within the AOR over the life of a well. District 3 apparently has not yet implemented those directives, based on the above responses and conversation with District staff. However, shut-in pressures are monitored and permission to inject can be rescinded when pressures fail to fall to zero after an extended period in idle status. Several historical examples of rescission for that reason were provided in the above responses.

OBJECTIVE: Understand the administrative permit application components.

Describe the public notification and participation process for applications under consideration by DOGGR. The Division publishes a Public Notice in the local newspaper, sends notification to the Regional Water Quality Control Board, and requires the operator to submit letters of notification to offset operators.

When and where is public hearing opportunity held on an application and how are they conducted? We have never had a need to hold a public hearing as part of the approval process.

What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed? We use the same financial assurance, bonding, as that of a producing well with the exception of a Commercial Class II Disposal bond.

Please elaborate on how adequate coverage is determined for single wells and multiple wells with blanket bonds. Are bonds or other financial assurance mechanisms required until a well is plugged and abandoned? If not, please elaborate. All well types and specific operations require bonding. It is not exclusive to injection wells. UIC project applications do not require bonds, only certain wells within the project. Our laws and regulations dictate the amount of bond coverage for single and multiple wells. No bonds can be released until they meet our completed definition. *What is the "completed definition"?* Six Months of continuous injection. See the regulations for details.

Conclusions

See Section 3.0 for more information.

OBJECTIVE: Understand the process for aquifer exemptions

How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests? There has only been one exemption that I can recall. It was for injection outside of the field boundary of the San Ardo field. It was injection into the same zones that are being injected into within the San Ardo field.

What were the criteria applied in the request? The injection interval was the same interval being injected into and produced within the designated field boundary. The injected water was similar in constituents as that of the zone being injected into. That zone is not a drinking water source. There were no towns nearby. We also had RWQCB and EPA review the applications.

How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials? I don't believe we have had any denied, however the process has been lengthy for one of our operators, and I don't believe the operator had a clear understanding of what constituted a complete application. There has also been some confusion in the past with who to submit the exemption request to EPA or the Division.

If there have been any aquifer exemption requests from your District, briefly describe the process for approval/denial of such request. Our office looks over the information and then submits the information and request to Sacramento's UIC coordinator, who then forwards the request to George Robin with EPA in San Francisco.

Conclusions

To our knowledge, the San Ardo aquifer exemption is only one of two exemptions that have been approved in the state since approval of Primacy in 1983. Two others were reported as pending approval, both in District 4, as of November 15, 2010. See Section 3.0 for more information.

PART III: Inspections

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District.

Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas.

How are inspection priorities determined? We strive to witness all initial testing of injection wells (Ra surveys, static temp surveys, SAPT's, PFO's). We then attempt to witness all additional testing. On occasion other tests out prioritize UIC testing. We prioritize environmental inspections by date last inspected. Priority does not relate to residential areas in our district since we have few fields within towns and cities.

Do you prioritize on the basis of the presence and relative risk to USDWs? Please identify fields and/or wells that fit that description Typically not. Water disposal wells would outweigh steamflood wells if we had to make a choice. Again we don't regulate based on the proximity of towns. We may on occasion analyze whether an operator's operations need to be verified/witnessed or another operation takes priority.

In what projects are not USDWs present? Fresh water is not present in the Casmalia, Orcutt, Arroyo Grande, Russell Ranch, and Lompoc fields

What professional qualifications and/or experience are required by DOGGR to be an inspector? Do District staff have the necessary qualifications and/or experience? What types of training do inspectors access or would like to access if funds were available? Field inspectors (Energy & Mineral Resources Engineers) typically have college degrees (ME, Chem E, Geologist). We do have staff that have been trained in-house and do not have degrees. The Division has publications (M13, MOI) that discuss proper procedures. Also Associate and senior field staff train new field staff in the field.

Do all District staff have the necessary qualifications and/or experience? What additional training may be needed to meet the minimum requirements? Have they attended UIC specific training courses such as those offered by EPA? Yes or they would not be here. If a question comes up where they may be unsure then they can consult with others in the office with more experience. Most staff have not attended UIC specific training courses offered by EPA.

What tools do the inspectors utilize? Are there additional tools that you can identify that would be useful? They use calculators, decimal books (Halliburton, etc), and laptops. It would be good to have computerized tablets that they could use in the field both for surveys and environmental inspections.

Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training. They receive on the job training from seasoned field engineers. They are supported for technical training with time and funds to attend classes and conferences within California related to UIC operations. They are also required to take H2S courses for safety training.

What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process? They have everything to do about enforcement cases. They could very well have found the deficiency, preformed follow-up inspections to determine it is now a violation, and provided the necessary field documentation to support any hearing or judicial process. They also provided first hand information as a witness. In our office we provided accounts to the EPA on our "undercover" operations to catch an operator. We answered questions posed by EPA representatives.

Conclusions

Inspections are not prioritized for wells where fresh water is present, and residential areas are not a consideration since the wells are located in rural areas. Witnessing initial testing of injection wells is a priority. Disposal wells would be given a higher priority than steamflood wells.

The professional qualification and/or work experience requirements for District 3 UIC inspectors are similar to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. Resumes were not provided, but training and *qualifications of inspectors appear to be adequate in most areas, based on District responses and discussions with staff at the District 3 office. Some field staff lack college degrees, but have been trained in-house and receive on-the-job training with seasoned field engineers. Most staff have not attended UIC specific training courses offered by EPA. Those staff members should probably attend the UIC Inspector Training Course offered by EPA at various regional offices on an annual basis.*

We were informed that the Division has authorized the employment of several additional UIC staff members statewide. If that includes additions in District 3, that should significantly improve the District's ability to process new project applications and perform inspections and the other UIC functions on a more timely basis.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District.

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations. We refer operators to the EPA website on approved Class II fluids. We use a list in our manual which includes the following: Waste waters from gas plants which are part of the production process, brines that come up with production, fresh water, diatomaceous earth filter backwash, thermally enhanced oil cogeneration plant fluid, water-softener regeneration brine, air scrubber waste, drilling mud filtrate, drill cuttings, tank bottoms, and rain water. While these may be on the list, if we suspect the fluid may not qualify we can require that it be tested to ensure that the fluid is not hazardous and have the operator self certify.

How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database the inspection data is stored in or attach the inspection verification documentation. Inspections at the well site could occur annually or every couple of years depending on location and ability to conduct lease inspections. We don't just single out the UIC wells. The UIC environmental inspection occurs at the same time the technician is inspecting oil & gas producers. Our field information is contained on an 8 ½" x 11" log sheet for each well in a binder. The binders are sorted by well type (WD/SF/WF).

A UIC database is referenced in your responses that follow. Is it utilized to store and review inspection data for each injection well? No. As I indicated in my original answer our UIC environmental inspection information is stored in a binder. The technician/EMRE's hand writes their observations. We do have an environmental lease database that does track when we last inspected a particular lease, but it is not used for UIC information. The UIC database we reference only contains test observations and information. *Will you be utilizing the CalWIMS database system that other districts have indicated is under development for use in all districts?* Yes, eventually.

Is the operator given advance notice of inspection and does the operator receive a copy of the report? Yes in most cases the operator is given advanced notice – but not always. Yes the operator receives an electronic copy of the entire inspection before the technician leaves the field if an email address is provided.

Describe the reporting and follow-up procedures used in the inspection program when there are violations. We have a follow-up system to remind staff to conduct reinspections. The clerical staff give the field staff the follow-up when it is due. I also put the follow-up tickler in my (deputy's) Outlook calendar.

How is the District notified of emergency situations regarding Class II wells and related incidents such as spills? We receive an email from the CalEMA agency and in some cases a telephone call. The operators will also notify our office by phone. And is some cases the local county agency will send us a report.

What type(s) of emergency situations has/have been reported involving UIC permitted wells? Please list the ones you have received over the last five years, or the most recent examples. We have had injection pipeline leaks related to wells in the San Ardo field. We have had injection tanks overflow due to mechanical pump issues related to injection wells. We have had packer failures related to wells. Without a better understanding of what "emergency" means I'm inclined not to provide a list at this time.

An emergency situation is one in which produced water and/or oil and gas related to the injection operation is released to the surface or subsurface wherein surface water bodies or USDWs may be endangered by the release or leak. Please respond in that context.

YEAR	VOLUME (bbl)	FIELD	OCCURRENCE
2010	250	Cat Canyon	SPILL - Electrical failure of injection pump
2010	200	San Ardo	SPILL –Control system failed with RO plant
2009	200	Santa Maria Valley	21
2008	250	Zaca	SPILL – Injection pump failure
2008	200	Cat Canyon	16
2008	100	San Ardo	43
2008	1500	Santa Maria Valley	SPILL – Line leak
2008	62	San Ardo	Spill – Line leak
2008	100	Cat Canyon	SPILL – Human error
2007	600	San Ardo	SPILL – Line leak
2007	119	San Ardo	SPILL – 38
2007	206	San Ardo	SPILL – Heater treater failure
2007	400	Lompoc	SPILL – Sump pump failed
2007	50	San Ardo	SPILL – Tank bottom failure
2007	1700	San Ardo	SPILL – 69
2007	190	San Ardo	SPILL – 71
2007	100	San Ardo	SPILL – 72
2007	200	Cat Canyon	SPILL – Injection pits overflowed
2006	350	San Ardo	SPILL – Tank leak

YEAR	VOLUME (bbl)	FIELD	OCCURRENCE
2006	800	San Ardo	SPILL – Line leak
2006	20	Cat Canyon	SPILL – Line leak
2006	70	Cat Canyon	SPILL – Line leak
2006	140	Cat Canyon	SPILL – Equipment malfunction at pump
2006	120	Zaca	SPILL – Electrical failure control tank level switches
2006	55	San Ardo	SPILL – Well control issue during foaming operations
2005	50	Zaca	SPILL – Tank failure
2005	75	Cat Canyon	SPILL – Transfer pump failed
2005	75	Cat Canyon	SPILL – Corrosion of injection line
2005	50	Santa Maria	SPILL – Line leak
2005	50	Cat Canyon	SPILL – Human error causing tank to overflow
2005	500	Cat Canyon	SPILL – Line failure
2005	50	Cat Canyon	SPILL – Line failure
2005	100	Cat Canyon	SPILL – Line leak
2005	250	Santa Maria Valley	SPILL – Injection pump failure
2005	50	Cat Canyon	SPILL – Line failure
2005	20	Zaca	SPILL – Tank failed
2005	50	Zaca	SPILL – Alarm failure on wastewater tank
			OTHER FAILURE INFORMATION LISTED IN TABLE BELOW

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. Field inspectors have internet access so that they can access Division maps, and online injection information. In the office they have the ability to access our UIC database, the inspection binders, and the individual well files and project files. They also each have an oil spill contingency plan with them that provides contact information.

What sorts of data are stored in the database? Please describe. The UIC database is only available in the office, not while out in the field. Our in office database has the following info: API #, Operator Name, well status, injection gradient and MASP, well location info, well type, survey frequency, next due date, records reviewed date, whom reviewed, past survey info which includes dates, rates, pressures, type, witnessed, results, received results in office. Also have SAPT info dates, results, next required test date, and PFO dates, results, and next due date, and of course a remarks sections to list special requirements or well conditions.

The UIC database is referred to as non-existent in a later response. Please clarify the above response in that regard. The database in use for the UIC program is the Access database developed by District 2 staff. The environmental reviews are placed in a binder.

How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily accessible database? If not, how does the District verify compliance with the MASP? The injection pressures are listed in our UIC database, and in the inspection binders. On some of the older permits it lists the MASP. No, not all of the MASP values are in an easily accessible database when the engineers are in the field. The field technician and engineers check it when they return to the office.

Conclusions

A list of the types of fluids approved for injection in Class II wells was provided. We have no reason to believe that any of the state accepted fluids listed above would be disallowed for injection into a Class II injection well. However, drill cuttings and rain water are not included in the list of fluids eligible for disposal in the MOI at Section 170.2.3. It would be a CDOGGR and an EPA decision to classify a particular fluid as eligible for injection into a Class II injection well.

The Division goal for inspecting each permitted well, for other than MITs, at least once per year may not have been attained in recent years, according to the District 3 response above. The District indicates that UIC inspections could occur annually or every couple of years. The MOI indicates that injection wells should be inspected annually. The District may need to hire additional inspectors to achieve the annual inspection goal; however, the recent Division directives state that inspections should occur at least every two years.

The District states that advance notice of a lease inspection is usually given to the operator. That could compromise the inspector's ability to find violations since the operator would have the opportunity to prepare for an inspection and possibly hide violations.

The reporting and follow-up procedures used in the UIC inspection program appear to be somewhat weak, based on the description of those procedures in the above response. Environmental inspection reports are stored in a binder at the District office. Well test data and results as well as MASP and other information are stored and tracked in an Access database, but inspectors have no access to the UIC database while in the field. Injection pressures noted in the field are compared with the MASP for a well in the UIC database when an inspector returns to the office. Follow-up procedures for violations are discussed in Part IV below. District 3 will change over to the CalWIMS database eventually, and possibly later this year, as will all District offices according to CDOGGR staff.

Most emergency situations in the past five years have been the result of equipment failures, line leaks, and tank leaks. Most occurred in the San Ardo and Cat Canyon Fields. Incidents that occurred in the past five years are listed above. No description of remedial operations were provided, but we assume that all of the failures were corrected.

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability. A casing pressure test using a vacuum truck, or an ADA test or fluid level test. A vacuum truck with a roper can only get up to 300 psi typically. A company will have to get larger pumps to perform a test pressure greater than that. The ADA test is costly but a great test type if for instance there are perfs above the packer. As the test is conducted they need to take fluid levels to ensure integrity.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? A Notice to Operator clearly defines the testing pressures and the time intervals that we use. Notices to Operators are considered a form of regulation/law.

What are the criteria for the test pressure, time interval, and change in pressure during a test? Please discuss the basis for the criteria for pass/fail. The test pressure in the Notice to Operators listed 200-300 psi. Time interval is 15 mins to 30 mins, but the results have to clearly demonstrate that the well casing has integrity. A change in pressure during the test typically indicates a failure, i.e. the pressure is bleeding off. Anything more than a 10% pressure decline is considered unacceptable. The basis is the Notice to Operators agreed upon by Division District Deputies and Headquarters. None of us in this office took part in those discussions.

If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM? Our district has been phasing out monitoring programs. Those APM programs that are “grandfathered” are typically only allowed in areas where there is no fresh water. The monitoring programs consist of fluid level shots that are taken on a quarterly or every 6-month basis. I don’t believe we have had any identified.

Are pressure gages or continuous recorders used to monitor and record annulus pressures? Are the pressures reported by the operator weekly or monthly? Pressure gauges are used. The readings are typically taken daily and then supplied to the district office on a quarterly basis. *Reporting annulus pressures on a periodic basis is unique to the District 3 office, according to the responses from the other distinct offices.*

If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail? While cement information is an important component, it is not used as a testing procedure.

Is it used to evaluate wells for USDW isolation in the casing/wellbore annulus during the technical review of a permit application? If not, is a CBL acceptable for this purpose?

Temperature or noise logs? Yes, cement evaluation during the AOR process is a major component. And yes, a CBL can be used in place of cement calculations. Temperature surveys used to determine cement lift can also be used within an acceptable timeframe following cementing operations.

Is a static temperature survey ever used for detection of fluid flow in the casing/wellbore annulus? Are there any examples you can provide? We may run a static temperature survey in horizontal wells and where RAT survey tool can't get deep enough to obtain an injection zone profile.

Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined? We have not used logs to determine MI. CBL's are used when reviewing an AOR for cement lift but is not used to test wells. Decisions to run test rest on the Associate and the District Deputy with input from the senior field staff. We would interpret the logs when appropriate.

Please clarify. Temperature and noise logs and CBLs can be used to evaluate cement placement/channels and fluid movement in the casing/wellbore annulus, which are not tests but do allow assessment of Part 2 (external) mechanical integrity. I may have misinterpreted your original question. Clearly we use different logs to determine BFW, zone tops, cement lift, but clearly we do not use these results to substitute for running mechanical integrity tests such as RAT surveys, static temperature surveys, casing pressure tests, and pressure falloff tests. And yes, temp, noise & CBL's can aid in the assessment of the condition or locating potential problems in injection wells.

What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone? Yes there are wells that are tested more frequently than the standard listed in regulation. Standard testing is 1 year, 2 yrs, 5 yrs for radioactive tracer/static temp testing of water disposal, waterflood, steamflood wells. Those wells that are required to be tested more frequently have mechanical issues, such as slim hole injectors. Risk is a result of mechanical issues.

Describe the follow-up and typical enforcement actions for MIT failures. Depending on the issue, the operator may be instructed to shut in the well immediately, receive a T-rept with a correct and repair with a time period to fix listed, or a letter requesting the corrective work.

Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed? MIT surveys are witnessed by EMRE's with rare occasions by the technician. A high percentage of the surveys are witnessed by this office. EMRE's complete a T-rept for all witnessed tests, and they enter the information into the UIC database, and also the UIC binder. In both the witnessed and waived tests the operator is required to submit the survey drafted copy. Once received the survey is reviewed and the information updated in the UIC database.

Can you be more specific? Please estimate if actual percentage of witnessed MITs is unknown.

YEAR	MIT Surveys	Casing Pressure Test	Pressure Fall-off	Percentage
2010 Witnessed*	64	80	40	77%
2010 Waived ∃	34	21	1	23%
2009 Witnessed	49	21	16	40% <
2009 Waived ∃	77	47	1	60%
2008 Witnessed	71	79	70	66%
2008 Waived ∃	58	52	1	34%
2007 Witnessed	63	47	26	56%
2007 Waived ∃	73	33	2	44%
2006 Witnessed	79	38	51	70%
2006 Waived ∃	60	8	5	30%
2005 Witnessed	78	40	24	61%
2005 Waived ∃	79	9	1	39%

* First 3 quarters data
∃ Includes tests where an operator may have failed to notify us for the tests
< Had only 2 field engineers available during the year covering all district operations
Numbers were generated from the District's Quarterly Report

In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate. Staff at the well site are instructed to shut in the well. In some cases a T-rept is send listing corrective action.

Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures? Yes they are required to complete corrective action or approval to inject into the well is terminated. They typically are given 30 days to repair the well. In some instances it may take longer so a variance may be given if warranted.

Please elaborate on acceptable measures for corrective action and variances for extending the time required to repair or P&A a well. Acceptable measures may be as simple as shutting the well in and disconnecting it. If the operator wants to continue using the well then they must repair it. It really depends on what the problem is. For instance if there is a hole in the casing then running and cementing an inner string would be acceptable, or squeezing the hole with cement, or running a casing patch. No matter what the corrective action chosen by the operator, the operator will have to satisfy us with a successful follow-up casing pressure test. For instance if there is a leaky packer, the operator most likely would run in and reset the packer or run and reset a new packer. No matter what the corrective action chosen, the operator will have to satisfy us with a successful Ra survey, or a casing pressure test to ensure the packer is holding. It really just depends on the problem as far as corrective action. A variance may be issued based on the type of repair needed, weather conditions, etc. It would not be often if at all where we would require the well be P&A'ed. The authority to inject would be terminated, the well discontinued, and then it would be followed-up with our idle well program and environmental inspections. It would only be in rare cases that we would require abandonment, for instance when injection in offset wells could potentially impact USDW's due to the MI failure.

If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work? It would depend on the work. For instance we have witnessed the cementing in of a new string of casing, or we will witness a SAPT if a hole or patch is used to fix the casing, or a SAPT may be witnessed to verify that the packer has been reset. Yes copies of the information must be filed.

What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time? We have very little failure rate overall. *Please estimate if actual failure rates are not known.*

See Chart Below and compare with test numbers

	High pickup		Shoe or top perf upward migration		Tubing or Packer leak	SAPT – casing failure			Problems Corrected	Wells Rescinded
	WD	EOR	WD	EOR	WD	EOR	WD	EOR		
2005	None	- - -	- - -	- - -	- - -	- - -	- - -	- - -		
2006	1	2							3	
2007		3				1		1	3	2
2008	3	5			1	1	1	1	7	5
2009		1								1
2010 (ytd)	4	3				1	1	3	7*	1

* 4 wells waiting resolution of problem (high pickup) as of 10/14/10

Mechanical Integrity Failures

What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well? They are required in their project approval letter to notify us. They will typically call us to report a failure. Once notified we will send a letter confirming our expressed actions verbalized in the phone conversation.

Are the operators required to monitor and record annulus pressures on a regular basis, such as weekly or monthly? Are they required to shut in a well when abnormal or excessive annulus pressure is observed, pending remedial operations and report that to the District office? No, there is no permit condition or specific language that addresses recording of annulus pressure. However, under good oil field practice, an operator's field staff should be looking at an active injector at least once a day and recording the information observed (tbg/csg pressures & meter volumes). Also in the project approval letter the operator is required to run a MIT if there is a pressure change and the Division notified to witness the test. The operator is also required to maintain data that establishes that there is no damage occurring and requires that injection be stopped if damage is occurring. Also as part of their project approval letter it states that the Division be notified within 24-hr of losing mechanical integrity and injection is discontinued if there is any evidence of damage observed.

Describe the data management system used in the various components of the MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure. Our UIC database allows us to run queries to determine if MIT surveys, SAPT's, or PFO's are overdue. It allows us to generate a list that we can send to the operator. Those letters are placed in follow up just like any letters, deficiencies or violations that are observed are placed in follow-up which the clerical staff pull to ensure the issue is resolved.

Conclusions

The SAPT requirements as described above are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in Sections 2.0 and 3.0 of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure. If a lower pressure were allowed, we would recommend more frequent testing and/or monitoring of casing pressure.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. Increasing that to 30 minutes, however, would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

CDOGGR has changed the SAPT standard to test at the MASP in wells where there is only a single string of cemented casing across a USDW (10,000 mg/L). I believe that will apply to a large number of wells since the historical construction standards applied do not require two strings of casing across a USDW. Two strings are commonly set below the BFW in more recently drilled wells, but not necessarily to the base of USDWs according to my limited review of California injection well records and information gained in responses to the EPA Questionnaire and office visits.

The District states 77 percent of RAT surveys and 80 percent of SAPTs were witnessed in 2010, which is an increase from 49 and 21 percent, respectively, in 2009. The reason stated for the increase is that only two field engineers were available in 2009 to cover all District operations. Percentages witnessed in prior years exceed 60 in most years going back to 2005. Those are relatively high percentages of MITs witnessed, compared to most other districts. However, District 3 has far fewer injection wells than do some districts, such as Districts 1, 4, and 5.

Wells that fail a MIT are usually required to cease injection immediately, but are not required to be repaired unless USDWs are potentially endangered while the well is shut in. That may be acceptable if a well fails a MIT due to a packer or tubing leak and the casing pressure declines to zero after shut in, however, one cannot be certain that a casing leak does not exist concurrently with a tubing or packer leak. If USDWs are present in a well with a casing leak, *there may be a risk for fluid movement into a USDW or other zones that lack cement in the casing/wellbore annulus between the leak and the USDWs or other zones. The risk increases with time in idle status and pressure on the casing, as the casing integrity becomes less certain over time without passing an annular pressure test. Pressure increases during shut-in status are possible, especially in waterflood injection wells and disposal wells that are located within the ZEI/AOR of another injection well and injection zone pressure is allowed to exceed normal hydrostatic pressure.*

Our understanding of the CDOGGR idle well requirements are as follows: a pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are required every two years in fresh water areas and five years in non-fresh water areas after five years in idle status, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. We believe that wells that lack MI should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area. We also recommend a casing pressure test be performed in idle wells rather than fluid level surveys unless USDWs are known to be absent in the area.

There seems to be some confusion or misunderstanding about the meaning of Part 2 MI. The District apparently uses that term to apply to the isolation of the injection zone based on testing, but not necessarily to cement placement in the casing/wellbore annulus for external MI and isolation of USDWs. The discussion of the assessment of Part 2 (external) MI in District 3 wells indicates that cement records are reviewed in addition to CBLs and temperature logs when they are available as a part of the AOR review process. CBLs apparently are not a requirement for that assessment, and are considered a voluntary choice of the operator, whereas temperature logs can be a CDOGGR requirement.

We would argue that CBLs are valuable tool in assessing external MI and are much more reliable than calculations of the depth to the top of cement in the annulus. If there are doubts about whether sufficient cement is present in the casing/wellbore annulus to isolate the injection zone, hydrocarbon bearing zones, and the base of USDWS from fluid movement in the annulus, a CBL should be run and/or squeeze cementing operations should be considered. The evaluation of cement bonding to the casing and wellbore wall is also an important consideration in assessing isolation between those zones.

Static temperature logs can be of value in detecting fluid movement in the annulus, as well as the top of cement in new wells. Our recommendation would be to run CBLs in all new and converted Class II injection wells where USDWs are present. Static temperature logs should be run if an existing well lacks sufficient cement at the base of USDWs, and/or squeeze cementing should be considered at the USDW base to ensure isolation from fluid movement.

State UIC regulations require adequate volumes of cement in the casing/wellbore annulus immediately above the injection zone, above hydrocarbon bearing zones, at the BFW, and behind surface casing. The presence of sufficient cement is determined by examination of cement records. Those standards should satisfy Part 2 MI requirements at least in part, but cement should be present at the base of all USDWs (10,000 mg/L TDs or less) for complete protection of

USDWs. In our view, the presence of heavy mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

The recent Division directives to the district offices and the authorization to hire additional UIC staff should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

What types of enforcement tools and legal actions are available to the District for the UIC program? How often in the last five years have you used them? Please list these or the most recent examples.

We can send deficiencies, violations, or issue civil penalties. We use them all the time. Too many to list for deficiencies. We have used it for violations and civil penalties in the last 5 years.

Please list and describe the most recent examples of enforcement actions taken for violations and civil penalties. How many in the past five years?

2010 – Violations:

- One violation for failure to file a history to reactivate an injection well. (Bell 143)
- One violation for failure to disconnect and discontinue injection in a waterflood well (Bradley Consolidated 4-22)
- One violation for failure to run a radioactive tracer survey (Squires 27)
- One violation for exceeding maximum allowable surface pressure (Security Fee 38)

2010 – Civil Penalties:
None involving injection wells

What types of formal enforcement actions have been taken relative to UIC violations in the District? If the requirements of a Notice of Violation (NOV) are not complied with, the Division issues a Formal Order to the operator. At the same time, or upon failure to comply with an NOV, the Division may issue a Provisional Formal Order Imposing Civil Penalty (PO). The operator may request a hearing to explain the violation, refute the evidence, and question Division staff. After such a hearing, or if the operator chooses not to request a hearing, a Final Order Imposing Civil Penalty is issued. The matter is not resolved until the operator complies with the requirements of the NOV and pays the penalty amount imposed in the Final Order. These actions are described in Section 135 and 136 of the Division MOI. Furthermore, as described in Section 170.15 E of the MOI, any violation of a formal enforcement action involving an injection well is a Significant Non Compliance, triggering the notification requirements.

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. We operate the same, however we can adjust corrective time periods for those operations that warrant it.

Does the District issue Notices of Violation (NOVs) or similar notices to the operator and attach penalties? How many have you issued in the last five years? Please list these or the most recent examples. We issue NOV's. Penalties, however, are typically only assessed for civil penalties. We have issued formal orders to plug and abandon wells for defunct operators.

How many civil penalty orders have been issued in the last five years? Please list the most recent

See table below:

Year	Number of Civil Penalties Issued	Were any related to Injection? If so explain.
2010	2	No
2009	1	No
2008	2	Yes, one (1) was issued for failure to maintain injection pressure below estimated fracture pressure. Fine: $1000. Corrective Action: Either reduce injection pressure to below MASP or terminate injection
2007	3	Yes, one (1) was issued for failure to file a notice to reactivate injection and failure to run a mechanical integrity test, Fine: 2500; And one (1) was issued for failure to file a notice to reactivate injection, failure to run a mechanical integrity test, and failure to file injection pressures and volumes Fine: $3000. Corrective Action: File notice, run survey & report volumes or terminate injection
2006	0	No
2005	1	No

What are the follow up procedures to assure compliance and correction of the violation? Field engineers conduct follow-up inspections. Once corrected a letter may be sent to the operator.

How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV? It really would depend on the violation. If it is going to threaten USDW's the well most likely has been shut in. Therefore corrective action is typically 30 days.

How much time is allowed to complete remedial operations for lack of MI when a major workover is required? Typically 30 days. The well may have been immediately shut in, depending on the test/issue. A field report (T report) is issued to the operator requiring the well be repaired and a successful test conducted on or before a certain date (typically 30 days), otherwise if the required repair work is not done then injection into the well is officially discontinued and the injection lines disconnected (a termination letter is sent following an inspection by the field engineer to verify disconnect). The key is the well is shut in immediately thereby eliminating the threat.

It appears that repairs are not required unless the operator intends to reactivate an injection well, only that the well remain inactive and disconnected until it is repaired and passes a SAPT. That would be consistent with responses from other districts, but 30-day time limit to repair a well is unusual except in wells that may endanger USDWs, based on responses from other districts. We assume that the 30-day limit to repair applies to wells that lack MI but that are not required to be shut in. Repairs are not required unless the well will be reactivated.

How and when do UIC violations escalate from non-compliance into formal enforcement actions? If the operator does not correct the violation. *Within the time allowed? Please elaborate.* Yes, within the time allowed. A typical violation is given 30 days, but it can depend on the type of violation. Injecting into a well over MASP may be given a shorted response time than say for instance filing a history. If the operator does not complete the work in the time allowed then it moves to the next level civil penalty actions. A district deputy may elect to issue a civil penalty directly if the offense is egregious.

W hat penalties have been assessed and collected on UIC violations in the past ten years? The only civil penalty assessed by District 3 in that period related to injection was in the amount of $2500 for a spill from an injection facility. The most egregious violation discovered in District 3 was referred to the USEPA and the Division issued no civil penalty.

Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? We can't be at every well 24-7. The ability to terminate approval to inject is a pretty powerful incentive to make the necessary corrective operations. Most issues do not get past the violation phase.

To clarify, are you able to witness the number of MITs and P&A operations to meet Division goals and provide for adequate enforcement? In addition, does the District have adequate resources in terms of staff and attorney support to proved adequate enforcement for the most egregious violations? Up until recently we had no defined State goals. Our own district informal goals were of course to witness as much as we can, striving for 100%. Our informal district goals have always been to inspect every well in our district every year. We've only done that once in the last 27 years, so with current staff probably not a reasonable goal. We recently added field staff to cover facilities and help with the field surveillance activity so I would assume that our percentage should increase some and you can see that in the numbers listed above. Increasing face-to-face project review meetings is not going to happen unless we have more Associates. Currently one Associate to cover all permitting and UIC activity permitting is just too thin. Will an attorney add value? Obviously we need an attorney to represent us in the hearing process, but as the numbers show, we don't get to that level very much. On the other hand a limited term position to review and modify current UIC language in our regulations is needed.

Conclusions

The enforcement procedures available to the District are highlighted in the responses above and are described in detail in the CDOGGR laws and regulations that apply to the UIC Program. Informal actions for noncompliance include: deficiency notices, shut-ins, NOVs and rescissions. Formal orders and civil penalties can be issued if the informal actions do not result in compliance. Violation of a formal enforcement action is a SNC. These actions are described in Sections 135, 136, and 170.15E of the MOI. Three civil penalties were issued in the past five years with fines up to $3,000 for each order, according to the District response to that question above. However, a later response indicates that only one was issued ***and collected*** *in the past ten years related to injection. The most egregious violation was referred to EPA and no civil penalty was issued by the Division.*

Remedial operations are not necessarily required after a well is shut in unless the violation would threaten an USDW, according to the District responses above and the MOI. Wells that lack MI but pose no ***apparent*** *threat to USDWs can apparently remain in idle status at least 15 years without a requirement for repair or P&A. In our view, wells that are in violation for lack of MI should be shut in and repaired or plugged and abandoned within three to six months, unless USDWS are known to be absent in the area.*

The District staff responded that they do not have enough resources and professional staff to provide adequate compliance/enforcement measures, process project applications on a timely basis, and conduct annual project reviews with all operators. They added field staff recently, which has resulted in increased surveillance activity, but the District could benefit from the addition of an Associate to address other deficiencies such as face-to-face project reviews, permitting, and other UIC activity.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public. We review the information and potentially notify other agencies such as RWQCB. Public complaints are reviewed for merit and addressed with meetings with the operator(s) and potentially testing to verify complaint. Once verified potentially corrective action could be enforced.

Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination? There was a well in San Ardo where there was potential USDW contamination. We alerted RWQCB, who then took over the case, requiring monitoring and fluid samples. From this the Division developed a policy for more frequent testing of slimhole injectors.

What actions are taken by the District when an alleged contamination report is received? We follow-up on the report immediately, either through calling the operator, making a report, or notifying other agencies. We take contamination very serious.

How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? One, due to casing failure as mentioned above. See below.

Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to the above question. Casing failure in a packerless steamflood injection well allowed injection fluid to enter an USDW. The well was ordered to be shut in and the case referred to the RWQCB and USEPA as a SNC for investigation and remediation.

What remedial and enforcement actions were taken? Division - We didn't require anything since the RWQCB took over with the investigation. We did however modify our testing frequency for all other slimhole injectors. We also looked at the cementing practices and potential failure that lead to the breakdown in integrity. RWQCB – They set forth withdrawal/flowback requirements. They required tests of the fluid being withdrawn.

Please identify the well in question. Aera Energy Orradre 51-68-2 well

Conclusions

One injection well, the Aera Energy Orradre 51-68-2 well in the San Ardo field, was suspected of causing USDW contamination in the past ten years. The well was ordered shut in and the case was referred to the RWQB for resolution, which is standard procedure in contamination cases. The RWQB required monitoring and fluid samples to be taken and analyzed. The cause was casing failure in a packerless steamflood completion that allowed injection fluid to enter an USDW. EPA was also alerted to the violation as a SNC for investigation and remediation. The district subsequently modified the testing frequency for all other slimhole injection wells. Cementing practices were also reviewed, but the outcome of that review was not discussed. Cement placement at the base of USDWs, which is not a CDOGGR requirement, might have prevented the injection fluid from entering the USDW. That is one of our primary concerns, and we encourage CDOGGR to consider making that a requirement in all injection wells where USDWs are present.

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.). Our plugging requirements follow that in regulation. Zone is plugged with cement and extends to 100' above the top perf, WSO hole, liner top or top of the zone whichever is highest; Upper zone plugs may be required even if not perforated and produced from– 100 ft; BFW plug straddles the BFW with a 100' long cement plug if there is cement behind casing, or if there is no cement behind casing the operator is required to shot perfs or a cavity shot and squeeze 100 linear ft. out behind casing as well as leaving 100 ft in the casing; the surface plug is typically 50 ft inside and 25 ft in the annulus; any portion of the well not filled with cement is filled with mud. See our regulations for additional plugging requirements.

What are the plugging requirements for isolation and protection of USDWs? A cement plug is put at the top of the productive zone opposite of cement behind casing to ensure that there is no upper migration of oil. A second plug, 100 ft in length, is also put straddling the fresh water – saltwater interface. A surface plug is also put in wells to ensure no one falls in the well, but it also prevents surface runoff from entering the wellbore.

Apparently, no plugs are required at the base of or across USDWs. That is consistent with responses from other districts and the Division HQ Expectations memo of May 20, 2010.

Are there UIC wells without surface casing installed? How are they plugged? Same as above.

If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed? They would follow our stub plug requirements.

Please describe the requirements. If casing was pulled and exposed the top of the zone then an open hole zone plug requirement would apply. This would require from at least 100 ft below the top of the plug to at least 100 ft above the zone. If the casing was pulled exposing the base of fresh water then there would be a minimum of a 200 ft plug straddling the fresh water/saltwater interface. If the casing is pulled and exposes the shoe of another casing then a shoe plug would be required. The shoe plug would require 50 ft below the shoe and another 50 ft up inside of the casing.

Are plug depths verified? When and how? Are all plugs required to be tagged? Open hole plugs are tagged ***if required***; Zone plugs are tagged; BFW plugs where perfs/cavity shots are required are tagged, BFW where cement is behind casing have a casing pressure test done and if approved the BFW plug is placed; Stub and Shoe plugs would be tagged; surface plug placement is witnessed and visual on the surface prior to placing.

When are open hole plugs not required to be tagged? Open hole plugs require tagging. Squeeze job plugs are tagged and witnessed by DOGGR inspector. *Does the tagging requirement also apply to USDW plugs?* If you can establish it is a closed system then you may in some cases be able to witness placement of the cement plug without tagging to verify the top of the cement plug. Our tagging requirements and State regulations have no distinction between USDW and non USDW areas with regard to plugging requirements.

What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations? 99%. We have the operator provide written documentation. With a level of confidence from years of working with a particular contractor we can waive some operations when necessary.

Describe the process used to get an idled and an orphaned well plugged. We terminate approval to inject and require idle well testing to prompt operators to access the viability of the well. On orphan wells we try to give them away (90-day agreement) or solicit funds from HQ to plug wells.

How long may an idle well remain inactive and how frequently is testing required? Give away to whom and for what purpose? There is no set limit on how long a well may be inactive. In fresh water bearing areas we test idle wells every 2 years. In non-fresh water areas we test the wells every 5 years. The Division has a program to "give" orphan wells away to operators that have the resources, and approval of the mineral rights owners to take over the wells. In some cases an operator has "test drove" an orphan well to see if it had potential as an injection wells. The operator has to test the casing prior to conducting an injectivity test.

Is the fluid level a determinant for testing an idle well, as it is in other Districts? Please discuss the testing requirement further. Yes, Fluid levels are measured at two year intervals for fresh water areas and five year intervals for non-fresh water areas.

Does the District maintain an inventory of abandoned (orphaned) UIC wells? Yes.

How many wells are currently in the abandoned inventory? There are a total of 5 orphan wells in our District inventory (we recently plugged the Huasna wells). You can visit our website for a comprehensive list of orphaned wells ftp://ftp.consrv.ca.gov/pub/oil/orphan/Orphan2008.pdf. We have 1 orphaned water disposal well "Brinan A" 3 and 1 air injection well in Paris Valley.

Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund. Yes. The funding comes from California producers. There is a limit on the amount of money we can spend every year. Some of the funds will be eliminated after a certain date.

How are the current plugging requirements different from those of 40 years ago? Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project? Obviously today's plugging requirements require more cement then in the old days. Also required cementing of casing may be different. Yes, this has an impact on the number of potentially "bad" wells within an AOR. Our office just requires the operators to fix the wells so it's an added financial burden for them.

Is this a UIC permit condition or must it be completed before a permit is approved or denied? It varies. Some operators come in and discuss the projects with us prior to filing the notices. In many of these cases they "see the writing on the wall" and repair wells prior to submitting their projects, or move well locations/projects so as not to have to have problem wells within the injection area. Others file their notices and we respond back with conditions placed on their permits, denying or limiting/restricting injection.

Conclusions

District 3 applies the existing statewide P&A standards, which are discussed in the state level section of this report and are described in detail in the CDOGGR regulations and MOI. The recent Division directives require a zonal isolation plug for all wells within the AOR of an active injection project, which is a new and more rigorous requirement for protection of USDWs from migration of injection fluid out of zone in those wells. In addition, a cement plug is required at the BFW zones in plugged and abandoned injection wells, but not in other wells within the AOR of an injection well or at the base of USDWs in any well.

District 3 written responses are not clear about their adoption of the new requirement for a zonal isolation plug in AOR wells. We support the new Division directives and urge District 3 to adopt those for application in the District as soon as possible. The lack of a requirement for placement of cement plugs at the base of USDWs is a concern, however, and modification of P&A requirements in that regard would greatly enhance the protection of USDWs containing more than 3,000 mg/L TDS. In our view, the USDW plug requirement should apply to all wells within the AOR when casing repairs occur or when plugged and abandoned.

The District indicates that older wells (pre-1970) often do not meet current plugging requirements when reviewing an injection project, and that impacts the number of potentially deficient wells within the AOR. Current CDOGGR plugging requirements for AOR wells require a zonal isolation plug through and above the injection/production zones in those wells, but not a BFW plug, according to the recent Division directives. We agree with the zonal isolation requirement, but recommend an additional requirement for placement of cement plugs at the base of USDWs in AOR wells and placement of cement at the USDW base in the casing/wellbore annulus in idle or active wells that lack cement at the base of USDWs.

District 3 states that most P&A operations are witnessed. That includes tagging cement plugs and cement squeezing operations, but may not include witnessing cement plug placement operations, as discussed in the state level section of this report. When P&A operations are not witnessed, District staff review the P&A report submitted by the operator to ensure compliance with P&A requirements. We have concerns about the absence of a CDOGGR inspector during cement placement operations, as discussed earlier in the state level section.

District 3 follows the statewide Idle Well Planning and Testing Program in managing P&A of idle and orphan wells. There are two orphan UIC wells in the District at this time. Our concerns regarding the management of idle wells are discussed below and at length in Sections 2.0 and 3.0 of the report.

The requirement for adequate volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well? Operators may run a BP as a TA but that BP will have to be removed after a certain period of time. The well is still idle even if it has some required plugs in it.

Please clarify why a BP must be removed. Do "idle" wells include wells that are shut in temporarily by the operator on a voluntary basis and/or wells ordered shut-in for lack of MI? Please elaborate. EPA describes TA status as a well which has been inactive for more than two years but must remain in compliance with MIT and other requirements while in TA status. If not in compliance, it must be plugged and abandoned. Reactivation requires passing a MIT. How does this compare to idle well status?

Retrievable BPs are pulled every 2 years to ensure they do not become stuck in the well.

Yes, operators shut-in wells based on economics. Operator's *must* shut-in injection wells that fail MI tests as we require until the MI is restored.

A TA well must have the *injection* zone isolated from the rest of the wellbore. The permit is terminated and the well is subject to idle well requirements once it has been TA'ed for 5 years. Please note that the Division does not have a formal "TA" designation. We consider wells either active, idle, or plugged and abandoned.

I have not seen that other Districts require zone isolation from the rest of the wellbore for idle wells. Is this requirement unique to District 3 and, if so, why is that so? A bridge plug is not a DOGGR requirement. It is an operator choice. Isolation of the injection zone from the rest of the wellbore is not required inside the casing in an idle well.

Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well? This would depend. In most cases the BP is placed below the BFW, in which case we test the upper portion of the well after installation of the BP.

Is this also applicable to USDWs? The bridge plug is set below USDWs as well as BFW? Yes, in most cases.

Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. How long may a UIC well remain in TA status before being reactivated or P&A. They are tracked as idle wells. There is no particular time interval. Once the well is not tested (Ra/SAPT) the approval to inject is terminated.

Is there a P&A requirement within a given time interval after approval to inject is terminated? Once terminated, can the operator reactivate a well without passing a MIT? Please elaborate.

No time interval. Again it is then treated as an idle well (no longer a UIC well with UIC testing protocol) and subject to all of the same idle well testing procedures and fees. No an operator cannot reactivate a well without passing MIT. We do allow for testing within the first 90 days so that would be the only time where an operator is allowed to inject without the MIT testing. The reason for the 90 days is so that the well can stabilize before testing. A SAPT is required also as part of the reactivation process. This test is typically conducted prior to initiating injection. If the pressure test of a BP fails, the leak must be isolated from BFW by setting a BP at the BFW to isolate. *This could expose USDWs to fluid migration if present below the bridge plug at the BFW.*

Conclusions

Temporary abandonment of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements are not as rigorous in terms of MIT, repair, and timely plugging. District 3 applies the statewide standards for management of idle and orphan wells.

District 3 allows the operator of idle well to use a retrievable bridge plug to isolate the injection zone, which is not a CDOGGR requirement. Using a bridge plug is an improvement in protecting USDWs over the statewide idle well requirement since the casing and USDWs are not exposed to possible increases in injection zone pressure while a well is in idle status, assuming external MI remains intact.

USDWs are not fully protected in idle wells in our view, even with a bridge plug installed. Those concerns are discussed at length in Section 3.0 and in other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs.

PART VII: Comments

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

We would like the necessary funding to tie all of our UIC data together to eliminate double entry of information.

Would be nice to have our UIC database available to the field engineers when they are in the field. Or, it would be nice to add the MASP to the online production report so that operators as well as field engineers could access the information. It would have to be listed wit6h the frac gradient, the confining point, and the fact that it did not take into account friction flow in the tubulars.

EPA should provide funding to plug and abandon all orphan idled/terminated injection wells.

I don’t like the tracking on this report. It would have been much better without the various colors and underlining. Very distracting!

Please discuss the basis for EPA to provide funding to P&A all orphan idled/terminated injection wells. This cost should be covered by bonds and/or the state plugging fund. While the state does require bonds, and the state has the approval of the legislature to increase assessments to pay for orphan wells, and additional idle well fees for plugging of hazardous wells, if the regulatory authority for Class II wells was still under the EPA's jurisdiction then they would be the ones to pay for the plugging. However, since the Division has been given that oversight and authority from EPA we should at least be able to recoup some of the expenditures associated with Class II injection wells.

Conclusion

The issue of EPA providing funding to P&A orphan idled/terminated injection wells is probably one that EPA is not able and/or willing to address. The federal Class II UIC Program and SDWA do not provide for such funding to primacy states.

4.4. DISTRICT 4

This section is organized in seven parts to address questions and responses from District 4. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. The last part is an opportunity for District 4 staff to provide their own comments. Each of the remaining six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 4 has a total of 25,570 active and inactive injection wells, which represent over 80% of state injection wells. Table 6 provides numbers of wells by well type for both active and inactive wells.

Table 6. District 4 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	SC	SF	WF	AI	WD	Total	% of State Wells
Active	-	63	14,310	3,380	2,893	-	604	**21,250**	**80.8%**
Inactive	-	16	-	3,064	851	12	377	**4,320**	
Total	**-**	**79**	**14,310**	**6,444**	**3,744**	**12**	**981**	**25,570**	

In their response to the EPA Questionnaire and its follow-up, District 4 staff provided many attachments. Relevant attachments are included in Appendix B1 for reference.

PART I: General

This part addresses UIC program organization for District 4, and interagency coordination and changes to the UIC Program.

UIC Program Organization

Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach. **See Attachment A** *(in Appendix B1)***.**

Interagency Coordination and Changes to the UIC Program

Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of *information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available.*

Memorandum of Understanding between the California State Office U.S. Bureau of Land Management and California Department of Conservation Division of Oil, Gas and Geothermal Resources**. See Attachment B** ***(in Appendix B1).***

Memorandum of Agreement between the State Water Resources Control Board and the Department of Conservation, Division of Oil and Gas. **See Attachment C** *(in Appendix B1)*

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes?

AB 1960, Facilities Management Regulations

The number of wells in the district:

Well Type	Number of Wells
Air Injection	10
Liquid Gas	1
Pressure Maintenance	83
Steamflood	6364
Water Disposal	1053
Waterflood	3767
Cyclic Steam (not strictly class II).	14,115
Total	25,393

Please describe how the implementation of these regulations has changed the administration of the program at the District level. The AB 1960 regulations have not been finalized yet. When they are we anticipate that some level of coordination will be necessary between our UIC program and the AB1960 Facilities/Environmental program to accomplish the goals of the two programs in the most efficient manner. This will likely be centered on wellhead and facilities compliance inspections.

Can you be more specific about the changes in the UIC program that will occur? Please discuss those changes. There will be some overlap and coordination of inspections of surface facilities with UIC inspections.

Please discuss how the implementation of the Division UIC Program Expectations Memorandum of May 20, 2010 will change the administration of the UIC program at the District level. More manpower will be required and it will slow down the project approval process considerably. Steam cycling wells to be included in the process. The District has clearance to hire four additional UIC personnel: 2 associates and 2 EMREs. The changes described in the memo are subject to further review and modification.

Conclusions

We support the Division directives for changes in the UIC Program described in the Division Expectations Memorandum. We believe that it could be improved, however, by providing more protection for USDWs in the implementation of the UIC Program in California. Those concerns and suggested improvements are presented in the Conclusions sections under relevant Objective discussions found below. Hiring of additional UIC personnel should help alleviate the added workload inherent in the recent Division Expectations Memorandum to the Districts.

PART II: Permitting and Compliance Review

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program.

Who receives the application from the operator? (District or Headquarters office). Generally the District receives the application but we have had applications submitted to HQ forwarded on to us.

How and by whom are permit applications screened for completeness? Generally an Associate but Senior and/or EMRE may review or assist in the review.

What are the procedures or protocols if an application is found to be incomplete? The operator is notified and the application is held in abeyance or returned depending upon length of time needed to supply the missing data.

Is the notification in writing or verbal? Could be either written or verbal or both. Written notice is not required. Notation to a checklist in the project approval file is entered.

What are the professional qualifications required for staff who conduct permitting and compliance activities? Do those staff members meet the minimum requirements? What types of training would staff like to access if funds were available?

See Attachments D & E *(in Appendix B1)***.** Yes. Technical and software training.

What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful? Academic knowledge, experience, operator and Division technological reports and studies, geological reports and maps, Division personnel and experience, Division and Federal regulations, other project and individual well file data. In the future, more application software and analytical tools will be needed in the review process.

Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal). The bonding requirements differ. Written requests required from operators to add a new source of waste. Manifests of each load delivered must be maintained by operator and available for Division review. Inspections are preformed with highest priority. Primarily increased commercial site security and access. Possibly more frequent sampling of commercial projects due to possibility of frequent changes in fluid sources.

Please describe how the bonding requirements differ. A commercial Class II well must carry a $50,000 for the lifetime of the injection well.

Describe any differences between the processing of a waterflood project and a CO_2 EOR project. Possible increased AOR due to higher mobility of CO_2 under certain conditions. Waterflood is a pressure maintenance project with a relative limit boundary of AOR. However, CO_2 injection needs more intensive review in AOR and monitoring for pressure plume and fluid distribution.

Conclusions

The application flow process is similar in all districts, and we have few additional comments or conclusions to offer beyond those included in the state level and other district sections of the report. Discussion of the staff qualifications and training requirement needs is satisfactory and is supplemented by further discussion under other Objectives listed below. The District stated that application software and analytical tools would be needed for the expanded review process. We agree with those comments and would recommend that the necessary software be acquired or developed in-house for all district offices that lack those tools.

Requirements for commercial Class II disposal wells are generally satisfactory, and are more stringent than those described by other districts and the MOI. Fluids from new sources should be analyzed to ensure that they qualify as Class II fluids. More frequent sampling of existing sources would also provide greater assurance that only approved fluids are injected.

OBJECTIVE: Understand the current compliance/file review process.

What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy. All wells within at least ¼ mile. Compliance history not a factor. Residential not a factor (all treated the same). Steamflood and cyclic steam in non-USDW areas not review due to lack of staff.

Please elaborate: Why not use compliance history as a criterion for setting priorities? Why not residential or other areas that contain USDWs that may be at higher risk of endangerment from injection operations? The policy described above is in accordance with the EPA Primacy Agreement. The overwhelming majority of our UIC projects are in areas of no USDW and are non-residential. We do not use compliance history as a guide because a bad well is a bad well, no matter the operator. We do treat projects in residential areas and in USDWs differently than those not in those areas. We will for example deny proposals for injection, either in whole or in part, require monitoring wells, regular monitoring reports, and/or put injection volume limits on the project. These limitations are based on our in-house calculations of reservoir capacity.

Please describe the calculations for reservoir capacity. The calculation is for volumetric capacity of the reservoir to accept injected fluids without endangering fresh water aquifers penetrated in wells located within the AOR. The Bernard equation is sometimes applied to calculate the pressure buildup in the injection zone over the life of the well to determine whether the ¼ mile radius of the standard AOR is sufficient to protect fresh water aquifers from fluid movement in wells located beyond ¼ mile from the injection well. Static fluid levels are sometimes monitored in key wells to ensure that they don't rise above the BFW.

Who performs the file review and what are the qualifications of the reviewers? **See Attachments D & E** *(in Appendix B1)***.**

Over a one-year period, what percentage of total UIC permits/wells receives a file review? All new project initiation and modifications, all UIC well permits and AOR wells are reviewed, except steamflood.

How is the quality of a file review assured and subsequently documented? Testing reviews documented in CalWIMS and/or well file.

What is CalWIMS? Please discuss how quality is assured. CalWIMS is our integrated database. Quality is provided by several engineers checking and cross checking data during the maintenance and updating of the database.

When deficiencies are discovered during the review, what actions are taken to correct the deficiency? The operator is notified and corrections are ordered. Permit(s) may be denied or rescinded.

Is *the notification in writing or verbal? Please describe the compliance tracking process.* When a bad well is discovered in an Area of Review, the operator is notified either in writing and/or verbally and the well(s) are either remediated prior to project approval, the project is specially monitored, or the project is denied.

This question refers primarily to the review of injection well operations for compliance with MITs, MASP, and other terms of an existing permit to operate as a Class II injection well. Please respond in that context. Operators are notified of deficiencies in writing.

How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually? File review done as described above. Project review deals with project performance, issues, changes, etc. 100% of projects are reviewed annually.

Please elaborate on the project review process and results. Does the District staff meet with the operator to discuss the results on an annual basis? The annual project review of all of our 517 active and suspended projects are done by mail but any questions or issues that arise from them may be discussed with the operators via the phone, E-mail, or in a meeting.

Conclusions

The few wells in residential areas and those where USDWs are present are treated more stringently than other wells. The District states that the Bernard equation for calculation of pressure buildup in the injection zone is sometimes applied and static fluid levels are sometimes monitored in key wells to ensure that they remain below the BFW. The ZEI determination and fluid level monitoring should apply to the base of USDWs, rather than the BFW, to be fully protective of USDWs. New and existing projects will require a ZEI/AOR determination and/or review, according to the Division Expectations Memorandum.

The District states that all new projects and modifications are reviewed, and all UIC well permits and AOR wells, except steamflood wells, are reviewed annually. All annual project reviews are done by mail, but issues that arise may be discussed with the operators over the phone, email, or meetings. The depth of those reviews is not known, but we wonder how the many injection wells in District 4 can all receive a complete review on an annual basis, given the staffing limitations in the District. The addition of staff discussed above should improve the District's ability to conduct more project review meetings with operators as well as increase the number of comprehensive file and project reviews annually.

OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected? Requirements follow PRC 3219, 3220; CCR 1722 (a) (c) (d) 1722.2, 1722.3, 1722.4, 1722.5. Generally depth is sufficient to anchor BOPE, protect fresh water, and isolate zones, with a casing shoe in a competent bed. Casing burst or collapse must meet hole conditions.

Does isolating zones include USDWs, other than fresh water aquifers? Is cemented casing required through all USDWs? If not, how are USDWs otherwise protected? Yes, where they exist, USDWs are protected by cement behind casing.

Cement is not required at the USDW base according to the MOI and responses of other districts. District 4 seems to consider the term USDW synonymous with BFW in this context. For clarification, fresh water aquifers (3,000 mg/L TDS or less) are usually USDWs unless exempted, but USDWs include saline waters containing more than 3,000 but less than 10,000 mg/L TDS.

How are USDWs identified in District 4 fields? Elog analysis? Formation water analysis? Other methods or sources? For clarification, what is the definition of a USDW versus fresh water? TDS of 10,000 ppm or 3,000 ppm? The District has a lot of water quality data available from produced water analyses. Swabbing of formation water is new zones is an option if other data are not available for that zone. Electric log calculations are also an option. In general terms, fresh groundwater is absent west of Highway I-5 and is present to the east of I-5 in the Central Valley sediments due to recharge from the Sierra Mountains to the east of the Valley.

To clarify the last response, our understanding is that cemented casing is not required at the USDW base or through all USDWs, as they are defined by federal regulations. Cemented casing is required at the BFW (3,000 ppm TDS) in new injection wells. Existing injection wells must have sufficient volumes of cement behind casing to isolate the BFW from the injection and hydrocarbon bearing zone, but not necessarily at the BFW under historic requirements. However, the recent Division directives will require existing injection wells to be cemented at the BFW.

USDWs contain less than 10,000 ppm TDS, but are not required to be isolated by cement at the base of USDWs behind casing unless TDS is less than 3,000 ppm. Adequate volumes of cement are required behind casing above the injection zone and hydrocarbon bearing zones to isolate fresh water from those zones. Groundwater containing more than 3,000 mg/L TDS is either exempted or otherwise is not required to be isolated by cement at base of USDWs under CDOGGR regulations, as understood by this writer.

What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected? Same as new wells. See above response.

Is cemented casing required through all USDWs? If not, how are USDWs otherwise protected? Is remedial cementing required during conversion, workover, or P&A operations? If necessary, remedial cementing is required. Other methods, if this is not possible, include limiting the injection interval or the quality of the injectate.

What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field? Regular surveys on injection wells. Casing/file reviews of others. In critical areas, subsurface monitoring may be required.

Please elaborate: What type of surveys, and how often are they run? Where are the critical areas and why are they considered critical? Injection profile is verified on most wells by RAT Tracer Surveys. The standard frequency is WD: annual, WF: biennial, SF: 5 years. In areas with severe subsurface movement we have approved other methods such as an injectivity plot using rate v. pressure. The term ‘critical’ applies to AORs that, due to bad well, may have to be specially monitored with the use of observation wells to monitor pressure, temperature, and/or fluid level.

Please explain the term “severe subsurface movement” and the injectivity plot method in the assessment of fluid confinement to the injection zone throughout the AOR. The term “severe subsurface movement” applies to ground shifting resulting from faulting, slumping, or subsidence which in turn may cause well tubulars to either crimp, part, and/or “dog leg.” This casing/tubing damage may affect the ability to adequately survey the injection well due to a high pick-up” depth above the perforations/injection zone. This is not uncommon in the South Belridge and North Belridge fields. In these fields, this office has reached an agreement with the operator involved, Aera, to run injectivity plots in lieu of RA tracer surveys, as per attached letter from this office, in those injectors with casing damage/high “pick-ups.” A typical injectivity plot is attached, and depending on the rate/psi indicated, can readily identify if the injection is occurring in the low permeability Diatomite injection zone or has breached into the high permeability Tulare formation above. *A copy of the letter and example injectivity plots referenced above are included in Appendix B.*

Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? Routinely yes, however if two or more strings of cemented casing exist or if no USDW is present or if fresh water is injected then a tubing/packer variance may be granted. Usually pressure tests and RAT surveys, occasionally spinner logs (1724.10(g) 1, 2, 3).

Please elaborate on the method for pressure testing in wells with no packer installed. Are temperature logs run with the RAT surveys? On new drills a pressure test is performed prior to drilling out the casing shoe and placing the perforations. In completed or newly converted wells the pressure test is performed by placing either tubing or packer or a retrievable bridge plug into the well. Temperature logs are ran during each RAT Survey.

Are dual (multiple) completions permitted? What requirements are different than single completions? What types? Yes. None, except RAT surveys are required on each string.

Are single string dual completions allowed with one packer between zones and injection in the upper zone? If so, please describe MIT procedures. Temperature surveys? Yes, they are. A MIT of the backside would be required in the form of either an ADA test or releasing a radioactive slug and surveying it with an RAT tool down the tubing. Yes, temp surveys are run.

Are static temperature surveys ever run for detection of casing leaks above a packer or fluid movement in the casing/wellbore annulus? No, except perhaps in single string wells in the South Belridge Field.

How are the locations of USDWs determined? Does the District consult with other state and federal water resource agencies regarding USDW information? USDW (10,000 ppm) generally unknown until tested. Other agencies such as RWQCB are consulted.

How is this tested? Are salinity calculations performed from wireline logs for TDS estimation in suspected USDWs that cannot be tested? A swab test is performed. The operator must swab 1 ½ times the volume of the well at which time the sample is taken. The operator sends the sample lab to be analyzed. The results are sent to us by the operator. A Division field engineer will witness the swab and take a sample as well. Recently the Division purchased a salinity meter which now is used on location for preliminary results.

Are log calculations performed for Rw and correlated with salinity of formation waters where sampling is not possible? Yes, a swab test is required in new wells unless water salinity data are available from nearby wells.

How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated? Geologic and engineering data derived from logs, core samples, and technical reports. Pursuant to CCR 1724.7.

What are the options to compensate for uncertainty in the adequacy of the confining system and how are the evaluated? If the uncertainty arises from a lack of sufficient data submitted we require additional data. This may include additional geologic and engineering maps and data or production and injection well performance records. If the uncertainty arises because of known or suspected adequacies options may range from denial of the project to requiring monitoring wells in the overlying formations and limitations to the project's volume or lifetime.

Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well. Combination of Division's monthly injection reports, project reviews, and wellhead inspections.

How often are wells inspected for reporting accuracy? Is annulus pressure monitored and reported on all wells that have tubing and packers installed and, if so, how often? Pressures gathered during wellhead inspections are not routinely crossed referenced against injection pressures reported. Annulus pressures are not required to be reported, however they are recorded during wellhead inspections and during SAPTs and RAT Surveys.

When the annulus has pressure on it, is the well required to be shut in until repaired and passes a SAPT? Annulus pressure monitoring is not required of the operators, but they are required to report abnormal pressures on the annulus in accordance with the project approval letter.

I find no direct reference in the standard project approval letter that requires reporting of anomalous annulus pressure and cessation of injection. Repairs and passing a SAPT are not required unless the operator plans to reactivate an inactive well or fresh water is endangered while a well is inactive.

How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose. Reservoir porosity/permeability/fracture gradient/ etc. Step rate test may be required to establish the maximum injection gradient. One recent example, (6/2010) was a SRT that the operator ran per Division's requirement on a Wheeler Ridge field, Valv Formation. Water Disposal project. Injection rates are generally requested by the operator in the initial project application review and monitored by annual project review, well head inspections and occasional pressure fall-off tests.

How is the MASP determined when SRTs are not run? Please provide a copy of the results and evaluation of this SRT. In the absence of SRT data the MASP has been calculated based on a fracture pressure obtained from the literature. We are now requiring SRT for all new and expanded projects.

What literature? Will you be reviewing existing projects for fracture gradients if not expanded? See the Bill Guerard in-house publication *M13*. Yes, eventually, in accordance with the new standards issued by Division HQ.

Conclusions

The technical review processes of permit application and related aspects of file reviews in District 4 follow the guidelines outlined in the MOI and are quite similar to those processes in other districts. As a result, we have concerns with District 4 technical review procedures similar to those expressed at the state and other district level sections of this report. We reiterate some of those concerns below.

USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance for total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement. In our view, CDOGGR should consider modification of cementing requirements to require placement of cement at the base of all USDWs penetrated by a well, not just at the BFW (3,000 mg/L or less TDS) zones, above the injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells and wells located within the AOR of an injection well during casing repairs or plugging operations in AOR wells. Monitoring to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.

Slimhole (tubingless) and multiwell completions are permitted in some fields in District 4, with special circumstances and/or requirements. Packers and tubing are not required if there are two strings of casing cemented through the fresh water zones, or there is no evidence of USDWs, or fresh water is injected. RAT surveys or spinner logs are used and in some cases packers or retrievable bridge plugs are run to test for casing integrity in those wells. Static temperature logs are not run except in single string wells in the South Belridge Field. The ADA test may be run in single string dual completions.

District 4 states that there are no fresh groundwater aquifers present in some fields. Generally, those west of Highway I-5 lack fresh water, and those fields in the Central Valley east of I-5 contain fresh water. Apparently, the presence of other USDWs in those fields west of I-5 is still possible. Unless there are USDWs present, which is unknown at this time, there are no particular concerns about the construction and testing requirements for those wells. We would need to examine well logs and other data in those fields to assess the presence or absence of USDWs. If USDWs are present, tubingless completions could be a concern in those wells.

District 4 states that MASPs are calculated on the basis of fracture pressure data presented in CDOGGR Publication M13, written by Bill Guerard. Those data are not field specific and apply to the major oil and gas producing basins in California. We reviewed a few projects that had approved gradients of 0.6 to 0.8 psi/foot. The few sample SRT reports that we reviewed were recent tests and were conducted in accordance with generally accepted industry standards.

District 4 has apparently required very few SRTs in the past. We understand that SRTs will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives are fully implemented at the district level. We support that directive with the recommendation that bottom hole as well as surface pressure gauges be used in SRTs. Bottom hole pressure measurements remove the uncertainty of calculated friction losses during a test and provide a more accurate measure of formation fracture gradient.

OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

How is the Area of Review (AOR) determined for enhanced recovery wells or projects? *M*inimum ¼ mile, more for high porosity/permeability/mobility of gas injection projects.

Please elaborate on this response. How does high porosity/permeability affect the determination? As specified in the 1981 Primacy Agreement this office uses the ¼ mile fixed radius of review as standard procedure. Where necessary (e.g.: known or suspected high porosity/permeability) we will use a radial flow equation such as the Bernard calculation to determine the zone of endangering influence. We note however that we believe the Bernard has quality limitations in areas of high well density such as will be found in this district.

What form of the Bernard equation is used to calculate the ZEI or pressure increase versus time? Where has it been applied? See the Excel spreadsheet developed by District 4 staff (Burt) for a description of the calculation. Bonanza Creek project. *The Excel spreadsheet for Bonanza Creek was provided during the visit.*

How is the AOR determined for saltwater disposal wells? Minimum ¼ mile, more for high porosity/permeability.

Please elaborate on this response. How does high porosity/permeability affect the determination? The answer to the question above applies. We make no distinction between well types for purposes of determining the AOR radius.

Water disposal wells may cause the ZEI to exceed quarter-mile over time. Does District 4 allow the static reservoir pressure to exceed hydrostatic in disposal wells? Are there any disposal wells that are permitted to inject into non-producing reservoirs? Pressures are not monitored closely. Yes, Mid-Valley Fields in the Etchegoin formation.

How is the AOR determined for commercial saltwater disposal wells? Minimum ¼ mile, more for high porosity/permeability.

This answer seems contrary to the theory for calculation of ZEI since higher porosity reduces the ZEI while higher permeability increases the ZEI based on the equation for drainage radius:

$$\mathbf{r_d = .029(kt/\Phi\mu c_t)^{0.5,}}$$

and the Theis equation for radius of endangering influence:

$r = \{2.25\ KHt/S10^x\}^{0.5}$

For clarification, the radius can increase with higher permeability and higher porosity because high porosity often results in high permeability, which is somewhat offsetting in the effect on ZEI. Additionally, permeability usually increases exponentially with increased porosity, which results in an exponential increase in ZEI and a lesser linear decrease in ZEI due to increased porosity. Thus higher porosity/permeability can result in a larger ZEI unless larger pore spaces are not well connected, as sometimes is the case in carbonate formations. Sandstone reservoirs with high porosity, such as those in District 4, typically have correspondingly high permeability

There is just one commercial WD well in District 4. High porosity reduces the ZEI, but high permeability increases the ZEI, based on those equations.

Please identify the commercial well and its location. The only currently permitted commercial water disposal well in District 4 is Central Valley Waste Water's SCWW-1 (API #030-42944) in Sec. 24, T.28S, R.20E in S. Belridge field

How is the AOR determined for CO2 EOR wells? Minimum ¼ mile, more for high porosity/permeability and possibly more depending on proposed injection pressure. Elk Hills Field has a WAG CO2 EOR pilot project, but new CO2 EOR projects are on hold by HQ because of the EOR vs. CO2 sequestration purpose issue, A Moratorium on CO2 EOR projects is in effect.

How are AORs determined for area permits and other multi-well projects? Minimum ¼ mile around each injection well, more for high porosity/permeability/mobility of gas injection projects. The great majority of our projects are closely spaced multi-well projects. AOR studies routinely involve hundreds of wells for each project. AOR boundaries are determined as noted above and are typically drawn as margins outlining the entire project.

Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? If not, are they performed for all disposal well permits? What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved? Is there any time period since the UIC program was approved when there were notable increases or decreases in ZEI determinations – please describe? No. No modeling done. Number of hand calculated is small and unknown.

Please elaborate on the calculation method. As previously noted the ¼ mile fixed radius is the AOR standard. In some cases we have used radial flow equations such at Bernard's to determine the zone of influence.

Where has the Bernard equation been applied. Please provide examples. See response above. Also applied in Fruitvale Field. The ZEI is calculated when an offset operator objects to a proposed injection well due to concerns about effects on offset operator wells.

Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects. All reporting done via monthly injection reports and annual project reviews.

Are fall-off tests ever required for determination of static reservoir pressure? If so, please elaborate. PFOs have been used when chronic high injection pressures are noted and remedial well work does not resolve the problem. Such tests have been required in the Santa Margarita zone in Kern River field, the Diatomite zone in the South Belridge field, and Etchegoin zone in the Lost Hills field where it was suspected that reservoir fill-up was causing surface breakouts.

Please provide copies of the PFOs listed above and the results of the analysis. Copies were provided during the office visit. The tests results in terms of reservoir fill-up were not fully discussed, but District comments below indicate the Santa Margarita zone in Kern River field had a static reservoir pressure in excess of normal hydrostatic pressure for that zone and the project was suspended for that reason. If hydrostatic pressures of USDWs in the area were exceeded in those zones, injection should be terminated or a ZEI analysis should be performed to assess the need to enlarge the AOR and consider corrective action in additional wells located within the expanded AOR.

Do the District staff review static reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples. Pressure build-up monitored via monthly injection reports, project reviews, RAT surveys and wellhead inspections. Cases of pressure build up have been attributed to poor injection profile (resolved by multi tubing/packer configuration) and exceeding volume capacity (resolved by suspending the project).

*I added the term "static" to clarify the question. I gather from the responses that **static** pressures are generally not monitored for pressure increases that could cause the ZEI to exceed the AOR. If such monitoring does occur, please describe the monitoring requirements and examples of where this has occurred and projects have been suspended. How is volume capacity determined?* Correct, **static** pressures are not routinely monitored by us. The only project that was suspended to reservoir pressure build-up was the Santa Margarita Fm. Water Disposal project in Kern River field.

Please provide the analysis of the project. A copy of the analysis will be provided.
Supplemental District Response:

This involved a Santa Margarita Water Disposal Project in Kern River field (API #34000030). The attached letter dated 9/23/86 form this office to Chevron identifies one well, D2-4, that was over-charged per the attached T-report. It was later reworked, brought into compliance , and the well and the project continued to inject. *A copy of the letter and T-report referenced above are included in Appendix B.*

What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR? Extremely few projects have shown reservoir pressure increases. AORs/ZEI not changed.

I gather that this answer refers primarily to ER projects. Please discuss your experience with pressure increases in disposal wells and actions taken to limit the pressure increases. As noted above, a WD project in the Kern River field was suspended due to overfilling the reservoir beyond its capacity. A commercial WD project was suspended following a fluid to surface event indicating reservoir overfilling. Whenever an indicator of reservoir over pressuring occurs our limiting actions will be to suspend, rescind, or require the operator to reduce the injection pressure. The specific response is determined by the indicator. Where over pressuring is indicated by a failed PFO, chronic high injection pressure, or other, the project is suspended or rescinded. Where a non-recurring high injection pressure is found the operator is issued a Notice of Deficiency and required to reduce the pressure to the MASP or lower.

Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? Please list the most recent examples. Yes. The most recent example was a water disposal project in Wheeler Ridge field in the Valv Formation where temporary injection was allowed for 90 days until a bad well in the AOR was to be remediated.

Please elaborate and describe the remedial operations. Any other examples? The case in question had a well within the AOR without cement outside of casing across the injection zone. Due to its distance from the proposed injector, a temporary permit to inject was issued after which time the remedial work to isolate the zone would be required. There are several cases where the remedial work on bad wells in an AOR has been ordered prior to commencement of injection.

Please identify those cases and provide details on the remedial work ordered. Wheeler Ridge Field and Northstar project are examples. More information is to be provided.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? Generally defective wells ordered repaired regardless of by whom, but the responsibility is with the permittee, otherwise no permit will be issued.

Conclusions

ZEI determinations were not performed for District 4 injection wells in past years. AORs were based on a quarter-mile fixed radius from the injection well, even for disposal wells. That may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project and reservoir pressure is maintained at a level that does not cause the position of the pressure front to expand beyond the quarter-mile AOR boundary. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. Where injection is into a depleted or producing zone, the fixed quarter-mile AOR radius may be appropriate, as may be the case in many of the District 4 disposal wells. Disposal wells in the Central Valley that inject into highly permeable formations may not cause pressure buildup beyond the quarter-mile AOR. A ZEI analysis should be performed for all disposal wells, however, to determine whether the quarter-

mile AOR is appropriate. This also applies to EOR projects if injected fluid volumes will exceed produced fluid volumes for an extended period, allowing reservoir pressures to increase and the pressure front to potentially expand beyond the quarter-mile AOR.

The District states that static reservoir pressures are not routinely monitored, but when pressures remain high for an extended period a project can be suspended or rescinded. The Santa Margarita Formation water disposal project in the Kern River Field is apparently the only project suspended for that reason, however, and extremely few projects have experienced significant reservoir pressure increases, according to the District staff. If the static pressure increase is not sustained but the injection pressure exceeds the MASP, the operator is issued a Notice of Deficiency and required to reduce the injection pressure to the MASP or lower.

We accessed the CDOGGR online database and district wells that were injecting at relatively high pressures were tabulated, and a sampling of those wells was reviewed for exceeding the MASP and for chronic high shut-in pressures. One well had high shut-in pressures for four months in 2009 that failed to decline during the period of inactivity, which would indicate a high static reservoir pressure and possible ZEI exceedance of the standard quarter-mile AOR. The well in question is the Elk Hills No. 312 and should be reviewed for rescission of the permit to inject. A significant number of wells were reported to be injecting at pressures exceeding 1,000 psi, which may exceed the MASP for those wells. Those wells warrant further review to ascertain whether that is the case. We reviewed well records for a few of those wells, but found no obvious MASP violations. Our search was somewhat limited because well records are apparently not yet available online for all District 4 wells.

Problem wells outside of the quarter-mile AOR but within the ZEI were apparently not addressed in the past. With the full implementation of the recent Division directives regarding ZEI/AOR procedures, those wells will be subject to corrective action considerations, and protection of USDWs should be significantly improved.

Apparently, pressure fall-off tests were rarely performed in the past, but may now be performed more often for disposal projects in the District when the recent Division directives are fully implemented in the District. That should provide the necessary reservoir pressure data to monitor pressure buildup and ensure that the pressure front is contained within the AOR over the life of a well. District 4 apparently has not yet fully implemented those directives, based on the above responses and conversation with District staff. Significant delays in processing new project applications have recently occurred due to the increased workload that the directives have incurred. However, the authorized addition of UIC personnel discussed above should help alleviate those deficiencies over time.

OBJECTIVE: Understand the administrative permit application components.

Describe the public notification and participation process for applications under consideration by DOGGR. Follow Division and Federal process. CCR 1724.6, 1724.7. **See Attachment F.**

When and where is public hearing opportunity held on an application and how are they conducted? When was the last public hearing held in your District? Please list the most recent *examples.* A public hearing may be held prior to issuance of a new permit or modification of existing permits at the discretion of the State Oil & Gas Supervisor. They are usually held in the jurisdiction of the district office receiving the request. The last public hearing in this district was on December 4, 1986. It was conducted by the State Oil & Gas Supervisor and UIC staff from the Bakersfield office.

What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed? Commercial project require $50,000 indemnity bond, or one well under super bond ($1,000,000) others only standard performance bond.

Is the permit applicant required to provide a P&A cost estimate for plugging injection wells and is that based on third party cost to P&A the wells? Can surety bonds or other financial assurance instruments be released before an injection is plugged or converted to production? A P&A cost analysis is not required of the applicant. Bond amounts are fixed by the division pursuant to PRC 3205.2. The class II commercial WD bond is only releasable upon the proper abandonment of the well or a when another valid bond has been substituted. *Surety bonds can be released after six months of continuous injection in noncommercial disposal wells.*

Conclusions

See Section 3.0 for more information.

OBJECTIVE: Understand the process for aquifer exemptions

How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests? One, justification was that the zone could not provide a source of drinking water.

Please elaborate on why the zone could not provide a source of drinking water. 1) the zone presently does not supply drinking water, 2) the zone is a productive oil zone d 3) determined that the zone could not reasonably provide a usable source of drinking water in the future. This determination was made under the guidelines outlined in 40CFR 146.4a & c.

*How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials? T*wo requests, approvals are pending.

If there have been any aquifer exemption requests from your District, briefly describe the process for approval/denial of such request. Process is outlined in federal register.

Please be more specific as to the process followed in District 4.

1. Gather all relevant data that support exemption request.
2. Make determination of the validity of the supporting data. The data must prove:
   a. The aquifer does not currently produce drinking water.
   b. The aquifer cannot now or in the future serve as a source of drinking water.

3. Place description of the request for public notice
4. Forward request to EPA with district recommendation.

Conclusions

See Section 3.0 for more information.

PART III: Inspections

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District.

Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas. Other high priority areas could be where injection operations are in close proximity to USDWs and/or drinking water aquifers. Oil/Gas fields existing under residential or planned residential areas and areas of USDW (active and non-active) include: Fruitvale, Kern River, Kern Bluff, Edison, Mountain View, Union Avenue, Stockdale, Canfield Ranch, Ten Section, Bellevue, West Bellevue, Greeley, Rosedale, and Rosedale Ranch.

How are inspection priorities determined? Public complaint, reinspection of deficiency/violation notice (including illegal/unauthorized injection), area and routine.

What professional qualifications and/or experience are required by DOGGR to be an inspector? Do District staff have the necessary qualifications and/or experience? Qualifications are met by staff, **see Attachments D and E** *(Appendix B1). What types of training do inspectors access or would like to access if funds were available?* Technical classes and courses related to UIC including EPA UIC training courses.

What tools do the inspectors utilize? Are there additional tools that you can identify that would be useful? Camera, GPS, salinity meter, pressure gauges, computers. Could use laptops with software applicable to the job and related duties.

Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training. Inspectors must have experience as an inspector/field engineer in our operations unit prior to moving into UIC unit. Additionally, the unit provides UIC training. Over time inspectors are encouraged to attend UIC based short courses and conferences. Safety topics are addressed each month during a field staff meeting. Official training includes H2S training, drivers training, CPR, first aid and outsourced technical classes.

What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process? Inspect wells and locations; compile documentation of deficiencies/violations, photograph location, surveillance of activity at location. Compose report on data and testify if needed.

Conclusions

Inspections are not necessarily prioritized for wells where fresh water is present, and residential areas are not usually a consideration since most wells are located in rural areas. Fourteen of the District 4 fields are listed as located in residential areas or areas where USDWs are present. In our view, those areas should receive a higher priority for inspections.

The professional qualification and/or work experience requirements for District 4 UIC inspectors are similar to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. Training and qualifications of inspectors appear to be adequate in most areas, based on District responses and discussions with staff at the District 4 office. Additional training in UIC operations, such as the EPA sponsored UIC Inspector Training, would be beneficial for new and recent hires.

We were informed that the Division has authorized the employment of four additional UIC staff members in District 4. That should significantly improve the District's ability to process new project applications, conduct more inspections, and perform the other UIC functions on a more timely basis.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District.

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations. Class II fluids outline in MOI 170.2.2 and 170.2.3. **See Attachment G**

Please elaborate. I don't see the answer to this question in Attachment G. EOR: water, steam (drive and cyclic), gas (press. Maint.) gas/miscible/non-miscible e.g.: CO_2. SWD: produced water, oilfield cogen regen brine water, waste gas from SF ops.

How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database the inspection data is stored in or attach the inspection verification documentation. Approximately every two years. No real difference in inspection rate EOR vs. SWD. The environmental unit routinely inspects all wells. Those inspections are entered in the CalWIMS environmental database. Well inspections conducted by an UIC EMRE are entered in CalWIMS UIC Inspections.

Is the operator given advance notice of inspection and does the operator receive a copy of the report? The operator is not given an advance notice of inspections; if deficiencies/violations are found during the inspection the appropriate letter is sent. An immediate phone call is sometimes necessary.

Describe the reporting and follow-up procedures used in the inspection program when there are violations. A notice of violation is sent to operator, an inspection conducted to ensure violation issues have been addressed and corrected, if not corrected documentation is compiled for and order with civil penalty. Critical situation may result in phone contact and shorter compliance period.

How is the District notified of emergency situations regarding Class II wells and related incidents such as spills? The operator reports the incident to the California Emergency Management Agency, who faxes the report to the Division office. Division personnel will contact the operator for additional information or clarification. District also notified directly pursuant to regulation and spill contingency plan.

What type(s) of emergency situations has/have been reported involving UIC permitted wells? Please list the ones you have received over the last five years, or the most recent examples. In 2008 a vacuum truck drove over a steam injection wellhead. The truck caught on fire, the driver's body was found outside the vehicle several feet away.

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. CalWIMS database, personnel can reference UIC and environmental database for a history of complaints.

Please describe the database and its contents in more detail. CalWIMS is a newer State database which catalogs all pertinent well information to include: the Operator, API number, lease and well number, location, well type, perforation depths, packer depths, MASP data, fracture gradient, well status such as new, active, or rescinded, deficiency dates, SAPT and RAT Survey due dates. Other information attached to well including Notices that have been issued, tests performed on wells such as RAT surveys and SAPT's witnessed or waived, a comment section is used for any other information found necessary for others to be able to access. Also, an environmental section provides information on previous lease inspections and previous complaint if any.

How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily accessible database? If not, how does the District verify compliance with the MASP? Inspectors carry a list of injection wells in vehicles which includes MASP for individual wells. The MASP is easily accessed in CalWIMS and reviewed during the Annual Project Review.
A listing of the types of fluids approved for injection in Class II wells is provided in the MOI at Sections 170.2 and 170.3. We have no reason to believe that any of the fluids listed in the MOI would be disallowed for injection into a Class II injection well. It would be a CDOGGR and an EPA decision to classify a particular fluid as eligible for injection into a Class II injection well.

The Division requirement for inspecting each permitted well, for other than MITs, at least once per year has not been met in District 4. The MOI at Section 170.13.2.1.D states that injection wells must be inspected annually. The frequency is approximately every two years, according to the response given above. The Division Expectations Memorandum states that all injection wells must have a wellhead inspection at least once every two years, which appears contrary to the MOI requirement. The CDOGGR Program Description is silent with regard to this requirement. In any event, the District plan to hire additional inspectors should allow more frequent inspections as the new hires gain the necessary training and experience.

Advance notice of a lease inspection is not given to the operator, but the operator is notified by a letter when deficiencies/violations are found. We support not giving advance notice of a routine inspection to an operator. That could compromise the inspector's ability to find violations since the operator would have the opportunity to prepare for an inspection and possibly hide violations.

The reporting and follow-up procedures used in the inspection program appear to be adequate, based on the description of those procedures in the above response. Violations and their resolution are recorded and tracked in the CalWIMS database, in addition to MASP data, well status, and several other critical elements of the UIC Program. The MASP for each well is maintained in CalWIMS and injection pressures are compared for compliance with the MASP during inspections and during the annual project review.

One emergency situation is reported to have occurred in recent years, which was caused by a vacuum truck driving over a steam injection wellhead resulting in a fire. That incident resulted in one fatality; the truck driver. No further information was provided. The operator is required to report emergency situations to CalEMA, which we understand has the primary responsibility to oversee remedial operations for spills and related incidents. CalEMA notifies the Division office, and the District office is notified by the operator pursuant to regulations and spill contingency plans.

The data management system available to field inspectors is CalWIMS which contains most of the data for District 4 wells. It is used to track field tests, inspections, and deficiencies/violations and to create inspection reports, deficiency notices, and track compliance. The CALWIM System is a new statewide database, which is to be implemented in all of the district offices by the end of this year. District 4 is one of first offices to implement CalWIMS. It appears to superior to the other databases that it will replace and perhaps more user-friendly than the existing systems.

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability. SAPT, a minimum of 200 psi, pressure must be stable for 15 min. with no more than 10% drop from the initial pressure. **See Attachment H** *(Appendix B1)*

Are there other types of tests applied, such as for wells completed without tubing, packers, and multi-well completions? If the conditions of the well completion type doesn't allow for a SAPT, then other types of MITs may be run such as an ADA test, setting a bridge plug above the perforations and pressure testing the casing, etc.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? A minimum final test pressure of 200 psi, pressure must be stable for 15 min. with no more than 10% drop in from the initial pressure. Primacy Agreement/MOI. **See Attachment H**

Please discuss the basis for these criteria. Are any wells tested to the MASP or maximum operating pressure? What determines the actual test pressure for wells? The test criteria are set forth the division's policy manual, the Manual of Instructions (MOI). Wells are not tested to the MASP or maximum operating pressure.

The "expectations" memo of 5/20/2010 states that testing to the approved MASP is required when there is only a single string of cemented casing across a USDW (10,000 mg/L TDS). Is this the standard now applied in District 4? Not yet. The standard is under review by HQ. A Notice to Operators is forthcoming from HQ on the final standard.

If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM? Not applicable.

If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail? Do not use cement records for this.

Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined? Primarily use RAT Survey. On rare occasion caliper log, spinner survey and temperature log. Permitting Engineer interprets. Failure determined by interpretation of the logs.

How is Part 2 MI evaluated? Are temperature logs and/or CBLs used for that purpose? Part 2 standard evaluation is the RAT Survey. These are paired with a temp log. Evaluation is done by district UIC staff. CBLs may be used as follow up to anomalous log results or if the isolation cement is suspect.

*Are cement records or **static** temperature logs reviewed to satisfy the Part 2 MI requirement. Please discuss the standards applied to satisfy Part 2 MI requirements based on cement records and/or temp logs.* Temperature logs and CBLs are reviewed when available in AOR wells. New wells require cement placement to 100 ft. above the BFW. Cementing records are reviewed for isolation of the BFW from the injection zone and hydrocarbon bearing intervals. .

What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone?

Initial SAPT – Class II Commercial Water Disposal Wells
Initial R/A Surveys – Class II Commercial Disposal Wells
Initial SAPT – Water Disposal Wells in fresh water areas
Initial R/A Surveys – Class II Water Disposal Wells in fresh water areas
Initial SAPT - Class II WD Wells
Initial R/A Surveys - Class II WD Wells
Initial R/A Surveys – Conventional Water Flood and Pressure Maintenance Wells
Ordered R/A Surveys due to MIT failure and repair (WD, WF, and PM)
Annual SAPTS
Annual R/A Surveys
Some wells are tested more frequently than the standard cycle, due to variances granted

<u>Standard cycle for MIT's is as follows</u>:

SAPT's	RAT Tracer Surveys
WD – 5 years	1 year
AI- 5 years	1 year
PM – 5 years	1 year
WF – 5 years	2 years
SF – 5 years	5 years

Please elaborate on the type of variances granted and typical MIT frequencies required when variances are granted. Typical variances granted include tubing/packer and SAPT when certain conditions are met, as allowed in the DOGGR's CCR and MOI. As a condition of these variances, more frequent RAs and SAPTs may be required.

Under what circumstances are variances typically granted? Where no fresh water is present or a project is permitted for injection to the surface and for steam injection or two strings of cemented casing are installed at the BFW. The Tulare formation is exempted to west of the District where no fresh water is present. *We should have followed up with a question about the presence of USDWs in that area.*

Describe the follow-up and typical enforcement actions for MIT failures. Depending on what kind of failure the well is ordered to be shut-in immediately and followed up with deficiency/violation letter. Typically, deficiency states the operator has 30 days to repair and retest. This 30 day period is entered into the CalWIMS UIC database as the next test date. If the well is not tested by given date the well is rescinded.

How much time is allowed before the permit for a well lacking MI is rescinded? How much time is the operator allowed before the well must be plugged, if not repaired? A well lacking it's required MI will have the permit rescinded in approximately 60 days. We do not require the wells to be abandoned. All rescinded wells must be disconnected.

For clarification, how much time is allowed before a well that fails a MIT is the permit rescinded? 60 days if fresh water is not present. If fresh water is present and there is fluid flow at the backside or fluid entering a fresh water zone is indicated, rescission is immediate.

Is *repair or abandonment required when a failed MIT may cause endangerment to USDWs?* Yes, definitely. *Repairs or P&A are apparently not required unless there is evidence of potential endangerment to a USDW.*

Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed? Field Inspectors (EMRE) witness tests. Approximately 52% of tests witnessed based on DOGGR schedule witnessed and waived tests EPA reporting year 2008-2009. A MIT sheet is filled out by EMRE, time spent on test is entered into the database and the UIC database is updated. Operators are required to send a PDF copy of ALL RAT Surveys. If an SAPT cannot be witnessed the operator is requested to chart test and send a copy of the chart to UIC personnel.

Please clarify: Does waived mean that no test or witnessing is required? What are the usual reasons for a waived test? Tests must always be performed, when the number of tests exceeds the number field engineers available the required witnessing of the test is waived.

In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate. If the failed MIT requires the well to be shut in and an operator does not have a representative on location during the test, a phone call would be made. A deficiency is sent to the operator outlining MIT failure, shut in and remediation requirements.

Please elaborate on why all MIT failures do not require the well to be shut in. What criteria are applied that require a shut-in? Shut in procedures are required on all wells that threaten and endanger USDWs in any way. Areas which do not threaten a USDW, and which has a minor deficiency such as a packer leak or high pick-up are not required to be shut in. High pick-up is defined by the RAT tool not able to reach perforations.

If there is a packer leak, how would one know if there isn't also a casing leak? If no flow occurs at the surface, there may not be a problem. *There may be a problem without flow at the surface if USDWs are present and are underpressured.*

Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures? Yes. Situation varies, repair or abandon. Could be 24 hours or up to 60 days.

Please elaborate: What type of repairs? And what determines the time allowed to repair or P&A? The operator is required to repair the well for casing holes, tubing holes, upward movement of fluid behind pipe, packer leaks or high pick-up. Repairs for a casing hole might be cement squeezed or the insertion of an inner string of casing. Tubing holes and packer leaks would require replacement of faulty tubing or packer. High pick-up would require a clean out. The determination of the time given is based on whether or not a USDW or zonal isolation is threatened. .

This response seems to differ from responses of other districts in that repairs and or P&A are not required unless the operator wants to return the well to injection. Does this response apply only to those situations and not if the well is not reactivated? Yes.

If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work? Sometimes witnessed, documentation is required.

What is the typical percentage of workovers that are witnessed and what determines which workover operations are witnessed? Difficult to quantify without lots of research but probably safe estimate less than 10%. All workovers due to MI failure are documented and records kept by district UIC staff. Workover witness priority would be: urban/residential, critical location defined by Calif. Code of Regulations (CCR) 1720, other such as history of the well, owner/operator, or rig operator.

What percentage of SAPTs subsequent to a rework operation is witnessed? Major repairs, such as a casing leak, require witnessing the subsequent SAPT. 90% of those SAPTs are witnessed. Re-seating a packer, for example, does not require witnessing the SAPT.

What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time? For EPA fiscal year 2008-2009 deficiencies and violation were 30 SWD's and 110 EORs. No significant changes over the years.

Please state in terms of percentages of MIT failures of SWD and EOR wells. 3% of SWD had failures. 3% of EOR well had failures.

What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well? **See Section *CCR* 1722(i) of the regulations.**

For clarification, the question refers to the discovery of excessive pressure on the tubing/casing annulus that would indicate a tubing or packer leak. Is the operator required to shut in the well and report the failure to the District immediately? How much time is allowed for corrective measures to restore MI? **See CCR 1722. (i).** Blowouts, fires, serious accidents, and significant gas or water leaks resulting from or associated with an oil or gas drilling or producing operation, or related facility, shall be promptly reported to the appropriate Division district office. All Project Approval Letters require the operator to stop injection if evidence of damage is occurring. Notification is usually by telephone. Time to repair is dependent on threat to USDW or fresh water, surface setting (e.g.: urban/residential), zonal isolation.

Describe the data management system used in the various components of MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure. CalWIMS has a UIC database. SAPTs and RAT Surveys have "Next SAPT" and "Next RAT Survey" date fields, which are monitored closely. A Survey Due letter is sent to operators showing which tests are coming due for each injection well at approximately 90, 60 and 30 days prior to the test due dates. This date field is also used for follow-up on failures. Operators and/or service companies call or email with scheduling details, which are entered into a separate Access database in called UIC schedule. Tests witnessed or waived are logged in CalWIMS UIC database. Surveys sent in are reviewed and entered in by letter. If required to shut in the well UIC personnel inspect and confirm disconnection. the UIC database. Operators are notified of failed test or deficiency.

Under what circumstances would a test be waived? When the number of wells scheduled for a MIT exceeds the number of UIC field engineers available to witness the MITs, the required witnessing of these tests is waived. The prioritizing of the witnessing of these tests is outlined above.

Conclusions

The SAPT requirements as described above are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in the state level portion of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure. If a lower pressure were allowed, we would recommend more frequent testing and/or monitoring of casing pressure.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. Increasing that to 30 minutes, however, would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

CDOGGR has changed the SAPT standard to test at the MASP in wells where there is only a single string of cemented casing across a USDW (10,000 mg/L). I believe that will apply to a large number of wells since the historical construction standards applied did not require two strings of casing across a USDW. Two strings are commonly set below the BFW in most recently drilled wells, but not necessarily to the base of USDWs, based on my limited review of California injection well records and information gained in the responses to the EPA Questionnaire. This new standard will not be applied in District 4 until the Division finishes its review and a Notice to Operators is issued for the new standard, according to the District response above.

Wells that fail a MIT are usually required to cease injection immediately, but are not required to be repaired unless USDWs are potentially endangered while the well is shut in. That may be acceptable if a well fails a MIT due to a packer or tubing leak and the casing pressure declines to zero after shut in; however, one cannot be certain that a casing leak does not exist concurrently with a tubing or packer leak. If USDWs are present in a well with a casing leak, there may be a risk for fluid movement into a USDW or other zones that lack cement in the casing/wellbore annulus between the leak and the USDWs or other zones. The risk increases with time in idle status and pressure on the casing, as the casing integrity becomes less certain over time without passing an annular pressure test. Pressure increases during shut-in status are possible, especially in waterflood injection wells and disposal wells that are located within the ZEI/AOR of another injection well.

Our understanding of the CDOGGR idle well requirements are as follows: a pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are required every two years in fresh water areas after five years in idle status (ten years in District 4) and five years in non-fresh water areas, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. We believe that wells that lack MI should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area. We also recommend a casing pressure test be performed in idle wells rather than fluid level surveys unless USDWs are known to be absent in the area.

The discussion of the assessment of Part 2 (external) MI in District 4 wells is incomplete and somewhat confusing. In one response, it states that cement records and logging tools such as CBLs are not acceptable for the assessment of external MI, but in a later response, it states that cement records are evaluated for Part 2 MI. Apparently, CBLs are not required, but other cement records are acceptable for evaluation of external MI. In our view, CBLs are a part of the cement record when run and should reviewed for assessment of external MI, especially for locating the top of cement in the annulus. The calculated tops of cement in the annulus are subject to considerable error and are much less accurate than CBL tops. In addition, we would recommend running CBLs in new and newly converted injection wells unless USDWs are known to be absent in the area.

State UIC regulations require adequate volumes of cement in the casing/wellbore annulus immediately above the injection zone, above hydrocarbon bearing zones, at the BFW, and behind surface casing. The presence of sufficient cement is determined by examination of cement records. Those standards should satisfy Part 2 MI requirements at least in part, but cement should be present at the base of all USDWs (10,000 mg/L TDs or less) for complete protection of USDWs. In our view, the presence of heavy mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

The District states that approximately 52 percent of MITs were witnessed in the reporting year 2008-2009. The percentage of SAPTs witnessed subsequent to major workover operations is 90 percent, but less than ten percent of workover operations are witnessed. Re-seating a packer *does not require a CDOGGR inspector to witness a subsequent SAPT, which seems contrary to the previous statement. In our view, SAPTs that follow packer re-seating operations should be witnessed whenever possible. Most workovers require re-seating the packer whether or not a major workover is involved, and packer integrity is key to maintaining the internal mechanical integrity of a well. Three percent of MITs performed were failures in the 2009 report year.*

The recent Division directives and the authorization to hire additional UIC staff in District 4 should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

What types of enforcement tools and legal actions are available to the District for the UIC program? How often in the last five years have you used them? Please list these or the most recent examples. Informal contact, Notice of Deficiency, Notice of Violation, Rescind Letters, Project Suspension and Civil Penalty PRC 3236.5. Informal contact and deficiencies used routinely. Deficiencies and Violations – 2063/5 years, Civil Penalty – 6/5 years. **See Attachment I.**

What types of formal enforcement actions have been taken relative to UIC violations in the District? Notice of Violation, Rescind Letters, Project Suspension and Civil Penalty PRC 3236.5.

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. The compliance times may differ and additional verbal communication with the operator would be necessary.

Please elaborate. Need clarification on what is meant by "paper" violation. If paper violation means a violation created by the operator not turning in paperwork the procedure may begin with an informal notification (phone call), then, in sequence: Notice of Deficiency, Notice of Violation, Provisional Order Imposing Civil Penalty, and Final Order with Civil Penalty. Operational violations such as threats to USDW are treated very seriously and normally result in immediate shut-in orders. If a USDW is threatened, the well would be shut-in immediately and remedial work to be completed within 30 days. If remedial work not completed within 30 days the well would be rescinded. The primary distinction between a paper violation and a threat to USDW is the immediate shut-in order of the latter.

Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties? How many have you issued in the last five years? Please list these or the most recent examples. NOVs are issued however penalties are not attached to the NOV's. If an operator is non-compliant on an NOV, a civil penalty may be issued. **See Attachment I**

What are the follow up procedures to assure compliance and correction of the violation? Operators are given compliance deadlines, reinspections of the violation or surveillance if necessary and MITs.

How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV? In cases where USDW is threatened immediate action is required. It ranges from immediate shut- in and disconnect and remediate within 30 days to shut in and remediate within 30 days.

How and when do UIC violations escalate from non-compliance into formal enforcement actions? If an operator misses the initial compliance deadline it is taken to the next level.

What penalties have been assessed and collected on UIC violations in the past ten years? **See Attachment J** *(Appendix B1)*

Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? The need for more personnel, equipment & computer software.

Conclusions

The enforcement procedures available to the District are highlighted in the responses above and are described in detail in the CDOGGR laws and regulations that apply to the UIC Program. Informal actions for noncompliance include informal contact, deficiency notices, and shut-in. Notices of Violation, rescind letters, project suspension, orders, and civil penalties can be issued if the informal actions do not result in compliance. Violation of a formal enforcement action is a SNC. These actions are described in Sections 135, 136, and 170.15E of the MOI. Thirteen civil penalties were issued in the past ten years with fines ranging from $250 to $25,000 for each violation, according to the District response above. The amounts collected are not stated. Most actions were related to unauthorized injection violations.

Remedial operations are not necessarily required after a well is shut in unless the violation would threaten an USDW, according to the District responses above and the MOI. Wells that lack MI but pose no ***apparent*** *threat to USDWs can remain in idle status 15 years or longer without a requirement for repair or P&A. A threat to USDWs due to lack of MI may not become apparent while inactive for so many years. In our view, wells that are in violation for lack of MI should be shut in and repaired or plugged and abandoned within three to six months, unless USDWs are known to be absent in the area.*

The District staff indicated that they do not have enough resources and personnel to initiate adequate numbers of compliance/enforcement actions given the large number of injection wells in the District. The hiring of an additional four staff members that was recently authorized by the Division should alleviate the lack of personnel to initiate and carry out UIC compliance/enforcement actions when violations occur.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public. Usually received by phone call or letter, an evaluation is made by UIC personnel, followed by an investigation and the necessary actions, to include remedial work and/or corrective action.

Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination? One, due to tubing and casing holes.

What actions are taken by the District when an alleged contamination report is received? Usually received by phone call or letter, an evaluation is made by UIC personnel, followed by an investigation and the necessary actions, to include remedial work and/or corrective action.

How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? One, none.

Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to the above question. The well failure involved migration of fluid through tubing holes and out shallow casing hole (USDW) extent of contamination unknown probably minor. Immediate violation and shut in until remediated. Tubing replaced and casing hole squeezed. SAPTs ordered quarterly.

Conclusions

Apparently, there was no investigation of the USDW contamination discussed above and no enforcement action other than shut-in and remedial operations to repair the leaks. It would be of interest to know the length of time the fluid leaked into the USDW, the extent of the contamination, and whether it would be possible and worthwhile to remediate the contamination.

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection *zone, base of USDW, and casing stubs, etc.).* Pursuant to CCR commencing with 1723**. See Attachment K.**

In reference to Attachment K, are cement plugs required at the base of USDWs in addition to those required at the BFW or useable water? What is the definition of "useable water"? No, a cement plug is not required at the base of a USDW, only at the base of fresh water (defined by the DOGGR as 3,000 mg/L TDS). "Useable water" contains 3,000 mg/L or less TDS. **Refer to section 1723 of the regulations.**

Are there UIC wells without surface casing installed? No.

If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed? Pursuant to CCR commencing with 1723. **See Attachment K.**

Are plug depths verified? When and how? Are all plugs required to be tagged? Yes. During plug back or plugging and abandonment operations. Yes, with tubing, coil tubing or bailer.

Are pressure tests of the casing and plugs required after the bottom plug is set? No.

Are possible casing leaks not a concern during P&A operations to ensure that plugs are placed where intended? Shouldn't casing leaks be squeeze cemented or otherwise isolated? Not necessarily. Tagging of cement plugs is required in those cases. P&A operations are witnessed ¾ of the time.

What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations? Percentage number is 80. Data submitted on history of well operations report.

Has the district ever required injection wells to be re-plugged because the plugging report from the operator was not approved for an unwitnessed plugging operation? How often has this occurred? Very rarely. Statistics on this unavailable.

Describe the process used to get an idled and an orphaned well plugged. Idle wells: Pursuant to DOG's Idle Well Panning & Testing Program all idle wells 15 years or older must provide DOG with a detailed engineering evaluation and plan for the future use. In lieu of this operator may opt to P/A a set number of wells, the number determined by agreement between the operator and the DOG.

Orphan wells: Orphan wells are abandoned by the state using funds from these funds: Hazardous Wells, Pollution Abatement, Hazardous & Idle Deserted Well Abandonment Fund and Acute Orphan Well Fund. Priority of wells selected for abandonment based on potential endangerment, location, age and other factors. State writes abandonment program, issues Invitation for Bids, awards abandonment contract to winning bidder, monitors abandonment operations.

Does "15 years or older" refer to the age of the well or the length of idle time? How long are idle wells allowed to remain inactive before reactivation or P&A is required? Are they allowed *to remain in disrepair if they lack MI? Are SAPT requirements the same as for active wells?* The "15 years or older" refers to the time the well has actually been idle. These wells may remain idle indefinitely but are subject to the division's idle well requirements. These require indemnification security such as bonds, escrow accounts, or elimination plans. Also included are integrity testing that may be a simple fluid level survey or the UIC MIT procedure. Remedial action can be ordered if necessary. The SAPT requirements for all idle wells varies depending on the length of time idle and the presence/lack of fresh water aquifers.

Please elaborate on the indemnification security options. Elimination plans require returning wells to production or P&A. Refer to the Idle Well Management Program.

It is my understanding that idle wells require only fluid level measurements unless the fluid level is above the BFW. Is that correct? Under what circumstances would a SAPT be required? It depends on the age of the well. Refer to the handout on the Idle Well Management Plan.

This response differs from other district responses regarding SAPT requirements for idle wells, It is my understanding that SAPTs are usually required by the regulations when fluid levels rise above the BFW in idle wells, unless no fresh water is present. That understanding is consistent with the Idle Well Planning and Testing Program.

Does the District maintain an inventory of abandoned (orphaned) UIC wells? Yes. *How many orphan wells are in the current inventory in District 4?* 18.

Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Describe the nature of the fund, sources of funding, and any limitations on the use of the fund. See discussion above. *Please discuss the sources of funding.* Assessments on oil and gas production and from oil and gas performance bonds.

How are the current plugging requirements different from those of 40 years ago? Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project? They are not significantly different than today and therefore have little to no impact on AOR. *We believe there are significant differences from those requirements of* ***more than 40 years ago****, based on our review of project files and responses from other districts. The question could have been better stated to elicit the expected response.*

Conclusions

District 4 applies the existing statewide P&A standards, which are discussed in Sections 2.6 and 3.6 and are described in detail in the CDOGGR regulations and MOI. The recent Division directives require a zonal isolation plug for all wells within the AOR of an active injection project, which is a new and more rigorous requirement for protection of USDWs from migration of injection fluid out of zone in those wells. In addition, a cement plug is required at the BFW zones in plugged and abandoned injection wells, but not in other wells within the AOR of an injection well or at the base of USDWs in any well. In our view, cement plugs should be placed at the base of USDWs in AOR wells when casing repairs occur or the well is plugged and abandoned.

District 4 written responses do not address the new requirement for a zonal isolation plug in all AOR wells. We assume that District 4 and the other districts will adopt that standard, if they have not already done so. We support the new Division directives and urge District 4 to adopt those standards if not already in place. However, the lack of a requirement for placement of cement plugs at the base of USDWs is a concern. Modification of P&A requirements in that regard would greatly enhance the protection of USDWs containing more than 3,000 mg/L TDS.

The District states that plugging requirements 40 years ago were not significantly different from current requirements and therefore would have little to no impact on AOR reviews. While that may be the case, we have concerns about the differences in those requirements from ***more than 40 years ago****. Our question was probably not stated clear enough to elicit the response we expected. We know from discussions with other districts and a review of well plugging records of that vintage that many of the older wells in the AOR of injection wells require corrective action before injection projects are approved. Furthermore, plugging requirements for protection of fresh water have improved substantially since the early days of oilfield development in California. Many wells in District 4 were drilled and plugged pre-1950 with methods that would not meet current standards. In addition, the District 4 responses in the AOR/ZEI discussion above indicates that there have been several cases where remedial work was required in AOR wells prior to commencement of injection. Nonetheless, the recent Division directive regarding zonal isolation plugging requirements is expected to require remedial cementing or other corrective actions in more AOR wells than was the case in the past.*

CDOGGR plugging requirements for AOR wells require a zonal isolation plug through and above the injection/production zones in those wells, but not a BFW plug, according to the recent Division directives. We agree with the zonal isolation requirement, but recommend an additional requirement for placement of cement plugs at the base of USDWs in AOR wells and placement of cement at the USDW base in the casing/wellbore annulus in idle or active injection wells.

District 4 states that 80 percent of well plugging operations are witnessed. That includes tagging cement plugs and cement squeezing operations, but may not include witnessing cement plug placement operations, as discussed in Sections 2.0 and 3.0. When P&A operations are not witnessed, District staff review the P&A report submitted by the operator to ensure compliance with P&A requirements. We have concerns about the absence of a CDOGGR inspector during cement placement operations, as discussed earlier in Sections 2.0 and 3.0 and in other district level sections of the Report. Witnessing those operations is optional, but should be required or given a higher priority, in our view.

The District applies the District 4 Idle Well Planning and Testing Program as described in Exhibit 138.3 of the MOI in managing P&A of idle and orphan wells, which is more detailed than the statewide idle well program, but is somewhat less rigorous in terms of the testing schedule. Our concerns regarding the management of idle wells are discussed below and at length in Sections 2.0 and 3.0 of the report.

The requirement for sufficient volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

Exhibit 180.3.4 in the Manual of Instructions provides guidelines for sodium bentonite plugging operations. The guidelines are applicable as field rules in the Bakersfield and Coalinga Districts, and elsewhere for gas exclusion. The use of bentonite plugs is contrary to federal UIC regulations, which require cement plugs in Class II injection wells. Bentonite is in use in only two fields in District 4, Midway-Sunset and Kern River, and by only one operator, Chevron, according to the District 4 office. However, no information on the basis for its use has been provided by DOGGR to date (June 20, 2011).

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well? Not applicable.

The above request has been edited to add "idle" where appropriate for clarification. For further clarification, the EPA definition of TA status is an injection well that has been inactive for more than two years, but remains in compliance with UIC regulations/permit conditions while in TA status. If not in compliance with MI and other requirements, the well must be repaired or plugged and abandoned. Do idle wells have similar requirements? Please elaborate on the definition and requirements for idle wells. District 4's Idle Well program is administered as outlined in the PRC 3206- 3206.5. Our Idle Well program doesn't begin tracking wells until they have been idle for 5 years. At that point, the Idle Well testing program kicks in (as outlined in CCR 1723.9). If an idle well, or any well, is determined to be a danger to a USDW it will be order repaired or abandoned.

Under what circumstances would it be determined that a USDW is in danger in an idle well? Fluid levels rise above the BFW or a well fails the SAPT. *The idle well program does not apply to protection of other USDWs except for isolation from the injection zone. Fluid levels that rise above the base of USDWs may result in fluid movement into a USDW if the casing leaks or the annular cement above the injection zone lacks integrity.*

Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well? Not applicable.

The above request has been edited to add "idle" where appropriate for clarification. Please describe how this applies to idle wells. No, an MIT is not required prior to classification as an idle well, but once idle then MITs are required per our Idle Well testing program.

Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. How long may a UIC well remain in TA status before being reactivated or P & A. Not applicable.

The above request has been edited to add "idle" where appropriate for clarification. Please describe how this question applies to idle wells. Idle wells are tracked through the district idle well program as idle wells in the idle well database. Within that context they are neither "active" nor "abandoned". The conditions of the Idle Well program for purposes of return to service or abandonment are the same as for idled producers, that is, there is no limit other than the financial assurance, testing, and inventory options and requirements of the idle well program.

Conclusions

Temporary abandonment of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements apparently are not as rigorous as federal requirements in terms of MIT, repair, and timely plugging. District 4 applies the statewide standards for management of idle and orphan wells, except for provisions specific to District 4 in Exhibit 138.3 of the Idle Well Planning and Testing Program. The two-year cycle testing requirement begins after ten years in idle status in District 4 versus five years in the statewide program. Testing requirements are less rigorous in areas that lack fresh water. Mechanical integrity tests are not required before idle status is approved or periodically while a well is in idle status or before reactivation as an injection well unless the fluid level is above the BFW.

Idle wells require a pressure test if the fluid level in a well reaches above the BFW in the tubing or annulus, but not the base of USDWs. USDWs are not adequately protected in idle wells in our view. Those concerns are discussed at length in Section 3.0 and in other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs, in our view.

PART VII: Comments

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

None offered.

4.5. DISTRICT 5

This section is organized in seven parts to address questions and responses from District 5. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. The last part is an opportunity for District 5 staff to provide their own comments. Each of the remaining six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 5 has a total of 2,042 active and inactive injection wells, which represent approximately 6.5% of state injection wells. Table 7 provides numbers of wells by well type for both active and inactive wells.

Table 7. District 5 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	SC	SF	WF	AI	WD	Total	% of State Wells
Active	-	-	369	276	136	-	29	**810**	**6.45%**
Inactive	1	-	-	694	501	-	36	**1,232**	
Total	**1**	**-**	**369**	**970**	**637**	**-**	**65**	**2,042**	

PART I: General

This part addresses UIC program organization for District 5, and interagency coordination and changes to the UIC Program.

UIC Program Organization

Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

District Deputy
Associate
Field Engineer
Field Engineer
Office Technician
Office Technician

All four engineers do permitting, file review, field inspections and public outreach.
The Deputy and Associate deal with compliance and enforcement

The Associate handles project applications.
All personnel are involved with data management.

Please provide more detail on the numbers, qualifications, responsibilities, and duties for each staff position.

Timothy Boardman, District Deputy (office supervisor), permitting, backup field support, degree in Geology, Fresno State University 1978, 29 years of oil, gas & geothermal field experience, California Registered Geologist, California Certified Hydrogeologist.

Glenn Muggelberg, Associate Engineer, permitting UIC and office support & backup office supervision, backup field support, degree in Geology, UC Davis 1977, 33 years of oil & gas field experience and mining.

Josh Jones, Field engineer district field tests, office support, degree in Earth Science, Western Oregon University 2008

Mary Kerr, Field Engineer district field test, office support, 7± year's oil & gas field experience.

Comments

A Division organization chart that includes all Districts was provided and is included in Appendix A5.

Interagency Coordination and Changes to the UIC Program

Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available.

UIC program agreement, US EPA region 9
State Water Resources Control Board
UIC relating to EPA Class II wells, BLM
Well records, BLM
Regulating oilfield operations, BLM
Pipeline safety, State Fire Marshall

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes? MOU with the BLM assigning responsibility to DOGGR for Class II well permits on federal property.

Conclusions

Some of the most significant changes in the UIC Program are described in the Division Expectations Memorandum. The MOUs listed above were not provided by District 5, but we received from other district offices and they are included in Appendix A.

<u>PART II: Permitting And Compliance Review</u>

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program.

Who receives the application from the operator? (District or Headquarters office) District

How and by whom are permit applications screened for completeness?

Well permit: Received by clerical and forwarded to permitting engineer (rotates weekly through all engineering staff). Engineer checks application and generates permit if complete and reasonable. Application and permit are forwarded to Associate (if the Associate is not currently the permitting engineer) for review. If acceptable, application and permit are forwarded to the Deputy for review and signature.

Project application: Received by clerical and forwarded to Associate. Associate reviews and approves if complete. Associate forwards application to Deputy for review and signature after public review process.

How do project and permit applications differ? Are permits issued for projects, on an area, or multi-well basis?

A well permit application is a request to perform a specified operation, (drill, convert, abandon etc.), for a single well. A well permit gives the operator approval to perform that operation and lists our requirements.

A project application is a request to inject within a specified zone and area. A project permit gives the operator approval to inject and lists our requirements. This may be for a single well or many. Wells are added or removed from the project through well permits.

Are AORs and corrective action requirements determined for each new well in a project or is that done for the entire project area? AOR reviews are performed for each well based on a ¼ mile radius from each well.

What are the procedures or protocols if an application is found to be incomplete? Send a written notice listing what is needed (or needs clarification). If a well permit application is grossly inadequate, it will be returned with the written notice.

What are the professional qualifications required for staff who conduct permitting and compliance activities? Do those staff members meet the minimum requirements? What types of training would staff like to access if funds were available? The staff is required to have experience in oil and gas operations or have a classical geology or engineering degree.

Please provide more detail on experience and educational requirements and whether staff members meet the minimum requirements for each position. What additional training may be needed to meet the minimum requirements? The minimum requirements for the field engineer has varied over time. In the 1980's a degree in geology or petroleum engineering was the requirement. In the late 1990's to early 2000, upward mobility was allowed and lower tiered staff was allowed to enter the field staff positions. Entry level geology and advanced math was required. Current hiring has gone back to degreed professionals.

Do current staff members meet the minimum requirements? What additional training may be needed to meet the minimum requirements? One staff member may not meet minimum requirements but is in training to eventually satisfy those requirements. A professional degree is preferred for Field Engineers but it is not a requirement. A professional degree is required of senior level positions. Training is mostly hands-on experience with guidance from senior staff in the office. PTTC classes and the EPA UIC Inspector training class are options to consider.

What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful? Specialized field maps (BFW etc.).

Please provide more detail on tools that reviewers utilize to review permit applications. The district office has an extensive engineering and geological library that is available for reference. We also interact with other agencies such as the California Water Quality Control Board.

Are there additional tools that you can identify that would be useful? Base of fresh water maps are also available in District 5 for reviewing permit applications. Other than the tools mentioned above, no additional tools were identified.

Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal). A commercial WD well requires a $50,000 (or minimum $250,000 blanket bond).

Please elaborate on differences in processing and requirements. Is there more stringent control of fluid sources injected into commercial wells and more well site security, for example? For a non-commercial WD we require an analysis of the injection fluid with the project submittal and when the source changes. If a commercial WD is receiving fluid by truck, each load could be a separate source and require a fluid analysis. *Class II fluids only?* Yes, but there are no commercial disposal wells in District 5 presently.

Describe any differences between the processing of a waterflood project and a CO2 EOR project. No CO2 projects.

Any steam flood or other EOR projects in the District? How does processing differ from a waterflood project, if any? Steamfloods and waterfloods are approved for Coalinga field. Both are processed in a similar manner.

Do the bonding, AOR, MASP, SRT, MIT, and P&A requirements differ? How? RAT surveys are required every five years instead of two years for waterflood and one year for disposal wells. Also, the SRTs and MASP are treated differently for steamflood wells since steam is much less dense than water and requires a higher surface injection pressure than water requires in the same well and/or formation. No difference for AORs and P&A requirements.

Conclusions

The application flow process is similar in all districts, and we have few additional comments or conclusions to offer beyond those included in the state level and other district sections of the report. Discussion of the staff qualifications and training requirements needs is satisfactory and is supplemented by further discussion under other Objectives listed below.

OBJECTIVE: Understand the current compliance/file review process.

What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy.

File review normally occurs as part of the periodic mechanical integrity testing (RAT surveys). For water disposal surveys, (usually witnessed), this is inherent in generating a report. For enhanced recovery wells, (usually waived), there is the option to review the file when the logging company submits their report. An operator with a poor compliance history will see more reviews. Other reviews occur when notices to drill/rework/abandon are received, or when field inspections or public inquiry brings a well to our attention. Idle/rescinded wells are less likely to be reviewed. This is a rural district – our only "high priority area" is the fresh water of the central valley. All UIC wells in this area are water disposal and are surveyed/witnessed/reviewed once a year at a minimum.

Who performs the file review and what are the qualifications of the reviewers? All engineering staff performs file reviews.

Over a one-year period, what percentage of total UIC permits/wells receives a file review? In 2009: WD – 78% ER – 33%

How is the quality of a file review assured and subsequently documented? A file review is not documented (other than its occurrence) unless a change is noted. Normally this is limited to an update of the casing record or an inquiry to the operator with a copy inserted in the well file. Quality assurance is limited to spot checks by the Associate.

When deficiencies are discovered during the review, what actions are taken to correct the deficiency? The engineer reviewing the well sends the operator notice requiring the operator to correct the problem within a time limit. With paper issues this could be a letter or e-mail with a 30 day limit. A serious physical issue might require a phone call, formal letter and immediate action by the operator. Compliance is tracked by the reviewing engineer.

How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually?

A representative of the operator is present to answer questions and make comments. The file review concerns the individual well largely in isolation. The project review deals with the wells, the overall project, and the effect of project changes on the wells.

Project reviews have rarely been face to face. Most are phone calls or questionnaires mailed or e-mailed to the operator. Results are a short write up on the phone call or a completed questionnaire (with notes of any follow-up). Recently the percentage of formal project reviews has been very low (<10%).

Are individual wells in the project subject to a file review? Why is the percentage of formal project reviews so low? Problem wells are reviewed. Lack of manpower in the District prevents a more comprehensive review of each project. The addition of one more Associate is proposed for District 5.

Conclusions

Project reviews should be performed at least annually to be in compliance with the CDOGGR Program Description and the MOI requirements described at Section 170.13.3.1. Annual meetings with operators to review active projects is an important element of the UIC Program, especially for those projects that have ongoing compliance issues that go unresolved within acceptable timelines. The lack of a project review with the operator is somewhat alleviated by the fact that individual wells in disposal projects are reviewed by means of the required annual RAT survey. However, that does not fully apply to enhanced recovery wells because waterflood wells are tested only on a two-year cycle and steamflood wells on a five-year cycle. Also, RATs will not detect a casing leak above the packer. The addition of another Associate should improve the District's ability to conduct more comprehensive project reviews with operators as well as increase the number of file and project reviews annually.

OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

The federal definition of USDWs (underground sources of drinking water) is found in the regulations at 40 CFR §144.3 which includes that an aquifer "...contains fewer than 10,000 mg/L total dissolved solids". Please distinguish when responses to questions pertaining to USDWs differ from the federal definition and describe how this difference is handled. This may apply to AOR/ZEI and MIT responses in other sections as well.

What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all

Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected? Casing is normally cemented to the surface and must of a weight and grade suitable for the anticipated pressure. In steamflood areas, 30% silica flour must be added to the cement to provide thermal stability,

If not cemented to the surface, is casing and cement required through all USDWs, or how are USDWs otherwise protected? Please discuss how silica flour provides thermal stability. All new wells must cement the surface casing from the shoe to the surface. An intermediate or completion string that penetrates the BFW must be cemented with at least 100' of cement across the BFW. The compressive strength of cement degrades on extended exposure to temperatures much above 200°F. The silica flour mitigates this.

What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected? When casing is not cemented across a USDW the operator is required to perforate the casing and squeeze cement across the base of the USDW. Tubing and packer should not be set above the cemented interval.

Is the cementing requirement a condition of the permit? When in the life of the well is it required? During conversion, workover, or P&A operations? The cementing requirement is a condition of the permit to convert the well to injection.

Cement placement at the base of USDWs in converted wells is apparently not a requirement in other Districts according to their responses to the questionnaire, only at the BFW. What is the definition for a USDW in District 5? That is true in District 5 as well. For clarification, the above response should be edited to replace USDW with BFW.

This was not stated but my understanding is that DOGGR defines (my words) USDWs generally as aquifers containing producible water with less than 10,000 mg/L TDS, unless exempted for injection based on the criteria described in the UIC regulations.

What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field? Confinement is tested periodically in the injection well (SAP and MIT). The geology and wells within the area the well is expected to influence are evaluated prior to injection. If there are issues, they are addressed by fixing problem wells, by requiring monitoring wells, by limiting the project area/pressure/volume or by a combination.

Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? Packers and tubing are routinely required. Not required if the well has two strings of cemented casing across the BFW. Slim hole (3-1/2" diameter or smaller) ER wells in the Coalinga field are permitted without tubing or packer. No alternative testing requirements are used; casing integrity is determined solely by the scheduled RAT/Temperature surveys.

Do those wells always include two strings of cemented casing across the base of USDWs and the BFW? Are slim hole completions routinely pressure tested for leaks during workover or plugging operations? Wells with two cemented casing strings are cemented across the BFW with the outer string and usually, but not always, with the inner string, which may only be cemented at the shoe. Slim hole injectors are not routinely pressure tested.

Are slim hole injectors not pressure tested during workover or plugging operations? If not, how is casing integrity evaluated. Casing is pressure tested for leaks during workover and plugging operations. If leaks are found the well is usually plugged rather than repaired.

Are dual (multiple) completions permitted? What requirements are different than single completions? What types? Multiple tubing/packer completions, annular injection, and slim hole completions with up to three tubing strings cemented within a conductor have been permitted within the Coalinga field. The only requirement change is permitting tracer surveys to substitute for the casing pressure tests with the slim hole wells.

How are the locations of USDWs determined? Does the District consult with other state and federal water resource agencies regarding USDW information? Maps (paper and electronic) of the base of fresh water (3,000 ppm) have been created over the years to determine plugging and cementing requirements. State Water Quality Board data was used for some of the wildcat maps where first hand data was limited. Outside of field areas, the operator is required to test a water sample from any involved formations to demonstrate that the TDS is above 10,000 ppm.

Is 10,000 ppm the protectable standard for USDWs within the field areas? If not, please explain. What is meant by the term "involved formations"? The 10,000 ppm limit is the standard unless the EPA has granted an exemption. An "involved formation" is any formation that will be used to inject into.

How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated? See above responses.

Pease elaborate on the geologic considerations. This is not the forum to discuss complicated geologic decisions. A book could be written on the subject. When you perform a site visit to the district office we can discuss this further. *Please discuss geologic considerations, in a general sense, during the site visit. Is adequacy of the confining system an issue in the AOR of any District 5 projects or wells?* It is not a significant issue because interbedded sands and shales in Valley fields generally provide adequate confinement and the Coalinga Field has no fresh water. *Are there USDWs in the Coalinga Field that would cause lack of confinement to be a concern?* Yes, Down dip on portions of the east side of the field there is water suitable for agricultural use.

Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well. The operator is required to record and report pressure and volume data to the Division. "An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device"

Does this include annulus pressure monitoring, recording, and reporting? What is the required frequency of reporting? Yes, but reporting is required only when requested.

How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose. Maximum injection rates have rarely been established. Maximum pressure gradients have typically been assigned to areas/zones. Injection over these gradients requires a step-rate test.

Assigned on what basis? Are formation fracture pressures determined for each well/project? Please provide examples of step rate tests conducted in the District, including the report and evaluation of each test. Maximum pressure gradients were assigned on an area basis from older projects. If a well was operating without difficulty at .70 psi/foot for example, then a slightly reduced gradient of .65 psi/foot might be assigned for new projects in the area. Three step rate tests have been witnessed since 2000.

WD in East Coalinga Extension field wells 32 and 35 on section 31 19S/16E. Unable to develop sufficient pressure (max 550psi @ 7 bbl/min, .51 psi/foot gradient). Decision: leave established gradient of .75 psi/foot unchanged.

WD in Tulare Lake field well “Salyer” 636 on section 8 22S/20E. Maximum pressure 2500 psi @ 3.8 bbl/min, 1.29 psi/foot gradient. Found all the fluid exiting a hole at 2490’. Restriction was too great to determine frac gradient.

Please provide copies of typical SRT reports and the determination of fracture pressure for those wells. Are some SRTs not witnessed? What is the basis for the MASP where there are no SRT data available? SRTs are performed infrequently in District 5, but are witnessed when they are performed. The default fracture gradient is 0.7 psi/foot in the District. The Gatchell 86-20 well in the Pleasant Valley Field was shut in due to injection pressure exceeding the MASP and a residual pressure of 80 psi after long-term shut-in.

Conclusions

The technical review processes of permit application and related aspects of file reviews in District 5 follow the guidelines outlined in the MOI and are quite similar to those processes in other districts. As a result, we have concerns with District 5 technical review processes similar to those expressed at the state and other district level sections of this report. We reiterate some of those concerns below.

USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance for total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement. CDOGGR should consider modification of cementing requirements to require placement of cement at base of all USDWs penetrated by a well, not just at the BFW (3,000 mg/L or less TDS) zones, above the *injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells and wells located within the AOR of an injection well when casing repairs occur or when the AOR wells are plugged and abandoned. Monitoring to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.*

Slimhole and multiwell completions are permitted in the Coalinga Field in District 5, with special circumstances and/or requirements. District 5 states that there are no fresh water zones present in the field, for example, although the absence of other USDWs has not been confirmed at this point. Slimhole completions are not pressure tested for MI except during workover or plugging operations. The RAT survey substitutes for the SAPT in those wells. Unless there are USDWs present, which is uncertain at this time, there are no particular concerns about the construction and testing requirements for those wells. We would need to examine well logs and other data in the Coalinga Field to assess the presence or absence of USDWs.

There are data that indicate the presence of produced water containing 5,900 mg/L TDS in the Coalinga Field, which, if present in non-exempted formations, would confirm the existence of USDWs. However, according to the approved Primacy Application, the Santa Margarita and Etchegoin formations are listed as non-hydrocarbon bearing exempted aquifers in most of the Coalinga Field, and are located above the main producing formation (Temblor) in the field. There is additional information from District project files that indicates the presence of fresh water to depths of 330 feet in parts of the field. That water is discounted by CDOGGR as due to surface recharge and suitable only for irrigation of salt tolerant crops, which would mean that TDS content is probably well below 10,000 mg/L. and it qualifies as an USDW if not exempted.

The historical fracture gradient assumption or 0.7 psi/foot reported for the District 5 area is apparently not based on SRT data and may be higher than the actual gradient in some injection formations, based on recent SRT data in other Districts and the other data presented in CDOGGR Publication M13. We found some projects that approved a 0.75 psi/foot gradient, however, without evidence of a SRT that would justify that gradient. We assume that the actual default gradient in District 5 is 0.8 psi/foot, which would be consistent with other Districts and statewide guidance. District 5 has required very few SRTs in the past. We understand that SRTs will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives are fully implemented at the district level. We support that directive with the recommendation that bottom hole as well as surface pressure gauges be used in SRTs. Bottom hole pressure measurements remove the uncertainty of friction losses during a test and provide a more accurate measure of formation fracture gradient.

A sampling of wells was reviewed for exceeding the MASP (based on a 0.8 psi/foot fracture gradient assumption) and pressure failing to fall to zero when shut-in. Based on our limited review of wells, the Gatchell 86-20 well discussed above is the only well reported to have been in violation of the MASP in recent years. No other wells were found to be in violation. Most disposal wells in the Central Valley apparently are capable of injection at high rates at relatively low injection pressures.

OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

How is the Area of Review (AOR) determined for enhanced recovery wells or projects? Quarter mile radius, if there is a geological reason the area may be expanded

How is the AOR determined for saltwater disposal wells? Quarter mile radius, if there is a geological reason the area may be expanded.

How is the AOR determined for commercial saltwater disposal wells? Quarter mile radius, if there is a geological reason the area may be expanded.

How is the AOR determined for CO_2 EOR wells? No CO_2 projects

How are AORs determined for area permits and other multi-well projects? Quarter mile radius from all injectors within the project/area.

Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? If not, are they performed for all disposal well permits? ZEI calculations have not been used.

Please elaborate on the reasons for not performing ZEI calculations for 1) Enhanced recovery wells/projects and 2) disposal wells. Until recently, simply using a ¼ mile radius for the area of review was standard practice. Using ZEI calculations were not considered for any project unless there was something odd about the project/geology.

What is the current practice for AOR determination? Does it differ for enhanced recovery wells versus disposal wells? A fixed radius of ¼ mile has been the standard AOR, but ZEI calculations are required under the new policy from HQ. Valley wells are highly permeable and take a lot of water with minimal pressure increases. The Tulare Formation is the main disposal zone in Valley wells.

The ZEI in wells injecting into the Tulare Formation may not exceed the quarter-mile fixed radius AOR based on its ability to take large volumes of water with minimal pressure increases over time. We could review pressure behavior and perform ZEI calculations in selected disposal wells completed in the Tulare zone to assess this assumption.

Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects. Determined on an individual basis, or when problems are suspected.

How are static reservoir pressures determined? Are fall-off tests required for disposal wells? How often? Static reservoir pressures have not been determined unless the wells began showing pressure at the surface while idle. Fall-off tests have not been required.

Would you consider a requirement for fall-off tests in disposal wells that show pressure at the surface after shut in for an extended period? Or would the permit for such a well be terminated?

Yes, but such a well would lose its permit to inject if shut-in pressure failed to failed to fall to zero after extended shut-in period

Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples. Yes. In the summer of 1989 the Texaco Inc. water disposal project on section 18 T20S/R15E MDB&M. Project was terminated after wells were shut in and pressures declined only a few psi per *month.*

Please provide more information on this occurrence. Any other occurrences? Texaco began injecting in late 1986. The four injection wells were chronically injecting at or above MASP. Injection was stopped in March 1988 when well WD-9 blew out during maintenance. The wells were shut in and the pressure monitored. When the pressure failed to decline the project was terminated. No other occurrences.

What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR? See above.

Are there other wells/projects that have experienced significant reservoir pressure increases? If so, please list them. No.

Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? There has been no change in the corrective action considerations since actual project permits were issued beginning in the 1980s. Deficient wells requiring corrective action have commonly been found within the AOR. Often this kills the project.

Helm field, Maxim Resources LTD., USA, WD, 6/3/1997 – required upgrading one abandoned well.

Coalinga field, Chevron USA Inc., SF, 4/8/1996 – required upgrading three abandoned wells.

Coalinga field, Santa Fe Energy Resources, Inc. WD, 7/30/1992 – upgrade one abandoned well, rework or abandon four wells, convert on well to observation.

Please elaborate on the upgrade procedures. What was done to upgrade the wells in these three examples?

Maxim Resources – Well “Capital” 47X-15, had no BFW plug and the zone plug was inadequate (leaking). Re-entered, cleaned out the old plugs, set new zone plug, squeezed BFW with cement, set BFW plug, shoe plug and surface plug.

Chevron USA – Wells S3, S5 and S6 had no BFW plugs and the zone plugs were inadequate, (annuli not covered). Re-entered, cleaned out the old plugs, squeezed zone with cement, set new zone plug, squeezed BFW with cement, set BFW plug and surface plug.

Santa Fe – Well “Penn-Zier” P-4 had an inadequate zone plug (annulus not covered). Project was never started. Shot and squeezed zone/junk and cemented to surface in 2001 as part of a steamflood expansion.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? Unless the defective well is already subject to corrective action by the Division, it is solely the responsibility of the permittee negotiate the repair of the well with the operator or land owner. If it is uncertain that the project will affect the well a monitoring system may be set up. If repair or monitoring is not feasible they must reduce the scope of the project so it does not impact the well or cancel the project.

Conclusions

Determination of ZEIs were not performed for District 5 injection wells in past years. AORs were based on a quarter-mile fixed radius from the injection well, even for disposal wells. That may be appropriate for most enhanced recovery projects since fluid withdrawals are usually in balance with fluid injection volumes over the life of a project and reservoir pressure is maintained at a level that does not cause the position of the pressure front to expand beyond the quarter-mile AOR boundary. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. Where injection is into a depleted or producing zone, the fixed radius quarter-mile AOR may be appropriate, as may be the case in many of the District 5 disposal wells. Disposal wells in the Central Valley that inject into the highly permeable Tulare formation may not cause pressure buildup beyond the quarter-mile AOR. A ZEI analysis should be performed for all disposal wells, however, to determine whether the quarter-mile AOR is appropriate. This also applies to EOR projects if injected fluid volumes will exceed produced fluid volumes for an extended period, allowing reservoir pressures to increase and the pressure front to potentially expand beyond the quarter-mile AOR.

Problem wells outside of the quarter-mile AOR but within the ZEI were apparently not addressed in the past. With the full implementation of the recent Division directives regarding ZEI/AOR procedures, those wells will be subject to corrective action considerations, and protection of USDWs should be significantly improved.

Pressure fall-off tests were rarely performed in the past, but may now be performed more often for disposal projects in the District when the recent Division directives are fully implemented in the District. That should provide the necessary reservoir pressure data to monitor pressure buildup and ensure that the pressure front is contained within the AOR over the life of a well. District 5 apparently has not yet implemented those directives, based on the above responses and conversation with District staff. However, shut-in pressures are monitored and permission to inject can be rescinded when pressures fail to fall to zero after an extended period. One *historical example (1989) of a rescission for that reason was provided and discussed in the above responses.*

In addition, the permit to inject in another disposal well was recently rescinded for exceeding the MASP by 660 psi and for apparent pressure buildup beyond hydrostatic. That well is the Gatchell 86-20 well, in the Pleasant Valley Field, which was rescinded in 2009. Permission to inject was granted again in 2010 with a provision that the injection pressure be maintained below the 340 psi MASP and the pressure continuously monitored with a recording device. In our view, a FOT and ZEI calculation should be performed to assess the potential effect on other wells in the AOR. There are pumping water wells in the vicinity of this well and there are problem wells within the quarter-mile AOR, according to information reviewed in the project file. USDWs may be endangered by continued injection if further corrective action is not required.

OBJECTIVE: Understand the administrative permit application components.

Describe the public notification and participation process for applications under consideration by DOGGR. The project is described in a legal notice published in a newspaper (or newspapers) within the area of the project (three consecutive days in a daily paper, once in a weekly paper). If there is public comment that cannot be resolved with direct communication then the Supervisor may schedule a public hearing.

When and where is public hearing opportunity held on an application and how are they conducted? No public hearings have been conducted.

If hearings are held, when and where would they be held and how would they be conducted? HQ would have the lead if attorneys are involved in the process. Otherwise, the District would look for guidance from HQ.

What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed? An operator must post an individual performance bond per well or a blanket bond for multiple wells. Individual bonds are $15,000 –well is less than 5000 feet deep, $20,000 – well is 5000 feet or deeper but less than 10,000 feet, $30,000 – well is 10,000 feet or deeper, Blanket bonds may be $100,000 to cover 50 wells or fewer or $250,000 to cover an unlimited number of wells. With the exception of a commercial disposal well, an individual bond is released after work on the injector has been successfully completed to the satisfaction of the Division. A commercial disposal well must maintain a $50,000 bond until abandonment or be covered by a minimum $250,000 blanket bond.

Have these amounts proven to be adequate to cover actual plugging and abandonment costs? How often are they reviewed for adequacy? Are the operators required to provide P&A cost estimates in a permit application and update those estimates periodically? Please clarify whether individual bonds are held 7 until the well is plugged and abandoned to the satisfaction of the District. The amounts on individual bonds are often not enough to cover abandonment costs. The amount of the bond is set by law (PRC 3204-3205.5). The bonds are not reviewed and cost estimates are not determined. Individual bonds are performance bonds – when the well has produced/injected commercially for six months the bond is released. *This is apparently a statewide practice, but releasing a bond before a well is plugged and abandoned is contrary to standard EPA requirements for Class II injection wells. EPA has no provisions for a plugging fund, however, while the State does provide for an orphan/deserted well plugging fund with funding provided by assessments on operator production revenues.*

Conclusions

See Section 3.0 for more information.

OBJECTIVE: Understand the process for aquifer exemptions

How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests? None

How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials? None

Conclusions

See Section 3.0 for more information.

<u>PART III: Inspections</u>

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District. Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas.

How are inspection priorities determined? This is a rural district – priority is assigned by presence or absence of fresh water.

Please identify fields that are high-priority due to presence of fresh water and/or USDWs. Burrel, Burrel Southeast, Camden, Chowchilla Gas, Gill Ranch Gas, Helm, Hollister, Merrill Avenue Gas, Mint Road Gas, Moffat Ranch Gas, Oakdale, Raisin City, Riverdale, San Joaquin, Trico, Northwest, Gas, Tulare Lake, Van Ness Slough.

What professional qualifications and/or experience are required by DOGGR to be an inspector? Do District staff have the necessary qualifications and/or experience? What types of training do inspectors access or would like to access if funds were available? The inspectors are required to have experience in oil and gas operations or have a classical geology or engineering degree.

What additional training may be needed to meet the minimum requirements? Each year we allocate funds for training. Our staff has traditionally taken advantage of training opportunities. Our headquarters has taken the subject further with the addition of a new Senior Oil & Gas Engineer position devoted to training. In the District senior and more educated staff members monitor the activities of junior staff and provide guidance.

What tools do the inspectors utilize? Are there additional tools that you can identify that would be useful? Tracking the wells is big issue in the district; desktop computer and database software have been available for years. We are just now starting to utilize laptop computers and their use in the field.

Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training. Training in the district is an ongoing process. Traditional one on one training is provided by the senior staff and short courses on geology/engineering are recommended and attended as they become available.

What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process? Inspectors gather the information and bring it back to the senior engineers. Inspectors are part of the enforcement process as they are witnesses to the field operations.

Conclusions

Inspections are prioritized for wells where fresh water is present, but residential areas are not a consideration since the wells are located in rural areas.

The professional qualification and/or work experience requirements for District 5 UIC inspectors are similar if not identical to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. Training and qualifications of inspectors appear to be adequate in most areas, based on District responses and discussions with staff at the District 5 office. However, more training may be needed in witnessing and analyzing RAT surveys and P&A operations in addition to other UIC operations, especially for new and recent hires. Attendance at the EPA sponsored UIC Inspector Training Course would be beneficial to the District UIC Program.

We were informed that the Division has authorized the employment of several additional UIC staff members statewide. If that includes additions in District 5, that could significantly improve the District's ability to process new project applications and perform the other UIC functions on a more timely basis when those personnel receive the necessary UIC training and experience. District 5 has proposed adding one Associate to the District staff, but Division approval of the addition is not known at this time.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District.

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations.

A Class II injection well is defined by U.S. EPA (40 CFR 146.5) and is used to inject the following fluids:

A. Fluids that are brought to the surface in connection with conventional oil or natural gas production. The fluids may be commingled with waste-water from gas plants, which are an integral part of production operations (unless the waste-water is classified as a hazardous waste at the time of injection).
B. Fluids used for enhanced oil recovery (EOR), including natural gas for pressure maintenance; and
C. Hydrocarbons for storage purposes that are liquid at standard temperature and pressure.

In addition, U.S. EPA's Final Policy for Class II wells (dated July 31, 1987) allows, aside from the use in EOR operations, the injection of the following four kinds of fluids in Class II wells:

A. Waste-waters (regardless of their source) from gas plants, which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.
B. Brines or other fluids brought to the surface in connection with oil or natural gas production or natural gas storage operations.
C. Brines or other fluids described in item A that, prior to injection, have been:
    1. Used on-site for purposes associated integrally with oil and gas production or storage, or
    2. Chemically treated or altered to the extent necessary to make them usable for purposes related integrally to oil and gas production or storage, or
    3. Commingled with fluid wastes resulting from the treatment in (2).
D. Fresh water (i.e., water containing less than 10,000 mg/L TDS) from groundwater or surface water sources, added to or substituted for the brine, as long as the only use of the water is for purposes associated integrally with oil and gas production or storage.

Aside from produced brines, the State Oil and Gas Supervisor has determined that a Class II water disposal injection well may accept the following nonhazardous fluids types that originate from oilfield activities:

1. Diatomaceous earth filter backwash;
2. Thermally enhanced oil recovery (TEOR) cogeneration plant fluid;
3. Water-softener regeneration brine;
4. Air scrubber waste;
5. Drilling mud filtrate;

6. Tank bottoms;
7. Slurrified crude-oil saturated soils;
8. NORM waste; and
9. Cuttings.

Exploration and Production wastes are considered California-hazardous if they fail any one of the toxicity, ignitability, corrosivity, or reactivity characteristics using the Toxicity Characteristic Leaching Procedure (TCLP) test and cannot be injected into Class II disposal wells. The clarification of the California-hazardous waste definition considers produced fluids that are within specified toxicity levels and do not exhibit ignitability, corrosivity, and reactivity characteristics or do not contain constituents that are listed in Title 22, Division 4.5, Chapter 11, Article 4 of the California Code of Regulations eligible for injection into Class II wells. The exemption is found in 22 CCR Section 66261.24, which basically incorporates the federal exemption in 40 CFR 261.4, but with the following limitation: The exemption is valid if toxicity is determined solely due to the TCLP. If toxicity is established by criteria other than TCLP, or if the waste meets other characteristics of hazardous waste (ignitability, corrosivity, reactivity), the exemption does not apply.

A pertinent example is benzene dissolved in produced water. If the benzene exceeds toxicity concentration levels, the produced water would be considered a hazardous waste; except, the produced water typically do not exhibit any other characteristics of ignitability, corrosivity, or reactivity. Therefore the fluid may be excluded from California-hazardous waste and can be injected into a Class II disposal well.

Another example is tank-bottom material that may exhibit only toxicity levels that exceed the *de minimus* threshold. If so, the tank-bottom material may be injected into a Class II disposal well because of the hazardous-waste exemption.

It is the generator's responsibility to determine if the waste is hazardous or nonhazardous by testing representative samples of the waste using the methods set forth in Chapter 11, Division 4.5, 22 CCR and/or applying knowledge of the hazardous characteristics of the waste in light of the materials or processes used to generate the waste. The later means either the generator, hauler, or injection well operator may self-certify (Title 22, section 66262.11).

How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database the inspection data is stored in or attach the inspection verification documentation. On average, for the last ten years, ER wells have a routine inspection once every 5 years; SWD wells once every 3 years. Data stored in F:\data\access\2000\Fldtests.accdb.

Does once every 3 years also apply to commercial SWD wells? There are none in District 5 at the present time.

Is the operator given advance notice of inspection and does the operator receive a copy of the report? For routine inspections, an operator is often given notice that an engineer will be present on a lease. The operator receives a report of any deficiencies.

Describe the reporting and follow-up procedures used in the inspection program when there are violations. Field inspectors make a computer entry that the well was inspected and that there was a problem. For minor issues, the engineer sends a notice to the operator to correct the problem within 30 days. The engineer checks back on the well after the operator has indicated compliance or after the 30 days has passed. If the problem is corrected, the database is updated and the operator is notified of our approval. For serious issues, or for minor issues that remain uncorrected, the operator receives a phone call or e-mail followed by a letter. Both notifications will inform the operator that immediate action is required and will specify that action. Non compliance may result in shutting in the well, fines and issuance of a formal order to abandon the well. If the problem is corrected, the database is updated and the operator is notified of our approval.

How is the District notified of emergency situations regarding Class II wells and related incidents such as spills? Either by direct self reporting by the operator, inspections and discoveries by the inspectors, or by the public. Wells are required to be signed with an emergency contact number posted.

Is there a deadline for a formal written report of an incident and operator response, such as 24 hours? No.

For clarification, is the operator not required to submit a written report and/or is there no deadline for submitting a report of a spill or other incidents that require immediate corrective action? The District doesn't require a written report, only verbal. The District office generates a spill report for the County *(Fresno?)* and the County responds to a spill incident. The operator must also have a SPCC plan in place. A copy of the San Joaquin Valley Oil Spill Plan was provided.

What type(s) of emergency situations has/have been reported involving UIC permitted wells? Please list the ones you have received over the last five years, or the most recent examples. Have had steam breakthrough into abandoned or idle wells with steam/oil release at the surface. Also, uncontrolled steam release on active wells.

Where and when did these incidents occur? Please identify the wells/fields and describe the response to these incidents and follow-up actions by the District. All the incidents have occurred within the Coalinga field.

- 8/7/1987 – Shell well "Esperanza" 25, Sec. 6 20S/15E, (idle producer), steam exiting between casing strings. Operator plugged and abandoned well. Division witnessed and approved abandonment operations.
- 8/28/1987 – Steam exiting from ground, identified source as nearby Chevron well 9-1, Sec. 25 20S/14E, (active producer). Steam was exiting casing holes near the surface. Operator plugged and abandoned well. Division witnessed and approved abandonment operations.
- 6/10/1992 – Santa Fe Energy well "Penn-Zier" Z-11, Sec. 1 20S/14E (idle producer), steam exiting tubing, communicated through producing formation with nearby active

producers on cyclic injection. Operator cemented tubing in well and converted to observation. Division approved conversion operations.

- 8/4/2007 – Chevron well “Spinks Crude” 10-2C, Sec. 12 20S/14E, (active producer), tubing parted and steam broke through well at the surface. Operator replaced tubing.
- 4/7/2008 – Aera Energy well “Penn-Zier” 368, Sec. 1 20S/14E, (active SF), well blew in during workover operations. Operator killed well and returned to injection.
- 7/30/2008 – Aera Energy well 22-19, (active SF), Sec. 30 19S/15E, steam exiting corroded fitting. Operator repaired pipe.

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. An Access database contains most of the data (still being populated) for the districts wells. Scanned data and logs are available through this database. It keeps track of field tests, inspections and any deficiencies/violations. It is used to create inspection sheets, deficiency notices, and track compliance.

How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily accessible database? If not, how does the District verify compliance with the MASP? Pressures are compared during field inspections and by reviewing the operator’s injection reports (by computer). The MASP for each well is maintained in the database.

Please describe the actions taken when non-compliance is discovered or reported. The operator is contacted by phone/e-mail and reminded of their requirement. A formal letter may be sent if the infraction is significant (well above the MASP or multiple wells). Check back inspections are done to ensure compliance. If the operator does not comply the well(s) are ordered shut in.

Conclusions

A listing of the types of fluids approved for injection in Class II wells was provided (Appendix A7). We have no reason to believe that any of the state accepted fluids listed above would be disallowed for injection into a Class II injection well. However, drill cuttings are not included in the list of fluids eligible for disposal in the MOI at Section 170.2.3. It would be a CDOGGR and EPA decision to classify a particular fluid as eligible for injection into a Class II injection well.

The Division requirements for inspecting each permitted well, for other than MITs, at least once per year has not been attained in the past ten years, according to the District 5 response above. The MOI indicates that injection wells should be inspected annually. Active disposal wells were inspected once every three years and enhanced recovery wells once every five years on average over the past ten years, which is less often than required by the MOI and the two-year cycle described in the recent Division directives. The District may need to hire additional inspectors to achieve the inspection goals.

Advance notice of a lease inspection is often given to the operator. That could compromise the inspector’s ability to find violations since the operator would have the opportunity to prepare for an inspection and possibly hide violations.

Based on the description of those procedures in the above response, the reporting and follow-up procedures used in the inspection program appear to be adequate. Violations and their resolution are tracked in an Access database. Failure to correct a violation may result in a shut-in order, issuance of a formal order to abandon the well, and/or fines.

Most emergency situations in the past five years have been the result of steam breakthrough into abandoned or idle wells with steam/oil release at the surface, in addition to uncontrolled steam release at active wells. All incidents occurred in the Coalinga Field. Examples are cited above and all were corrected by actions such as P&A or well repairs.

The data management system available to field inspectors is an Access database which contains most of the data for District wells. It is used to track field tests, inspections, and deficiencies/violations and to create inspection reports, deficiency notices, and track compliance. The Access database will eventually be replaced by the CalWIMS System, which is the statewide system to be implemented in all of the district offices by the end of this year. The MASP for each well is maintained in the database and injection pressures are compared for compliance with the MASP by reviewing the operator's monthly injection reports and well *inspection reports. CalWIMS is considered superior to and more user-friendly than the current Access database system.*

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability. Annular pressure test or an RAT survey (if the well is permitted to operate without a packer) is acceptable.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? The well must hold 200 psi for at least 15 minutes with no more than a 10% loss.

Please discuss the basis for these criteria. It appears from the response that 200 psi is the standard rather than at least 200 psi. Is that accurate? How is the test pressure determined for individual wells if greater than 200 psi? The intent was to determine if the casing is intact. The higher the pressure, the easier it is to determine if there is a leak. 200 psi is a generic minimum pressure and should reveal a leak within the test period.

Has the District considered testing at the MASP, as discussed in the "expectations' memo of 5/20/2010? The District is waiting for further direction form HQ on this matter. Operators would probably lower the MASP in many wells in order to avoid damaging the casing, if this requirement is implemented as currently written.

If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required Not used

*If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail? N*ot acceptable

Are cement bond logs acceptable for determination of Part 2 MI and are they commonly run in new injection wells in your district? Were CBLs commonly run in existing injection wells in your district? No, cement bond logs are not acceptable. CBLs are run on fewer than half of the new injectors. CBLs are less common on older injection wells.

What criteria are used to determine Part 2 MI pass/fail if cement records or CBLs are not acceptable? Is the cementing requirement for zonal isolation of the injection zone from BFW and USDWs applied? For example, 500 feet of annular cement in post 1978 wells? Please discuss in the context of the 5/20/2010 Division memo. Cement records are evaluated for Part 2 mechanical integrity. Few CBLs were run in historical wells. More recent wells were cemented to surface. District 5 staff lacks confidence in CBL quality and interpretation. Lack of adequate cement is a common issue in older wells and will require remedial cementing for zonal isolation or the permit will be denied.

Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined? RAT surveys are the primary method. Static temperature surveys are used on occasion. We have not had occasion to order running special log suites. The Associate interprets the logs. If fluid is observed exiting into formations out of the permitted zone or into the annulus behind a packer the test fails.

Are wells evaluated for significant fluid movement from non-injection zones into USDWs in the casing/wellbore annulus? Rarely. Would probably use static temperature surveys to evaluate a well for fluid movement in the casing/wellbore annulus.

What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone? Wells are required to have a pressure test initially, every five years thereafter, and whenever the tubing/packer is moved. An RAT survey is required every five years for steamfloods, two years for waterfloods and every year for water disposal wells.

Are there wells tested more frequently than the standard cycle? Does the standard cycle vary depending on well condition or risk of fluid migration outside of the injection zone? No. The District formerly required twice the number of MI surveys in slim hole completions, but that has been discontinued. *Why discontinued?* The increased survey frequency was not catching any problems.

Describe the follow-up and typical enforcement actions for MIT failures. The operator receives a phone call or e-mail and is followed by a letter if shutting in the well is warranted. Both notifications will inform the operator that immediate action is required and will specify that action. If the well must be shut-in, a field inspection is performed to confirm. Non compliance may result in fines or issuance of a formal order to abandon the well. If the problem is corrected, the database is updated and the operator is notified of our approval.

Are operators required to report MIT failures immediately when not witnessed by a District Inspector? If not, how soon must it be reported? Yes, but not always reported. *What are the circumstances wherein a well that fails the MIT is allowed to continue injection?* A well with a packer/tubing failure in the Coalinga field may receive a variance to continue (it would essentially then be a slim hole injector).

Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed? Any of the engineers may witness MITs. For tracer surveys run since 2000, 93% of the WD surveys, 4% of the WF surveys and less than 1% of the SF surveys have been witnessed. A report is written and becomes part of the hardcopy well record and the database. The operator is required to furnish a log of the survey whether the well was witnessed or not.

In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate. The operator is notified by phone or e-mail, followed by a formal notice in the mail. If fluid is exiting into non-permitted formations the well is shut in. With a tubing or packer failure, within the Coalinga field, the operator may be given a variance to inject with a single string of protection.

Please clarify. Is a well shut in when: 1) a casing leak results in a MIT failure, 2) a leak in the tubing or packer causes a MIT failure? If no fresh water is present in the area, what actions are required to bring the well into compliance? A well is shut in when a casing leaks or there is fluid migration behind casing into a non-permitted zone. A well with a tubing/packer failure is shut in unless the well is within the Coalinga field and receives a waiver (SF and WF only).

Except for Coalinga wells receiving a waiver to inject with a single string of protection, all tubing and packer failures must be repaired and the well must pass an annular pressure test before injection may continue.

No USDWs in the Coalinga Field? Not sure but some areas have no shallow ground water.

Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures? A failed MIT within a fresh water area results in the well being shut-in by the DOGGR. The well must be repaired before it can again be utilized. A variance may be issued for tubing /packer failures in the Coalinga field, (the well is treated as a slim-hole injector).

If no fresh water is present in the area, what actions are required to bring the well into compliance? How much time is allowed to complete the repair and pass a MIT? Why are *variances issued for Coalinga field wells? Are variances to the repair requirement approved for tubing/packer failures in other fields or wells? Please describe the basis for the variances.* The requirements to bring a well that failed a MIT back to compliance are the same in areas with or without fresh water. There is no time limit to repair a well provided the well is properly shut in.

Variances may be issued to Coalinga wells to continue injecting with a failed tubing or packer since we permit injection on new SF and WF wells (slim holes) without tubing or packer. Coalinga field has no or very poor "fresh water" depending on the area. There are no similar variances for other fields.

Please explain the term "poor fresh water". Injection zone water contains less than 3,000 mg/L TDS but is exempted.

If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work? Normally we do not witness remedial work. A history of the work must be submitted within 60 days. Details of the work must be available to the witnessing engineer when the well is re-tested.

What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time? The failure rate for ER wells has been steady at 1%-2% since 1982, and ran 1% in 2009, (3 wells). The failure rate for WD wells has been more erratic, generally averaging 2%-4%, and ran 8% in 2009, (3 wells)

What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well? The project approval letters and general division regulations states that altering the casing of a well requires a notice to rework. Once the notice is filed the progress of the repair work can be tracked. The DOGGR requires certain aspect of the work be witness by DOGGR staff. Once the well is completed a written well history is submitted and stored in the permanent well file. *This response does not answer the question and may have been misunderstood. The operator would be required to shut in the well, but repairs would not be required unless USDWs were at risk of fluid inflow, according to my understanding of Division requirements. Such a well should be shut in and repairs made before injection is resumed or left in long-term idle status.*

Are notices and tracking required for tubing/packer failures, such as those indicated by excessive pressure on the tubing/casing annulus? Does that require the well to be shut in pending repairs and MIT? Please identify the aspects that require staff to witness the work. Tracking is required for tubing/packer failures. Formal notices are optional if the operator has already shut in the well. The well must be shut in pending a successful MIT. The staff will witness or review the MIT.

Do you mean a pressure test or RAT survey for the MIT? What percentage of these post-repair MITs are witnessed? Please discuss the procedures followed for monitoring, reporting, and correcting excessive casing pressures on the casing/tubing annulus. These MITs refer to pressure tests. Most MITs are witnessed, especially wells located in the Valley where fresh water is present. Pressure on the casing/tubing annulus is indicative of a MI failure and the operator must shut the well in pending a successful MIT.

Please describe the procedures for operator monitoring, reporting, and repairing a well when excessive pressure is observed on the casing/tubing annulus. What is the frequency of monitoring annulus pressure? Is the operator required to report the MI failure and the shut the well in immediately? If excessive pressure is seen on the annulus (or the tubing experiences a sudden pressure decline) the operator must shut the well in and investigate the problem. If there is a MI failure the operator must contact this office before injection resumes. There is no set frequency for monitoring the annulus pressure. If there is a MI failure the operator must shut in the well immediately and contact this office.

Responses to related questions indicate that the operator isn't required to repair a well when it fails MI. That would be a concern for possible fluid movement into a USDW through a casing leak when the pressure does not decline to zero or the pressure increases after an extended shut-in period.

Describe the data management system used in the various components of the MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure. The data management system tracks well permitting including required tests and submittal of records. All tests and field inspections, (including their results) are entered into the system. Periodic and follow-up testing is monitored. Reports are available to generate inspection sheets, deficiency reports, compliance reports, records due notices, well status inquiries, notification that periodic testing is due,

Conclusions

The SAPT requirements as described above are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in Sections 2.0 and 3.0 of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure. If a lower pressure were allowed, we would favor more frequent testing and/or monitoring of casing pressure.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. Increasing that to 30 minutes, however, would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes described above, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

CDOGGR has changed the SAPT standard to test at the MASP in wells where there is only a single string of cemented casing across a USDW (10,000 mg/L). I believe that will apply to a large number of wells since the historical construction standards applied do not require two strings of casing across a USDW. Based on my limited review of California injection well records and information gained in the responses to the EPA Questionnaire, two strings are *commonly set below the BFW in most recently drilled wells, but not necessarily to the base of USDWs.*

The District states that four percent of RATs in waterflood wells and less than one percent of RATs in steamflood wells since 2000 were witnessed. The percent of RATs in disposal wells witnessed since 2000 was 93 percent and most SAPTs are witnessed, according to District responses above. In our view, witnessing RATs in enhanced recovery wells should be given a higher priority, especially where USDWs may be present such as in parts of the Coalinga Field. Static temperature surveys are rarely run, but should be run more often in slimhole completions where USDWs are present and especially for USDWs that are protected by only one casing string and/or lack cement at the base of USDWs.

Wells that fail a MIT are usually required to cease injection immediately, but are not required to be repaired unless USDWs are potentially endangered while the well is shut in. That may be acceptable if a well fails a MIT due to a packer or tubing leak and the casing pressure declines to zero after shut in, however, one cannot be certain that a casing leak does not exist concurrently with a tubing or packer leak. If USDWs are present in a well with a casing leak, there may be a risk for fluid movement into a USDW or other zones that lack cement in the casing/wellbore annulus between the leak and the USDWs or other zones. The risk increases with time in idle status and pressure on the casing, as the casing integrity becomes less certain over time without passing an annular pressure test. Pressure increases during shut-in status are possible, especially in waterflood injection wells and disposal wells that are located within the ZEI/AOR of another injection well and injection zone pressure is allowed to exceed normal hydrostatic pressure.

Our understanding of the CDOGGR idle well requirements are as follows: a pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are required every two years after five years in idle status in fresh water areas and five years in non-fresh water areas, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. We believe that wells that lack MI should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area. We also recommend a casing pressure test be performed in idle wells rather than fluid level surveys unless USDWs are known to be absent in the area.

The discussion of the assessment of Part 2 (external) MI in District 5 wells is incomplete and somewhat confusing. In one response, it states that cement records and logging tools such as CBLs are not acceptable for the assessment of external MI, but in a later response, it states that cement records are evaluated for Part 2 mechanical integrity . Apparently, CBLs are not acceptable but other cement records are acceptable for evaluation of external MI. That seems consistent with federal UIC regulations, but in our view, CBLs are a part of the cement record when run and should be used for assessment of external MI, especially for locating the top of cement in the annulus. The calculated tops of cement in the annulus are subject to considerable error and much less accurate than CBL tops. In addition, we would recommend running CBLs in new and converted injection wells unless USDWs are known to be absent in the area.

State UIC regulations require adequate volumes of cement in the casing/wellbore annulus immediately above the injection zone, above hydrocarbon bearing zones, at the BFW, and behind surface casing. The presence of sufficient cement is determined by examination of cement records. Those standards should satisfy Part 2 MI requirements at least in part, but cement should be present at the base of all USDWs (10,000 mg/L TDs or less) for complete protection of USDWs. In our view, the presence of heavy mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

The recent Division directives to the district offices and the authorization to hire additional UIC staff should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

What types of enforcement tools and legal actions are available to the District for the UIC program? How often in the last five years have you used them? Please list these or the most recent examples. Order a well shut in, rescind a well for injection, terminate a project, order a well abandoned,, fines, legal action.

How often have you used them in the past five years? Please list the most recent examples. Raisin City well "Noble" W.I. 1 was ordered abandoned on July 7, 2007 after desertion by the operator (Big Valley Resources). Coalinga, East, Extension Well "Gatchell" 86-20 was ordered shut in and rescinded for repeatedly exceeding MASP. Please see comments below.

What types of formal enforcement actions have been taken relative to UIC violations in the District? Primary enforcement actions are ordering wells shut in and formal orders to abandon.

What types of formal actions have been initiated in the past five years? Coalinga, East, Extension Well "Gatchell" 88-20 was ordered shut in and rescinded for repeatedly exceeding MASP. Please comments below.

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. Injection may continue with a "paper" violation, subject to a time limit; the well is shut in for serious violations.

Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties? How many have you issued in the last five years? Please list these or the most recent examples. Notices of Violation are rare; deficiency notices are common. The last NOV was issued last year for repeated injection over MASP.

How many NOVs have been issued in the last five years? Please elaborate on the MASP violation and its resolution. One. On May 12, 2009 during a regular field inspection, the injection pressure on Coalinga, East, Extension well "Gatchell" 88-20 was 900 psi, 450 psi over MASP. The operator was contacted by phone to correct this and a notice was mailed. On May 28, 2009 the well was found again injecting at 900 psi – the operator was again notified by phone and letter and issued a warning. The well was inspected several times over the next month with no new pressure issues. On June 28, 2009 the well was observed injecting at 1000 psi. The well was ordered shut-in and was rescinded for injection.

Does rescission require a formal order? What is the process to rescind a well for injection? No. The well is shut in and disconnected when permission to inject is rescinded. A Notice of Intent (NOI) and DOGGR approval are required before the well can be reworked and reactivated.

What are the follow up procedures to assure compliance and correction of the violation? Frequent check-back inspections to monitor the well status and a testing the condition of the well before resuming injection.

How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV? A violation that would threaten a USDW is dealt with immediately. Either the well is shut-in or the problem is corrected on the spot. Generally 30 days is granted to correct paper violations.

How much time is allowed for remedial operations to be completed after the well is shut in? Remedial operations are not necessarily required after a well has been shut in unless USDWs are threatened. Permit to inject is rescinded after two years in idle status

How and when do UIC violations escalate from non-compliance into formal enforcement actions? When an operator performs willful violations, demonstrates an inability to correct the situation or abandons their responsibility.

What penalties have been assessed and collected on UIC violations in the past ten years? None

Please discuss the monetary penalties that can be assessed per day, per violation, and in total. Penalties are prescribed by regulation and law. Once a penalty is noted the district must follow the law and regulations. Individual districts do not have discretion on the monetary amounts. *What do the regulations and law prescribe?* Statewide requirement was $5000 per violation maximum, but has been increased to $25,000 per violation maximum. The District can recommend the amount to be assessed.

Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? The biggest problem we have is maintaining the disposal survey schedule. Many times the operator(s) will go a bit past the year time period for disposal well RAT surveys. It's usually due to a lack of available equipment and having enough work at a particular time to justify the scheduling of the surveys. We are working on the fix and that entails working with the operator and the service companies. We make the list of wells available to both the operators and to the service companies. Some of the smaller operators will work together and coordinate well surveys.

In addition, does the District have adequate resources in terms of staff and attorney support to provide adequate enforcement for the most egregious violations and enough field staff to witness most MITs and P&As? No. An additional Associate is needed and has been proposed by the District.

Conclusions

The enforcement procedures available to the District are highlighted in the responses above and are described in detail in the CDOGGR laws and regulations that apply to the UIC Program. Informal actions for noncompliance include telephone calls, written communications, emails, deficiency notices, shut-ins, and rescissions. District 5 has not initiated many formal enforcement actions in the last five years and no penalties have been collected in the past ten years. One well in the Raisin City Field was ordered abandoned after desertion by the operator. One NOV was issued in the past five years for UIC violations. That NOV was issued to the operator of the Gatchell 86-20 well, which was ordered shut in and rescinded for repeatedly exceeding the MASP. However, it was apparently permitted to resume injection in early 2010 but with restrictions on the injection pressure and a requirement for continuous recording of the injection pressure and an automatic shut-off device if the pressure exceeds the MASP.

Remedial operations are not necessarily required after a well is shut in unless the violation would threaten an USDW, and in that case the threat is dealt with immediately, according to the District response above and the MOI. Wells that lack MI but pose no apparent threat to USDWs can apparently remain in idle status at least 15 years without a requirement for repair or P&A. In our view, wells that are in violation for lack of MI should be shut in and repaired within three to six months, unless USDWS are known to be absent in the area.

The District staff responded that they do not have enough resources to provide adequate enforcement measures and enough field staff to witness most MITs and P&A operations. They have proposed the addition of an Associate in the District to address that deficiency.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public.

First, we very little experience in this aspect of the UIC program because we just have not had much problems. If we receive a report of contamination, we would immediately conduct an investigation. Most likely this would be a onsite well inspection. Notes would be taken, photo gathered etc. We would have contacted the operator and if appropriate we would probably would shut-in the well. Generally our records are open to the public, we do not withhold data if it is requested.

Once data is gathered ,the senior engineers in the office review the data and try to come up with a solution. Meetings with the operator are done if a solution is simple. If we sense criminal behavior on behalf of the operator, then we consult headquarters and move forward from there.

Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination? One alleged contamination incident was reported in September 2003. A landowner was concerned with the high TDS from a water well located near an active WD. The cause was determined to result from extensive surface disposal of produced water prior to the 1970s.

What actions are taken by the District when an alleged contamination report is received? In the incident presented above, the landowner was interviewed and water samples from his water wells were analyzed. The samples indicated he did have a problem. The disposal well was checked but no historical or current leakage was indicated. A check of historical data, old field maps indicated a water disposal sump used to be active near the problem water well. An old study by the water board showed contamination of the fresh waters from surface disposal at the site of the water well.

Please describe any remedial and enforcement actions taken related to the surface disposal of saltwater and resultant contamination of fresh water at the site described above. Unknown - this occurred over forty years ago and was handled by the water board.

How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? None for injection or abandoned wells.

Conclusions

The District states that there was one alleged and actual USDW contamination incident reported in the past ten years. The incident was reported in 2003 and the cause was determined to result from extensive surface disposal of produced water prior to the 1970s. An active water disposal well was located near the water well that was affected, but there was no historical or current leakage indicated. It was concluded that the contamination of fresh water was caused by a water disposal sump, located near the problem water well, which was used over 40 years ago for disposal of produced water. Remedial and enforcement actions are not known since they were referred to the RWQB, which is consistent with the MOA with the RWQB.

No contamination incidents due to injection wells or abandoned unplugged wells have occurred, according to District responses above. If one did occur, the District indicated that they would follow standard procedures outlined in the MOI, including a thorough site inspection, evaluation of any test results and site characterization studies, and a report to the operator and other interested agencies, with the support of Division headquarters staff. We have no major concerns relating to the above responses, except that there seems to have been a lack of coordination and follow up with the RWQB on the one incident discussed above. We are curious about the actions taken to address the remediation of contaminated ground water and disposition of the case.

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.). Please see attached regulations. *Are plugs required at the base of USDWs.* Plugs are required at the BFW, but not necessarily at the base of USDWs. BFW maps and electric log analysis are used to determine the BFW.

Are there UIC wells without surface casing installed? How are they plugged? Yes. Same as above. *Please describe the plugging procedure.* Usually these are shallow wells, with the production casing cemented to surface. Plugging is done as with any other well.

If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed? No special requirements.

Are plug depths verified? When and how? Are all plugs required to be tagged? Yes. After the plug has hardened sufficiently, tubing is lowered until the plug supports 2000 pounds or the tubing weight. Critical plugs (zone, BFW) are usually tagged. Witnessing placement (no tag) may be acceptable in cased hole.

Please clarify. Is the bottom plug not always tagged in cased holes? Are the casing and plugs pressure tested to ensure the absence of leaks? Please describe the procedure for finding and isolating casing leaks during P&A operations. On some shallow wells the operator may simply displace cement from TD to surface. On these we do not require separate tags on the zone or BFW plugs. If a zone plug is tagged low on an abandonment in cased hole, then we may accept witnessing the placement of the top off plug in lieu of a tag. All perforations must be covered, the well must hold pressure and the operator must pump at least 50% more cement than is calculated for the job. To test casing integrity during abandonment, the casing is pressured and monitored for loss (no set pressure or duration but usually a couple hundred pounds for several minutes).

What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations? 96% of required operations on UIC well plugging have been witnessed since 2000. The field engineer reviews previous unwitnessed operation when witnessing a test. The submitted history of a plugging is reviewed. *Please clarify. What type of test?* This refers to the environmental inspection at abandonment of the surface.

Describe the process used to get an idled and an orphaned well plugged. A formal order is issued to operator. Once the order is ignored the well is put on the orphaned list. When DOGGR funds become available the well is contracted and plugged and abandoned. The funding is decided on a priority basis each year.

How long after a well is classified as an orphan well is it typically plugged by DOGGR? It depends on funding authorized by the State for plugging orphan wells each year. Residential areas are a priority.

Does the District maintain an inventory of abandoned (orphaned) UIC wells? Yes. *How many wells are currently in the abandoned inventory?* No UIC wells. 10-15 production wells

Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund. The DOGGR has several funds to eliminate both idle and hazardous wells. The source of the fund is a well assessment.

Has the District collected bonds to plug abandoned wells? If a bond exists on a well and if the district has issued a formal order the bond is always pursued for collection, please note the bonding requirements for a well is prescribed by law and the district(s) have no discretion on the bonds. It is common practice to go after bonds (if present) when the Division goes to the trouble of plugging and abandoning a well.

How are the current plugging requirements different from those of 40 years ago? Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project?

The plugging requirements from 40 years ago are not substantially different. However, prior to the 1960s, fresh water plugs were not mandatory. This leaves a lot of wells that do not pass muster when reviewing an injection project.

What sort of corrective action has been required in those projects? Have applications been denied or withdrawn due to the unwillingness of the applicant to perform the corrective actions required for a permit to be approved? How often has this occurred in the past ten years? Please provide and describe examples. The wells must be entered to cement off the fresh water, or the operator must modify the project so that the wells are not affected. One application was withdrawn - Redbank Oil applied for a WD project in East Coalinga Extension. One abandoned well on a neighboring lease and one on the Redbank lease needed to be entered and plugs set across the BFW. Three idle/active wells on the Redbank lease needed a cement squeeze across the BFW in the annulus. The operator was unwilling to perform this work and dropped the matter.

Conclusions

District 5 applies the existing statewide P&A standards, which are discussed in Sections 2.0 and 3.0 of this report and are described in detail in the CDOGGR regulations and MOI. The recent

Division directive requires a zonal isolation plug for all wells within the AOR of an active injection project, which is a new and more rigorous requirement for protection of USDWs from migration of injection fluid out of zone in those wells. In addition, a cement plug is required at the BFW zones in injection wells, but not in other wells within the AOR of an injection well or at the base of USDWs in any well.

District 5 written responses are not clear about their adoption of the new requirement for a zonal isolation plug in AOR wells. We support the new directives and urge District 5 to adopt those for application in the District as soon as possible. However, the lack of a requirement for placement of cement plugs at the base of USDWs is a concern, and modification of P&A requirements in that regard would greatly enhance the protection of USDWs containing more than 3,000 mg/L TDS. In our view, the USDW plugging requirement should apply to all wells within the AOR.

The District states that freshwater plugs were not required prior to the 1960s, which results in many wells that do not meet corrective action requirements when reviewing an injection project. Division plugging requirements for AOR wells require a zonal isolation plug through and above the injection/production zones in those wells, but not a BFW plug, according to the recent Division directives. That seems to be inconsistent with the preceding District statement. District 5 describes a disposal well project application that was withdrawn because of the requirement for a BFW plug and squeeze cementing operations in some of the wells in the AOR of that project. We agree with the zonal isolation requirement, but recommend an additional requirement for placement of cement plugs at the base of USDWs in AOR wells and placement of cement at the USDW base in the casing/wellbore annulus in idle or active wells that lack cement at the base of USDWs.

District 5 states that most P&A operations are witnessed. That includes tagging cement plugs and cement squeezing operations, but may not include witnessing cement plug placement operations, as discussed in Sections 2.0 and 3.0 of this report. When P&A operations are not witnessed, District staff reviews the P&A report submitted by the operator to ensure compliance with P&A requirements. We have concerns about the absence of a CDOGGR inspector during cement placement operations, as discussed earlier in Sections 2.0 and 3.0.

District 5 follows the statewide Idle Well Planning and Testing Program in managing P&A of idle and orphan wells. There are no orphan UIC wells in the District at this time. Our concerns regarding the management of idle wells are discussed below and at length in the state level section of the report.

The requirement for adequate volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We would recommend that CDOGGR modify that procedure to require cement plugs at the base of USDWs.

Exhibit 180.3.4 in the Manual of Instructions provides guidelines for sodium bentonite plugging operations. The guidelines are applicable as field rules in the Bakersfield and Coalinga Districts, and elsewhere for gas exclusion . The use of bentonite plugs is contrary to federal UIC regulations, which require cement plugs in Class II injection wells. We requested that the Bakersfield office to explain the basis for the use of bentonite plugs in plugging operations, but have not received a full response to date (June20, 2011).

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well? We do not use this category. A well is active, idle or abandoned.

Do idle wells require MITs at the same frequency as active wells and must the operator demonstrate future utility for the well to remain in idle status? Does "abandoned" mean plugged and abandoned or orphaned without being plugged and abandoned? Does the term "idle wells" include wells that are shut in temporarily by the operator on a voluntary basis and wells ordered shut-in for lack of MI? Please elaborate on those categories. All idle wells, (producer or injector), have the same testing criteria. In areas of fresh water, the wells are tested every two years to determine if fluid in the casing is above the BFW. If so, an MIT is conducted. In areas with no fresh water the wells are tested every five years for fluid level or an MIT is run. Abandoned means plugged and abandoned. A well is considered idle only after it has not produced/injected for five years.

Wells ordered shut in have a specific problem that the Division requires the operator to deal with before injection may resume, (a Division witnessed test or inspection will be required). An operator may shut in and reactivate a well on their own as long as they keep the tracer surveys and annular pressure tests current.

Does the District require a mechanical integrity test to be run on a TA/idle well before it is approved for TA/idle status, periodically while in TA/idle status, and before reactivation as an injection well? N/A to TA wells. *See above response and the Idle Well Planning and Testing Program regarding idle well MIT requirements.* N/A.

Describe how TA/idle wells are tracked. How long may a UIC well remain in TA/idle status before being reactivated or P&A.? N/A to TA wells. *See above response and the Idle Well Planning and Testing Program regarding idle well tracking and other requirements.* Fluid levels are monitored in idle wells. If it rises above the BFW depth, a SAPT is required. A UIC well may remain in idle status indefinitely if in compliance with the Idle Well Program requirements. Three to five percent of noncompliant idle wells must be removed from idle status per year. An order can be issued by DOGGR to plug wells using the plugging fund when the operator fails to comply or deserts a well.

Conclusions

Temporary abandonment of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements are not as rigorous in terms of MIT, repair, and timely plugging. District 5 applies the statewide standards for management of idle and orphan wells,

USDWs are not adequately protected in idle wells in our view. Those concerns are discussed at length in Section 3.0 and in other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs, in our view.

PART VII: Comments

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

This was an extensive document to complete. We welcome the opportunity to meet with anyone to review our UIC enforcement/management process. We manage hundreds of wells and the paper work gathering is huge. Our main focus is maintaining the integrity of the program is regards to protecting fresh water areas, whether it be an enhanced recovery or water disposal well.

4.6. DISTRICT 6

This section is organized in seven parts to address questions and responses from District 6. Most parts are then organized by objective of the EPA Questionnaire, followed by a conclusions section where relevant. The last part is an opportunity for District 6 staff to provide their own comments. Each of the remaining six parts addresses one of the following topics:

- General considerations;
- Permitting and compliance review;
- Inspections;
- MIT;
- Compliance/Enforcement; and
- Abandonment/Plugging.

District 6 has a total of 181 active and inactive injection wells, which represent less than 1% of state injection wells. Table 8 provides numbers of wells by well type for both active and inactive wells.

Table 8. District 5 Injection Wells by Well Type for Active and Inactive Wells

Injection Well Type	GS	PM	SC	SF	WF	AI	WD	Total	% of State Wells
Active	104	-	-	-	-	-	26	**130**	**0.57%**
Inactive	41	-	-	-	-	-	10	**51**	
Total	**145**	-	-	-	-	-	**36**	**181**	

PART I: General

This part addresses UIC program organization for District 6, and interagency coordination and changes to the UIC Program.

UIC Program Organization

Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach. Attached. The Sacramento District is situated in the lower right hand corner of the Division Organization Chart. Hal Bopp is the District Deputy, Pam Ceccarelli is the Lead UIC Engineer, and the Field Engineers conduct MIT, wellhead, and facilities inspections as required. Data management is handled by headquarters staff, and public outreach is handled by Department of Conservation Public Affairs Office. Qualifications of staff are discussed later.

Comments: *Hal Bopp and Pam Ceccarelli, named above, left the CDOGGR District 6 office after responding to the EPA questionnaire. Tim Kustic was identified as the acting Deputy at the time of the on-site visit in October 2010. See the Division Organization Chart in the Appendix*

Interagency Coordination and Changes to the UIC Program

Attached are memoranda of agreements with USEPA, US Bureau of Land Management, and the State Water Resources Control Board. The Memorandum of Agreement with BLM does not apply to the Sacramento District, because there are no federal UIC injection wells, but I worked on it and it's got a big section on UIC.

Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes? There have been new reporting requirements implemented by USEPA over time.

Conclusions

Some of the most significant changes in the UIC Program are described in the Division Expectations Memorandum. The MOAs are included in Appendix A.

PART II: Permitting and Compliance Review

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the application flow process of the UIC program.

Who receives the application from the operator? (District or Headquarters office) District office

How and by whom are permit applications screened for completeness? Associate Oil and Gas Engineer prepares an application check list.

What are the procedures or protocols if an application is found to be incomplete? The applicant is contacted either by phone or via e-mail by the Associate Oil and Gas Engineer.

What are the professional qualifications required for staff who conduct permitting and compliance activities? Do those staff members meet the minimum requirements? What types of training would staff like to access if funds were available? Job specifications for Associate Oil and Gas Engineer and Energy and Mineral Resources Engineer (EMRE) are attached. Basically, an EMRE needs a degree in geology or relevant engineering, or must have equivalent experience, or experience as an Oil & Gas Technician combined with college level education. All Sacramento District staff meet the minimum requirements. Training desired by staff would include mechanical integrity testing, step rate testing, UIC documentation and calculations. The training that USEPA has provided has been valuable, and we could use more.

What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful? California Code of Regulations

(CCR), California Laws for Conservation of Petroleum and Gas (PRC), well files, well logs, Ca Oil & Gas Fields-Volume 3, UIC Manual of Instructions, "The Book", DOGGR maps. *"The Book" refers to the new requirements described in the "expectations" memo in addition to the existing standards for managing the Class II UIC program.*

Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal). No difference – application requirements are the same except the commercial is required to have information on their imported fluids. A commercial disposal well must have a $50,000 individual bond.

Does this require the operator to report the sources and contents of imported fluids? Fluid analysis and chain of custody procedures are required. A manifest is required of the operator of the source wells. Otherwise the requirements are no different from non-commercial disposal wells. Bonding amounts need to be increased, but it is a legislative issue and it hasn't been a priority of late.

Describe any differences between the processing of a waterflood project and a CO2 EOR project. N/A – District 6 has no waterflood or CO2 EOR projects.

Conclusions

A further review of commercial Class II disposal well requirements may be necessary to ensure that only Class II fluids are injected into Class II commercial disposal wells in District 6.

OBJECTIVE: Understand the current compliance/file review process.

What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy. Our understanding is that USEPA defines "file review" as the review conducted of a project that was in existence prior to a primacy agreement to assure that it conforms to current requirements. Based upon that understanding, there are no "file reviews" conducted, as this was all done back in the 1980's. We've gone ahead and answered this question based on some assumptions we've made about what the difference between a "file review" and an "annual project review" might be. What it amounts to is that when we receive any sort of Notice of Intent to work on a UIC well, we "review the file" in course of issuing a permit. Also, in conducting our annual project review, we "review the files" to make sure everything is current and in compliance. Files are reviewed when an operator sends in a Notice of Intention to rework the well, when a history is received, and/or when a MIT log is received. When a field engineer witnesses any work on the well and a T-report is written for the work that was witnessed, it is reviewed by the Associate Oil and Gas Engineer for compliance with the project approval letter.

Due in part to the small number of UIC projects in our district; we have never encountered any significant compliance, urban area, or proximity to USDW issues. While we haven't really discussed gas storage projects in the Program Review Questionnaire, we do have a proposed gas storage project going through CEQA review that will be located in an urban area. Gas storage projects are under close scrutiny already, so I don't anticipate additional monitoring or surveillance requirements other than the requirement for downhole safety devices.

Who performs the file review and what are the qualifications of the reviewers? The Associate Oil and Gas Engineer would review the files.

Over a one-year period, what percentage of total UIC permits/wells receives a file review? +/- 30%

How is the quality of a file review assured and subsequently documented? All information submitted for the file is processed by filling out a 'blue' sheet. When a MIT log is received, the Associate Oil and Gas Engineer also makes an entry to the database for the UIC program. The issuance of a permit to Rework is documentation that the permitting engineer reviewed the file.

When deficiencies are discovered during the review, what actions are taken to correct the deficiency? The operator is contacted via e-mail or phone followed by a letter.

How much time is the operator allowed to correct the deficiency? 30 days or less depending on the urgency for corrective action. Can be extended to 60 days if warranted.

How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually? District 6 reviews each well that is included in a project. Basically file and annual reviews are combined. District 6 can do this because most of our projects only contain 1-3 wells. 90%-100% project reviews are done annually.

Conclusions

District 6 has only 35 Class II injection wells to manage and only half of those are in active status. The District is able to review nearly all active projects annually and 30 percent of wells receive a file review each year. Annual meetings to review projects with operators were not discussed and it is not known whether those occur on a regular basis. Ideally, meetings should be held with operators to review compliance issues and other UIC matters, especially when there are ongoing issues to be addressed. Since there are so few wells in District 6, it may be possible to address those issues without regular face-to-face meetings with operators.

OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

The federal definition of USDWs (underground sources of drinking water) is found in the regulations at 40 CFR §144.3 which includes that an aquifer "...contains fewer than 10,000 mg/L total dissolved solids". Please distinguish when responses to questions pertaining to USDWs differ from the federal definition and describe how this difference is handled. This may apply to AOR/ZEI and MIT responses in other sections as well.

What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected? All wells have surface casing in the shallow zones which is cemented from the shoe to surface. Sometimes surface casing can go as deep as 2500' depending on the field rules. If the Base of Fresh Water is determined to be below the shoe of the surface casing, then an operator is required to cover the fresh waters with sufficient cement to fill to at least 100 feet above the base of the fresh water deposits. They can do this by cementing through the shoe of the production string with 125% of the volume of cement calculated to fill the casing/hole annulus from the shoe to 100' above the base of the fresh water deposits. Or, cement through ports set 50-100 feet below the base of fresh water deposits, with sufficient cement to fill 300' of the casing/hole annulus and cement bond logs (CBLs) are run and submitted to DOGGR. Note that DOGGR "Base of Fresh Water" (BFW) is defined as 3,000 ppm TDS. For the case of a UIC injection project, the USEPA defined USDW is also protected where appropriate.

Please elaborate on where USDW protection may not be appropriate. Is casing set and cemented through all USDWs? USDW protection is always appropriate. Casing is always set through USDW's but may not always be cemented in older wells. In that case, if a new project is submitted, the issue must be addressed. The USDW must be protected before a project is approved.

What is considered adequate protection of USDWs? Is it casing and cement at the base or just casing and mud in the annulus of wells that have adequate isolation from the injection zone? Cement is required at BFW, either behind surface casing or production casing. Mud is adequate protection if there is adequate volume of cement above the injection zone in AOR wells, until the well is abandoned. USDWs are adequately protected by mud if there is adequate volume of cement above the injection zone to isolate the USDWs from injection fluids.

What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected? Wells in District 6 have surface casings which are cemented to surface. If they are old wells with no cement on the back side of a production casing at the base of fresh waters, the cementing would be addressed during abandonment procedures. Operator would then be required to perforate the casing 50' below the BFW and squeeze 100 lineal ft. through the perforations with 100' of cement inside the production casing. Until abandonment on these wells, the USDW is protected by casing, packers and tubing. If the USDW also requires protection, we would require that it be cemented as well. This normally isn't the case, because you've got adequate cement lifted above the injection zone.

MIT/RAT survey testing, determines if there is any migration outside the intended zone of injection. These tests are done on an annual basis. If the well is a 5-year idle well, a fluid level test is required. If the fluid level is above the determined BFW, a casing integrity test is required. If the casing fails MIT, remedial work or abandonment may be necessary.

Please elaborate on the rationale for not placing cement at the base of USDWs during abandonment, if not placed during the conversion or later casing repair operations. Plugging for abandonment across the BFW, as opposed to the USDW, is consistent with California Code of Regulations (CCR) requirements. Abandoned oil and gas wells throughout the state are consistently plugged at this interface. Wherever there is an active UIC project, the need to protect the USDW would also come into play, and the lack of cement plugging across the USDW could impact a proposed UIC project where one did not exist.

What is considered adequate protection of USDWs? Is it casing and cement at the base or just casing and mud in the annulus of wells that have adequate isolation from the injection zone. Same requirements apply to converted injection wells as for new injection wells regarding cement at BFW and USDWs. Cement is required at BFW when AOR wells are abandoned.

What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field? Before project approval, DOGGR reviews all the wells within the AOR. If any are improperly plugged, completed or abandoned and penetrate the injection zone, they will have to be addressed for corrective action.

For the water disposal injection wells, DOGGR requires an annual radioactive tracer survey, and static temperature survey to determine that the fluid are confined to the intended zone of injection. Every 5 years, a casing pressure test is required on the injection well. Note that all District 6 fluid injection wells are classified as water disposal. There are no EOR projects in District 6.

Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well? Packers and tubing are used in District 6 for all water disposal wells.

Are dual (multiple) completions permitted? What requirements are different than single completions? What types? Yes, dual completions are permitted. If there are dual completions, the requirements are the same. There are no dual completion injectors in this district, however.

How are the locations of USDWs determined? Knowledge of the stratigraphy and subsurface conditions in the project area. Information is obtained by electric logs (e-logs) run in open hole of other wells drilled in the area, or determined from the Federal Department of the Interior BFW groundwater map and/or CA Oil and Gas Fields, Vol.3. *Does the District consult with other state and federal water resource agencies regarding USDW information?* If the proposed aquifer has fewer than 10,000 mg/L TDS and is an aquifer that has not been exempted by the EPA then an aquifer exemption is necessary. It is initiated by DOGGR to the EPA. For every project, the local RWQCB is notified. Note that District 6 has not been required to apply for an aquifer exemption, as all injection zones have been exempt as hydrocarbon productive and/or non-USDW.

How is the adequacy of the confining zone/system determined? Reservoir characteristics, reservoir fluid data, casing diagrams, structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area, an Isopachous map of each injection zone or subzone, at least one geologic cross section through at least one injection well in the project area, e-logs, characteristics of the cap rock.

If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated? The Associate O&G Engineer reviews the project, looking at all the wells in the AOR– and all the submitted data, and if there is uncertainty, the Associate will contact the operator to discuss and to obtain possibly more information which may consist of further testing or remedial work by the operator. It is important to note that if uncertainty remains, we would not approve the project.

Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well. DOGGR receives production/injection information on a monthly basis from the operator. On an annual basis, each well is visited to perform an environmental inspection to evaluate environmental compliance and pressure monitoring purposes. At that time the pressures are taken from the gauges at the wellhead and compared to the approved MASP. Also, during the MIT testing; flow, pressure and facilities are checked. All the observed data is compared to reported data to ensure operator is complying with project approval, P reports and other requirements.

Does this monitoring and reporting include observation or measurement of annulus pressures? The operator is not required to report annulus pressures unless a MI failure is evident from monitoring annulus pressure during operations. The well must be shut in pending repairs if that is the case. DOGGR inspects the annulus pressure during annual MIT surveys. The casing valve is open during RAT surveys, which will reveal excessive pressure on the annulus.

How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose. Due to known stratigraphy and subsurface condition in District 6, a standard 0.8 psi/foot gradient is used to calculate MASP. We use a gradient of 0.465 for salt water – subtract from 0.8 and multiply by the depth of the top perforation. We don't consider friction loss in our determination. Step rate tests are required if the operator wants to possibly inject at a higher pressure than the MASP and need to prove to DOGGR that they will not be going over fracture gradient.

When a step rate test is performed the operator starts from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first.

Please elaborate on how the standard 0.8 gradient was established for wells throughout District 6. Is it based on step-rate tests or other pressure data, or on other calculations? The 0.8 psi/foot gradient has been a statewide/central valley standard. In my experience with the Bakersfield District (1975-2003), step rate tests conducted for water disposal projects were in line with the 0.8 psi/foot gradient. We have had one new water disposal project approved during my one-year tenure with this district. The step rate test conducted for this project determined a fracture gradient of 0.6 psi/foot. The project is completed into the Hamilton & McCormick zones, in Maine Prairie gas field, with perforated intervals between 5,300'-5,700'. The operator should have no difficulty injecting anticipated water volumes at the MASP based upon 0.6 psi/foot.

Are step rate tests required of all new injection wells in District 6, and are you implementing the SRT standards discussed in the Division "Expectations" memo of May 20, 2010? Have SRTs been conducted in existing wells in the District? Have you considered adjusting the 0.8 psi/foot standard downward in view of the 0.6 psi/foot gradient established from a SRT in the new WD project discussed in your response, or is the injection zone not representative of other disposal wells in the District? Yes, SRTS are required of all new injection wells in District 6 in accordance with the "Expectations" memo of May 20, 2010. See DOGGR publication MO13 for historical basis for 0.8 psi/foot fracture gradient, The SRT results in the well described above are not accepted as representative because the test was performed using rig pumps. The well will be retested using service company pumps and technology. The standard historical gradient of 0.8 psi/foot may need to be adjusted in light of more recent SRT data in the basin.

Conclusions

As discussed in Sections 2.0 through 4.0, USDWs containing more than 3,000 mg/L TDS are not fully protected from fluid movement in injection wells and AOR wells in which the casing/wellbore annulus is uncemented at the base of USDWs. Heavy mud alone does not provide adequate assurance of total suppression of fluid movement in the annulus, especially in older wells wherein the mud has degraded over time and lacks the density and other properties necessary to prevent fluid movement.

In our view, CDOGGR should consider modification of cementing requirements to require placement of cement at the base of all USDWs penetrated by a well, not just at the BFW (3,000 mg/L or less TDS) zones, above the injection zone, and behind surface casing. That should apply to wells converted to injection as well as new injection wells and wells located within the AOR of an injection well when casing repairs occur or when the AOR wells are plugged and abandoned. Monitoring to ensure zonal isolation may be an option for corrective action in certain situations if the District has sufficient staff to properly monitor and regulate those wells.

The historical fracture gradient assumption of 0.8 psi/foot for District 6 is possibly higher than the actual gradient in some wells, based on a review of available SRT data in the state and the other data presented in CDOGGR Publication M13. District 6 has required very few, if any, SRTs in the past. We understand that step-rate tests will be required in new and existing wells where fracture gradients have not been determined from historic SRTs when the Division directives are fully implemented at the district level. We support that directive, with the recommendation that bottom hole as well as surface pressure gauges be used in SRTs. Bottom hole pressure measurements remove the uncertainty of friction loss estimates during a test and provide a more accurate measure of formation fracture gradient. District 6 confirmed that SRTs will be required of all new injection wells in the District in accordance with the Division Expectations Memorandum. However, SRTs in existing wells were not included in that confirmation. If fracture gradients in existing wells are based solely on the assumption of 0.8 psi/foot, we believe that SRTs should be run in those wells if none have been run in those or nearby wells in the past.

A sampling of wells were reviewed for exceeding the MASP (based on a 0.8 psi/foot fracture gradient assumption) and pressure failing to fall to zero when shut-in. One of the wells exceeded the MASP in one month, but the injection pressure dropped below that in subsequent months. None of the well records reviewed indicated that the MASP was exceeded.

OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

How is the Area of Review (AOR) determined for enhanced recovery wells or projects? N/A - No enhanced recovery wells in Dist. 6

How is the AOR determined for saltwater disposal wells? District 6 uses the fixed radius method – a standard ¼ mile determination.

How is the AOR determined for commercial saltwater disposal wells? Same as above.

How is the AOR determined for CO2 EOR wells? N/A

How are AORs determined for area permits and other multi-well projects? ¼ mile around each injection well.

Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? No. *If not, are they performed for all disposal well permits? No. What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved?* None in District 6. *Is there any time period since the UIC program was approved when there were notable increases or decreases in ZEI determinations – please describe?* No

Please discuss why the ZEI calculations are not performed in District 6. The number of wells involved in a standard area of review are so small in the District, that the conservative approach of checking all wells in that standard area for potential avenues of migration is considered the conservative approach.

Is this practice consistent with the 5/20/2010 Division memo? It would seem that the ZEI may exceed the quarter-mile radius AOR standard in disposal wells that inject into undepleted oil or gas reservoirs or non hydrocarbon bearing zones. Do any wells in District 6 inject into such reservoirs or zones? If so, which ones? Most, if not all disposal wells inject deep depleted gas reservoirs. Disposal reservoirs are generally non-contiguous sands of limited areal extent. The Lodi WD #1 and #2 wells inject 2-3 months per year into undepleted zones. The Wild Goose # 1WD well is another well that injects into an undepleted zone but the well is located outside of the field boundary and there are not many wells in the area. *Based on this response, we can't be sure that District 6 ZEI calculation policy is totally consistent with the Division expectations memo.*

Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects. It is submitted by the operator with a project application

Is it not a requirement for the operator to measure and report static reservoir pressure on a periodic basis during the life of a well? Are there no fall-off test requirements? Pressure fall-off tests have not been conducted in this District. As a general response to Part II, the following applies to this District. The Sacramento District comprises the natural gas fields of Northern California, some low volume oil fields mostly in the La Honda area, and some significant gas storage projects with related water disposal projects to inject the small volumes of water resulting from dehydration operations. Of the 35 total water disposal wells in this District's inventory, there were 18 that were active in month of April, the most recent reporting month. These 18 wells injected at an average rate of 180 barrels of water per day per well. There are no high-volume water injection wells, and all of the injection wells inject at pressures well below MASP. This District has never seen any evidence of pressure buildup in the water disposal wells that are regulated, not surprising due to the low fluid injection volumes. There are no high volume/high pressure wells, enhanced recovery wells, wells injecting into confined aquifers, or a multitude of other issues that confront the other Districts.

Does the pressure in any wells fail to fall to zero after an extended shut-in period? Would that be concern to the District? Which wells fit that description, if any? None are known to fail to fall to zero in District 6. It would be a concern to the District if that were not the case.

Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples. No evidence of this problem in District 6. Injection pressures are monitored during MIT's and reviewed at annual reviews. In large part due to the relatively low volumes of fluid injection in District 6, there has never been evidence of reservoir pressure buildup. *Please describe the limitations that would be imposed to prevent the static pressure from exceeding the normal hydrostatic pressure of the injection zone over the life of a disposal well if this were to become a problem.* For this District, the follow-up request is speculation. I would imagine that we would shut-in a project where hydrostatic pressure was exceeded. I can't imagine a scenario in the District with an imperative to keep such a project operating.

What projects/wells have shown significant static reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR? None

Have there been any reservoir pressure increases - significant or not - in any of the District 6 fields or reservoirs? Please clarify if data is not available. Data is not available, because we have never had any reason to suspect reservoir pressure increases.

How does the District measure and monitor static reservoir pressures to ensure that hydrostatic pressure is not exceeded? Injection and shut-in pressures are monitored. Fall-off tests could be run if that became a concern.

Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of *the permit?* Yes. *Please list the most recent examples*. Operator wanted to start a drilling mud disposal project – but in reviewing the 5 wells within the AOR, there was no cement behind casing through the zone of injection. The operator was contacted about the problems and then chose to stop their proposed project.

When and where did this occur? Can you provide other examples? 2009, Grimes gas field. A recent proposed project, Central Valley gas storage project proposal in Princeton gas field (depleted), includes two wells that will require remedial work before injection approval. The project application is being reviewed presently.

Please discuss this project and the remedial work that will be required for project approval. The Grimes Gas Field project was for mud disposal but an application was never submitted. In the Princeton gas field project, remedial cementing to repair casing will be required in one well. The other well was plugged and abandoned properly. These two wells are proposed gas storage wells. An application for a water disposal well will be submitted for the project later.

How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee? The project operator is responsible to remedy the wells in question. They are responsible for contacting the offset operators. We can assist the operator in making contacts; however, if the wells in question cannot be remedied, the project cannot be approved.

Conclusions

ZEI determinations are not performed for District 6 injection wells. AORs are based on a quarter-mile fixed radius from the injection well. There are no enhanced recovery wells in District 6. In disposal wells, reservoir pressure will increase unless more fluids are produced from the reservoir than are injected over the life of a well, which is usually the case where disposal is into a producing reservoir. Reservoir pressure will increase in depleted and other underpressured reservoirs, however, if there are no withdrawals from the reservoir over the life of a disposal well. That increase could eventually cause the reservoir pressure to exceed the normal hydrostatic pressure of the USDWs and lead to the ZEI exceeding the fixed radius AOR.

Where injection is into a depleted or producing zone, the fixed radius quarter-mile AOR may be appropriate, as is apparently the case in most of the District 6 disposal wells. A ZEI analysis should be performed for all disposal wells, however, to determine whether the quarter-mile AOR is appropriate over the life of the project. The District 6 practice of monitoring static reservoir pressures to ensure that they do not exceed hydrostatic pressure should reduce the risk of exceeding the AOR. This may not be the case, however, where the static pressure of USDWs is less than the normal hydrostatic pressure, which can occur due to pumping the aquifer over a prolonged period and/or natural causes.

The standards described in the Division Expectations Memorandum had not yet been implemented in District 6 in October 2010. Problem wells outside of the quarter-mile AOR but within the possibly larger ZEI were not addressed in the past. With the full implementation of this procedure, those wells will be subject to corrective action considerations, and protection of USDWs will be significantly improved. We fully support the Division requirement to review

ZEI/AORs and require corrective action as a condition for issuing permits for new drills, redrills, conversions, and return to injection operations.

The District indicated that standard fall-off have not been run in District disposal wells, but could be run if static reservoir pressures exceeded hydrostatic pressure while a well was inactive for an extended period. Monitoring shut-in pressures may provide the necessary reservoir pressure data to limit pressure buildup and ensure that the pressure front is contained within the AOR. Where shut-in pressure fails to fall to zero in a timely fashion, FOTs could be run to determine the static reservoir pressure. The MOI at section 170.7.1.1 states that, in most cases, a pressure FOT should be conducted periodically on water-disposal wells to ensure that the zone pressure is below hydrostatic. We concur with that statement, but recommend that bottom hole pressures be measured in addition to surface pressures during a FOT. Not exceeding the hydrostatic pressure in overlying USDWs should be the goal, rather than the hydrostatic pressure in the injection zone, however, because the USDWs may be underpressured relative to the disposal zone. That can occur where the USDW hydrostatic head has been reduced due to pumping and/or natural causes.

OBJECTIVE: Understand the administrative permit application components.

Describe the public notification and participation process for applications under consideration by DOGGR. After a cursory review is made by the Associate Oil and Gas Engineer, and no aquifer exemption is required from EPA, then a letter is sent to the RWQCB notifying them of the new project for review and comment – While waiting for comments (14 days) the project is reviewed in detail and if everything looks good, a draft approval letter is written and sent to RWQCB. At that time a legal notice is placed in a local newspaper to run three consecutive days allowing the public 15 days to comment. If no comments are received, the final approval letter is sent to the operator with a cc: to RWQCB.

When and where is public hearing opportunity held on an application and how are they conducted? When was the last public hearing held in your District? Please list the most recent examples. Depending on the issues, either a response in writing is sent or a public hearing would be heard in a convenient location near the project area.

Have any hearings been held in the past ten years? None

What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed? No bond is required with the UIC application. However, if a well is drilled, redrilled, operation permanently altering casing or converted, then financial assurance is required. The bond amount is determined by the depth of the well. Note that individual well bonds are released once the well has been successfully completed to production or injection for a period of six months, or has been successfully plugged and abandoned. A blanket bond can be used for these operations.

For a commercial Water disposal well, a $50,000 indemnity bond is required until the well is abandoned. A blanket bond may be used in lieu of the bond. However, only one Class II commercial well may be covered by a blanket bond. Additional Class II commercial wells must be covered by individual bonds of $50,000 each.

Is the applicant required to provide a P&A cost estimate? Is it based on third party estimates? Please clarify: Are bonds or other financial assurance mechanisms not required to be in place until a well is successfully plugged and abandoned. No. The bond amounts are set in statute. Also, since we regularly contract for plug and abandonment of deserted wells, we have a pretty good idea of plugging costs. Bond coverage is required until the well is successfully plugged and abandoned, and the site remediated at which point the bond is released.

It appears that bond coverage is required until a commercial disposal well is successfully plugged and abandoned, but is required only for six months after injection has commenced in a noncommercial disposal well, or the well has been plugged abandoned. Is that correct? That is correct, but must be six months of continuous injection. Plugging costs for orphaned non-commercial disposal wells are funded by an assessment on production of $.11 per bbl of oil or 10,000 mcf of gas, which varies from year-to-year.

Conclusions

The administrative permit application components are essentially the same statewide and are described in the MOI. We expressed our concerns about the financial assurance requirements in Section 3.7.

OBJECTIVE: Understand the process for aquifer exemptions

How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests? None

How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials? None

Conclusions

See Sections 2.0 and 3.0 for more information on the aquifer exemption process at the state level.

<u>PART III: Inspections</u>

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand how field operations are conducted and managed by the District.

Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas. Other high priority areas could be *located where injection operations are in close proximity to USDWs and/or drinking water aquifers.*

We have no UIC projects located under existing or planned residential areas, or other high priority areas. We do have a gas storage project going through the CEQA review process, with the California Public Utilities Commission acting as lead agency, that would be located adjacent to and underlying a residential area; however, gas storage is not UIC.

Please identify wells that are drilled through fresh water and/or USDWs. Essentially all wells in the District penetrate fresh water and USDWs. The Humboldt and Half Moon Bay wells may be the exceptions. Wells in the Brentwood and Rio Vista Fields are located in or near residential areas.

How are inspection priorities determined? District 6 tries to get all environmental inspections on a yearly basis as required under CCR Sec. 1722, Secs.1770 - 1779. Disposal wells are required to be tested on a yearly basis and during the testing, the field engineer will also perform an environmental inspection of the site.

What professional qualifications and/or experience are required by DOGGR to be an inspector? Qualifications for the Energy and Mineral Resources engineer and above positions. *Do District staff have the necessary qualifications and/or experience?* Yes. *What types of training do inspectors access or would like to access if funds were available?* Specific to UIC, additional training provided by USEPA, as discussed in Part II above would be helpful.

What tools do the inspectors utilize? Are there additional tools that you can identify that would be useful? Laptop computers, maps, vehicles, cameras, well data, approved MASP, inspection forms, Manual of Instruction, PRC and CCR's. Additional software to provide additional mapping, well file, production and injection records, and project file information to engineers directly in the field would always be useful.

Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training. Initial training is done by new field engineers accompanying experienced engineers. Training of new field engineers is accomplished with the assistance of an EMRE Training Manual/Checklist. The Manual of Instruction, Desk Manuals, laws and regulations are available. Operators have been helpful in describing their operations and equipment; classes are available on safety, equipment, DOGGR programs.

What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process? If a deficiency is noted, a Deficiency letter is sent to the operator to correct within 30 days. If during a field inspection follow-up, it is noted that the deficiencies are not corrected, a Notice of Violation is sent to the operator giving them 30 days to correct. If the correction is not done in the time allowed, then an Administrative (Civil) Penalty may be assessed – then if the violation is not corrected, the well can be ordered abandoned. For a flagrant violation, such as unauthorized injection, an immediate Notice of Violation and Cease and Desist Order could be issued, and an Administrative Penalty administered. If the operator does not comply, along with Administrative Penalties a Formal Order could be issued to conduct specified work on the well. The Division can conduct this work and assess the operator if necessary. If there were a hearing resulting from an appeal to either the Administrative Penalty or the Formal Order, the inspector would be fully involved in both the development of the enforcement action and providing testimony at the hearing. District 6 has never had a UIC-related case advance to the point of Administrative Penalty, Formal Order, or a hearing process.

Conclusions

Injection wells apparently not prioritized for inspections based on proximity to residential areas or areas where USDWs are present. Essentially all wells in the District penetrate fresh water and USDWs and none are located under existing or planned residential areas, with the possible exception of the Brentwood and Rio Vista wells. All Class II injection wells in District 6 are permitted for disposal operations. Some are associated with gas storage projects. It is District policy to conduct inspections on all wells on an annual basis and the District attempts to witness all permitted tests.

The professional qualification and/or work experience requirements for District 6 UIC inspectors are similar if not identical to those in all districts. A combination of formal training and on-the-job work experience is provided to new employees. Training and qualifications of inspectors appears to be adequate in most areas, based on District responses and discussions with staff at the District 6 office. More training may be needed in MI testing, step rate testing, UIC documentation and calculations, especially for new and recent hires. The training that USEPA has provided in the past was described as valuable, and more of that could be helpful.

We were informed that the Division has authorized the employment of several additional UIC staff members statewide. That increase in staff should significantly improve the District's ability to implement the recent Division directives with regard to field operations in all districts. Replacement of the District Deputy and UIC Lead Engineer, both of whom retired in 2010, with highly qualified people should be a high priority and we assume that to be the case. Their replacements may create other vacant positions to fill as well, whether in District 6 or other Districts or at the Division office. We were informed by various district staff and understand why the hiring of qualified staff from industry or academia can be a difficult challenge. The primary reason for that is that salary levels in CDOGGR positions are well below the industry levels for qualified engineers and geologists. Increasing CDOGGR compensation amounts may be necessary to attract qualified candidates for the vacancies and the new positions authorized in the Districts.

OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District.

Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations. With the exception of some gas storage project water disposal projects, all water disposal projects in the district inject produced water only. The gas storage water disposal projects include some non-hazardous chemicals related to dehydration and corrosion inhibiting.

How often is each UIC permitted well inspected for aspects other than MITs? Once a year. *Class II ER vs. SWD wells?* We only have SWD wells in District 6. *Please reference the database the inspection data is stored in or attach the inspection verification documentation*. UIC database updated by the Associate Oil and Gas Engineer

Is the operator given advance notice of inspection and does the operator receive a copy of the report? Sometimes, but more commonly there is no advanced notice of inspection – an operator will receive a copy of the report only if a deficiency is noted.

Describe the reporting and follow-up procedures used in the inspection program when there are violations. See Inspections discussion above.

How is the District notified of emergency situations regarding Class II wells and related incidents such as spills? Each company should have a spill contingency plan – they will follow that. OES is notified, and DOGGR is notified either by the operator or OES. If the incident is major, a District 6 field engineer will perform an inspection of the site and document findings. The incident report is handed over to the District Deputy for further review and determination if further action is required. OES has been replaced by the acronym CalEMA, which is the California Emergency Management Agency.

What type(s) of emergency situations has/have been reported involving UIC permitted wells? None.

Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations. All UIC wells have a hand drawn map in a binder near the well file cabinets – also, a UIC database is updated to reflect all current information and is accessible to all engineers.

What kinds of data are maintained in the database? Well name, location, MASP, date of survey, date of project reviews, project review documents, field testing reports, status (Active/Idle), casing pressure test date, zone of injection, and deficiency issues, letters to operators, commercial/noncommercial, and remarks. *The District staff provided a demonstration of the database during the office visit.*

How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? There should be adequate, calibrated pressure gauges on the wellheads, and during an inspection, the inspector will have MASP data with them. If the well is active and there are no gauges on the wellhead, the company will be contacted to have a gauge accessible to take the reading. The pressure reading at the wellhead is then compared to the approved MASP.

Also, during the annual RAT surveys, these pressures are noted. *Do all the injection wells have approved MASP values in an easily accessible database?* Yes.

Conclusions

Inspections are conducted yearly on all wells in District 6. Advance notice of an inspection is uncommon, but the operator will receive a copy of the report if deficiencies are noted. We believe that copies of an inspection report should be given to the operator whether deficiencies are found or not.

According to District 6 responses above, no emergency situations have been reported involving UIC permitted wells. In the event they do occur, procedures for notification and response to emergency incidents are also described above.

The UIC database in use in the District is described above and was demonstrated during the on-site visit. It includes the approved MASP for each well, which is compared to the injection pressure on a well during an inspection. The database appears to be more than adequate for managing and tracking the few disposal wells in the District.

PART IV: Mechanical Integrity Testing

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability. District 6 requires a combination of radioactive tracer survey, static temperature survey, and Standard Annular Pressure Testing (SAPT) to test MIT.

What criteria are used for the pass/fail of a pressure test and why were these criteria selected? At least 200 psi for 15 minutes with no more than 10% bleed off - these criteria has been determined by the Division Injection Surveillance Committee (ISC), after review and acceptance by Division Deputies.

What determines the actual pressure applied in a well? Is there any correlation of the test pressure with the MASP or maximum operating pressure for an individual well? I assume we are talking about the SAPT casing pressure test generally conducted on the "backside" tubing/casing annulus. In that case, there wouldn't be any particular correlation with the MASP or actual injection pressure. Pressure on the "backside" would be zero, or whatever the column of fluid in the annulus was.

Yes. I am referring to the SAPT required every five years and after well workovers when the packer is unseated. Are District 6 SAPT procedures consistent with the "expectations" memo?

If not, do you have plans to modify procedures in accordance with that memo? The SAPT requirements described in the memo will be implemented in District 6. Another version of the memo will be issued soon, but mostly for clarification. No major shifts in policy are contemplated. The Division will take a more active role in monitoring District compliance with the policy changes described in the memo per Tim Kustic.

If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? N/A *Is an initial pressure test required?* Yes.- prior to injection. *How many times in the last five years has failure of MI been identified by APM?* We have absolutely no evidence of there ever being a case of mechanical integrity failure being identified by annular pressure monitoring; however, it would be possible for a case to be handled by the operator – and documented in a submitted well history if work was done on the well.

If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail? CBL – is the casing cemented behind pipe? Yes or no.

Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined? Temperature Survey and RAT Survey logs. The field engineer witnessing the test determines if surveys have passed or failed while witnessing the tests. If the tests have failed while engineer is on location, the operator will be asked to shut in the well.

If the tests were not witnessed by DOGGR engineer, the log is submitted by the operator and reviewed in the office. If a log is submitted without adequate information the Associate O&G engineer will contact the operator for more details or if still inadequate to prove MI, a new MIT be run within 60 days.

If the log shows a failure, the Associate O&G engineer will call it a failed test and require the well be shut in within 24 hours and to repair the well within 60 days.

What is the priority schedule of wells to be tested? All water disposal wells are to be tested annually. *Are there wells tested more frequently than the standard cycle?* Sometimes – depending on the availability of the logging trucks for the operators. *What is the standard cycle for SAPTs and does it vary depending on well condition or risk of fluid migration outside of the injection zone?* SAPTs are required every 5 years unless the operator does a rework and/or resets a new packer.

Describe the follow-up and typical enforcement actions for MIT failures. If the situation is an immediate danger to USDW, then the well is ordered to be shut in within 24 hours and to be repaired within 60 days. A notice of Intention to rework and a permit is required before work commences. If the operator fails to repair the well within 60 days, the permit may be rescinded and the operator is ordered to shut-in the well within 24 hours (if still active), disconnect the injection line at the wellhead within 10 days and notify the appropriate district office when the injection line has been disconnected. If the well is not repaired within 120 days, the permit WILL be rescinded.

How much time is the operator allowed after rescinding a permit before P&A is required? Here's where I think there's a distinction between USEPA and DOGGR. Once the UIC injection permit is rescinded, that well is no longer part of the UIC system, as far as DOGGR is concerned (although it is still carried as a "Shut-in" or "Idle" injection well for database purposes). Once the injection permit is rescinded, the well is considered shut-in, unless it is returned to production or, with a new permit, injection. If the well remains shut-in for a period of five years, it is defined by statute as an "Idle Well" and it enters the idle well system where it must be periodically tested for mechanical integrity, and be subject to the other provisions of PRC Section 3206. There is really no distinction made regarding the past history of the well at this point, it's an Idle Well, plain and simple.

There are definite differences between USEPA and DOGGR requirements for idle injection wells. Injection wells that are inactive for two years or more are considered temporarily abandoned and must be plugged and abandoned unless the operator demonstrates that the well will not endanger USDWs while in TA status and the well has future utility. MIT and other UIC requirements are the same as for active wells. The UIC permit remains in force unless terminated for cause, but the operator must notify EPA and perform a MIT before resuming injection. In any event, an injection well cannot remain in idle status indefinitely. EPA can require P&A if the well isn't activated in a reasonable period of time, either as an injector or producer. If the well fails a MIT, it must be repaired or plugged within a certain timeframe unless an extension is justified and approved. Bonding must continue until the well is plugged and abandoned or converted to production status, If converted, BLM or the state agency assumes full regulatory authority for the well. Bonds often do not cover the full cost to P&A a well and EPA has no alternate funding mechanism, such as CDOGGR and other states have for plugging orphan wells.

Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed? District 6 witnesses 80% of temperature and RAT surveys, sometimes will witness casing pressure tests, depending on the situation. If it is a rework, the operator runs the test and submits the documentation in a well history. If an annual RAT survey is waived, the operator is required to send the logs to the District office – and they will be reviewed in the office by the Associate O&G Engineer.

What situations do not require witnessing of casing tests and what percentage of casing tests are witnessed? All required SAPTs, basically the SAPT that is required every five years, include the requirement to be witnessed. The only occasion in which an SAPT would not be witnessed would be due to the unavailability of an inspector, and at least 80% of these would be witnessed.

In the event of MIT failure, how is the operator notified to shut the well in. DOGGR is usually on location and will order the well shut in. Additionally, a written order will follow. If the test failed and DOGGR was not on location, a written order to shut in the well within 24 hours and repair the well is sent to the operator. If the operator fails to comply with this written order, a Notice of Violation and/or Formal Order would be issued ordering immediate shut in of the well. The order would likely be hand-delivered and/or posted at the well. District 6 has never been required to deal with the situation where a well failing MIT was not shut-in and the operator did not comply with the initial written order.

Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? Unless it is a situation where immediate damage to a USDW cannot occur, the well is ordered to be shut in within 24 hours and repaired within 60 days.

Is there a P&A requirement if the well is not repaired and if so, how much time typically passes before that requirement is enforced? Please refer to the follow-up response above.

How long is the operator given to take corrective measures? 60 days-120 days, but if the operator does not repair the well within that time frame, the individual injection well permit can be rescinded. – Lines are ordered to be disconnected.

If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work? The permit will include any operations the District would need to witness. It usually includes a witness of the casing pressure test and a MIT is required following repair if the well is returned to injection.

What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time? The failure rates are minimal and there have been no significant changes over time. In past five years, there have been four MI failures, all of which were addressed.

What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well? The operator will need to obtain a permit to perform the remedial rework operation on the well. If the rig is on location and the problem requires more than the permit allows, the operators will call to receive a verbal approval to proceed. The permit always states that No program changes are made without prior Division approval. Depending on the situation, a supplementary notice may be required.

The operator will do the repairs, run a new casing integrity test and submit history to DOGGR. If DOGGR is required to witness anything, it is noted on the permit and operator has the responsibility of contacting DOGGR. An MIT is required following repair if the well is returned to injection.

Describe the data management system used in the various components of the MIT program In this district, the Associate deals with 34 water disposal wells, 18 which are active. The data is covered on one screen worth of information.

Conclusions

The SAPT requirements as described in Section 4.1 and the MOI are apparently applied uniformly on a statewide basis. The minimum 200 psi pressure standard is a concern for wells that have a MASP higher than 200 psi. This is discussed at length in the state level and District

1 sections of this report. We support the Division directive to test at the MASP unless well conditions and/or age would warrant a lower pressure. More frequent testing and/or monitoring of casing pressure should be required, however, when a well is tested at less than the MASP. The new Division standards for SAPTs will be implemented in District 6, according to their response to this question above.

The 15-minute duration standard is not an uncommon practice in other state UIC programs. Increasing that to 30 minutes would provide additional assurance of the absence of a significant leak. We support the requirement for a stable pressure lasting 15 minutes described above, but we are unsure that the stable pressure standard is applied in all tests, especially those that are not witnessed.

The District states that at least 80 percent of MITs are witnessed, which is well above the federal UIC guidelines to witness at least 25 percent of MITs. RATs are required annually in disposal wells, which is more often than the five year cycle prescribed for MITs in federal regulations. SAPTs are required once every five years, or whenever the packer is unseated during workover operations, or at the request of the district deputy, which is consistent with federal UIC requirements.

In addition to the SAPT, annual inspections of wells can reveal a MI failure if pressure is observed on the casing/tubing annulus, and the operator would be required to shut in the well if that were the case. If a pressure gauge is not installed on the annulus, however, there would be no way to observe pressure on the annulus, and permanent installation of a gauge on the annulus is not a requirement. If the operator is given advance notice of the inspection, a gauge could be installed, but the operator would be able to bleed off casing pressure before the inspection occurs. We would favor installation of a pressure gauge on the casing annulus as a permanent fixture on all injection wells so that the operator would not need to have advance notice of a routine inspection.

Wells that fail a MIT are required to cease injection within 24 hours and are required to be repaired within 60 days, according to responses in the discussion above. The requirement for repairs is contrary to responses from other districts, except when the operator intends to resume injection in a well that fails a MIT, or when USDWs may be endangered by the lack of MI. District 6 responses regarding the repair requirement within 60 days appear inconsistent in the dialogue above. In one instance, repairs are seemingly required regardless of the lack of USDW endangerment, but later in the dialogue, repairs are required if there is "immediate danger to (a) USDW." It is not stated explicitly, but the inference is that a well that fails a MIT must be repaired immediately when USDWs may be endangered. We support the requirements for repairs within 60 days or immediately if USDWs are in danger as stated above, but we have doubts that repairs are actually required without endangerment to USDWs. District 6 should provide clarification on that point. In our view, wells that fail MITs should be repaired or plugged and abandoned within a set time period (three to six months or sooner depending on the nature of the leak) unless no USDWS are penetrated by the well.

The response to the question about reporting and corrective measure requirements for a well in which a MI failure occurs during routine injection operations was apparently misunderstood.

The response addressed those requirements for a well that was undergoing a workover rather than for a MI failure that occurs during injection operations.

District 6 states that an idle well must periodically be tested for mechanical integrity after five years in idle status. It is our understanding from reviewing the statewide idle well program that a pressure test is not required after five years in idle status as it is for an active well. Fluid level measurements are required every two years after a well has been inactive for five years, but a pressure test is not required unless the fluid level is above the BFW. That standard is not fully protective of other USDWs penetrated by the well. Fluid level soundings are not MITs and are not indicative of MI. We believe that SAPTs should be required in all idle wells, and those that lack MI should be repaired or plugged and abandoned, preferably within 90 days for a known casing leak and six months for a tubing or packer leak, unless USDWs are known to be absent in the area.

The discussion of the assessment of Part 2 (external) MI in District 6 wells is incomplete. Cement records and logging tools such as CBLs and static temperature surveys are apparently acceptable for the assessment of external MI, which is consistent with federal regulations. State UIC regulations require adequate volumes of cement in the casing/wellbore annulus immediately above the injection zone, above hydrocarbon bearing zones, at the BFW, and behind surface casing. The presence of sufficient cement is determined by examination of cement records and CBLs. Those standards should satisfy Part 2 MI requirements at least in part, but cement should be present at the base of all USDWs (10,000 mg/L TDs or less) for complete protection of USDWs. In addition, we would recommend running CBLs in new and converted injection wells unless USDWs are known to be absent in the area.

Implementation of the recent Division directives to the district offices and the authorization to hire additional UIC staff should alleviate some of the concerns discussed above.

PART V: Compliance/Enforcement

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understand enforcement procedures used by the District

What types of enforcement tools and legal actions are available to the District for the UIC program? The Law and Regulations spell out the legal and enforcement process. Basically we have access to an informal compliance process, formal orders, and administrative penalties. *How often in the last five years have you used them?* None

Does the response "None" refer to just formal enforcement actions? How many informal actions have been initiated in the last five years. Yes. Aside from telephone calls and emails as reminders or inquiries, which is done occasionally, we have had informal written communication with one operator, North Valley Gaswell Services. North Valley operates one water disposal injection well in Kirkwood gas field, and we had to send letters to conduct mechanical integrity testing between 9/04 and 11/05, early in the project. We also sent a reminder letter to North Valley in 4/09 to perform MIT, and the test was performed promptly.

Have there been any permit rescissions in the past five years, or ten years? At least two projects and three wells were rescinded in the past 10 years. *Please identify the projects and wells that were rescinded and the reasons for the rescissions.* The eight projects and wells that were rescinded in the past 10 years and the reasons for the rescissions are listed in an attachment titled "District 6 UIC Projects/Injection Permits Rescinded SUMMARY". The DOGGR rescission letters for those projects/wells are also provided. *Copies of the SUMMARY table and rescission letters are included in Appendix B.*

What types of formal enforcement actions have been taken relative to UIC violations in the District? None

Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs. Violations threatening USDW's would be an immediate action asking operator to shut in well within 24 hours, repair well within 60 days. Paper violations are usually starting with 30 days to correct.

Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties? Yes occasionally. *How many have you issued in the last five years?* For UIC = none

What are the follow up procedures to assure compliance and correction of the violation? Follow-up field inspection, or witness of a casing pressure test, and/or RAT survey.

How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? 60 days to repair – after 120 days, well is rescinded – lines should be disconnected. This is after the injection well has been shut-in. *How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV?* 30 days – if not corrected then possible issuance of an Administrative penalty.

How and when do UIC violations escalate from non-compliance into formal enforcement actions? None

What penalties have been assessed and collected on UIC violations in the past ten years? None

Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement? None

Are resources sufficient to witness most MITs, P&As, and remedial operations, and to carry out formal enforcement actions? Yes. In this case, I would be going into shear speculation beyond that.

Conclusions

The enforcement procedures available to the District are highlighted in the responses above and are described in detail in the CDOGGR laws and regulations that apply to the UIC Program. District 6 has not initiated any formal enforcement actions in the last five years and no penalties have been collected in the past ten years. At least two projects and three wells were rescinded in the past ten years. We have no further information at present as to the reasons for the rescissions, but they were likely due to prolonged idle well status. Informal actions for noncompliance include written communications, emails, and telephone calls. No NOVs have been issued in the past five years for UIC violations. It appears that there has been only minimal enforcement action taken in District 6 in the last five to ten years, based on responses above. That is probably due to the small number of Class II injection wells in the District, and most wells may have been in compliance over the past five to ten years.

OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public. If DOGGR was to receive a complaint, a field engineer will perform a thorough site inspection. A report will be completed by the engineer and notification to the operator or any other agencies, that need to be included, will be done. Evaluation of possibly more elaborate testing will be determined by all the information collected.

Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination? None

What actions are taken by the District when an alleged contamination report is received? If it were to occur, the Associate and District Deputy would use the outline in the UIC manual to begin the process. It is something that District 6 has not done in the past, so this is would be a rare occurrence to District 6.

How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells? N/A

Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to Question #3 above. N/A

Conclusions

The District states that there have been no alleged or actual USDW contamination incidents in the past ten years. If one did occur, the District would follow the standard procedures outlined in the MOI, including a thorough site inspection, evaluation of any test results and site characterization studies, and a report to the operator and other interested agencies,

PART VI: Abandonment/Plugging

This part is organized by objective, with conclusions sections provided after each objective, where relevant.

OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.). All wells are required to be abandoned by the California Law and California Code of Regulations. All producing zone, shall be cemented from the bottom perforation to 100' above the top perforation. The injection zone must be plugged across the perforated interval to 100' above the top perforation. DOGGR will witness tag on that plug. All portions of the hole not plugged with cement are filled with inert mud fluid having a minimum density of 72 lbs./cu. ft. and a minimum gel-strength (10 min) of 20 lbs./100 sq. ft. Base of fresh water if cemented behind the production casing will be cemented with 50' below to 50' above the BFW inside the production casing. DOGGR to witness the tag. If the BFW is behind the cemented surface casing and the production casing is not cemented behind pipe, then perforations 50' below the BFW and 100' lineal feet cement squeeze in the annulus of the surface and production casing – and 100' inside the production casing. DOGGR will witness squeeze and location and hardness of BFW plug. A surface plug 25' shall be place in production casing and all annulus – casing shall be cut 5' from ground surface.

D*o the BFW requirements not apply to USDWs as well?* Please refer to a related follow-up response above. Plugging and abandonment requirements in the CCR protect the State-defined BFW, not the USEPA-defined USDW. Of course, if the USDW is not protected in a plugged and abandoned well, that lack of protection could jeopardize a future UIC project. But generally, it is the BFW that is plugged in all wells that are abandoned in the state.

Are there UIC wells without surface casing installed? No

If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed? None – same as above

Are plug depths verified? Yes *When and how?* DOGGR witnesses tags and/or placement. *Are all plugs required to be tagged?* Yes – with or without DOGGR's presence. Operator is required to call in the tags if DOGGR waived witness.

What percentage of UIC well pluggings are witnessed by District inspectors? Mostly all of them. *What control is exercised over unwitnessed plugging operations?* Operator is to keep DOGGR informed – call in each tagged depth, and submit a complete abandonment history.

Describe the process used to get an idled and an orphaned well plugged. Idle wells are not required to be plugged and abandoned unless the operator shows credible evidence of desertion. Then a formal order to abandon would be issued.

In 1976, the Division of Oil, Gas, and Geothermal Resources was authorized to plug and abandon certain hazardous and idle-deserted wells (see Article 4.2 of the PRC (PDF)). Most wells that fall into this category are orphan wells. From 1977 to 2004, the Division plugged 1,062 orphan wells at a total cost of $14.8 million.

Currently, the Division is authorized to spend up to $ 2 million per year to plug orphan wells. A list of prospective well abandonment contractors (Excel file) is maintained and companies on the list are sent bid packages whenever the Division needs their services.

If P&A is not required, are idle wells pressure tested for MI with the same requirements as active wells? Is desertion the same as orphaned? Is the formal order to abandon issued to the former operator, or to DOGGR to P&A the well? The Idle Well Program, as outlined in PRC Section 3206, and in the DOGGR "Idle Well Planning & Testing Guidelines", requires fluid levels starting at the point when a well is defined as "Idle". If the fluid level is above the BFW, or when a well becomes "Long-Term Idle", the mechanical integrity of the casing must be tested, generally with a casing pressure test. The terms "desertion" and "orphaned" are pretty much interchangeable. Actually, the term "orphaned" is not used in the PRC. "Deserted" and "Idle-Deserted" are used in PRC Sections 3237, 3251, and elsewhere as a basis for ordering such wells plugged and abandoned. The term "orphaned" has gained national acceptance, so we use it as well. The formal order is issued to the former operator, sometimes to multiple operators. One provision of PRC 3237 allows DOGGR to require the former operator of a well, back to 1996, to plug and abandon the well, if the current operator of the well lacks the financial resources.

If the well is deserted and the operator(s) has/have gone out of business, does the state plugging fund apply in those cases. Yes

Does the District maintain an inventory of abandoned (orphaned) UIC wells? Yes – see www.conservation.ca.gov. There are 19 wells on the District orphan well list. None are former UIC wells.

Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Yes – only orphaned well. Usually idle wells have viable operators.

Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund. See above.

How are the current plugging requirements different from those of 40 years ago? More protective – more stringent. BFW plugs are important in the abandonment process. *Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project?* Absolutely. *Are USDW plugs important as well? Please discuss the impacts on corrective action requirements and conducting AORs or approvals for an injection project.* Regarding USDW and plugging requirements, I would refer you to previous responses.

Wells that were plugged and abandoned more than 40 years ago are obvious candidates for problems in conducting an AOR, because they are far more likely to have been inadequately plugged and provide potential avenues of migration.

Conclusions

District 6 applies the existing statewide P&A standards, which are discussed in Sections 2.0 and 3.0 of this report and are described in detail in the CDOGGR regulations and MOI. The recent Division directive requires a zonal isolation plug for all wells within the AOR of an active injection project, which is a new and more rigorous requirement for protection of USDWs from migration of injection fluid out of zone in those wells. In addition, a cement plug is required at the BFW zones in plugged and abandoned injection wells, but not in other wells within the AOR of an injection well or at the base of USDWs in any well.

District 6 written responses are not clear about their adoption of the new requirement for a zonal isolation plug in AOR wells. We support the new Division directives and urge District 6 to adopt those for application in the District as soon as possible. The lack of a requirement for placement of cement plugs at the base of USDWs is a concern, however, and modification of P&A requirements in that regard would greatly enhance the protection of USDWs containing more than 3,000 mg/L TDS. In our view, the USDW plugging requirement should apply to all wells within the AOR.

District 6 states that most P&A operations are witnessed. That includes tagging cement plugs and cement squeezing operations, but may not include witnessing cement plug placement operations, as discussed in Sections 2.0 and 3.0 of this report. When P&A operations are not witnessed, District staff review the P&A report submitted by the operator to ensure compliance with P&A requirements. We have concerns about the absence of a CDOGGR inspector during cement placement operations, as discussed earlier in Sections 2.0 and 3.0 of this report.

District 6 follows the statewide Idle Well Planning and Testing Program in managing P&A of idle and orphan wells. There are no orphan UIC wells in the District at this time. Our concerns regarding the management of idle wells are discussed below and at length in Sections 2.0 and 3.0 of this report.

The requirement for adequate volumes of cement at the BFW and above the injection zone and hydrocarbon bearing zones is not fully protective of other USDWs penetrated by a well. In our view, the presence of mud is not an adequate substitute for cement at the base of USDWs, especially in long-term idle wells that lack casing integrity and in abandoned wells. We urge the Division to give serious consideration for modification of that standard.

OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

Describe the District administrative program for TA wells and how a TA well is defined. The well was not completed, sitting as a drilling idle, plugged back but not completely abandoned.

The well must be securely capped at the surface and the site in a safe condition. In order to reenter the well, a Notice of Intention to rework is required.

We have received variable responses from the other District offices, but mostly that TA or suspended terms are apparently not in use in other Districts. What is the definition of "long-term idle"? 10 years is considered "long-term idle by statute. However, the permit to inject will be rescinded after two years in idle status. There are increasing penalty fees assessed for wells that are idle more than 5, 10, and 15 years. Refer to the Idle Well Management Program for details.

How is a TA well different from an idled well or one that is orphaned? There are approved plugs in the well, and therefore the BFW's are not in danger.

What limitations are imposed on the operator once TA status has been approved by the District for a given well? 2 years – then a letter is sent to the operator asking them to submit plans for the well. Either complete or abandon the well. Note that this Division does not have a statutory or regulatory definition for Temporary Abandonment; therefore, you will likely get responses all over the map from the various districts. For the purposes of this response, we interpreted TA to be a 'suspended" well, either drilling-idle or plugged back. A "suspended" well is an administrative definition of this Division, as opposed to "idle" and "long-term idle" which are defined in statute.

Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well? No

Is there a requirement for a pressure test of the plug and casing integrity for TA wells or idle wells? Yes, if the fluid level in a well reaches above the BFW in the tubing or annulus. Fluid levels in idle wells are monitored by DOGGR on a five-year cycle. *(A two year cycle applies in fresh water areas according to the MOI.)* If no packer or plug is installed in the well, an ADA test could be run to assess mechanical integrity of the casing.

Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. An operator is required to send a Notice requesting well be in a 'suspended' status. They are tracked by remaining in our ACTIVE well files – and will be purged in 2 years. They are tracked as "SUSPENDED" – "Idle-drilling' but not active or abandoned. *How long may a UIC well remain in TA status before being reactivated or P&A.* 2 years – but the operator will need to obtain a new project approval.

Conclusions

Temporary abandonment of injection wells is not a term that CDOGGR uses, but idle wells fit the general description for TA wells, except that idle well requirements are not as rigorous in terms of MIT, repair, and timely plugging. District 6 applies the statewide standards for management of idle and orphan wells, but also has requirements for TA, or in their terms, "suspended" wells, which is an administrative definition of the Division. Those wells have approved plugs in place, which increases the protection of fresh water zones, whereas plugs are *not required in idle wells. Mechanical integrity tests are not required before TA status is approved or periodically while a well is in TA status or before reactivation as an injection well, according to the District response to that question. Idle wells, on the other hand, do require a pressure test if the fluid level in a well reaches above the BFW in the tubing or annulus. Fluid levels are monitored on a two-year cycle in idle wells located in a fresh water area. The five-year cycle, cited by District 6 above, applies to areas with no fresh water, according to the Idle Well Testing Guidelines in the MOI. A UIC well may remain in TA status for two years before being reactivated or plugged and abandoned, according to District responses above, which is comparable to EPA requirements for TA wells, but inconsistent with our understanding of statewide P&A requirements. We understand that authorization to inject can be rescinded after two years in TA or idle status, but P&A is not a requirement, based on the MOI and responses by other districts.*

USDWs are not adequately protected in idle wells in our view. Those concerns are discussed at length in Section 3.0 and at other sections of the report. Consideration should be given to modification of the idle well program to strengthen the protection of USDWs.

PART VII: Comments

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

District 6 is unique in its UIC program. We are a small district of a total of 35 W/D wells; These 35 wells involve 6 active commercial W/D, 12 active W/D, and 17 idle. Additionally, fluid volumes and injection pressures are relatively low, because, with a couple of exceptions, injection fluid is produced water associated with natural gas production.

5.0 RECOMMENDATIONS

Recommendations for improving the CDOGGR Class II UIC Program are provided based on a review of a state and district-level documents and data, district responses to the EPA questionnaire, and interviews during district office visits by Mr. Walker. They are provided herein at the state level for each reviewed topic, with a final section on general and district-level recommendations.

5.1. USDW DEFINITION AND PROTECTION

The CDOGGR Class II UIC Program should address the lack of clarity regarding USDW protection and ensure that all USDWs are fully protected from fluid movement and resulting degradation. USDWs containing more than 3,000 mg/L TDS should be protected as much as fresh water aquifers are protected in the permitting, construction, operation, and abandonment of injection wells.

5.2. AREA OF REVIEW /ZONE OF ENDANGERING INFLUENCE

These recommendations address AOR/ZEI determinations, well construction practices and status of well located within the AOR, and corrective action requirements.

AOR/ZEI Determinations

- The ZEI should be calculated, especially for disposal wells, with an accurate representation or reasonable estimate of all the relevant parameters that determine the ZEI, including the static pressures of the injection zone and USDWs in the project area.

- Disposal into nonhydrocarbon zones and normally pressure hydrocarbon bearing zones should be carefully monitored for reservoir pressure increases beyond normal hydrostatic pressures that could cause the ZEI to increase beyond the AOR over time.

- A fall-off pressure test should be run to determine the static reservoir pressure in wells in which shut-in pressures do not fall to zero after an extended shut-in period. If not done, the permit to inject should be rescinded.

- The ZEI calculations should be reviewed if fall-off test results indicate higher than normal hydrostatic pressure in the injection zone. If the original AOR is smaller than the ZEI, the AOR should be expanded, or the permit to inject should be rescinded.

Well Construction Practices and Status of Wells Located within the AOR

- When casing repairs occur or when wells are plugged and abandoned, cement placement should be required at the base of USDWs in injection wells and AOR wells.

- Unless USDWs are known to be absent in the area, new injection wells should be required to have long string casing cemented to the surface.

Corrective Action Requirements

The new Division standards should be modified to provide protection of USDWs in AOR wells as described above.

5.3. CDOGGR ANNUAL PROJECT REVIEW

This recommendation addresses records of well activity, pressures, inactive well and non-compliance data associated with injection well projects. Comprehensive project reviews should be conducted annually for all active injection well projects, including meetings with the operators for the most critical projects.

5.4. MONITORING PROGRAM

These monitoring program recommendations address MITs and MASPs.

Mechanical Integrity Tests

- SAPT pressures equal to the maximum allowable surface injection pressure should be required if it will not cause damage to the casing. The newer wells should be able to withstand the MASP.
- If tested at less than the MASP, more frequent SAPTs and monitoring/reporting for anomalous pressure on the annulus should be required.
- Static temperature logs should be required more often in slimhole/tubingless completions where USDWs are present and especially for USDWs that are protected by only one casing string and/or lack cement at the base of USDWs.
- Cement bond logs should be required in new and newly converted injection wells unless USDWs are known to be absent in the area.
- Static temperature logs should be required if an existing well lacks sufficient cement at the base of USDWs, and/or squeeze cementing should be considered at the USDW base to ensure isolation from fluid movement.

Maximum Allowable Surface Injection Pressures

- Injection pressure should be maintained below fracture pressure in all new and existing projects, as determined by approved SRTs.
- SRTs should be required in new wells to determine the fracture pressure of the injection zone unless the formation fracture gradient is known with acceptable confidence based on SRTs in nearby wells.

- A pressure gauge should be required to measure bottom-hole pressures in SRTs directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates.

5.5. INSPECTIONS AND COMPLIANCE/ENFORCEMENT PRACTICES AND TOOLS

- A high priority should be placed for inspection of wells in or near residential areas and where USDWs are present.
- Cement placement operations should be witnessed to ensure the correct volumes and quality of cement are pumped into a well.
- Witnessing RATs in enhanced recovery wells should be given a higher priority, especially where USDWs may be present. At least 25 percent of RATs and all SAPTs in wells where USDWs are present should be witnessed.
- Whenever possible, districts should avoid giving advance notice of routine inspections to operators.
- Copies of an inspection report should be provided to the operator whether or not deficiencies are found during inspections.
- The installation of a pressure gauge on the tubing and the casing/tubing annulus should be required as a permanent fixture on all injection wells.
- Wells that fail MITs should be repaired or plugged and abandoned within a set time period, preferably within six months or sooner depending on the nature of the leak and potential threat to USDWs.

5.6. IDLE WELL PLANNING AND TESTING PROGRAM

- The idle well management and testing guidelines at Section 138 in the MOI should be modified to clarify which provisions apply statewide and which apply only to District 4.
- Idle well fees and bond/escrow amounts should be reviewed and increased amounts to levels that would encourage operators to reactivate or plug idle wells.
- The testing program should be modified to base the fluid level survey pass/fail results on the rise of fluid to the base of USDWs rather than the BFW.
- SAPTs should be required in wells after two years of inactivity and every two years after that where USDWs are present.
- Regardless of the fluid level survey results, an SAPT should be required if USDWs are present in wells with tubing and packers installed.

- Bridge plugs or cement plugs above the injection and below the base of USDWs should be required where USDWs are present in wells lacking tubing and packers. In addition, wells should be required to successfully pass an SAPT to remain in idle status.

- Idle wells that fail the SAPT should be repaired or plugged and abandoned within six months in areas where USDWs are present, or within 60 days if USDWs are at risk of potential fluid movement.

5.7. FINANCIAL RESPONSIBILITY REQUIREMENTS

- Bond amounts should be reviewed and updated periodically to cover current plugging and abandonment costs.

- The financial responsibility program should be modified to require bonds and other financial responsibility instruments be held until wells are plugged and abandoned.

- Operator funding requirements and the number of deserted wells plugged and abandoned should be increased to numbers that will significantly reduce the inventory of orphan/deserted wells each year.

5.8. PLUGGING AND ABANDONMENT REQUIREMENTS

- Cement plugs should be placed at the base of USDWS to ensure long-term protection from fluid movement into or between USDWs.

- The presence of a CDOGGR inspector should be required during cement placement in P&A operations to monitor and ensure that adequate cement quality and adequate quantities are pumped into a well.

5.9. UIC STAFF QUALIFICATIONS

- UIC-specific training (e.g., EPA-sponsored UIC Inspector Training Course) should be provided to new and recent hires in the CDOGGR UIC Program within one year of employment.

- Inspectors should be required to hold a petroleum engineering or geology bachelor's degree or related degree or equivalent college courses and relevant experience.

- Consideration should be taken to adjusting compensation and benefits for UIC professional positions to levels more consistent with the oil and gas industry.

5.10. GENERAL AND DISTRICT SPECIFIC RECOMMENDATIONS

These recommendations are provided on a general basis (i.e., applicable to all districts), and are followed by recommendations specific to certain wells, or districts (identified in bold font).

- All district offices should adopt and implement the Division directives in the Division Expectations Memorandum (Appendix A3) and the recommended modification to those directives, described in this report, to increase the protection of USDWs.

- The MOI at Section 170.4.2 should provide more definitive requirements for Class II commercial water disposal wells by adding provisions for sampling and analysis of injected fluids, Class II fluid certification, chain of custody requirements, record-keeping, and adequate site security. Fluids from new sources should be analyzed to ensure that they qualify as Class II fluids. More frequent sampling of existing sources would also provide greater assurance that only approved fluids are injected. For example, **District 4** requirements are described in their responses to the EPA Questionnaire (Section 4.4) for guidance. Also, EPA Guidance Memorandum #77, dated June 22, 1992 provides more information on this issue and is available on the EPA UIC website.

- Software should be acquired or developed for constructing casing diagrams and predicting pressure build-up and fluid migration for all district offices that lack those analytical tools.

- The presence of USDWs should be assessed for all disposal and waterflood injection wells, and the base of those USDWs should be determined.

- **District 2** and possibly other district offices should put more of an emphasis on formal enforcement actions in the UIC Program.

- The two active disposal wells in the **District 3** Cat Canyon Field in which shut-in pressures failed to fall to zero over at least two months should be reviewed. The API numbers for those wells are listed as 08621009 and 08301517. All districts should review any disposal or waterflood injection wells wherein similar behavior is noted.

- One well in **District 4** was found with high shut-in pressures for four months in 2009 that failed to decline during the period of inactivity. This would indicate a high static reservoir pressure and possible ZEI exceedance of the standard quarter-mile AOR. The well in question is the Elk Hills No. 312 and should be reviewed for rescission of the permit to inject.

- A significant number of wells in **District 4** were reported to be injecting at pressures exceeding 1,000 psi, which may exceed the MASP for those wells. Those wells warrant further review to ascertain whether that is the case.

- Inspections are not necessarily prioritized for wells where fresh water is present, and residential areas are not usually a consideration since most wells are located in rural areas in **District 4**. Fourteen of the **District 4** fields are listed as located in residential areas or areas where USDWs are present. Those areas should receive a higher priority for inspections than was indicated by the District 4 responses.

- The use of compressed bentonite in P&A operations in **District 4 and 5** should be discontinued unless its use is explained to the satisfaction of USEPA.

- The idle well requirements in District 4 should be modified to make them more consistent with the statewide program and more protective of USDWs. Idle well testing requirements should be required after five years of inactivity instead of ten years.

- The permit to inject in the **District 5** Gatchell 86-20 well in the Pleasant Valley Field was rescinded in 2009 for exceeding the MASP by 660 psi and for apparent pressure buildup beyond hydrostatic. Permission to inject was granted again in 2010 with a provision that the injection pressure be maintained below the 340 psi MASP and that the pressure be continuously monitored with a recording device. **We recommend that a fall-off test and ZEI calculation should be performed to assess the potential effect on other wells in the AOR.** There are pumping water wells in the vicinity of this well and there are problem wells within the quarter-mile AOR, according to information reviewed in the project file. USDWs may be endangered by continued injection if further corrective action is not required.

REFERENCES

California Oil and Gas Fields, Contour maps, cross sections, and data sheets for California oil and gas fields

- Volume 1-Central California (1998, 35MB, 499 pg)
- Volume 2-Southern, Central Coastal, Offshore California (1992, 45MB, 645 pg)
- Volume 3-Northern California **(**1982, 22MB, 300 pg)

Letter from California Deputy Attorney General to Chief of California Branch, EPA Region 9, "*RE: California Application for Primacy, Class II UIC Program*." December 3, 1982

Memorandum of Agreement between EPA Region 9 and CDOGGR. September 29, 1982

<u>Federal Regulations</u>

- Safe Drinking Water Act
- Title 40 Code of Federal Regulations, Parts 144 to 148, UIC Program

<u>California Regulations</u>

- California Public Resource Codes, PRC01
- California Code of Regulations, Sections 1722 to 1724
- California Senate Bill 1763

<u>CDOGGR References</u>

- Bill Guerard. 1984. CDOGGR Publication M13, Evaluation and Surveillance of Water Injection Projects.
- Management and staff in the six DOGGR district offices
- Questionnaire responses from DOGGR district offices, including the STRONGER questionnaire of 2000 provided by District 2, and site visits to the six district offices
- CDOGGR online databases, well records, and publications
- CDOGGR District project files, permit files, monitoring data, mechanical integrity tests and surveys, step-rate test reports, and other injection reports
- CDOGGR Annual Report, 2008
- CDOGGR Preliminary Report, 2009
- CDOGGR Manual of Instructions
- CDOGGR Field Engineer Training Manual
- CDOGGR Primacy Application, including Program Description, Statement of Legal Authority, and appendices, April 1981
- CDOGGR UIC Program, Power Point Presentation, March 2010
- SPE Paper 62576, CDOGGR Idle Well Management Program, November 2008.

Appendix A1

Memorandum of Agreement between CDOGGR and EPA Region 9

Underground Injection Control Program
Memorandum of Agreement
Between
California Division of Oil and Gas
and
the United States Environmental Protection Agency
Region 9

I. General

This Memorandum of Agreement ("Agreement") establishes the responsibilities of and the procedures to be used by the Division of Oil and Gas ("Division") and the United States Environmental Protection Agency ("EPA") in administration of wells in the Class II portion ("Class II program") of the Underground Injection Control ("UIC") program in California. In general, this Agreement supplements the program described in the demonstration submitted in accordance with Section 1425(a) of the Safe Drinking Water Act ("1425 demonstration").

After it is signed by the Supervisor and the Regional Administrator, this Agreement shall become effective on the date notice of the Class II program approval is published in the Federal Register. The parties will review this Agreement at least once each year during preparation of the annual program update, during the State-EPA agreement ("SEA") process or at other times as appropriate (e.g. at mid-year review). The annual SEA shall be consistent with this Agreement and may not override this Agreement.

This Agreement may be modified upon the initiative of either party in order to ensure consistency with State or Federal statutory or regulatory modifications or supplements, or for any other purpose mutually agreed upon. Any such modifications or supplements must be in writing and must be signed by the Supervisor and Regional Administrator.

This Agreement shall remain in effect unless EPA determines that the Division's 1425 demonstration is no longer valid. Such a determination by EPA will be in accordance with Section 1425(c) of the Safe Drinking Water Act ("SDWA").

Nothing in this Agreement shall be construed to alter any requirements of SDWA or to restrict EPA's authority to fulfill its oversight and enforcement responsibilities under SDWA or other Federal laws, or to restrict the Division's authority to fulfill its responsibilities under State statutes. Nothing in this Agreement shall require or be construed to require EPA to violate Federal law or the Division to violate State law.

II.

A. Policy Statement

The purpose of the UIC program is to prevent any underground injection that endangers an underground source of drinking water ("USDW").

The Division has primary responsibility and authority over all Class II injection wells in the State of California. This includes Class II wells drilled and operated on Federally owned lands, but does not include such wells on Indian lands. The Division is responsible for administering the Class II program including but not limited to reports, permits, monitoring and enforcement actions. Implementation of the Class II program will be as described in the 1425 demonstration and will be supported by an appropriate level of staff and resources.

The Supervisor and the Regional Administrator agree to maintain a high level of cooperation and coordination between Division and EPA staff to assure successful and effective administration of the Class II program.

The Division shall promptly inform EPA of any proposed or pending modifications to laws, regulations, or guidelines, and any judicial decisions or administrative actions that might affect the program and the Division's authority to administer the program. The Division shall promptly inform EPA of any resource allocation changes (e.g. personnel, budget, equipment) that might affect its ability to administer the program.

EPA shall promptly notify the Division of the issuance, content, and meaning of Federal statutes, regulations, guidelines, standards, judicial decisions, policy decisions, directives, and other factors (including budgetary changes) that might affect the Class II program.

B. Information Sharing

1. Division

The Division agrees that all information and records obtained or used in the administration of the Class II program including all UIC permit files shall be available for inspection by EPA or its authorized representative upon request. Division records may be copied by the EPA only when they are required by EPA to bring an enforcement action or for other such specific purpose. Any information obtained from the Division by EPA that is subject to a claim of confidentiality shall be treated by EPA in accordance with EPA regulations governing confidentiality (40 CFR Part 2 and 40 CFR 122.19).

The Division shall retain records used in the administration of the program for at least three years (40 CFR 30 and 40 CFR 35). If an enforcement action is pending, then all records pertaining to such action shall be retained until such action is resolved or the previously mentioned time period is met.

2. EPA

Copies of any written comments about the Division's program administration received by EPA from regulated persons, the public, and Federal, State, and local agencies will be provided to the Supervisor within thirty (30) days of receipt.

3. Emergency Situations

Upon receipt of any information that any Class II injection operation is endangering human health or the environment and requires emergency response, the party in receipt of such information shall immediately notify by telephone the other party of the existence of such a situation.

C. Permits

1. Division

Within 10 working days of receipt, the Division shall provide a written response to any written notice of intent to commence drilling.

2. EPA

Upon receipt by EPA, any Class II permit application and supporting information shall be immediately forwarded to the Division.

Some facilities and activities may require permits from the Division and EPA (and/or other State agencies) under different programs. When appropriate, the Division and EPA will participate in a joint permit processing procedure. The procedure will be developed on a case by case basis.

D. Compliance, Monitoring and Enforcement

1. Division

The Division shall adhere to the compliance monitoring, tracking, and evaluation program described in the 1425 Demonstration. The Division shall maintain a timely and effective compliance monitoring system including timely and appropriate actions on non-compliance.

Each year, 100% of the disposal wells will be inspected for mechanical integrity.

2. EPA

EPA shall conduct periodic site and activity inspections on injection operations, giving priority to operations having the greatest potential to endanger public health.

EPA may participate with the Division in the inspection of wells or operator records. EPA shall notify the Division usually at least ten (10) days prior to any proposed inspection and shall describe the well(s) or record (s) to be inspected and the purpose of such inspection. If the Division fails to take adequate enforcement action against a person violating the requirements for a Class II well, EPA may take Federal enforcement action. Federal enforcement actions will be in accordance with the State, facility and public notification procedures in Section 1423 of SDWA.

3. Emergency Situations

Situations endangering human health will receive immediate and paramount attention by the Division and EPA. The party with initial knowledge of such situation shall immediately notify the other party by telephone.

E. Program Review and Evaluation

1. Division

The Division shall provide EPA with an annual report on the recent operation of the Class II program. Specific contents of the report are described in Attachment #1 and may be renegotiated from time to time. The period to be covered by the annual report shall be the calendar year ending December 31, with reports completed and available to EPA no more than 60 days later (March 1).

In addition, the Division shall provide a separate report of preventive actions taken by operators of new Class II wells. At minimum, this report shall include:

a. the number and general type (e.g. injection pressure limit) of preventive actions proposed in the applications;

b. the number and general type of preventive actions actually taken; and

c. if necessary, a brief summary explaining the reason(s) for any differences between proposed and actual preventive actions (e.g., pending actions).

The report is due within 3 months after the second anniversary of the effective date of this Agreement. The final format will be negotiated at least 3 months prior to the due date.

If the Division proposes to allow any mechanical integrity tests other than those specified or justified in the 1425 Demonstration, the Division shall provide in advance to EPA sufficient information about the proposed test that a judgment about its usefulness and reliability can be made.

2. <u>EPA</u>

EPA shall conduct mid-year evaluations at least during the first 2 years of the Division's operation of the program. In part, the mid-year evaluations will be based on the reports provided above. At least 10 days prior to the evaluation, EPA shall notify the Division regarding the information, material, and program areas that will be covered. This may include selected permit files, budget records and public notification and complaint files. The evaluation may be conducted at either the Division's headquarters or one of its district offices.

F. Public Participation

1. <u>Division</u>

The Division shall provide adequate public notice for its proposed actions as described in the Division's 1425 Demonstration. At minimum, the Division shall provide a 15 day public comment period, and make the non-confidential portions of the project plan and the representative Report on Proposed Operations available for review. If the Supervisor determines that a public hearing is necessary, public notice shall be provided at least 30-days prior to the public hearing.

If there are any substantial changes to the approved project plan or representative Report on Proposed Operations, additional public notice will be provided. Examples of substantial changes include significant increases in injection pressures, changes in injection zone, or significant changes in injection fluid.

Copies of such notices shall also be sent to:

a. Director, Water Management Division, EPA-Region 9;

b. Chairperson, State Water Resources Control Board; and

c. Chairperson of the affected Regional Water Quality Control Board.

The Division's final decision on proposed actions shall contain a response to comments that summarizes the substantive comments received and the disposition of the comments. This shall become a part of that particular project file.

At a minimum, the Division shall apply these public participation procedures to applications for new underground injection projects, significant modifications to existing permits, and to aquifer exemptions.

2. EPA

EPA shall participate at any scheduled public hearing at the request of the Division. Such requests shall be made at least 10 days prior to the hearing.

Any appropriate comments on the proposed action shall be made by EPA within the normal fifteen day comment period. The exception is the designation of exempted aquifers (see the section on Aquifer Exemptions).

G. Program Revision

A program revision may be necessary when the Division's or EPA's statutory authority is modified or when there is a substantial modification to the program. The procedure for revising the program shall be that described in 40 CFR 123.13(b).

H. Aquifer Exemption

An Underground Source of Drinking Water (USDW) may be exempted for the purposes of a Class II injection well if it meets the criteria in 40 CFR 146.04.

Aquifers exempted by the Division and EPA under this Agreement shall only be applicable for the injection of fluids related to Class II activities defined in 40 CFR 146.05(b).

Aquifer exemptions made subsequent to the effective date of this Agreement shall not be effective until approved by the Administrator or Regional Administrator (if delegated) in writing.

After the effective date of this Agreement, an aquifer exemption must be in effect prior to or concurrent with the issuance of a Class II permit for injection wells into that aquifer.

Aquifers which were proposed for exemption in the 1425 Demonstration and exempted are identified in Attachment #2. Any aquifer or portion of an aquifer denied an exemption may be resubmitted for consideration. At minimum, the resubmission should include either new data, new boundaries or other modification to the original proposal.

All exempted aquifers are subject to review by the Division and by EPA. For good reason and by mutual agreement between the Division and EPA, the exemption status of an aquifer can be withdrawn. The public participation procedures in the 1425 Demonstration shall be applied prior to the withdrawal of any exemption status.

1. EPA

Within 10 days after receipt of the information on the aquifer(s) proposed by the Division for exemption, EPA shall notify the Division if any additional information is deemed appropriate. EPA shall either approve or disapprove the aquifer exemption within 60 days after receipt of all appropriate information. Any disapproval by EPA shall state the reasons for the decision. Requests for additional information and final determinations on aquifer exemptions shall be in written form.

If the new aquifer proposed for exemption is a non-hydrocarbon bearing USDW, EPA will coordinate its public participation activities on aquifer exemptions with the Division's public participation activities during project review.

I. Other Agency Involvement

The Division shall administer the Class II program and maintain close cooperation with California's State Water Resources Control Board (SWRCB) and the Minerals Management Service.

J. Definitions

1. Class II well is defined in 40 CFR 146.05(b).

2. Aquifer is defined in 40 CFR 146.03 and 122.3.

3. Day in this Agreement is defined as a working day.

4. Underground Source of Drinking Water (USDW) is defined in 40 CFR 146.03 and 122.3.

5. 1425 Demonstration includes:

   a. the Division's primacy application dated April, 1981;

   b. the additional information provided by letter dated March, 1982; and

   c. the clarifying information provided by letter dated September, 1982.

Sonia F. Crow
Sonia F. Crow
Regional Administrator
Environmental Protection Agency
Region 9

Sept. 29, 1982
Date

Simon Cordova for
M.G. Mefferd
State Oil and Gas Supervisor
California Division of Oil and Gas

Sept. 28, 1982
Date

Attachment 1

Annual Report Contents

At a minimum, the Annual Report shall include:

a. an updated inventory;

b. a summary of surveillance programs including results of monitoring and mechanical integrity testing, the number of inspections conducted, the number of new wells, corrective actions ordered and witnessed, instances of wells out of compliance and their current status;

c. an account of all complaints reviewed by the Division and the actions taken;

d. results of the review of existing wells made during the year;

e. a summary and status of the enforcement actions taken;

f. number of emergency permits issued and current status; and

g. instances of variances and discretionary exemptions during the year.

APPENDIX A2

EPA QUESTIONNAIRE

California Department of Conservation

Division of Oil, Gas and Geothermal Resources

Class II Underground Injection Control (UIC)

Program Review Questionnaire

May 2010

Prepared by:

James Walker Environmental Consulting

under subcontract to

Horsley Witten Group, Inc.

for U.S. EPA Region 9 (Contract No. EP-C-08-018)

Class II UIC PROGRAM REVIEW

Table of Contents

PROGRAM REVIEW DESCRIPTION

PURPOSE

The purpose of this review is to evaluate the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) Class II UIC Program to determine if current program implementation practices are consistent with the approved Application for Class II UIC Primacy, Program Description, and Memorandum of Agreement (MOA) with EPA Region IX signed by the Regional Administrator on September 29, 1982. The projected outcome of this effort is to memorialize current practices and identify program recommendations as needed.

REVIEW PROCESS

With support of the Horsley Witten Group (contractor), EPA Region 9 (EPA) will conduct a review of the DOGGR Class II UIC Program and produce a final report that summarizes findings of the review and any program recommendations. The report is intended to provide information to EPA on focused aspects of the current management and implementation of the DOGGR Class II UIC Program. The final report will provide EPA and DOGGR with a detailed compilation of information on the strengths and weaknesses of the program, which can be used to advance the program and enhance the protection of underground sources of drinking water (USDWs) in the state of California.

Each District Office is requested to complete the following questionnaire by Monday, June 21, 2010. Responses should be inserted into the body of the questionnaire. An electronic copy of the completed questionnaire and all attachments should be sent to:

- Mark Nelson, Horsley Witten Group (mnelson@horsleywitten.com); and,
- Jim Walker, James Walker Environmental Consulting (subcontractor to Horsley Witten) (jameswalker5@msn.com)

This is the first step of the review process. After responses are reviewed and evaluated, arrangements will be made for an onsite visit from the subcontractor to the District Offices to gather and review additional information as needed. The onsite visit may include inspection of UIC permits, operation protocols and interviews with District staff and management. All site visits will be coordinated in advance with the District Deputies and a list of items for review will be submitted in advance as well.

The contractor will develop a draft document of findings that incorporates the information and submittal material provided from the questionnaires and additional documentation gathered during the site visits. This draft document will be sent to EPA and DOGGR for review and comment prior to finalizing the report.

PROGRAM REVIEW FOCUS

Area of Review (AOR)/Zone of Endangering Influence (ZEI)

- Representative samples of Class II UIC projects/wells in areas of special interest will be selected for a comprehensive review of the AOR/ZEI applied in the permit application/approval/follow-up monitoring process.
- Well construction practices and status of wells located within the AOR will be examined.
- Corrective action requirements that were imposed in the permits, if any, will be reviewed.

DOGGR Annual Project Review

- Records of well activity, pressures, inactive well and non-compliance data, etc. and DOGGR actions taken to correct non-compliance will be reviewed.

Monitoring Program

- Mechanical Integrity Testing (MIT) surveys/reports will be examined for compliance with UIC requirements and consistency with actual MIT results.
- Procedures for establishing Maximum Allowable Injection Pressures (also known as Maximum Allowable Surface Pressures (MASPs)) and monitoring for compliance, including the review of selected step rate tests and other data on record will be evaluated.

UIC Staff

- Staff qualifications for proper implementation and enforcement of the DOGGR Class II UIC program will be evaluated, including review of staff resumes, job descriptions, work experience, and training. **Staff names on those documents shall be omitted for the purpose of this review.**

DOGGR CLASS II UIC - QUESTIONNAIRE

District Office:
Deputy Director's Name:
Email:
Telephone Number:
UIC Class II Lead Staff Name:
Email:
Telephone Number:

Please insert your response below each question. Additional materials can be attached and will be considered. However, please reference the inclusion of any additional materials below the appropriate question.

In your response, please distinguish where the response reflects standards or requirements that have been adopted relatively recently - in the last few years. If this is the case, please describe the previous/historic requirements and procedures and explain why modifications were implemented.

Please incorporate in your responses if fields (active and non-active) are located below or may affect residential (or other high-priority, e.g., due to vertical proximity to USDWs) areas. These fields need to be listed or depicted clearly on a map(s).

If you have any questions or comments regarding the questionnaire or how to submit the requested documentation, please contact Jim Walker, James Walker Environmental Consulting (subcontractor to Horsley Witten) via email at jameswalker5@msn.com or at 720-472-9359.

PART I: GENERAL

A. UIC Program Organization

1. Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

B. Interagency Coordination and Changes to the UIC Program

1. Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental

entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available.

2. Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes?

PART II: PERMITTING AND COMPLIANCE REVIEW

A. OBJECTIVE: Understand the application flow process of the UIC program.

1. Who receives the application from the operator? (District or Headquarters office)

2. How and by whom are permit applications screened for completeness?

3. What are the procedures or protocols if an application is found to be incomplete?

4. What are the professional qualifications required for staff who conduct permitting and compliance activities? Do those staff members meet the minimum requirements? What types of training would staff like to access if funds were available?

5. What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful?

6. Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal).

7. Describe any differences between the processing of a waterflood project and a CO2 EOR project.

B. OBJECTIVE: Understand the current compliance/file review process.

1. What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy.

2. Who performs the file review and what are the qualifications of the reviewers? [Please do not include the name of the staff but rather their professional title and qualifications.]

3. Over a one-year period, what percentage of total UIC permits/wells receives a file review?

4. How is the quality of a file review assured and subsequently documented?

5. When deficiencies are discovered during the review, what actions are taken to correct the deficiency?

6. How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually?

C. OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

The federal definition of USDWs (underground sources of drinking water) is found in the regulations at 40 CFR §144.3 which includes that an aquifer "...contains fewer than 10,000 mg/l total dissolved solids". Please distinguish when responses to questions pertaining to USDWs differ from the federal definition and describe how this difference is handled. This may apply to AOR/ZEI and MIT responses in other sections as well.

1. What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected?

2. What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected?

3. What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field?

4. Packer and tubing requirements: Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well?

5. Are dual (multiple) completions permitted? What requirements are different than single completions? What types?

6. How are the locations of USDWs determined? Does the District consult with other state and federal water resource agencies regarding USDW information?

7. How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated?

8. Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well.

9. How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose

D. OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

1. How is the Area of Review (AOR) determined for enhanced recovery wells or projects?

2. How is the AOR determined for saltwater disposal wells?

3. How is the AOR determined for commercial saltwater disposal wells?

4. How is the AOR determined for CO2 EOR wells?

5. How are AORs determined for area permits and other multi-well projects?

6. Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? If not, are they performed for all disposal well permits? What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved? Is there any time period since the UIC program was approved when there were notable increases or decreases in ZEI determinations – please describe?

7. Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects.

8. Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples.

9. What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR?

10. Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? Please list the most recent examples.

11. How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee?

E. OBJECTIVE: Understand the administrative permit application components.

1. Describe the public notification and participation process for applications under consideration by DOGGR.

2. When and where is public hearing opportunity held on an application and how are they conducted? When was the last public hearing held in your District? Please list the most recent examples.

3. What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed?

F. OBJECTIVE: Understand the process for aquifer exemptions

1. How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests?

2. How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials?

. If there have been any aquifer exemption requests from your District, briefly describe the process for approval/denial of such request.

PART III: INSPECTIONS

A. OBJECTIVE: Understand how field operations are conducted and managed by the District. Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas.

1. How are inspection priorities determined?

2. What professional qualifications and/or experience are required by DOGGR to be an inspector? Do District staff have the necessary qualifications and/or

experience? What types of training do inspectors access or would like to access if funds were available?

3. What tools do the inspectors utilize? Are there additional tools that you can identify that would be useful?

4. Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training.

5. What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process?

B. OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District. Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations.

1. How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database the inspection data is stored in or attach the inspection verification documentation.

2. Is the operator given advance notice of inspection and does the operator receive a copy of the report?

3. Describe the reporting and follow-up procedures used in the inspection program when there are violations.

4. How is the District notified of emergency situations regarding Class II wells and related incidents such as spills?

5. What type(s) of emergency situations has/have been reported involving UIC permitted wells? Please list the ones you have received over the last five years, or the most recent examples.

6. Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations.

7. How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily accessible database? If not, how does the District verify compliance with the MASP?

PART IV: MECHANICAL INTEGRITY TESTING

A. OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

1. What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability.

2. What criteria are used for the pass/fail of a pressure test and why were these criteria selected?

3. If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM?

4. If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail?

5. Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined?

6. What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone?

7. Describe the follow-up and typical enforcement actions for MIT failures.

8. Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed?

9. In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate.

10. Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures?

11. If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work?

12. What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time?

13. What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well?

14. Describe the data management system used in the various components of the MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure.

PART V: COMPLIANCE/ENFORCEMENT

A. OBJECTIVE: Understand enforcement procedures used by the District

1. What types of enforcement tools and legal actions are available to the District for the UIC program? How often in the last five years have you used them? Please list these or the most recent examples.

2. What types of formal enforcement actions have been taken relative to UIC violations in the District?

3. Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs.

4. Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties? How many have you issued in the last five years? Please list these or the most recent examples.

5. What are the follow up procedures to assure compliance and correction of the violation?

6. How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV?

7. How and when do UIC violations escalate from non-compliance into formal enforcement actions?

8. What penalties have been assessed and collected on UIC violations in the past ten years?

9. Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement?

B. OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

1. Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public.
2. Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination?
3. What actions are taken by the District when an alleged contamination report is received?
4. How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells?
5. Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to Question #3 above.

PART VI: ABANDONMENT/PLUGGING

A. OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

1. Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.).
2. Are there UIC wells without surface casing installed? How are they plugged?
3. If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed?
4. Are plug depths verified? When and how? Are all plugs required to be tagged?
5. What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations?
6. Describe the process used to get an idled and an orphaned well plugged.

7. Does the District maintain an inventory of abandoned (orphaned) UIC wells?

8. Does the state maintain a well plugging fund that is used to plug idled and orphaned wells? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund.

9. How are the current plugging requirements different from those of 40 years ago? Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project?

B. OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

1. Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well?

2. Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well?

3. Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. How long may a UIC well remain in TA status before being reactivated or P&A.

PART VII: COMMENTS

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

APPENDIX A3

CDOGGR LETTER OF EXPECTATIONS TO DISTRICT OFFICES

DEPARTMENT OF CONSERVATION

Managing California's Working Lands

Division of Oil, Gas, & Geothermal Resources

801 K STREET • MS 20-20 • SACRAMENTO, CALIFORNIA 95814

PHONE 916 / 445-9686 • FAX 916 / 323-0424 • TDD 916 / 324-2555 • WEB SITE conservation.ca.gov

TO: District Deputies
Underground Injection Control Staff

FROM: Elena M. Miller, State Oil and Gas Supervisor EMM
Robert S. Habel, Chief Deputy (RSH)
Division of Oil, Gas, and Geothermal Resources

DATE: May 20, 2010

SUBJECT: Underground Injection Control (UIC) Program Expectations

To better understand the roles and responsibilities of staff working in the UIC Program, the following standards (expectations) are provided to help ensure that UIC Program requirements are being applied in a manner consistent with the laws, regulations, primacy application, and agreements the Division is mandated to enforce.

Staff Expectations (Roles and Responsibilities)

1. All staff should adhere to and enforce all laws and regulations under the Division's authority. If the laws and/or regulations are unclear, it is each person's responsibility to ask for clarification.

2. All staff should adhere to and enforce the requirements of the Division's UIC Program with its mandated federal program requirements. If you do not understand UIC Program requirements, refer to the US EPA Primacy Application (AP) for clarification. If you still do not understand the program's requirements, contact the UIC Program Manager.

3. UIC Program staff should implement the major requirements of the UIC Program as outlined below in the Program Requirements and Conditions (please see below).

4. Some statutes or regulations allow for waivers or variances at the discretion of the District Deputy. Ultimately, the Supervisor of Oil and Gas is responsible for such an exercise of discretion and any decision to grant a waiver or variance must be vetted with the Supervisor or Chief Deputy.

5. The following requirements and conditions shall be implemented immediately.

UIC Program Requirements and Conditions

The following UIC Program requirements and conditions are provided to ensure that all staff are implementing the UIC Program as required by the laws, regulations, primacy application, and Division policy.

A. Existing Injection Projects

1. **Injection fluid must be confined to the permitted zone of injection.** This is required whether or not a USDW is present.

Confinement means:

- All wells (Primacy Agreement, p.2) within the "area affected by the (injection) project" (CCR §1724.7 (a) (4)) (Division's Area of Review - AOR) must have a minimum of 100 feet of cement in the annular space behind casing above the oil and gas zones and anomalous pressure intervals. A CBL or temperature survey (other methods may be used if approved by the State Oil and Gas Supervisor) should be used to evaluate and confirm top of cement in the annular space behind casing. If a CBL or temperature log is not available, the theoretical top of cement should be calculated. When calculating theoretical cement top, there must be enough cement to fill the annular space to at least 150 feet above the oil and gas zones or anomalous pressure interval. This 150' allows for a margin of safety when calculating theoretical top of cement. (The margin of safety allows for variations in hole size, cementing procedures, pre-flush conditions and displacement of fluids, and provides a conservative estimate of the top of cement.)

NOTE: Prior to 1978, Division regulations required 100 feet of cement in the annular space behind casing above oil and gas zones. Therefore, at a minimum, there should be at least 100 feet of cement in the annular space for all wells drilled before 1978 unless a variance is expressly provided by the Supervisor, based on known geologic conditions.

After 1978, regulation Section 1722.4 was amended to require 500 feet of cement in the annular space behind casing unless known geologic conditions supported adoption of a variance. Therefore, at a minimum, there should be at least 500 feet of cement in the annular space for all wells drilled after 1978 unless a variance has been expressly provided by the district deputy and the justification, as documented in the well file, is based on known geologic conditions. All variances, new or existing, to the cementing requirements described above must be cleared through the Chief Deputy State Oil and Gas Supervisor.

- All plugged and abandoned wells within the area affected by the project (AOR) must have cement across all perforations and shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil and gas zone, whichever is highest (CCR §1723.1). (Zonal isolation is required by Section 3228 of the PRC.) In those rare cases where cement does not cover all perforations, for reasons such as the presence of junk in the hole, damaged casing, or that the well was drilled before clear standards were expressed in regulation, there must be, at a minimum, zonal isolation (PRC §3228). This means that the injection fluid must be confined to the approved zone and therefore should not be allowed to migrate up or down the wellbore into a non-approved zone.

- Injection fluid must not be allowed to migrate to a different zone through another well, geologic structure, faults, fractures, or fissures, or holes in casing. This includes prevention of injection fluid break through to the surface where the injection zone is exposed at the surface.

- Injection pressure must be maintained below fracture pressure, as determined by approved step-rate tests (CCR §1724.10(i)).

- All injection wells must have, in addition to cement above the oil and gas zones, cement across the base of freshwater interface (BFW) with at least 100 feet above the BFW interface.

  Note: Historically, the Division has protected water quality of ~3,000 mg/l TDS or less. This is supported by both the State Water Resources Control Board Resolution No. 88-63 (included in the attached material) and the Federal aquifer exemption regulations (3,000 mg/l TDS or less is considered a major aquifer exemption). A minor aquifer exemption is required for water quality between 3,000 and 10,000 mg/l TDS. The Division's construction standards, consisting of the use of casing, mud, and cement, are adequate to prevent fluid migration and the comingling of lesser quality fluids. The hole and casing annulus space, between the top of the cement isolating the oil and gas zones and the base of the cement covering the BFW interface should have heavy mud to prevent the movement of fluids. Therefore, it is reasonable to conclude that the water quality of 10,000 mg/l TDS or less will be protected by the standards that are in place.

  Failure to meet any one of these conditions without an appropriate variance indicates non-confinement, which is not allowed.

2. "Area affected by the project" (Division's AOR) will be determined using 1, 2 and 3 below:

(1) One of the following methods:

a. Fixed radius (minimum ¼ mile) or
b. Calculated area,

<u>and</u>

(2) Must include the distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid outside of the proposed injection zone,

<u>and</u>,

(3) The calculated injection time equal to the expected life of the injection project.

NOTE: The "area affected by the project," found in Division regulation Section 1724.7(a) (4), is comparable to the federal "Area of Review" with a few exceptions. The federal AOR definition is more detailed but not necessarily more encompassing. The Division's mandate is broader than the federal since it includes protection of all hydrocarbon resources and waters usable for irrigation and domestic purposes. The federal Safe Drinking Water Act protects public and domestic drinking water sources (USDWs). Since primacy, the Division's UIC Program encompasses protection of hydrocarbon resources, waters suitable for irrigation and domestic purposes, including USDWs.

The federal AOR (40 CFR §146.6) is determined using one of two methods: (a) the Zone of Endangering Influence; or (b) the Fixed Radius. The Zone of Endangering Influence is defined as "that area the radius of which is the lateral distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an USDW and is calculated for an injection time period equal to the expected life of the injection well." The fixed radius method begins with a minimum ¼ mile radius and requires that other factors be considered when determining the AOR. These other factors include: the chemistry of the injected and formation fluids, hydrogeology, population and ground-water use and dependence, and historical practices in the area. Both these methods are instructive for Division staff to use when determining the area affected by the project, with the condition that fluid confinement to the permitted zone is mandatory.

3. All existing projects will have an annual project review. The purpose of the annual injection project review is to determine if the injection project still meets the permit conditions and is meeting its purpose; ensure that all required testing has been performed; determine if there have been any changes to the project, including if any wells have been drilled, reworked, or plugged and abandoned within the AOR and if the work was completed appropriately, to confirm that the injection fluid is confined to the permitted zone of injection; and to confirm that no damage is occurring as a result of the injection project.

4. All required Mechanical Integrity Testing (MIT) must be performed within the timeframes established under §1724.10(j). The second part of the MIT must be performed within 3 months after injection begins. After that, testing must occur at the following frequencies:

    - Water disposal: at least once per year
    - Waterflood: at least once every two years
    - Steamflood: at least once every five years

   The deputy may grant a variance to this schedule for individual wells, but only for good cause if supported by documented evidence.

5. All Standard Annular Pressure Tests (SAPT) must be performed at least once every five years (CCR §§1724.10(f) and (j)(1)). For those situations where there is only a single string of casing across a USDW (10,000 mg/l TDS), the SAPT must be tested at the approved Maximum Allowable Surface Pressure (MASP) for the well. All tests must be evaluated to ensure casing integrity, i.e. that there are no leaks in the casing and that the fluid is confined to the permitted zone.

6. If the injection fluid is not confined to the intended zone or damage is known to be occurring, the operator must be ordered to cease injection. Operation of a project in a manner that is not consistent with applicable standards and permit conditions also may warrant such an order, depending on the nature of the noncompliance.

7. All injection wells must have a wellhead inspection at least once every two years and the injection pressure on the well tubing must be confirmed to be below the approved MASP. If the injection pressure is above the approved MASP, the operator must be contacted immediately and the operator must immediately reduce the injection pressure. There must be a database or records, listing the MASP for <u>all</u> injection wells, which is easily accessible to field personnel to verify that the MASP is not being exceeded.

B. <u>New Injection Projects (Injection fluid must be confined to the proposed zone)</u>

8. Injection fluid must be confined to the permitted zone of injection. This is required whether or not a USDW is present.

9. All required data (see checklist in Appendix A) must be submitted and evaluated to determine if there will be injection fluid confinement (CCR §1724.7).

a. Engineering study:

i. Statement of the primary purpose of the project
ii. Reservoir characteristics of each injection zone
iii. Reservoir fluid data
iv. Casing diagrams - casing diagrams must be provided that include cement plugs, and actual or calculated cement fill behind casing, of all idle, plugged and abandoned, or deeper-zone producing wells within the are affected by the project, and evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to like, health, property, or natural resources (CCR §1724.7 (a) (4)). This includes casing diagrams of all sidetracked holes and redrills.
v. The planned well drilling and plugging and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and plugged and abandoned wells, and unit boundaries.

b. Geologic Study:
   i. Structural contour maps
   ii. Isopachous map
   iii. Geologic cross section through the injection well
   iv. Representative electric log with notations of all formation tops, confining layers, geologic markers, depth of BFW interface, and any faults.

c. Injection Plan:
   i. Map showing injection facilities
   ii. Anticipated MASP and pump rates by injection well
   iii. Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the intended zone or zones of injection
   iv. Method of injection
   v. Cathodic protection
   vi. Treatment of the injection fluid
   vii. Source and analysis of injection fluid
   viii. Source well data
   ix. Other data as required. (i.e. fluid compatibility study(s), etc.)

   All data must be evaluated to determine if the injection fluid will be confined to the intended zone(s).

10. Step rate test(s) must be run to determine the fracture pressure of the injection zone(s) (CCR §1724.10(i)).

11. MITs must be performed on all injection wells (CCR §1724.10(j)). Prior to injection, each well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks (CCR §1724.10(j) (1)). Within 3 months after injection has commenced a second MIT must be performed using an RA survey tool, and either a static temperature or spinner survey (CCR §1724.10(j) (3)). The District Deputy may modify the schedule if supported by evidence, and as long as it does not exceed five years between MITs. (40 CFR §146.23)

12. If there is insufficient data to determine if the injection fluid is confined to the intended zone, additional information must be requested and used to confirm injection fluid confinement.

13. All cyclic steam and steam flood projects must meet the same data requirements as a waterflood project (CCR §1724.8) Steam flood projects have shown that the steam quality may no longer be fresh and therefore, pose a threat to freshwater.

C. Project Files and Well Records

14. A minimum of the last two injection MIT surveys must be maintained in the well file.

15. Step-rate test data must be maintained in both the injection project file and the well file of the well the test was performed.

16. Project files must be maintained up to date. This includes adding casing diagrams for any new wells drilled within the AOR, any step-rate tests conducted, annual project review documentation, project correspondence with the operator or other governmental organizations, and copies of any deficiencies, violations, civil penalties, or formal orders associated to the injection project. The project file must be maintained in a single location and clearly identified so that it can be easily pulled by district staff. The project file should also have documentation for all testing and survey scheduling, listing the last time the required testing/survey was completed.

17. Any well injecting into a non-hydrocarbon zone is defined as a water disposal well, even if there are zones with enhanced oil recovery. Therefore, a water disposal project application and approval is required.

D. Approval of an Injection Project Application

18. The project application approval checklist (Appendix A) must be completed that confirms that all required injection project data was received. All project data should be thoroughly evaluated and a written description with conclusions must be included in each section of the checklist.

19. The project application approval checklist must be forwarded to the UIC Program Manager, signed by both the reviewing engineer and the District Deputy, certifying that the injection project review process has been completed and the project meets program requirements. An electronic copy of the project application and draft project approval letter should be submitted with the project application approval

checklist to the UIC Program Manager. The UIC Program Manager will review the application and draft approval letter for compliance with UIC program requirements (this is not necessarily a technical review). If necessary, modifications to the project will be specified prior to UIC Program Manager's signature. The UIC Program Manager will sign off on the project review and draft approval letter, if appropriate.

APPENDIX A4

CDOGGR PROJECT REVIEW QUESTIONNAIRE

Project Review Questionnaire

Project (SF☐, WF☐, WD☐) Project Code:

Operator: Area:

Field: Pools (s):

Location: Sec. , T. , R. , B&M.

Contact Person/Title: Phone: ( )

The following information may be reorganized, included with additional statements, or deleted in part, depending on individual project requirements.

Project Performance Data (applies only to waterflood or steamflood projects)

1. Number of production wells associated with the project:
   - Active
   - Shut-in
   - Idle (disconnects)

2. Gross Fluids (for stimulated zone (s), if not commingled):
   - Oil
   - Water
   - Gas
3. Incremental oil production attributable to this project (total in barrel on a calendar year basis, only).

4. Average reservoir pressure and temperature.

Injection Data:

1. Number of injection wells (for WD projects, list each well by name):
   - Active
   - Shur-in
   - Idle (disconnected)

2. Injection rates and pressures (maximum & average)

3. Type of injection fluid (produced water, regeneration brines, scrubber effluent, etc.)

4. Water analysis (produced & injected fluids)

5. Source of injection fluid:
   - Fluid (s)
   - Wells(s)
   - Zone (s)
   - Operator(s)

6. Commercial bond required: yes ☐ no ☐

7. Disposition of produced fluid (reinjected, sewage, etc.)

8. Method of fluid transportation:
   Pipeline
   Truck

9. For trucked fluid:
   Names of haulers authorized to unload at site.
   Hours haulers may unload at well.
   Number of loads and volumes received per day/per week.
   What precautions are taken to prevent unauthorized unloading at the facility.

10. Anticipated project charges (expansion, suspension/termination, new drills, conversions, abandonment, fluid type or sources changes, new stimulation techniques, step-rate tests, modifications, to existing facilities, etc.)

11. Problems wells (mechanical, fluid, corrosion, scale, etc.) and discuss course of action, if any (type of work-over & results)

12. Has the packer been reset since the last review or not? If so, was the annulus pressure-tested after the packer was reset?

13. Idle injectors (fluid levels, casing pressure, abandonment program, future plans, etc.)

14. Annual surveys (discuss wells that have overdue, deficient and/or questionable surveys.

15. New geologic or other interpretative data.

16. Problems with State or Local jurisdictions (permitting, fees, etc.)

17. Public Input (complains, vandalism, etc.)

18. Additional information (change of ownership, environmental concerns, urban development, etc.)

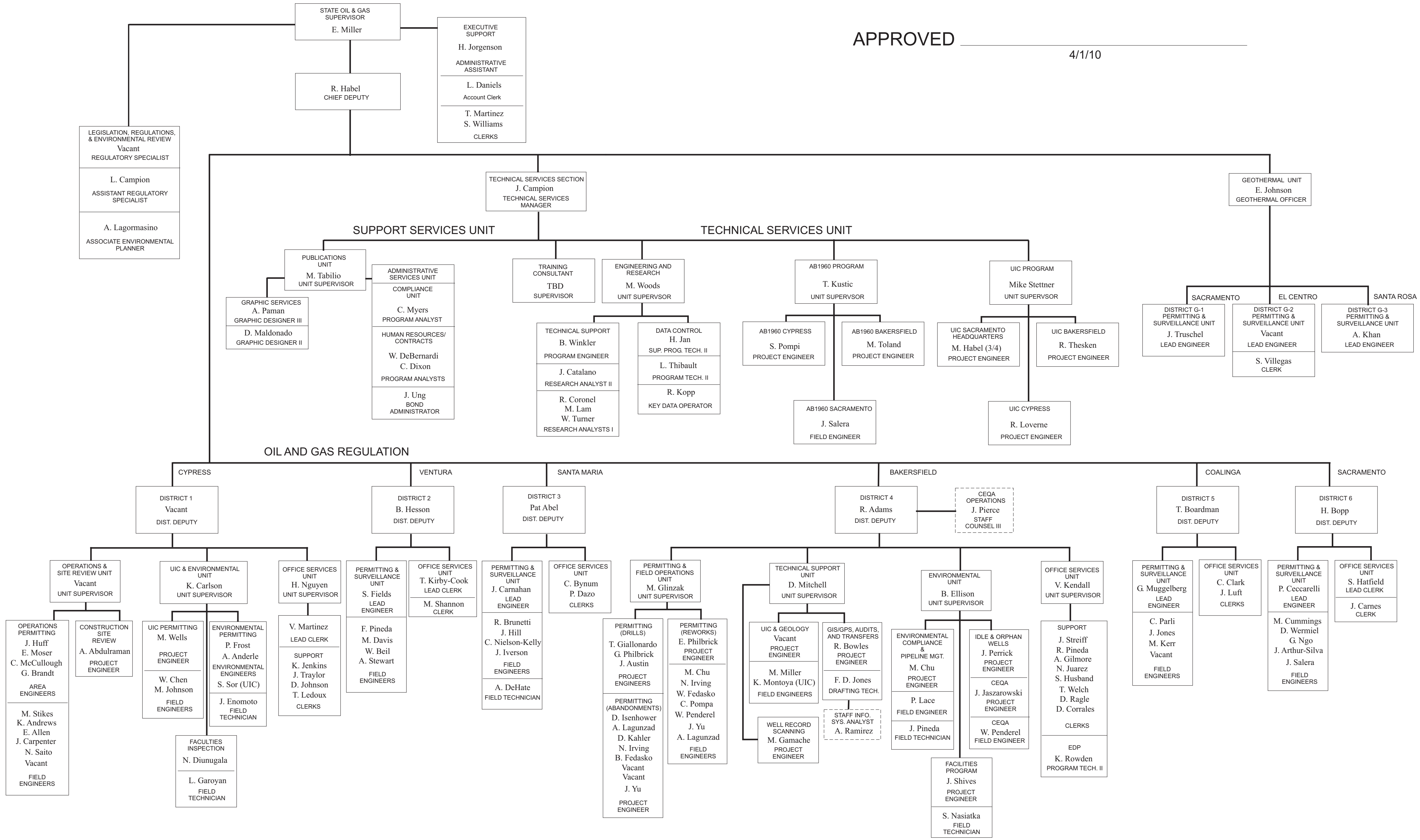
19. How is produced condensate and/or compressor oil still in the water handled?

APPENDIX A5

CDOGGR ORGANIZATION CHART

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

APPROVED ______________________ 4/1/10



APPENDIX A6

CDOGGR 2009 ANNUAL REPORT TO EPA REGION 9

FORM 7520

DEPARTMENT OF CONSERVATION

DIVISION OF OIL, GAS AND GEOTHERMAL RESOURCES

801 K STREET • MS 20-20 • SACRAMENTO, CALIFORNIA 95814

PHONE 916 / 445-9686 • **FAX** 916 / 323-0424 • **TDD** 916 / 324-2555 • **WEBSITE** conservation.ca.gov

OIL, GAS & GEOTHERMAL

November 4, 2009

Mr. George Robin
Water Management Section (W-6-3)
U.S. Environmental Protection Agency
Region IX
75 Hawthorne Street
San Francisco, California 94105-3901

Dear George,

Enclosed is the annual report for fiscal year 2008/09. If you have any questions, please feel free to contact me. Form Part III, VIIA captures the number of wells that were out of compliance but were repaired within 180 days.

We also had an unusual number of SNC's this quarter due to an operator injecting without permits in an area with fresh water formations. We are pursuing legal action and will keep you informed as we progress through this process.

Sincerely,

Michael Stettner

Michael Stettner
UIC Program Manager

George,
I took these
to go with the
rest of the 7520s
11/19/09

Please type or print all information. Please read instructions. OMB No. 2040-0042 Form Expires 12/31/2011

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
Washington, DC 20460

EPA

UIC Federal Reporting System
Part I: Permit Review and Issuance/ Wells in Area of Review

(This information is solicited under the authority of the Safe Drinking Water Act)

I. Name and Address of Reporting Agency

United States Environmental Protection Agency

CA DOGGR
801 K ST. MS 20-20
SACRAMENTO CA 95814

II. Date Prepared (month, day, year): 11/4/09

III. State Contact (name, telephone no.): Mike Stettner

IV. Reporting Period (month, year): From October 1, 2008 To 9/30/09

Item					I	II SWD 2D	II ER 2R	II HC 2H	III	IV	V
V. Permit Application	Number of Permit Applications Received					112	1082				
VI. Permit Determination	Permit Issued	A	Number of Individual Permits Issued (One Well)	New Wells		31	553				
				Existing Wells		81	528				
		B	Number of area Permits* Issued (Multiple Wells) (*See instructions on back)	New Well Field		0	0				
				Existing Well Field		0	0				
		C	Number of Wells in Area Permits (See B above)	New Wells		0	0				
				Existing Wells		0	0				
	Permit Not Issued	D	Number of Permits Denied/Withdrawn (after complete technical review)			3	10				
	Modification Issued	E	Number of Major Permit Modifications Approved			29	42				
VII. Permit File Review	Number of Rule-Authorized Class II Wells Reviewed			Wells Reviewed		1263	3399				
				Wells Deficient		32	117				
VIII. Area of Review (AOR)	Wells Reviewed	A	Number of Wells in Area of Review	Abandoned Wells		370	406				
				Other Wells		618	1191				
	Wells Identified for C/A	B	Number of Wells Identified for Corrective Action	Abandoned Wells		3	9				
				Other Wells		7	13				
	Wells with C/A	C	1. Number of Wells in AOR with Casing Repaired/Recemented C/A			0	7				
			2. Number of Active Wells in AOR Plugged/Abandoned			0	0				
			3. Number of Abandoned Wells in AOR Replugged			0	2				
			4. Number of Wells in AOR with "Other" Corrective Action			2	3				

IX. Remarks/Ad Hoc Report (Attach additional sheets if necessary)

Certification

I certify that the statements I have made on this form and all attachments thereto are true, accurate, and complete. I acknowledge that any knowingly false or misleading statement may be punishable by fine or imprisonment or both under applicable law.

Signature and Typed or Printed Name and Title of Person Completing Form	Date	Telephone No.

EPA Form 7520-1 (Rev. 12-08) Previous edition is obsolete.

Please type or print all information. Please read instructions on reverse. OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
Washington, DC 20460

UIC Federal Reporting System
Part II: Compliance Evaluation

(This information is solicited under the authority of the Safe Drinking Water Act)

I. Name and Address of Reporting Agency

United States Environmental Protection Agency

CA DOGGR CLASS II
801 K ST MS 2020
Sacramento 95814

II. Date Prepared (month, day, year): 11/4/09

III. State Contact (name, telephone no.): Marilu Habel

IV. Reporting Period (month, year): From October 1, 2008 To 9/30/09

			Item	I	II SWD 2D	II ER 2R	II HC 2H	III	IV	V
V. Summary of Violations	Total Wells	A	Number of Wells with Violations		236	560				
	Total Violations	B	1. Number of Unauthorized Injection Violations		4	9				
			2. Number of Mechanical Integrity Violations		65	126				
			3. Number of Operation and Maintenance Violations		22	5				
			4. Number of Plugging and Abandonment Violations		0	0				
			5. Number of Monitoring and Reporting Violations		193	420				
			6. Number of Other Violations (Specify)		0	0				
VI. Summary of Enforcement	Total Wells	A	Number of Wells with Enforcement Actions		235	551				
	Total Enforcement Actions	B	1. Number of Notices of Violation		37	123				
			2. Number of Consent Agreements		0	0				
			3. Number of Administrative Orders		0	9				
			4. Number of Civil Referrals		0	0				
			5. Number of Criminal Referrals		0	0				
			6. Number of Well Shut-ins		196	417				
			7. Number of Pipeline Severances		4	6				
			8. Number of Other Enforcement Actions (Specify)		8	11				
VII. Summary of Compliance	Number of Wells Returned to Compliance		A. This Quarter		2	2				
			B. This Year		229	536				
VIII. Contamination	Number of Cases of Alleged Contamination of a USDW				1	0				
IX. MIT Resolved	Percent of MIT Violations Resolved in 90 Days				100	100				

X. Remarks/Ad Hoc Report (Attach additional sheets) MIT Violations Resolved in 90 days SWD= 315 ER= 560

Certification

I certify that the statements I have made on this form and all attachments thereto are true, accurate, and complete. I acknowledge that any knowingly false or misleading statement may be punishable by fine or imprisonment or both under applicable law.

Signature and Typed or Printed Name and Title of Person Completing Form	Date	Telephone No.
		(916) 445-9686

EPA Form 7520-2A (1-88) Replaces EPA Form 7520-2 which is obsolete

Please type or print all information. Please read instructions on reverse. OMB No. 2040-0042 Approval Expires 4/30/07

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
Washington, DC 20460

UIC Federal Reporting System
Part II: Compliance Evaluation
Significant Noncompliance

(This information is solicited under the authority of the Safe Drinking Water Act)

I. Name and Address of Reporting Agency

United States Environmental Protection Agency
CA DOGGR CLASS II
801 K ST MS 2020
SACRAMENTO CA 95814

II. Date Prepared *(month, day, year)*: 11/04/2009

III. State Contact *(name, telephone no.)*: Marilu Habel

IV. Reporting Period *(month, year)*: From October 1, 2008 To 09/30/2009

Item				I	II SWD 2D	II ER 2R	II HC 2H	III	IV	V
V. Summary of Significant Non-Compliance (SNC)	Total Wells	A	Number of Wells with SNC Violations		0	9				
	Total Violations	B	1. Number of Unauthorized Injection SNC Violations		0	9				
			2. Number of Mechanical Integrity SNC Violations		1	0				
			3. Number of Injection Pressure SNC Violations		0	0				
			4. Number of Plugging and Abandonment SNC Violations		0	0				
			5. Number of SNC Violations of Formal Orders		0	0				
			6. Number of Falsification SNC Violations		0	0				
			7. Number of Other SNC Violations *(Specify)*		0	0				
VI. Summary of Enforcement Against SNC	Total Wells	A	Number of Wells with Enforcement Actions Against SNC		0	9				
	Total Enforcement Actions	B	1. Number of Notices of Violation		0	0				
			2. Number of Consent Agreements/Orders		0	0				
			3. Number of Administrative Orders		0	9				
			4. Number of Civil Referrals		0	0				
			5. Number of Criminal Referrals		0	0				
			6. Number of Well Shut-ins		0	0				
			7. Number of Pipeline Severances		0	0				
			8. Number of Other Enforcement Actions Against SNC Violations *(Specify)*		0	0				
VII. Summary of Compliance	Number of Wells in SNC Returned to Compliance		A. This Quarter		0	0				
			B. This Year		1	0				
VIII. Contamination	Number of Cases of Alleged Contamination of a USDW				1	0				
IX. Well Closure	Class IV/Endangering Class V Well Closures		Involuntary Well Closure							
			Voluntary Well Closure							

Certification

I certify that the statements I have made on this form and all attachments thereto are true, accurate, and complete. I acknowledge that any knowingly false or misleading statement may be punishable by fine or imprisonment or both under applicable law.

Signature and Typed or Printed Name and Title of Person Completing Form	Date	Telephone No.
	11/04/2009	(714) 816-6847

Please type or print all information. Please read instructions on reverse. OMB No. 2040-0042 Approval Expires 4/30/07

EPA

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
Washington, DC 20460

UIC Federal Reporting System
Part III: Inspections
Mechanical Integrity Testing

(This information is solicited under the authority of the Safe Drinking Water Act)

I. Name and Address of Reporting Agency

United States Environmental Protection Agency
CA DOGGR
801 K ST MS 2020
SACRAMENTO CA 95814

II. Date Prepared *(month, day, year)*: 11/04/2009

III. State Contact *(name, telephone no.)*: Marilu Habel

IV. Reporting Period *(month, year)*: From October 1, 2008 To 09/30/2009

Class and Type of Injection Wells

Section			Item		I	II SWD 2D	II ER 2R	II HC 2H	III	IV	V
V. Summary of Inspections	Total Wells	A	Number of Wells Inspected			1,048	2,986				
	Total Inspections	B	1. Number of Mechanical Integrity Tests (MIT) Witnessed			584	380				
			2. Number of Emergency Response or Complaint Response Inspections			1	5				
			3. Number of Well Constructions Witnessed			0	28				
			4. Number of Well Pluggings Witnessed			15	255				
			5. Number of Routine/Periodic Inspections			540	2,464				
VI. Summary of Mechanical Integrity (MI)	Total Wells	A	Number of Wells Tested or Evaluated for Mechanical Integrity (MI)			1,172	3,312				
		B	No. of Rule-Authorized Wells Tested/Evaluated for MI	Passed 2-part test							
				Failed 2-part test							
	For Significant Leak	C	1. Number of Annulus Pressure Monitoring Record Evaluations	Well Passed		22	1,613				
				Well Failed		0	106				
			2. No. of Casing/ Tubing Pressure Tests	Well Passed		214	218				
				Well Failed		1	12				
			3. Number of Monitoring Record Evaluations	Well Passed		0	0				
				Well Failed		0	0				
			4. No. of Other Significant Leak Tests/Evaluations *(Specify)*	Well Passed		73	490				
				Well Failed		1	4				
	For Fluid Migration	D	1. Number of Cement Record Evaluations	Well Passed		0	0				
				Well Failed		0	0				
			2. Number of Temperature/ Noise Log Tests	Well Passed		20	5				
				Well Failed		0	0				
			3. No. of Radioactive Tracer/ Cement Bond Tests	Well Passed		940	2,669				
				Well Failed		33	176				
			4. No. of Other Fluid Migration Tests/Evaluations *(Specify)*	Well Passed		0	0				
				Well Failed		0	0				
VII. Summary of Remedial Action	Total Wells	A	Number of Wells with Remedial Action			16	146				
	Total Remedial Actions	B	1. Number of Casing Repaired/ Squeeze Cement Remedial Actions			4	6				
			2. Number of Tubing/Packer Remedial Actions			10	120				
			3. Number of Plugging/Abandonment Remedial Actions			0	0				
			4. Number of Other Remedial Actions *(Specify)*			2	19				

VIII. Remarks/Ad Hoc Report *(Attach additional sheets)* --- NONE---

Certification

I certify that the statements I have made on this form and all attachments thereto are true, accurate, and complete. I acknowledge that any knowingly false or misleading statement may be punishable by fine or imprisonment or both under applicable law.

Signature and Typed or Printed Name and Title of Person Completing Form

Date: 11/04/2009

Telephone No.: (714) 816-6847

EPA

United States Environmental Protection Agency
Office of Ground Water and Drinking Water
Washington, DC 20460

UIC Federal Reporting System

Part IV: Quarterly Exceptions List

(This information is collected under the authority of the Safe Drinking Water Act)

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

I. Reporting Period

From: 10/01/2008 To: 09/30/2009

II. Well Class and Type	III. Name and Address of Owner/Operator	IV. Well ID No. (Permit No.)	V. Summary of Violations: Date of Violation	Mark ('X') Violation Type: Unauthorized Injection	Well Mechanical Integrity	Injection Pressure	Plugging and Abandonment	Formal Order	Falsification	Other (Specify)	VI. Summary of Enforcement: Date of Enforcement	Mark ('X') Enforcement Type: Notice of Violation	Consent Agreement	Administrative Order	Civil Referral	Criminal Referral	Well Shut-in	Pipeline Severance	Other (Specify)	VII. Date Compliance Achieved
	--- NONE ---																			

Certification

I certify that the statements I have made on this form and all attachments thereto are true, accurate, and complete. I acknowledge that any knowingly false or misleading statement may be punishable by fine or imprisonment or both under applicable law.

Signature of Person Completing Form	Typed or Printed Name and Title	Date	Telephone No.
M. Habel CA DOGGR CLASS II	Marilu Habel	11/04/2009	(916) 445-9686

APPENDIX A7

CALIFORNIA HAZARDOUS WASTES THAT CAN BE INJECTED IN A CLASS II WATER DISPOSAL WELL

California hazardous wastes that can be injected in a Class II WD well.

Currently, E&P wastes are manage as non-hazardous solid wastes under Federal law, pursuant to the E&P exemption codified in Title 40 Code of Federal Regulations (40 CFR), Section 261.4(b)(5), and included, with limitations, in Title 22 California Code of Regulations (22 CCR) Section 66261.4(b)(2) and 66261.24(a)(1). The exemption applies in California if the waste displays the toxicity characteristic for hazardous waste based solely on the Toxicity Characteristic Leaching Procedure (TCLP), as provided under 22 CCR, Section 66261.24.

The E&P exemption was also incorporated into California regulations, 22 CCR, Section 66261.24(a)(2) and 66261.24(a)(1), but it is limited in scope. The exemption applies in California in cases where the waste is hazardous solely by meeting the Federal characteristic for toxicity under the TCLP. Thus, a waste that is hazardous solely by meeting or exceeding the maximum contaminant concentration for constituents extracted by TCLP, and for which Federal regulator thresholds have been established, is exempted from regulation as hazardous waste in California. The exemption does not apply if toxicity is determine based on criteria other than TCLP, or the waste meets any of the other three characteristics of hazardous waste in California. The exemption does not apply if toxicity is determined based on criteria other than TCLP, or the meets any of the other three characteristics of hazardous waste codified in 22 CCR, Article 3, Sections 66261.20 et seq., namely ignitability, corrosivity, and reactivity.

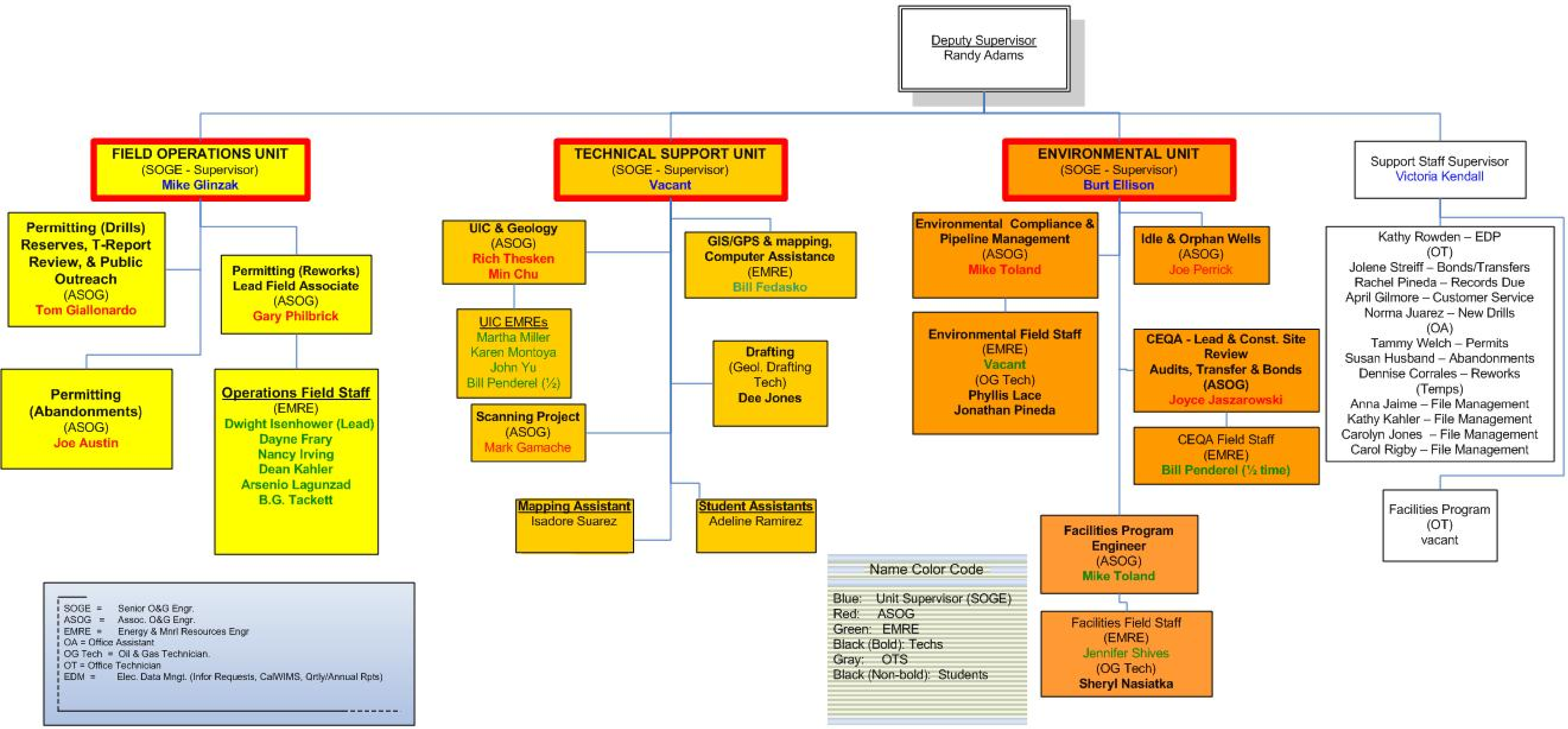
APPENDIX B1

ATTACHMENTS TO THE DISTRICT 4 RESPONSES TO THE EPA QUESTIONNAIRE

- ATTACHMENT A - DISTRICT 4 ORGANIZATION CHART
- ATTACHMENT B - MEMORANDUM OF UNDERSTANDING WITH BLM
- ATTACHMENT C - MEMORANDUM OF AGREEMENT WITH STATE WATER QUALITY CONTROL BOARD
- ATTACHMENT D - ENERGY AND MINERAL RESOURCES ENGINEER POSITION SPECIFICATIONS
- ATTACHMENT E - OIL AND GAS ENGINEER POSITION SPECIFICATIONS
- ATTACHMENT H - STANDARD ANNULAR PRESSURE TEST REQUIREMENTS
- ATTACHMENT J - DISTRICT 4 PROVISIONAL ORDERS AND CIVIL PENALTIES, 2000 TO 2009

Attachment A – District 4 Organization Chart

District 4 Organization Chart



MEMORANDUM OF UNDERSTANDING

BETWEEN THE

CALIFORNIA STATE OFFICE
U.S. BUREAU OF LAND MANAGEMENT
AND
CALIFORNIA DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Revised October 2008

I. PURPOSE

This Memorandum of Understanding (MOU) is made and entered into by and between the U.S. Bureau of Land Management in California, hereinafter called the "BLM" and the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, hereinafter called the "Division." The purpose of this MOU is to delineate procedures for regulating oilfield operations where both the BLM and the Division have jurisdictional authority, hereinafter called "BLM Administered Land," to streamline operations and minimize duplication. Unless otherwise noted, this MOU applies to oilfield operations on all federally-owned land administered by BLM in California, whether that land is owned in total by the federal government or is a "split-estate" (when the federal government owns either the minerals or the surface, but not both). Wells within a federal unit operation but located on land with private surface and minerals ownership are not considered to be on "BLM Administered Land", unless the unit agreement stipulates BLM regulation of the land, and then only to the extent stipulated by the unit agreement. However, production verification for both private and federal wells in federal units will be performed by BLM.

The BLM and the Division recognize that it is in the best interest of the respective agencies and the public to exchange information and combine resources where possible. Further, this MOU acknowledges the value of the Oil and Gas Work Group, hereinafter called the "Group," as a means of accomplishing this exchange. The Group will continue to meet regularly and may form subcommittees to address specific issues. The Group will conduct the Oil and Gas Conference as a forum for communication between government agencies, industry, and the public at large. Furthermore, the Group may make recommendations to the BLM and the Division, either collectively or individually.

This MOU is not intended to limit such partnerships or make them exclusive. Also, this MOU is not intended to supersede any compliance requirements with other federal or state laws and regulations.

II. AUTHORITIES

This cooperative agreement is entered into with full recognition of the following regulatory mandates/authorities:

A) The BLM has mandated responsibilities for regulation of all oilfield operations on BLM Administered Land, under Title 43 of the Code of Federal Regulations (CFR), Group 3100 Oil and Gas Leasing, Title 40, Subpart 1500 of the CFR, the National Environmental Policy Act (NEPA), the Endangered Species Act, and other applicable laws. Under Federal Regulations, the BLM as the minerals and/or surface owner, is considered to wholly regulate oilfield operations (downhole and surface) on all BLM Administered Lands.

B) The Division has the statutory responsibility under Division 3 of the Public Resources Code (PRC) to regulate all oilfield operations in the State of California. The Division is considered by California statute to wholly regulate downhole operations and be responsible for appropriate surface regulations. The Division has been delegated authority, under provisions of Section 1425 of the Federal Safe Drinking Water Act, to administer the Underground Injection Control (UIC) program for Class II injection wells in the state of California. Also, the Division has discretionary permitting authority under the California Environmental Quality Act (CEQA). The Division serves as lead agency for drilling activities within unincorporated areas of Kern County. It serves as a responsible agency for drilling activities in incorporated areas of Kern County where the local agency issues a discretionary permit.

C) Both the BLM and the Division are mandated to protect hydrocarbon reservoirs, groundwater, and health and safety; however, Division statutes effectively place liability for downhole well operations with the operator, while BLM, as the landowner, maintains considerable liability for both downhole and surface conditions. The BLM is responsible for enforcing a wide range of surface land-use issues, including fresh water protection from surface discharges and endangered species habitat.

III. OPERATING AGREEMENTS

To implement this MOU in the most effective manner, Operating Agreements will be utilized to outline specific procedural and technical working relationships between the BLM and the Division. The following Operating Agreements have been developed, attached to, and made a part of this MOU.

A) Downhole Well Permitting
B) Surface Operations
C) Idle/Orphan Well Program
D) Bonding
E) Underground Injection Control (UIC)
F) Exchange of Resources/Information
G) Unified Incident Response

Other Operating Agreements may be developed at the recommendation of BLM, the Division, or the Group. Operating Agreements may be added, modified or deleted with the consent of the BLM and the Division and with input from the Group. Unless otherwise noted, whenever an Operating Agreement states that applications, permits, or records will be furnished to the other party, that information will be furnished within thirty (30) days of being available.

IV. CONCLUSION

This MOU replaces and nullifies the MOU adopted in December 1995, presently in effect between the BLM and the Division. This MOU may be modified in the future, by mutual consent and agreement of the BLM and the Division, as conditions warrant. This MOU does not limit the BLM and the Division from reaching other agreements, within the limit of their statutory responsibilities and authorities, either with each other or with other parties or agencies. Nothing in this MOU may supersede or exceed the statutory or regulatory authority, or responsibility of either agency.

This MOU will be effective upon signature of the designated parties. This MOU can be terminated by either party by providing written notice at least 45 days in advance.

______________________ Mike Pool State Director Bureau of Land Management	______________________ Bridgett Luther Director Department of Conservation
______________________ Timothy Z. Smith Bakersfield Field Office Manager Bureau of Land Management	______________________ Hal Bopp State Oil and Gas Supervisor Division of Oil, Gas, and Geothermal Resources

DATE: ___________________

**DOWNHOLE WELL PERMITTING
OPERATING AGREEMENT**

To provide an effective, streamlined, coordinated application and permitting/approval process, and to reduce or eliminate duplicative administration of regulations and requirements, the BLM and the Division hereby agree to adhere to the procedures set forth in this Operating Agreement for Downhole Well Permitting. The procedures in this Operating Agreement shall be carried out in a cooperative manner, to fulfill the objectives of the BLM and the Division and reduce the regulatory burden on industry.

The BLM is mandated to post all Applications for Permit to Drill (APDs) for a 30-day public review period, while the Division is obligated to respond to Notices of Intention to Drill New Wells within 10 working days. Otherwise, BLM and Division Permits to Conduct Well Operations are substantially equivalent in the specifications required to drill, rework, and plug and abandon wells. The BLM will utilize Division requirements that are clearly more stringent. Applicable Division requirements that are more stringent are outlined in Section C of this Operating Agreement.

Downhole well permitting on BLM Administered Land will be conducted as follows. (Note: Permitting of UIC wells is outlined in the UIC Operating Agreement attached to the MOU.)

A) <u>BLM-owned Fee Land and Split-estate BLM-owned Minerals</u> (Note: includes cases where the BLM owns less than 100% of the mineral estate, and also where a well is drilled directionally through both BLM and private minerals.)

<u>BLM Responsibility</u>

1) The BLM authorizes all applications/operations for APDs, Sundries, and Abandonments, as mandated in Title 43, Subpart 3160, of the CFR.

2) Applications and permits for downhole well operations, except for UIC wells, shall be obtained from the BLM. All approvals for variances and all inspections will be conducted by the BLM.

3) The BLM will forward a copy of all APDs to the Division within 24 hours of receipt, by the most expedient means possible, for the purpose of assigning API Numbers, verifying proper well designations, posting in the Division issued Summary of Notices Received, and assuring State bond coverage.

4) The BLM will review Sundries (notices to perform downhole work on an existing well) and determine State bond coverage requirements. The Division will be notified if the operator needs to provide state bond coverage.

5) The BLM will develop surface and downhole conditions of approval (COAs) for each application and will forward a copy of the approval to the Division for its records.

Division Responsibility

1) The Division will accept copies of BLM notices and permits/approvals for its records. No separate approval from the Division will be required for production operations.

2) Operators will continue to furnish production and injection reports, well summaries, histories including results of BLM inspections, logs, and other records required by the PRC to the Division.

3) The Division will keep BLM advised of state bonding requirements so BLM may make accurate financial assurance determinations.

B) Split-estate Privately-owned Minerals

Oil and gas development activities on split-estate with BLM-owned surface and privately-owned minerals are uncommon. As of March 2002, this situation has occurred only in the Alpaugh/Trico Gas area. When oil and gas development activities occur in such a situation, the following will apply:

BLM Responsibility

1) The BLM Natural Resource Team will authorize applications to conduct surface disturbing activities and will provide COAs to comply with requirements for surface disturbance on BLM-owned surface.

2) The BLM will accept copies of Division notices and permits/approvals for its records. No separate approval from the BLM for downhole operations will be required.

3) The BLM will provide the Division with BLM surface ownership information for areas where drilling activities are likely.

Division Responsibility

1) The Division permits proposals to drill, redrill and to perform work in existing wells that constitute a permanent mechanical change under PRC 3203, or to plug and abandon wells (PRC 3229).

2) Applications will be submitted to and permits for downhole well operations will be received from the Division. All approvals for variances and all inspections will be conducted by the Division. The Division will develop the COAs for each application, on the Division Permit to Conduct Well Operations form, for each application. If the application or permit involves surface disturbance, the Division will inform operators that BLM approval is required prior to beginning operations.

3) The Division will forward a copy of the notice and approval to the BLM for its records.

C) More Stringent Division Requirements

Where applicable, the BLM will specify the following more stringent Division downhole requirements. These specifications are in addition to existing BLM specifications. The BLM will consult with the Division if there are any questions about more stringent requirements.

1) For plugging and abandonment, the base of fresh water (BFW) will be protected with a cement plug. Base of fresh water is designated as 3,000 parts per million (ppm) total dissolved solids (TDS), although there are some variances for local conditions. The BFW will be protected with a minimum 200-foot plug across the fresh-saltwater interface in open hole, a 100-foot plug across the interface inside cemented pipe, or a 100-foot plug inside pipe, with sufficient cement placed outside pipe if uncemented. For new or existing wells, the base of fresh water must be protected with cement behind pipe lifted to at least 100 feet above the interface.

2) In open hole, a cement plug shall be placed to extend from the total depth of the well, or from at least 100 feet below the bottom of each oil or gas zone or injection zone, to at least 100 feet above the top of each oil or gas zone or injection zone. In cased hole, all perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, an oil or gas zone or injection zone, whichever is highest. For massive sand intervals, or any depleted productive interval more than 100 feet thick, a variance may be allowed that the cement shall extend from at least 100 feet below the top of the zone to at least 100 feet above.

3) A bridge plug may not be used over the top oil or gas interval, but may be used above the lowermost zone in a multiple-zone completion, if that zone is isolated from the upper zones by cement behind casing. In some cases, multiple bridge plugs may be used in alternating zones, where multiple zones exist, so long as a cement plug is placed across the uppermost zone.

4) Cement plugs shall extend at least 100 feet above casing stubs or junk. Prior to placing a 100-foot plug above junk where the base of freshwater, or oil or gas zones were not plugged properly, cement will be downsqueezed past the junk to the extent possible.

5) All portions of the hole not plugged with cement will be filled with inert mud fluid having a minimum gel-shear strength (10 minute rheometer measurement) of 20 lbs./100 sq. ft. and capable of balancing formation pressures. (This generally requires 9.6 lb/gal mud.)

6) The state well spacing statutes, specified in PRC Sections 3600 through 3609, will be utilized. The spacing statutes generally accommodate line agreements. Any areas of disagreement or deviation from spacing statutes would require a separate agreement.

D) <u>Alternate Plugging and Abandonment Requirements</u>

The use of hydrated sodium bentonite as a solid plugging material may be allowed in lieu of cement by either BLM or the Division, within operational guidelines developed by the Division. These guidelines presently allow the use of bentonite for plugging wells located in the San Joaquin Valley that are shallower than 4,000 feet with a zone pressure differential that is less than 500 psi from an upper zone. The permitting of well abandonments using the alternative bentonite plugging technique is discretionary on the part of BLM and the Division, and may be permitted on a case-by-case basis in the best judgment of either agency.

SURFACE OPERATIONS
OPERATING AGREEMENT

Generally, the BLM has more extensive requirements for surface operations. The BLM enforces protection of endangered species habitat, cultural resources and other resource values, and assesses the cumulative impact of development on all BLM Administered Land. The BLM also conducts field production accounting audits on all leases with federal minerals. Otherwise, both the BLM and Division enforce substantially equivalent requirements for the operation of surface facilities. Therefore, inspection and surveillance of surface operations on BLM Administered Land will be conducted as follows:

A) Environmental Lease Inspections

BLM Responsibility

1) The inspection and enforcement of compliance for the surface condition of oil and gas leases, including pipelines and aboveground tanks, will be the responsibility of the BLM, with the exception of UIC facilities. The BLM will inspect the leases, issue citations, and enforce remediation actions, as applicable, in accordance with existing federal regulations.

2) The BLM will set the conditions for the reclamation of the disturbed surface.

3) The operation and proper closure of surface impoundments will be the responsibility of the operator, under the oversight of the BLM, and in accordance with guidelines provided by BLM to federal operators (dated 4-8-94). The guidelines were developed by a subcommittee of the Work Group and were adopted by the full Work Group.

Division Responsibility

1) The Division will be responsible for the inspection and enforcement of compliance for the surface condition of UIC facilities, including UIC injection wells, injection pipelines, and injection pumps. The Division will be responsible for determining remediation requirements for leaking and otherwise deficient UIC facilities.

2) **On split-estate leases with a privately-owned surface**, the Division will enforce provisions of the PRC, only if necessary for the protection of the private surface owner and the environment, and in consultation with the BLM.

3) **On split-estate leases with privately-owned minerals**, the Division will enforce provisions of the PRC, in consultation with the BLM, if necessary, for the protection of subsurface reservoirs and protection of groundwater.

B) Well Abandonment and Surface Restorations

BLM Responsibility

1) The BLM will receive, evaluate, set the COAs and approve any request/application relating to abandoned well surface restoration, including UIC wells, in accordance with all existing federal regulations.

2) Upon completion of restoration activities and notification by the operator, the BLM will inspect the restored surface to ensure that work done is consistent with the COAs. If the COAs are met, the BLM approves the final abandonment notice (FAN).

3) **For split-estate leases with a privately-owned surface**, exceptions to standard surface restoration requirements may be made with the written consent of the surface landowner, and in consultation with the Division, including the conversion of abandoned oil wells to water wells.

4) The BLM will not forward a copy of the FAN approval to the Division for its records. This document is no longer required by the Division.

Division Responsibility

1) The Division will not issue a separate report of final abandonment approval unless necessary for state-required bond release or other administrative reasons. In any case, the Division's final abandonment approval will indicate only that all required records have been received, all Division requirements have been met, and that final approval will be the responsibility of the BLM.

2) **For split-estate leases with BLM-owned surface**, the Division will issue a Final Letter of Abandonment Approval upon completion of downhole plugging and abandonment operations. The letter will state that downhole plugging and abandonment procedures have been completed in accordance with Division regulations and that surface restoration is the responsibility of the operator, in accordance with BLM requirements.

3) **For split-estate leases with privately-owned surface**, the Division will enforce provisions of the PRC only if necessary for the protection of the surface landowner and the environment, and in consultation with the BLM.

4) If the Division issues a Final Letter of Abandonment Approval, a copy will be forwarded to the BLM for its records.

C) Pipeline Management Program

BLM Responsibility

1) The BLM will exercise jurisdiction for pipelines/flow-lines and pipeline repair requirements, including jurisdiction for pipeline leaks resulting in spills, within its authority on BLM Land.

2) The BLM will receive, upon request, from the Division copies of all records related to the Division's pipeline management program for pipelines located on BLM Land.

Division Responsibility

1) The Division will be responsible for regulating pipelines pursuant to California Code of Regulations (CCR) Section 1774 (e) through 1774 (l), which includes environmentally sensitive pipelines, as defined in CCR Section 1760 (d). Under this program, operators must prepare pipeline management plans that include mapping, maintenance programs, and testing for certain pipelines.

2) The Division will inspect and may witness mechanical integrity testing of all pipelines included in the pipeline management plans.

3) The Division will furnish BLM, upon request, copies of all records, including pipeline management plans, maps, and testing results for applicable pipelines located on BLM Land.

D) Well Access, Well Reabandonment, and the California Environmental Quality Act (CEQA) Program

In its role as a CEQA Responsible Agency, the Division comments on various proposed surface developments throughout the state. These comments include recommendations to provide access for future exploration and development, requirements to maintain access to existing wells, and locating previously plugged and abandoned wells. Using the discretionary authority of the lead agency, the Division may require testing and replugging previously abandoned wells to current standards. BLM wells may be involved in this review if they are located on a split estate where private surface is being developed.

On split-estate leases with a privately-owned surface:

BLM Responsibility

1) The BLM will consult with the Division regarding retaining access to existing wells and maintaining access for future oilfield development.

2) The BLM will consult with the Division, if necessary, for reabandonment specifications and will issue reabandonment specifications if downhole work will have an impact on BLM-owned minerals.

Division Responsibility

1) The Division will act in its capacity as a CEQA responsible agency, and in consultation with BLM, recommend requirements for retaining access to existing wells

and maintaining access for future oilfield development when private surface development is proposed and conducted.

2) The Division will act in its capacity as a CEQA responsible agency, and in consultation with BLM, specify reabandonment work for wells not plugged and abandoned in accordance with current standards when private surface development is proposed. This reabandonment work will be accomplished by the surface developer. If the reabandonment involves substantial downhole work, BLM will be contacted to issue reabandonment specifications.

IDLE/ORPHAN WELL PROGRAM
OPERATING AGREEMENT

A) Idle Well Program

The BLM conducts an idle-well program under Title 43 CFR 3160, WO-IM-No. 92-149 and CA-94-40 and has adopted a formal idle-well policy that was developed in full partnership with the Oil & Gas Work Group. The Division conducts an idle-well program under the authority of PRC Sections 3106, 3202, 3206, 3206.5, 3237, and 3250 and has adopted a formal idle-well policy. The BLM and Division idle-well policies have similar goals and require testing of idle wells to ensure mechanical integrity, protection of groundwater, and protection of reservoir integrity. The BLM and Division require plans from operators to place long-term idle wells back on operational status or to plug and abandon such wells.

The idle-well program on BLM Administered Land will be conducted as follows:

BLM Responsibility

1) The BLM will administer its formal idle/orphan well program and policy.

2) **On split-estate leases with privately-owned minerals**, the BLM will have input, as to the status of idle wells, on its property.

3) The BLM will furnish the Division with mechanical integrity test results.

4) The BLM will participate in the Division's Idle Well Reduction Program as agreed to by the Agencies.

Division Responsibility

1) The Division will continue to maintain records of idle wells on BLM Administered Land for the purpose of enforcing the PRC.

2) **On split-estate leases with privately-owned minerals**, the Division will administer its idle-well program. The Division will share its idle-well program data with the BLM.

3) Operators may meet the long-term idle well elimination requirements of PRC Section 3206(a)(4) by elimination of wells on BLM Administered Land.

4) The Division will include the BLM in all Idle Well Reduction activities where these activities involve federal wells.

B) Orphan Well Program

The BLM and the Division define an orphan well as a well for which the operator is deceased, defunct, bankrupt, or otherwise inaccessible, and there is no or insufficient bond coverage for plugging and abandonment operations. Both the BLM and Division conduct programs to minimize the number of orphan wells, by finding responsible parties or operators willing to acquire such wells and return them to production, attempting to assure adequate financial responsibility when well ownership/operatorship is transferred or, ultimately, to contract for plugging and abandonment to abate a public nuisance. The Division, at its discretion, may utilize PRC Section 3258 funding to plug and abandon orphan wells on BLM Administered Land. The BLM may utilize federal bond funds and/or federally budgeted orphan well funds to participate in plugging and abandonment operations with the Division on a case-by-case basis. The vehicle for transferring these funds to the Division is an Assistance Agreement.

These programs are developed in cooperation with industry through subcommittees of the Group, the Conservation Committee of California Oil and Gas Producers, and other ad hoc committees. The BLM and the Division will continue to work together, and with these subcommittees, to make the best use of funds and other resources available for remediating idle-deserted, hazardous, and orphaned wells.

BONDING
OPERATING AGREEMENT

The BLM and the Division acknowledge that bonding statutes are an obvious example of duplicative requirements. Under current provisions of the PRC, the Division is mandated to require bond coverage on all wells, including those on BLM Administered Land. The BLM and the Division will work together to eliminate duplication, while recognizing the need to maintain bonds consistent with existing statutes. Hence, the following:

BLM Responsibility

A) The BLM will continue to maintain bond coverage consistent with the level of liability for all operations on BLM Administered Land (surface and minerals) as mandated under CFR Title 43, Subpart 3104. Under this regulation, the BLM requires bond coverage for operating individual leases.

Division Responsibility

A) The Division will continue to require a performance bond, in conformance with PRC Sections 3202 (e) and 3204 through 3206, during idle well acquisitions and for either drilling a new well or making mechanical changes to an existing well on BLM Administered Land.

UNDERGROUND INJECTION CONTROL (UIC) OPERATING AGREEMENT

The U.S. Environmental Protection Agency (EPA), under provisions of Section 1425 of the Safe Drinking Water Act, has delegated authority (primacy) to the Division to administer the UIC program for Class II injection wells in California, including those on BLM Administered Land. The Division does not approve notices to drill injection wells, or convert existing wells to injection, without an approved UIC project or injectivity test.

CFR Title 43, Subpart 3162.5, in conjunction with Federal Onshore Order No. 7, mandates that the BLM approve underground injection and the disposal of produced water on BLM Administered Land. The BLM assigns to the Division injection approval authority, except for surface use conditions of approval, on BLM Administered Land. The UIC program and disposal of produced water will be conducted as follows:

BLM Responsibility

A) Prior to project approval:

1) The BLM will receive, from the Division, a copy of the project application along with the draft conditions of approval. No action will be required on the part of BLM, although comments may be provided to the Division if the BLM desires.

B) Drilling an injection well outside an approved UIC project:

1) A well cannot be approved for injection unless it is within the scope of an approved UIC project, and injection is not allowed until the project, or injectivity test is

approved. On BLM-owned minerals, the operator could file an APD with the BLM and subsequently file a notice to convert to injection with the Division.

C) Drilling an injection well inside an approved UIC project:

1) The BLM will receive a copy of the Notice of Intention from the Division.

2) The BLM will receive from the operator **an Application for Permit to Drill (APD)** for any UIC injection well application on **all** BLM-owned land, **whether BLM owns the surface or not**, to evaluate and set surface use Conditions of Approval.

D) Abandonment of injection wells:

1) The BLM will receive from the operator a Sundry Notice for any UIC injection well application to plug and abandon a well on **all** BLM-owned land, to evaluate and set surface use Conditions of Approval.

2) The BLM will be responsible for surface restoration after the downhole plugging and abandonment work is accomplished.

E) Surface facilities:

1) The BLM will receive from the operator a Sundry Notice for the installation or modification of any UIC surface facilities, including UIC injection pipelines, injection fluid storage tanks, and injection pumps, on **all** BLM-owned land, to evaluate and set surface use Conditions of Approval.

F) Cyclic steam wells:

1) Wells used to inject steam on a cyclic basis, in conjunction with cyclic production, will receive permits and be administered by BLM as production wells, with consideration for specific injection issues subject to input from the Division.

G) Conversion of UIC wells to production, or other non-UIC use:

1) On BLM-owned minerals, notices to convert existing UIC wells to production wells, or other non-UIC use, will be filed on a Sundry Notice with the BLM. A copy of the notice and permit will be furnished to the Division.

H) Gas and Air (In Situ Combustion) injection wells/projects:

1) Wells used for gas and air (in situ combustion) injection, including gas-storage wells, are considered to be UIC wells and will be drilled, operated, permitted, and regulated under the provisions of this Operating Agreement.

I) Rights of Ways:

1) All rights of ways for pipelines associated with disposal of off-lease water will require BLM approval.

J) Filing Well Records

1) The BLM will receive from the operator well histories, including results of Division inspections, and logs.

Division Responsibility

A) Under UIC Primacy, the Division will receive for approval all UIC injection projects (steamflood, waterflood, water disposal, etc.). Subsequently, the Division will prepare a draft approval letter, in accordance with program requirements, and furnish a copy of the project application to the BLM. The final project approval by the Division will address BLM comments and concerns. **The Division will ensure that a stipulation is included in their Permit to Conduct Well Operations (for drilling and abandonment of all UIC wells) notifying the operator that it must receive an approval from the BLM for surface disturbance prior to move in.**

B) The Division will be responsible for the inspection and enforcement of compliance for the surface condition of UIC facilities, including UIC injection wells, injection pipelines, injection fluid storage tanks, and injection pumps. The remediation of leaking and otherwise deficient UIC facilities will be the responsibility of the operator, in conformance with Division specifications.

C) Applications for aquifer exemptions will be filed with the Division and processed in accordance with EPA regulations. A copy of applications located on, or which would include BLM Administered Land, will be forwarded to the BLM for review and comment as described under BLM responsibilities in this section.

D) Notices to conduct downhole well operations for drilling new UIC injection wells within an existing UIC project, reworking existing UIC injection wells, converting existing non-UIC producing wells to UIC injection wells, or abandoning UIC injection wells will be filed with the Division for approval. A copy of the notice and the Division's Permit to Conduct Well Operations will be furnished to the BLM.

E) Any files of cyclic steam project letters, and any related correspondence will be kept by the Division. Copies of cyclic steam project letters will be furnished to the BLM. The Division will be responsible, in consultation with the BLM, for any issues related to cyclic steam projects or wells that are specifically related to the steam injection phase.

EXCHANGE OF RESOURCES/INFORMATION OPERATING AGREEMENT

A) Well Records and Technical Information

Within reasonable guidelines, and to the extent practical, the BLM and the Division will exchange and make available well records and other technical information, subject to confidentiality limitations. Publications, maps, and copies will be exchanged at no cost. This exchange will include access to technical training.

The BLM and the Division agree to work cooperatively and share information, regarding the development of well record automation, so that information can be shared and accessed electronically.

B) Tank Inventory

The BLM maintains an inventory of all tanks on BLM Administered Land. The Division is responsible for maintaining an inventory of aboveground tanks containing hydrocarbons with a capacity greater than 250 barrels. The BLM provides to the Division tank inventory information at the request of the Division.

C) Operator Transfers

Both the BLM and the Division are required to process operator transfers, resulting from sales, acquisitions, or other means, and enforce their respective requirements, including bond coverage. The BLM and the Division will notify each other of operator transfers **/ lease conveyances** on BLM Administered Land. **Either agency may request that the transfer approval be delayed pending resolution of issues of concern.**

D) Field Rules

The Division will advise the BLM, and consider BLM comments, when it develops field rules for oil and gas fields that include BLM Administered Land. The BLM will consider incorporating Division field rule provisions in its COAs.

E) Personnel

The BLM and the Division may exchange personnel (petroleum engineers, petroleum engineering technicians, geologists, surface compliance specialists, and other field staff) for periods not to exceed ninety (90) days at any given time. BLM staff may be detailed to work in the Division office, while an equivalent number of Division staff may be detailed to work in the BLM office. Both the BLM and the Division agree that only employees of similar classification will be exchanged at any time. This process will help familiarize the BLM and the Division with each other's functions and operational processes.

UNIFIED INCIDENT RESPONSE

Both the BLM and Division are required to respond to incidents such as fire, spills, and other events where damage to life, property, or the environment has occurred within their respective jurisdictions.

Where such incidents involve both federal and private lands, the following unified incident response plan will apply:

A) The Division will be responsible for assessing damage to private lands. This will include damage caused by or to any facilities related to UIC operations on federal lands.

B) The BLM will be responsible for assessing damage to federal lands. This will include damage to property or the environment, exclusive of facilities, related to UIC operations.

C) The Division and BLM will establish a joint response team to exchange damage assessment information and make response recommendations to the Incident Command Center, if established.

D) In most cases involving multiple jurisdictions, the Division will defer to the federal designated spokesperson for media communication. The joint response team will provide coordinated information to the media spokesperson.

PERMITTING /INSPECTION MATRIX

PERMITS, INSPECTIONS VARIANCE APPROVALS FOR:	BLM FEE	BLM MNRLS/ PRIVATE SURFACE	BLM Srfc./ PRIVATE MINERALS	Private Srfc/ Private Mnrls in BLM Unit
PRODUCTION VERIFICATION	**BLM**	**BLM**	**N/A**	**BLM**
DOWNHOLE OPERATIONS (Non-UIC) Drills, Reworks, & Abd. Permits, Variance Approval & Inspections	**BLM**	**BLM**	**DOG**	**DOG**
Directional BLM + Private Compl.	**BLM**	**BLM**	**N/A**	**N/A**
ENVIRONMENTAL LEASE INSP. (see UIC exception below)	**BLM**	**BLM**	**BLM**	**DOG**
ABD WELLSITE RESTORATION	**BLM**	**BLM**	**BLM**	**DOG**
UIC: 1. Project Approval	**DOG**	**DOG**	**DOG**	**DOG**
2. Drill, Rework w/in project	**DOG**	**DOG**	**DOG**	**DOG**
3. Drill, Rework outside of project	**BLM**	**BLM**	**DOG**	**DOG**
4. Abandonment (downhole)	**DOG**	**DOG**	**DOG**	**DOG**
5. Cyclic Well	**BLM**	**BLM**	**DOG**	**DOG**
6. Convert UIC to Prod. (OG)	**BLM**	**BLM**	**DOG**	**DOG**
7. Convert Prod. to UIC	**DOG**	**DOG**	**DOG**	**DOG**
8. Gas Injection Well	**DOG**	**DOG**	**DOG**	**DOG**
9. Observation Well	**BLM**	**BLM**	**DOG**	**DOG**
10. Facilities Inspection	**DOG**	**DOG**	**DOG**	**DOG**
11. Surface Conditions of Approval	**BLM**	**BLM**	**BLM**	**N/A**

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EXHIBIT

MEMORANDUM OF AGREEMENT
BETWEEN THE
STATE WATER RESOURCES CONTROL BOARD
AND THE
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

Purpose

The purpose of this Memorandum of Agreement (MOA) is to outline the procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. These procedures are intended to provide a coordinated approach resulting in a single permit satisfying the statutory obligations of both parties to this MOA. These procedures will ensure that construction or operation of oil, gas, and geothermal injection wells and surface disposal of waste water from oil and gas and geothermal production does not cause degradation of waters of the State of California.

General

Responsibilities of the Agencies

The Department of Conservation, Division of Oil and Gas (CDOG) has the statutory responsibility to prevent, as far as possible, damage to underground and surface waters suitable for irrigation or domestic purposes resulting from the drilling, operation, maintenance, or abandonment of oil, gas, and geothermal wells (Public Resources Code Sections 3106 and 3714). In March 1983, CDOG received primacy from the Environmental Protection Agency (EPA) pursuant to the provisions of Section 1425(a) of the federal Safe Drinking Water Act that gives CDOG additional authority and responsibility to regulate Class II wells in the State. Class II wells are used to inject fluids into the subsurface that are related to oil and gas production.

The State Water Resources Control Board (SWRCB) and the nine California Regional Water Quality Control Boards (collectively RWQCB) have statutory responsibility to protect the waters of the State and to preserve all present and anticipated beneficial uses of those waters (Water Code, Division 7, Chapters 1 through 7).

Scope of Agreement

The following procedures have been formulated and adopted by the CDOG and SWRCB to: (1) simplify reporting of proposed waste discharges by the oil, gas, and geothermal operators; (2) achieve coordination of activity; and, (3) eliminate duplication of effort among the State agencies. As far as these agencies are concerned, the method of reporting proposed oil, gas, and geothermal underground injection and surface discharges will be uniform throughout the State. The attached maps show district and regional boundaries and office addresses.

The following procedures will not generally be applicable to injection wells or surface disposal methods used by operators to dispose of wastes other than produced water and fluids defined by the EPA as Class II. Other discharges (e.g., refinery wastes) must be issued waste discharge requirements or waivers through the appropriate Regional Water Quality Control Board (Water Code, Division 7, Chapter 4). Such discharges will not be subject to regulation by CDOG unless the subject disposal well is within the administrative limits of an oil, gas, or geothermal field. In such case, the CDOG must also issue a permit for the well construction (Public Resources Code Sections 3008 and 3203). The conditions of this permit should be in agreement with the waste discharge requirements for this well.

The CDOG personnel shall report all pollution problems, including spills to the ground surface or surface streams, to the appropriate Regional Board.

Procedures

Underground Injection

1. Application: Oil, gas, or geothermal operators must file an application for all proposed injection projects with the appropriate CDOG District office. The District office will forward a copy of the application to the appropriate Regional Board for its review and comment. Data to be included with the application shall include: (1) a chemical analysis, as appropriate, to characterize the proposed injection fluid considering the source of the fluid and/or the exposures the fluid has or will undergo before disposal; (2) a chemical analysis, as appropriate, from the proposed zone of injection considering the characteristics of the zone (to include name, location, depth and formation for well from which zone fluid was sampled); and, (3) depth, location, and injection formation of the proposed well. If the Regional Board wishes to comment prior to the issuance of a draft permit for review, comments shall be received by CDOG within 14 days.

2. Review and Consultation: During the review of the application, the CDOG, the Regional Board and the State Board shall consult with one another and local agencies, as necessary, and may require the applicant to submit additional data, as necessary, to demonstrate that the proposed injection will not cause a water quality problem. Additional data required by the RWQCB, if reasonably available, shall be forwarded upon request. Data regarded as confidential by CDOG, or the applicant, will be identified and kept confidential by the RWQCB.

3. Permit Preparation and Issuance:

   a. CDOG will prepare a draft permit, including monitoring requirements, for the injection in accordance with statutory obligations, furnishing a copy of the draft document to the appropriate Regional Board.

   b. The Regional Board will have the opportunity to comment on the draft requirements during the public review period established pursuant to the Memorandum of Agreement (MOA) between the CDOG and the Environmental Protection Agency (EPA).

   c. The Regional Board shall determine whether or not the draft requirements provide protection to ground and surface waters having present or anticipated beneficial uses. If the draft requirements are not adequate, the Regional Board shall, within 30 days, propose conditions or revisions which would satisfy Regional Board concerns. CDOG will not issue final requirements until Regional Board concerns have been satisfied.

      If no response is received from the Regional Board by the end of the public comment period, the requirements will be presumed to be acceptable to the Regional Board.

      CDOG will furnish a copy of the final requirements to the Regional Board.

Surface Discharge

1. Application: The oil, gas, or geothermal operator shall file a Report of Waste Discharge with the appropriate Regional Board. The Regional Board will review the Report of Waste Discharge in accordance with applicable state and federal requirements, including 40 CFR Part 435. No report need be filed when such a requirement is waived by the Regional Board pursuant to Water Code Section 13269.

   When a Report of Waste Discharge is not adequate in the judgment of the Regional Board, the Board may require the applicant to supply additional information as it deems necessary. If a surface disposal site is within the administrative limits of an oil, gas, or geothermal field, the Regional Board shall send a copy of the Report of Waste Discharge to the CDOG for review and comment when the report is complete. If CDOG wishes to comment, the Regional Board should receive comments within 14 days to ensure consideration of these comments during the drafting of waste discharge requirements.

2. Preparation and Adoption of Waste Discharge Requirements:

a. The Regional Board will prepare draft waste discharge requirements for the disposal of production waters by surface discharge. If a surface disposal site is within the administrative limits of an oil, gas, or geothermal field, a copy of the draft document shall be furnished to the appropriate CDOG District office.

b. The CDOG shall determine whether or not the draft requirements fulfill CDOG's statutory obligations related to water quality. If the draft requirements are not adequate, the CDOG shall, within 30 days, propose conditions to the Regional Board which would meet these statutory obligations. The Regional Board will not issue final requirements until CDOG concerns have been satisfied.

If no response is received from CDOG by the end of the public comment period, the requirements will be presumed to be acceptable to CDOG. The Regional Board will furnish a copy of the final requirements to CDOG.

Enforcement Coordination

After construction, CDOG will notify the appropriate Regional Board of any pollution problems noticed during its inspection activities. The Regional Boards will notify CDOG of any suspected violations of CDOG requirements uncovered during the Regional Boards' inspection activities.

If a determination is made by CDOG, or by the Regional Board, or the SWRCB, that an injection or surface disposal operation is violating the terms of its permit or is causing an unacceptable water quality problem, the permitting agency shall take any necessary actions to assure that compliance is achieved, or that the practice causing water pollution is abated forthwith. If necessary, the permitting agency shall order work to be done and/or order operation to be halted. Enforcement actions involving both statutory authorities should be coordinated among the parties involved in this MOA, but neither agency is precluded from taking independent enforcement action.

Modification of this Agreement

This agreement will be effective upon signature by the designated parties. The agreement may be modified upon the initiative of either party for the purpose of ensuring consistency with State or Federal statutes or regulations, or for any other purpose mutually agreed upon. Any such modifications must be in writing and must be signed by the Director of the Department of Conservation, the State Oil and Gas Supervisor, and the Chairman of the SWRCB.

Randall M. Ward — 3-9-88

State Department of Conservation — Date

M. G. Mefferd — 3-4-1988

State Oil and Gas Supervisor — Date

W. Don Maughan — MAY 19 1988

Chairman, State Water Resources Control Board — Date

James B. [illegible] — MAY 19 1988

Executive Director, State Water Resources Control Board — Date

STATE WA..ER RESOURCES CONTRO.. BOARD
P. O. Box 100, Sacramento, CA 95801

CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARDS

NORTH COAST REGION (1)
1440 Guerneville Road
Santa Rosa, CA 95403
(707) 576-2220

SAN FRANCISCO BAY REGION (2)
1111 Jackson Street, Rm. 6040
Oakland, CA 94607
(415) 464-1255

CENTRAL COAST REGION (3)
1102-A Laurel Lane
San Luis Obispo, CA 93401
(805) 549-3147

LOS ANGELES REGION (4)
107 South Broadway, Rm. 4027
Los Angeles, CA 90012
(213) 620-4460

CENTRAL VALLEY REGION (5)
3443 Routier Road
Sacramento, CA 95827-3098
(916) 361-5600

Fresno Branch Office
3614 East Ashlan Ave.
Fresno, CA 93726
(209) 445-5116

Redding Branch Office
100 East Cypress Avenue
Redding, CA 96002
(916) 225-2045

LAHONTAN REGION (6)
2092 Lake Tahoe Boulevard
P. O. Box 9428
South Lake Tahoe, CA 95731
(916) 544-3481

Victorville Branch Office
15371 Bonanza Road
Victorville, CA 92392
(619) 241-6583

COLORADO RIVER BASIN REGION (7)
73-271 Highway 111, Ste. 21
Palm Desert, CA 92260
(619) 346-7491

SANTA ANA REGION (8)
6809 Indiana Avenue, Ste. 200
Riverside, CA 92506
(714) 782-4130

SAN DIEGO REGION (9)
9771 Clairemont Mesa Blvd. Ste. B
San Diego, CA 92124
(619) 265-5114

145.4

STATE WATER RESOURCES CONTROL BOARD
RESOLUTION 88- 61

APPROVAL OF AMENDMENTS TO THE MEMORANDUM OF AGREEMENT BETWEEN THE STATE WATER RESOURCES CONTROL BOARD AND THE DEPARTMENT OF CONSERVATION, DIVISION OF OIL AND GAS REGARDING CLASS II INJECTION WELLS

WHEREAS:

1. The State Water Resources Control Board (State Board) and the Department of Conservation, Division of Oil and Gas executed a Memorandum of Agreement (MOA) in August 1982 that outlined the procedures for reporting proposed oil, gas, and geothermal field discharges and the procedures for prescribing permit requirements for said discharges.

2. The CDOG received primacy to administer the federal Underground Injection Control Program for Class II wells in California from the U.S. Environmental Protection Agency (EPA) in March 1983.

3. The EPA revised its classification of materials that are considered Class II fluids in July 1987.

4. The EPA revised classification requires revisions to the MOA for consistency.

5. Additional revisions to the MOA are necessary to clarify procedures.

THEREFORE BE IT RESOLVED:

That the State Board approves the revised MOA with CDOG and directs the Chairman and Executive Director to sign said agreement.

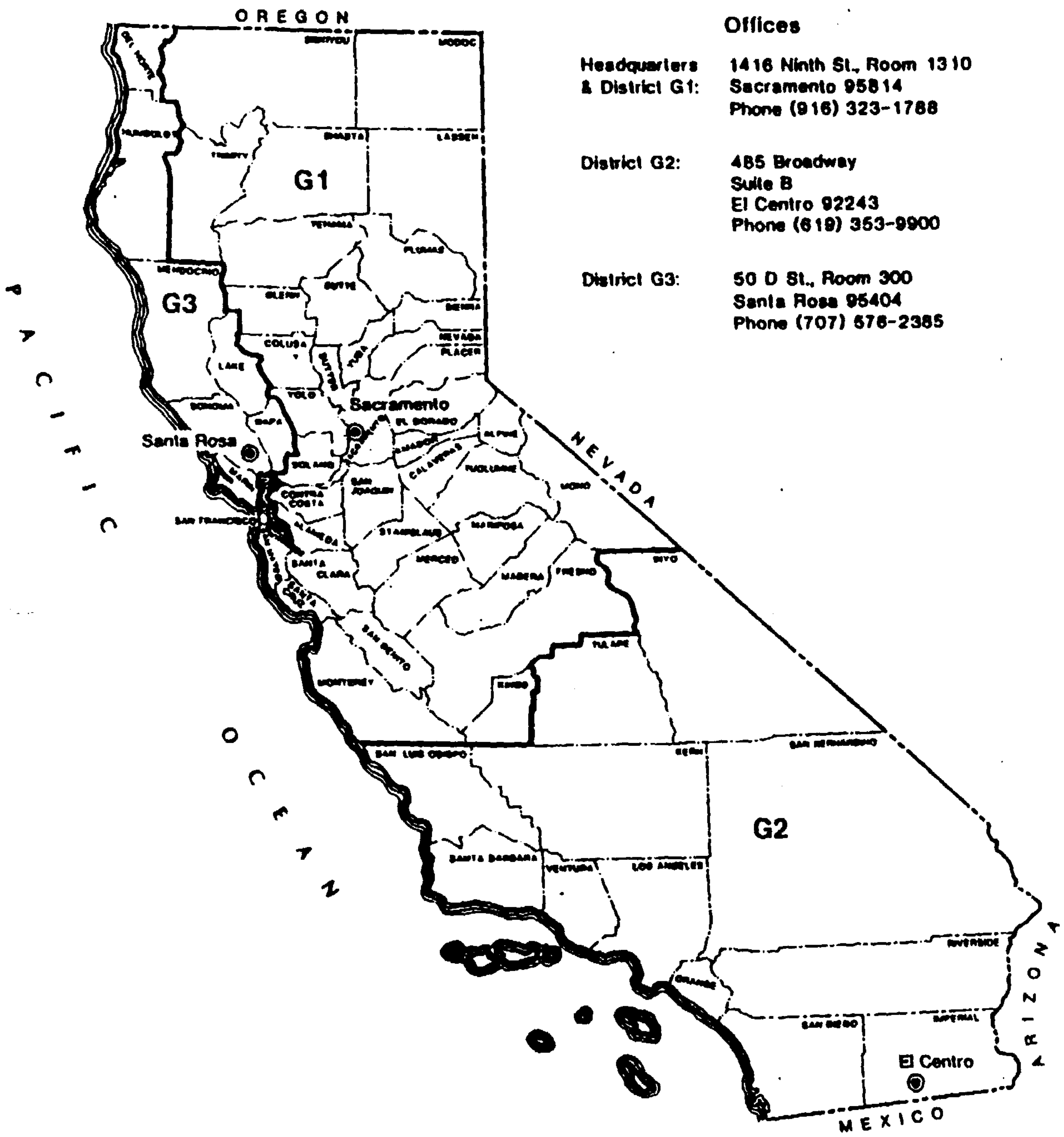
CERTIFICATION

The undersigned, Administrative Assistant to the Board, does hereby certify that the foregoing is a full, true, and correct copy of a resolution duly and regularly adopted at a meeting of the State Water Resources Control Board held on

MAY 19 1988

Maureen Marche'
Administrative Assistant to the Board

GEOTHERMAL DISTRICT BOUNDARIES
of the
Division of Oil and Gas



Offices

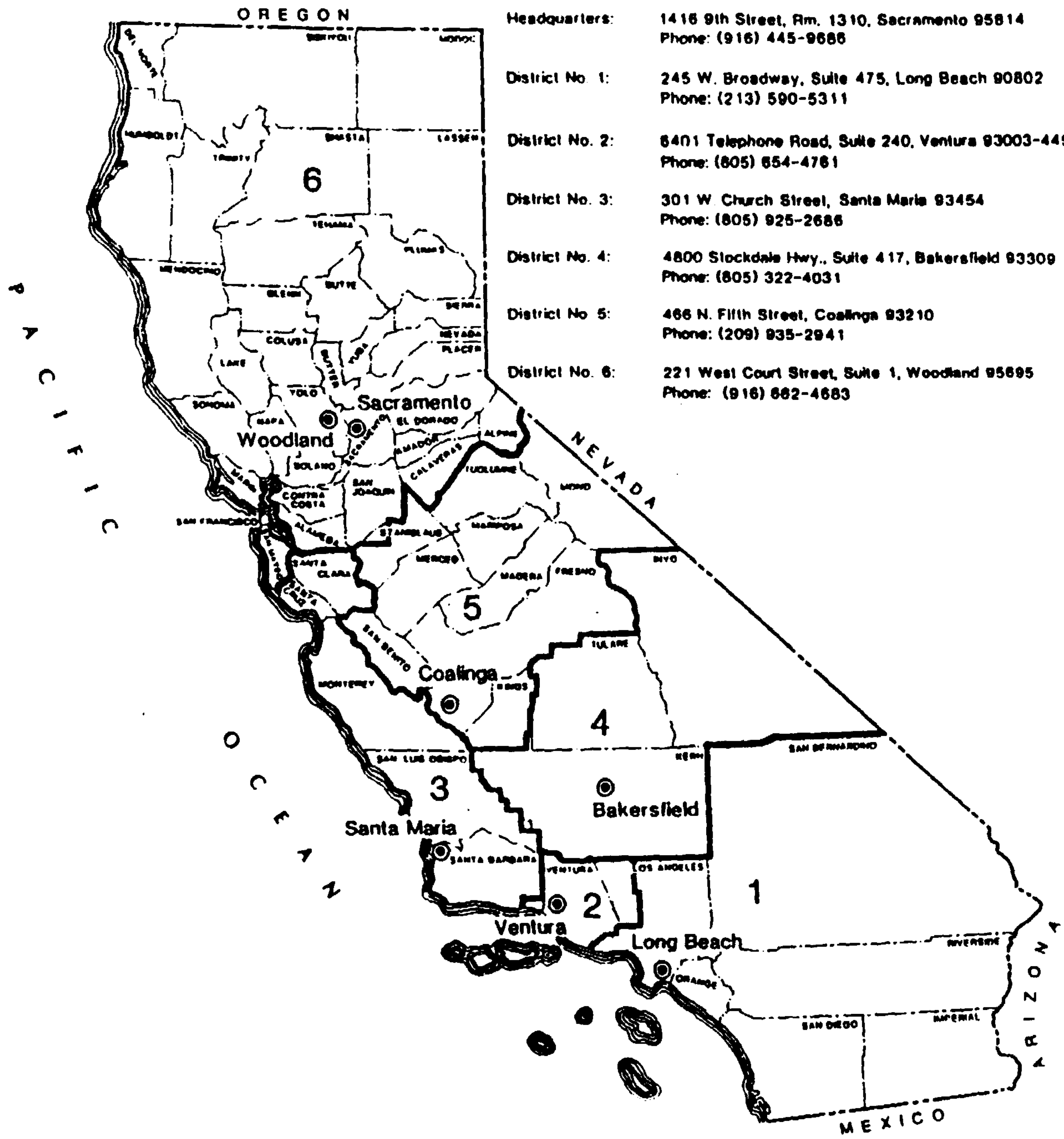
Headquarters & District G1:	1416 Ninth St., Room 1310 Sacramento 95814 Phone (916) 323-1788
District G2:	485 Broadway Suite B El Centro 92243 Phone (619) 353-9900
District G3:	50 D St., Room 300 Santa Rosa 95404 Phone (707) 576-2385

145.4

OIL AND GAS DISTRICT BOUNDARIES
of the
Division of Oil and Gas

Offices

Headquarters:	1416 9th Street, Rm. 1310, Sacramento 95814 Phone: (916) 445-9686
District No. 1:	245 W. Broadway, Suite 475, Long Beach 90802 Phone: (213) 590-5311
District No. 2:	5401 Telephone Road, Suite 240, Ventura 93003-4458 Phone: (805) 654-4761
District No. 3:	301 W. Church Street, Santa Maria 93454 Phone: (805) 925-2686
District No. 4:	4800 Stockdale Hwy., Suite 417, Bakersfield 93309 Phone: (805) 322-4031
District No. 5:	466 N. Fifth Street, Coalinga 93210 Phone: (209) 935-2941
District No. 6:	221 West Court Street, Suite 1, Woodland 95695 Phone: (916) 662-4683



SPEC: ENERGY AND MINERAL RESOURCES ENGINEER
CALIFORNIA STATE PERSONNEL BOARD

SPECIFICATION

Schematic Code: HV25
Class Code: 3784
Established: 9/4/74
Revised: 12/21/99
Title Changed: --

ENERGY AND MINERAL RESOURCES ENGINEER

DEFINITION

Under supervision, performs engineering work of average difficulty in any phase of the Energy and Mineral Resources Program.

JOB CHARACTERISTICS

The class of Energy and Mineral Resources Engineer is a recruiting and developmental class for work in either the Oil and Gas Engineer or Mineral Resources Engineer series. Incumbents are assigned duties and responsibilities commensurate with their background and training. Range A is the entry and training level. Incumbents in a training capacity assist higher-level engineers in the less difficult engineering or engineering surveillance work. Range B is the first working level at which incumbents under close supervision perform less difficult mineral resources engineering work. Range C is the intermediate working level. Incumbents under supervision perform and assist higher-level staff in energy and mineral resources engineering work of average difficulty. Positions are permanently allocated to this class when the major portion of the functions inherent in the position do not include the more responsible, varied, and difficult assignments found at the full journeyperson level.

TYPICAL TASKS

Incumbents at the entry, training, and first working level may assist engineers of higher level by performing under close supervision the less difficult engineering or engineering surveillance work in connection with the issuance, control, and administration of leases for the extraction of oil, gas, geothermal, and mineral resources to ensure compliance with lease/permit requirements; witness various tests of equipment and materials used in oil, gas, and geothermal well operations; perform inspections of oil, gas, and geothermal operations, including well sites, facilities, and equipment; make various physical and chemical tests of produced or injected fluids and drilling fluids; write reports on tests and inspections; compile graphic data and prepare technical reports; assist in the preparation of extractive permits or leases, oil, gas, and mineral reserves and values, engineering and subsurface geological studies or investigations, and participates in field investigations for compliance with regulations; review and check well records filed by operators; prepare and update graphical and statistical office records and reports; may make recommendations to operators regarding the construction or maintenance of drilling and producing facilities; and compile graphical data, prepare maps, and technical reports.

At the intermediate working level, incumbents perform the above duties on a more independent basis as well as other engineering work of average difficulty. Incumbents may assist in the technical evaluation and permitting of proposed well operations; interpret geological and engineering maps and data; draft technical directives or reports in response to proposals or lease applications, or in response to observations made during tests and inspections; perform field inspections for compliance with regulations and lease provisions; investigate complaints and occurrences of damage; conduct or participate in studies of operations and reservoirs involving the interpretation of geological and engineering data; prepare and review various environmental documents; estimate oil, gas, and mineral reserves and values; prepare various geologic and engineering reports, maps, cross-sections, graphs, and statistical data on extractive operations, investigations, tests, or studies for publication, regulatory, or lease compliance purposes; and furnish information to operators and the public on State laws, regulations, and procedures.

MINIMUM QUALIFICATIONS

Either I

Education: Equivalent to graduation from college with major work in geology, petroleum engineering, or a closely related field of engineering. (Qualifying experience may be substituted for the required education on a year-for-year basis. This experience must have included responsibility for inspection of oil, gas, and geothermal well drilling, production, maintenance and abandonment operations, and related activities or must have included work in a minerals extraction program. In California state service, one year at the Oil and Gas Technician III level meets this qualification.) Registration as a senior in a recognized college will admit applicants to the examination, but they must produce evidence of graduation before they can be appointed.

Or II

Experience: One year of experience performing the duties of a Mineral Resources Engineering Technician III. and

Education: Completion of the equivalent of 18 college semester units in engineering, geology, or a closely related field.

KNOWLEDGE AND ABILITIES

Knowledge of: California laws regulating the drilling, operation, maintenance, and abandonment of oil, gas, and geothermal wells and the extraction of other minerals; principles, methods, equipment, and terminology of petroleum engineering and geology; physical and chemical tests used in analyzing oil, gas, and water.

Ability to: Interpret engineering and geologic reports, maps, graphs, and other statistical data relating to oil, gas, geothermal, and other mineral extraction operations; work harmoniously with those contacted on the job; prepare clear and concise correspondence and reports relating to oil, gas, geothermal, and other mineral extraction operations; objectively witness and make field inspections.

SPECIAL PERSONAL CHARACTERISTICS

Interest in learning the practical application of engineering and geological principles to oil, gas, and geothermal resources problems and other mineral extraction operations; willingness to do routine or detailed work; willingness to work at night, on weekends and holidays, and at unusual hours; willingness and ability to work in remote areas with limited access; ability to work well with other governmental and industry field personnel; ability to communicate effectively; and the willingness and ability to accept increasing responsibility.

ADDITIONAL DESIRABLE QUALIFICATION

Positions with the Department of Conservation may require possession

of a valid driver license of the appropriate class issued by the
Department of Motor Vehicles.

SPEC: OIL AND GAS ENGINEER SERIES
CALIFORNIA STATE PERSONNEL BOARD

SPECIFICATION

OIL AND GAS ENGINEER
Series Specification
(Established April 10, 1969)

SCOPE:

This series specification describes four Oil and Gas Engineer classifications used by the Department of Conservation.

Schem Code	Class Code	Class
HV20	3783	Associate Oil and Gas Engineer
HV50	3727	Senior Oil and Gas Engineer (Specialist)
HV10	3780	Senior Oil and Gas Engineer (Supervisor)
HU90	3777	Supervising Oil and Gas Engineer

DEFINITION OF SERIES

The Oil and Gas Engineer series describes work concerned with the technical supervision of oil, gas, and geothermal resource exploration and development operations through well permitting and field surveillance procedures to protect life, health, property, and natural resources. Principal work assignments include the evaluation of proposed projects and well operations for engineering soundness and determination of potential hazards; technical responses to proposals specifying requirements for compliance with State laws; the performance of tests and inspections of facilities, operations, and materials; monitoring ongoing operations for legal compliance; taking legal enforcement actions; petroleum and geothermal engineering and subsurface geological studies; investigations of operations; preparation and dissemination of technical and statistical information; the development and implementation of well programs to prevent or correct damage; or the supervision and administration of these activities.

Work assignments are varied and may be comprised of field and office engineering work.

ENTRY LEVEL

Entry into this class series is typically at the Associate Oil and Gas Engineer level. One year of experience as an Energy and Mineral Resources Engineer, Range C, or equivalent permits entry into the Associate Oil and Gas Engineer class.

FACTORS AFFECTING POSITION ALLOCATION

Level of difficulty, variety, and complexity of assigned duties; independence of action and decision; degree of supervision received; nature of public contacts; and at the Senior and Supervising levels, the degree of administrative responsibility assigned serve as differentiating factors between individual classes.

DEFINITION OF LEVELS

ASSOCIATE OIL AND GAS ENGINEER

This is the journey level. Incumbents independently perform assignments that require a high degree of skill in hydrocarbon or geothermal technology, difficult engineering work, including the technical evaluation of proposed oil, gas, and geothermal projects, and well operations to determine possible hazards to life, health, property, and natural resources; monitor and investigate the legality and advisability of proposed operations; prepare technical and legal directives, and advise operators of preventive or corrective actions required for compliance with protection or conservation laws and sound engineering practices; prepare permits documenting technical requirements for operation; conduct complex studies of operations and reservoirs; make complex calculations, such as oil and gas reserve calculations; prepare and interpret complex technical data, maps, and statistics; write reports on investigations and studies for publication or regulatory use; may direct and review the work of other engineers and technicians in a lead capacity; may witness well tests and perform field inspections; and may make presentations on division programs before various groups.

SENIOR OIL AND GAS ENGINEER (SPECIALIST)

This is the staff specialist level of the series. Positions are characterized by assignments that require the most highly skilled practitioners who serve as prime resource persons and innovators in specialized areas of hydrocarbon or geothermal resource management programs. Positions in this class may function as leadpersons over subordinate staff and team members.

The class of Senior Oil and Gas Engineer (Specialist) is distinguished from the Associate Oil and Gas Engineer classification by the assignment of projects characterized by complexity and sensitivity of work assignment and high skill level necessary to determine the feasibility, impact, or potential impact of a variety of hydrocarbon and geothermal operations, projects, or proposals on a statewide or regional basis.

SENIOR OIL AND GAS ENGINEER (SUPERVISOR)

This is the first full supervisory level. Incumbents have charge of activities of a small district; or assist in directing activities of a larger district; or direct a major technical or administrative program of divisionwide significance; prepare technical directives for oil field operations; direct and review the work of staff and train and evaluate their performance; represent the division at administrative and legislative hearings and meetings; prepare material for administrative hearings and assist in the preparation of legal actions; and prepare and review technical articles for publication.

SUPERVISING OIL AND GAS ENGINEER

Incumbents have charge of the activities of a large oil and gas district and may coordinate activities for several districts; or direct more than one technical or administrative program of major importance within the division; represent the division at administrative and legislative hearings and meetings; supervise the preparation of technical directives for major program or field operations; prepare material for administrative hearings and assist in the preparation of legal actions; and review technical articles for publication.

MINIMUM QUALIFICATIONS

ALL LEVELS:

Possession of a valid driver license of the appropriate class issued by the Department of Motor Vehicles. (Applicants who do not possess the license will be admitted into the examination but must secure the license prior to appointment.)

ASSOCIATE OIL AND GAS ENGINEER

Either I

Experience: One year of experience in the California state service performing the duties of an Energy and Mineral Resources Engineer, Range C. (Applicants who have completed six months of service performing the duties of an Energy and Mineral Resources Engineer, Range C, will be admitted to the examination, but they must satisfactorily complete one year of this experience before they can be eligible for appointment.)

Or II

Experience: Four years of progressively responsible experience as a professional engineer or geologist in oil, gas, or geothermal resource drilling or production operations, or in the technical inspection of such operations, exploration, or development work. (A graduate degree in petroleum engineering, geology, or a closely related field of engineering may be substituted for two years of required nonspecialized experience.) and

Education: Equivalent to graduation from college with major work in petroleum engineering, geology, or a closely related field. (Registration as a senior in a recognized college will admit applicants to the examination, but they must produce evidence of graduation before they can be appointed.)

SENIOR OIL AND GAS ENGINEER (SPECIALIST)

Either I

Experience: Two years of experience in the California state service performing the duties of an Associate Oil and Gas Engineer.

Or II

Experience: Three years of experience in the California state service performing hydrocarbon or geothermal resources engineering duties in a class at a level of responsibility equivalent to the class of Associate Oil and Gas Engineer.

Or III

Experience: Five years of progressively responsible experience as a professional engineer or geologist in oil, gas, or geothermal resource drilling or production operations or in the technical inspection of such operations, exploration, or development work. (A graduate degree in petroleum engineering, geology, or a closely related field of engineering may be substituted for two years of required nonspecialized experience.) and

Education: Equivalent to graduation from college with major work in petroleum engineering, geology, or a closely related field. (Registration as a senior in a recognized college will admit applicants to the examination, but they must produce evidence of graduation before they can be appointed.)

SENIOR OIL AND GAS ENGINEER (SUPERVISOR)

Either I

Experience: Two years of experience in the California state service performing the duties of an Associate Oil and Gas Engineer.

Or II

Experience: Five years of progressively responsible experience as a professional engineer or geologist in oil, gas, or geothermal resource drilling or production operations or in the technical inspection of such operations, exploration, or development work. (A graduate degree in petroleum engineering, geology, or a closely related field of engineering may be substituted for two years of required nonspecialized experience.) and

Education: Equivalent to graduation from college with major work in petroleum engineering, geology, or a closely related field. (Registration as a senior in a recognized college will admit applicants to the examination, but they must produce evidence of graduation before they can be appointed.)

SUPERVISING OIL AND GAS ENGINEER

Either I

Experience: Two years of experience in the California state service performing the duties of a Senior Oil and Gas Engineer (Specialist) or Senior Oil and Gas Engineer (Supervisor).

Or II

Experience: Broad and extensive (more than five years) experience as a professional engineer or geologist in oil, gas, or geothermal resource exploration, production, or development work, at least two years of which shall have been in a supervisory capacity. (A graduate degree in petroleum engineering, geology, or a closely related field of engineering may be substituted for two years of the nonsupervisory experience.) and

Education: Equivalent to graduation from college with major work in petroleum engineering, geology, or a closely related field. (Registration as a senior in a recognized college will admit applicants to the examination, but they must produce evidence of graduation before they can be appointed.)

KNOWLEDGE AND ABILITIES

ALL LEVELS:

Knowledge of: Principles, methods, equipment, and terminology of petroleum engineering and geology; methods and equipment used in drilling, maintaining, and operating oil, gas, and geothermal wells; California laws and regulations concerning the drilling, maintenance, operations, and abandonment of oil, gas, and geothermal wells; well operations; principles of effective supervision and safety practices; the organization, policies, and objectives of the division and its operating units; advanced engineering technologies and trends in hydrocarbon or geothermal resources management problems in California; principles of research, design, and analytical techniques used in hydrocarbon and geothermal resources studies; principles of electronic data processing; principles of program planning and evaluation; social and economic aspects of hydrocarbon or geothermal resources development; principles of environmental planning and impact assessment; principles, practices, and trends in public policy development and evaluation; formal and informal aspects of the legislative and administrative regulation processes; Federal, State, local government, and private agencies involved in hydrocarbon or geothermal resource development and regulation; recent research projects and literature on hydrocarbon or geothermal resources; principles of effective communication.

Ability to: Reason logically and creatively in solving complicated hydrocarbon or geothermal resources problems; interpret and analyze scientific and engineering data; perceive impacts of findings and present ideas and information effectively; develop and utilize a variety of analytical and technological research techniques to resolve complex resource management and conservation problems; develop and evaluate alternatives and make recommendations; consult with and advise management, staff, and high-level government and industry personnel on hydrocarbon or geothermal issues, problems, and needs; gain and maintain the confidence and cooperation of others; represent the division before the Legislature and professional groups, at hearings, and at meetings with government and private agencies; analyze situations accurately and take effective action;

act as a team or conference leader; utilize interdisciplinary teams in the conduct of studies and projects; establish and maintain project priorities.

SENIOR OIL AND GAS ENGINEER (SPECIALIST)

Knowledge of: All of the above, and reservoir engineering; resource assessment; exploration and development technology; subsurface geology; analysis and evaluation of regulatory requirements; resource price control; resource information systems; environmental assessments; public resource management policy development and evaluation; intergovernmental resource management; special government task forces; safety and legality of proposed operations; methods of monitoring production; injection and development including estimation of reserves; efficiency of production operations.

Ability to: Do all of the above, and perform difficult and specialized engineering work of the division which requires the exercise of analytical skill, creativity, and critical judgment; utilize technical expertise to provide consultative services and advice on the feasibility, impact, or potential of a variety of operations, projects, or proposals; advise top management, staff, legislative bodies, governmental entities at all levels, and industry representatives on hydrocarbon or geothermal resources or resource management programs.

SENIOR OIL AND GAS ENGINEER (SUPERVISOR)

Knowledge of: All of the above, and principles and techniques of personnel management, labor relations, and supervision; the organization's affirmative action objectives and a manager's role in meeting those objectives; oil, gas, and geothermal reservoir characteristics and behavior; safety and legality of proposed operations; methods in monitoring production and development, including estimation of reserves and efficiency of production operations.

Ability to: Do all of the above, and effectively plan, organize, direct, coordinate, and evaluate the work of others; motivate and supervise technical and professional engineers; apply the laws regulating oil, gas, and geothermal operations to specific proposals and form valid conclusions regarding safety and adequacy of operations; prepare technical directives and administrative orders to assist in proper oil field operation and good conservation policies and practices; act as a team or conference leader; utilize interdisciplinary teams in the conduct of studies and projects; establish and maintain project priorities; prepare, review, and edit written reports and proposals; effectively contribute to meeting the organization's affirmative action objectives.

SUPERVISING OIL AND GAS ENGINEER

Knowledge of: All of the above, and principles of fiscal management, budgeting, and other administrative functions; organization and objectives of the Division of Oil, Gas, and Geothermal Resources and of other conservation and regulatory agencies in the resources field; administrative hearing procedures and case preparation for processing legal actions.

Ability to: Do all of the above, and coordinate the activities and develop uniform policies and procedures of the Division of Oil, Gas, and Geothermal Resources or for a statewide division program.

ADDITIONAL DESIRABLE QUALIFICATIONS

SENIOR OIL AND GAS ENGINEER AND ABOVE

Possession of a valid certificate of registration as a professional engineer or geologist issued by a California State Board of Registration is preferred for appointment as a Senior Oil and Gas Engineer (Supervisor), (Specialist), or above in the California Division of Oil, Gas, and Geothermal Resources.

CLASS HISTORY

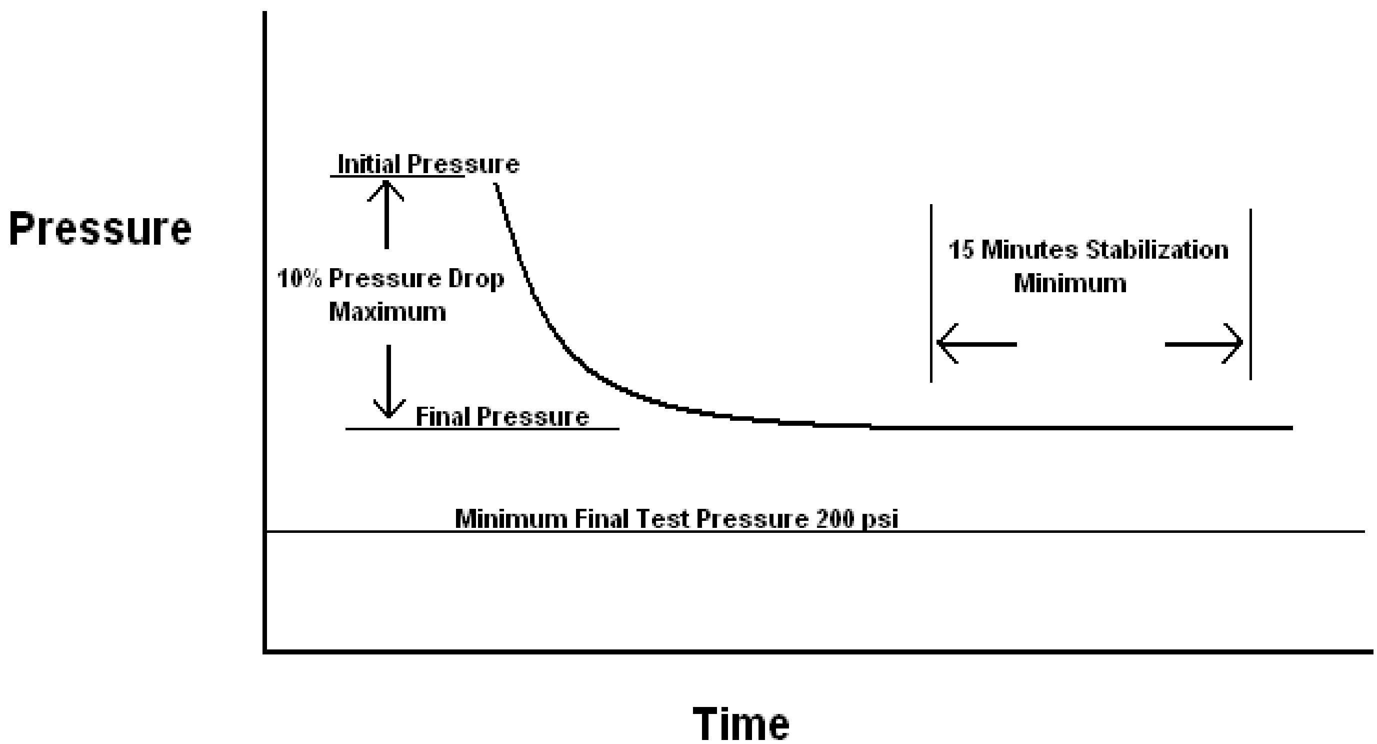
Class	Date Established	Date Revised	Title Changed
Associate Oil and Gas Engineer	1931	9/6/00	9/8/45
Senior Oil and Gas Engineer (Specialist)	4/19/88	9/6/00	--
Senior Oil and Gas Engineer (Supervisor)	9/8/45	9/6/00	4/19/88
Supervising Oil and Gas Engineer	5/25/31	9/6/00	3/8/52

Standard Annular Pressure Test (SAPT) Requirements

A standard annular pressure test is required prior to injection, every time a packer is reset, and at least once every five years for both water disposal (WD) and waterflood (WF) wells.

The Division requirements for an SAPT are a minimum final test pressure of 200 psi, a minimum stabilization time of 15 minutes, and a maximum pressure loss of 10 percent of the initial test pressure. These standards are represented graphically below:

Graph of an SAPT - Pressure v. Time



Provisional Orders Imposing Civil Penalty (2009 to 2000)

Year: 2009

Operator: Coffee Petroleum.

Well # / Field: "Coffee" 9, Round Mountain.

Violation and Civil Penalty:

(1). Unauthorized injection into "Coffee" 9, a violation of Section 1724.10 (b) of the CCR. ($10,000).

(2). Failure to properly conduct the required injection survey and SAPT on well "Coffee" 9, a violation of Section 1724,10 (j) of the CCR. ($5,000)

Operator: Northstar Energy Ltd.

Well # / Field: "Raydon" 3-24, South Belridge.

Violation and civil Penalty: Failure to properly dispose of oilfield wates, a violation of the Section 1775(a) of the CCR. ($25,000)

Year: 2008

A. **Operator: Northstar Energy Ltd.,**

Well #/ Field: "Raydon" 3-24, South Belridge

Violation and Civil Penalty: Failure to properly notify and receive approval of a change in the injection project, a violation of the Project Approval Letter and Section 1724.10 (a) of the CCR. ($500)

B. **Operator: Nevada Titan Energy.**

Well # / Field: "B & R" 9000, Midway-Sunset.

Violation: Unauthorized injection into well "B $ R" 9000 beyond the 90 day injectivity test limit, a violation of Section 1724.6 of the CCR. ($3,000)

Year: 2005

Operator: Berry Petroleum.

Well # / Field: "D.E.E.P." RB 3, Midway – Sunset.

Violation and Civil Penalty: Unauthorized injection into "D.E.E.P." RB3, a violation of Section 1724.6 & 1724.10 of the CCR. ($1,500)

Year: 2004

Operator: Sunray Petroleum.

Well # / Field: “Muir” 123, Mountain View

Violation and Civil Penalty: Unauthorized change of source fluids injected into well “Muir” 123, a violation of CCR Section 1724.10 (d). ($3,000)

Year: 2003

Operator: New Chaparral Petroleum Inc.

Well # / Field: Well No. 8 and 10, Kern River.

Violation and Civil Penalty:

(1). Unauthorized injection into well no.8, a violation of CCR Section 1724.6. ($2,000)

(2). Unauthorized injection into well no. 10, a violation of CCR Section 1724.6. ($2,000)

Operator: T. Lewy Company.

Well # / Field: “J.O.L.” 23-2, Jasmin

Violation and Civil Penalty: Unauthorized injection into well “J.O.L.” 23-2, a violation of CCR Section 1724.6. ($2,000)

Operator: Sunray Petroleum, Inc.

Well # / Field: “Arvin Waterflood Unit” G10, Mountain View

Violation and Civil penalty: Unauthorized injection into well “Arvin Waterflood Unit” G10, a violation of CCR Section 1724.6. ($4,000)

Year: 2002

Operator: Sunray Petroleum, Inc.

Well # / Field: “Altoona” 5, Midway – Sunset.

Violation and Civil penalty: Unauthorized injection into well “Altoona” 5, a violation of CCR Section 1724.6, ($2,000).

Year: 2000

Operator: Sunset Petroleum Inc.

Well # / Field: “Nomeco Yates” 15-33, Rosedale.

Violation: Failed to comply with Section 1724.6 of the CCR by using, without approval, well “Nomeco-Yates” 15-33 for injection purposes. ($2,250)

Operator: New Chaparral Petroleum Inc.

Well # / Field: “KRU” 16-33, Kern River.

Violation: Failed to comply with Section 1724.6 of the CCR by using well “KRU” 16-33 to inject fluids, without approval. ($250)

APPENDIX B2

DISTRICT 2 RESPONSES TO THE EPA QUESTIONNAIRE WITH STRONGER DOCUMENT ATTACHMENT

California Department of Conservation

Division of Oil, Gas and Geothermal Resources

Class II Underground Injection Control (UIC)

Program Review Questionnaire

May 2010

Prepared by:

James Walker Environmental Consulting

under subcontract to

Horsley Witten Group, Inc.

for U.S. EPA Region 9 (Contract No. EP-C-08-018)

Class II UIC PROGRAM REVIEW

Table of Contents

PROGRAM REVIEW DESCRIPTION

PURPOSE

The purpose of this review is to evaluate the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) Class II UIC Program to determine if current program implementation practices are consistent with the approved Application for Class II UIC Primacy, Program Description, and Memorandum of Agreement (MOA) with EPA Region IX signed by the Regional Administrator on September 29, 1982. The projected outcome of this effort is to memorialize current practices and identify program recommendations as needed.

REVIEW PROCESS

With support of the Horsley Witten Group (contractor), EPA Region 9 (EPA) will conduct a review of the DOGGR Class II UIC Program and produce a final report that summarizes findings of the review and any program recommendations. The report is intended to provide information to EPA on focused aspects of the current management and implementation of the DOGGR Class II UIC Program. The final report will provide EPA and DOGGR with a detailed compilation of information on the strengths and weaknesses of the program, which can be used to advance the program and enhance the protection of underground sources of drinking water (USDWs) in the state of California.

Each District Office is requested to complete the following questionnaire by Monday, June 21, 2010. Responses should be inserted into the body of the questionnaire. An electronic copy of the completed questionnaire and all attachments should be sent to:

- Mark Nelson, Horsley Witten Group (mnelson@horsleywitten.com); and,
- Jim Walker, James Walker Environmental Consulting (subcontractor to Horsley Witten) (jameswalker5@msn.com)

This is the first step of the review process. After responses are reviewed and evaluated, arrangements will be made for an onsite visit from the subcontractor to the District Offices to gather and review additional information as needed. The onsite visit may include inspection of UIC permits, operation protocols and interviews with District staff and management. All site visits will be coordinated in advance with the District Deputies and a list of items for review will be submitted in advance as well.

The contractor will develop a draft document of findings that incorporates the information and submittal material provided from the questionnaires and additional documentation gathered during the site visits. This draft document will be sent to EPA and DOGGR for review and comment prior to finalizing the report.

PROGRAM REVIEW FOCUS

Area of Review (AOR)/Zone of Endangering Influence (ZEI)

- Representative samples of Class II UIC projects/wells in areas of special interest will be selected for a comprehensive review of the AOR/ZEI applied in the permit application/approval/follow-up monitoring process.
- Well construction practices and status of wells located within the AOR will be examined.
- Corrective action requirements that were imposed in the permits, if any, will be reviewed.

DOGGR Annual Project Review

- Records of well activity, pressures, inactive well and non-compliance data, etc. and DOGGR actions taken to correct non-compliance will be reviewed.

Monitoring Program

- Mechanical Integrity Testing (MIT) surveys/reports will be examined for compliance with UIC requirements and consistency with actual MIT results.
- Procedures for establishing Maximum Allowable Injection Pressures (also known as Maximum Allowable Surface Pressures (MASPs)) and monitoring for compliance, including the review of selected step rate tests and other data on record will be evaluated.

UIC Staff

- Staff qualifications for proper implementation and enforcement of the DOGGR Class II UIC program will be evaluated, including review of staff resumes, job descriptions, work experience, and training. **Staff names on those documents shall be omitted for the purpose of this review.**

DOGGR CLASS II UIC - QUESTIONNAIRE

District Office: Ventura
Deputy Director's Name: Bruce H. Hesson
Email: Bruce.Hesson@Conservation.ca.gov
Telephone Number:805.654.4761
UIC Class II Lead Staff Name: Steve Fields
Email:Steve.Fields@conservation.ca.gov
Telephone Number:805.654.4769

Please insert your response below each question. Additional materials can be attached and will be considered. However, please reference the inclusion of any additional materials below the appropriate question.

In your response, please distinguish where the response reflects standards or requirements that have been adopted relatively recently - in the last few years. If this is the case, please describe the previous/historic requirements and procedures and explain why modifications were implemented.

Please incorporate in your responses if fields (active and non-active) are located below or may affect residential (or other high-priority, e.g., due to vertical proximity to USDWs) areas. These fields need to be listed or depicted clearly on a map(s).

If you have any questions or comments regarding the questionnaire or how to submit the requested documentation, please contact Jim Walker, James Walker Environmental Consulting (subcontractor to Horsley Witten) via email at jameswalker5@msn.com or at 720-472-9359.

General Comment

In 1990, under the auspices of the IOGCC (Interstate Oil and Gas Compact Commision), states were reviewed in order to improve the oil and gas regulatory program. In 2000, a non-profit corporation was established for the purposes of moving the State review process forward and creating balanced stakeholder control of the process. In 2000, the State Review of Oil and Natural Gas Enviromental Regulations, Inc. (STRONGER) reviewed California. Prior to that review, a similar "questionnaire" was completed. In the effort to not duplicate that questionnaire, it has been attached. It should be noted that while attachments are noted in the STRONGER questionnaire, they have not been included. In answering questions, where differences have occurred since the 200 review, they are noted in this document.

PART I: GENERAL

A. UIC Program Organization

1. Attach a District organizational chart and identify UIC positions (qualifications, responsibilities, number of staff, etc.) assigned to permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

***See Page 47 and page 48 of STRONGER Questionnaire.*.**

Office engineering staff consists of a District Deputy (Senior Engineer), Permitting Engineer (Associate Oil & Gas Engineer), and four Field Engineers (Energy & Mineral Resource Engineers). Each field engineer in the Ventura (D2) district is on-call one week out of four during which time they witness permitted field tests, including MIT's and SAPT's. Field engineers also conduct environmental inspections, which includes UIC wells. In addition to verifying compliance with DOGGR environmental regulations, inspectors also inspect UIC wells to determine if they are injecting above their established MASP. MASP data is printed out prior to conducting their inspections. If the injection pressure is above the MASP, they inform the Permitting Engineer who then follows-up with the operator. File review and data management is performed by the Permitting Engineer. Qualifications for staff are established during the hiring and promotional process and differ by classification. (Please

note that a flowchart could not be added to this section without changing the document format).

B. Interagency Coordination and Changes to the UIC Program

1. Please list any memoranda of agreements or similar agreements between the District and/or Division and other state agencies or other governmental entities which are actionable and relate to your District's application of the Class II regulation, oil and gas waste, sharing of information, or processing of complaints. Attach the actual agreements or directives (policy or guidance) if available.

   See Page 4 and Page 8 of STRONGER Questionnaire.

2. Describe any significant changes that have occurred within the District, State, or federal level that have affected the administration of the Class II UIC program at the District level. For example, have new statutes been adopted or have there been major regulatory changes?

   No changes have been made at a District level. All statues and regulatory changes are adopted on a State-wide basis and the District adheres to those changes. See page 8 of *STRONGER Questionnaire.*

PART II: PERMITTING AND COMPLIANCE REVIEW

A. OBJECTIVE: Understand the application flow process of the UIC program.

1. Who receives the application from the operator? (District or Headquarters office)

   See Page 10 of STRONGER Questionnaire.

2. How and by whom are permit applications screened for completeness?

   See Page 10 of STRONGER Questionnaire. In District 2, the permit application is screen by Steve Fields.

3. What are the procedures or protocols if an application is found to be incomplete?

   See Page 10 of STRONGER Questionnaire.

4. What are the professional qualifications required for staff who conduct permitting and compliance activities?

   See Page 11 of STRONGER Questionnaire.

   Qualifications for staff are established during the hiring and promotional process and differ by classification.

   Do those staff members meet the minimum requirements? **Yes**

   What types of training would staff like to access if funds were available? **Industry training specific to UIC wells and UIC well testing that are applicable to California unique engineering and geological conditions. We have a designated individual that was recently made to oversee our training needs and expectations. Marilu Habel would be the one to answer this question.**

5. What tools, technical and other, do the reviewers utilize to review permit applications? Are there additional tools that you can identify that would be useful?

   This District requires two copies of the application. One copy must be in a pdf format. This copy is placed on the Division's FTP site. While proceeding thru the approval process, the application is reviewed by California Regional Water Quality Control Board, and by local agencies (Ventura County Planning Department)

   The AOR is reviewed based upon scanned images of the well files and comparison those with the data that the operator submitted.

6. Describe any differences between the processing and requirements of commercial and non-commercial applications for a Class II well (Class II ER enhanced recovery and Class II SWD disposal).

   See Page 12 of *STRONGER Questionnaire.*

7. Describe any differences between the processing of a waterflood project and a CO2 EOR project. **N/A in this District**

B. OBJECTIVE: Understand the current compliance/file review process.

1. What is the file review strategy? (i.e., how are wells selected for file review?) Is compliance history a factor of selection? Please include how residential (or other high-priority) areas affect this strategy.

The file review consists of determining whether the well is operating in accordance with regulations. The file reviews consists of periodically determining whether a mechanical integrity test has been performed, both internally and external as specified, whether the well is operating in accordance with specific approved injection pressure, and whether wells that permission to inject has been rescinded have indeed, stopped injection operations. The answers are found in performing database queries in several databases. Documentation of a file review is maintain in the District UIC database that includes the date that the file review was conducted and the person that conducted the file review. The file reviews are performed on a minimum of once a month and sometimes at greater time periods if time permits. The ease of the file report is facilitated by the use of a complex Access database linked to the Production/Injection Reporting system of the Division and the knowledge of running queries on the databases.

2. Who performs the file review and what are the qualifications of the reviewers? [Please do not include the name of the staff but rather their professional title and qualifications.]

   UIC Permitting Engineer and Field Engineers (See above)

3. Over a one-year period, what percentage of total UIC permits/wells receives a file review?

   100% of all UIC wells are reviewed each year. The file reviews are done as indicated above at least monthly.

4. How is the quality of a file review assured and subsequently documented?

   The Districts UIC database maintains a date and the person whom conducted the reviewed. The queries used to review the UIC database and the injection statistics are pre-programmed to be user friendly.

5. When deficiencies are discovered during the review, what actions are taken to correct the deficiency?

   The operator is notified either by telephone, email or letter or a combination of any of them.

6. How is the file review different from the annual project review? Please describe this annual project review process and the results. What percentage of projects is reviewed annually?

The difference between a project review and a file review is the same review for water-disposal projects. The differences for enhanced recovery projects are that a review of the project effectiveness is conducted. (i.e. is the injection enhancing oil production) The percentage of projects reviewed using this method is less than 10% per year. Please note that 100% of the UIC wells are reviewed while a much lower number of the projects are reviewed.

C. OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

The federal definition of USDWs (underground sources of drinking water) is found in the regulations at 40 CFR §144.3 which includes that an aquifer "...contains fewer than 10,000 mg/l total dissolved solids". Please distinguish when responses to questions pertaining to USDWs differ from the federal definition and describe how this difference is handled. This may apply to AOR/ZEI and MIT responses in other sections as well.

This complete section can be found on Page 14 of the *STRONGER* Questionnaire. A rough estimate is that over 75% are in fields in which no USDW is found.

1. What are considered to be adequate casing and cementing requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all Underground Sources of Drinking Water (USDWs)? If not, how are USDWs otherwise protected?

   The answer is the same Statewide

2. What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the USDWs protected?

   The answer is the same Statewide

3. What assurance exists that fluids are confined to the intended zone of injection both at the injection well and throughout the field?

   The answer is the same Statewide

4. Packer and tubing requirements: Are packers and tubing routinely required for all newly completed and converted wells? If there are exceptions, what

criteria are used? What are the alternative requirements for annular pressure testing if packers and tubing are not installed in a well?

The answer is the same Statewide

5. Are dual (multiple) completions permitted? What requirements are different than single completions? What types?

   This District has no dual completions permitted.

6. How are the locations of USDWs determined? Does the District consult with other state and federal water resource agencies regarding USDW information?

   See Page 16 of STRONGER Questionnaire.

7. How is the adequacy of the confining zone/system determined? If the adequacy of the confining system is in question, what options are considered to compensate for this uncertainty and how are they evaluated?

   This office does not use the concept of a confining zone. We use the concept that injection is confined to the permitted zone only. Injection outside the permitted zone is not allowed at all.

8. Describe the monitoring system requirements for flow rate, cumulative volumes, tubing pressure, annulus pressure, etc. for a Class II injection well.

   See Page 17 of STRONGER Questionnaire.

9. How are the maximum injection pressures and rates established? Please provide examples of step rate tests conducted and other data used for this purpose

   See Page 17 of STRONGER Questionnaire.

D. OBJECTIVE: To understand the Area of Review/Zone of Endangering Influence considerations and procedures.

1. How is the Area of Review (AOR) determined for enhanced recovery wells or projects?

   THE AOR is determined by a fixed distance of ¼ mile from each injection well unless it can be easily determined that a greater distance is require based on the reservoir and geological conditions.

2. How is the AOR determined for saltwater disposal wells?

   Same as above

3. How is the AOR determined for commercial saltwater disposal wells?

   Same as above

4. How is the AOR determined for CO2 EOR wells?

   N/A

5. How are AORs determined for area permits and other multi-well projects?

   N/A

6. Are Zone of Endangering Influence (ZEI) calculations or the use of computer modeling performed routinely for all permits? If not, are they performed for all disposal well permits? What percentages or what numbers of a) enhanced recovery and b) disposal well permits have been subjected to the ZEI determination since the UIC program was approved? Is there any time period since the UIC program was approved when there were notable increases or decreases in ZEI determinations – please describe?

   N/A

7. Describe the requirements for monitoring and reporting static reservoir pressures for disposal well projects.

   This Division has a policy not to allow the static reservoir pressure to be above hydrostatic pressure. The requirements are that a "poor boy" pressure-fall off test, the well is shut-in and if the well does not dropped to zero pressure, the operator is required to determine the cause. Injection may not be allowed to continue until the cause is determined.

8. Do the District staff review reservoir pressure buildup data and take action to expand the AOR if exceeded by the expanding ZEI? How often and where has that occurred? Please list, with dates, the most recent examples.

   No recent examples have been done.

9. What projects/wells have shown significant reservoir pressure increases over the life of the project/wells that could have caused the ZEI to expand beyond the original AOR?

   N/A

10. Describe any corrective action considerations or requirements associated with permits issued historically and for later permits, for example, those since 2000. Were any wells located within the AOR found to have plugging and/or construction deficiencies that required corrective action contingent on issuance of the permit? Please list the most recent examples.

    During either a new project application or when a new well is proposed, an AOR is done. In the event that any remedial action is required then it is done at that time. This number is very low as operator determine that the remedial action is more costly then the project. (I.e. they will attempt to find an alternative well to be used) However we have required operators to plugged and reabandon wells in which the well determined to be a "possible" conduit of the injection zone to a zone outside the permitted zone.

11. How does the District handle situations where defective wells are located within the AOR but outside of the control of the permittee?

    They are required to performed the work on any well that is deemed "defective".

E. OBJECTIVE: Understand the administrative permit application components.

1. Describe the public notification and participation process for applications under consideration by DOGGR.

   The public notification and participation process in the same statewide.

2. When and where is public hearing opportunity held on an application and how are they conducted? When was the last public hearing held in your District? Please list the most recent examples.

   No public hearing has ever been conducted in this District

3. What types of financial assurance mechanisms are used in connection with UIC applications? How is adequate coverage per well determined? Under what conditions is blanket surety coverage allowed?

   See Page 19 of STRONGER Questionnaire.

F. OBJECTIVE: Understand the process for aquifer exemptions

   No aquifer exemptions has been done in this District but see *Page 20 of STRONGER Questionnaire.*.

1. How many exemptions have been requested and approved since 1982 and what were the criteria most often used for the requests?

2. How many requests have been requested and denied since 1982 and what basis or reasons were given for the denials?

. If there have been any aquifer exemption requests from your District, briefly describe the process for approval/denial of such request.

PART III: INSPECTIONS

A. OBJECTIVE: Understand how field operations are conducted and managed by the District. Please identify fields (active and non-active) that are underlying either existing residential areas or planned residential areas and other high priority areas.

1. How are inspection priorities determined?

The District attempts to witness all permitted tests. In the event a field engineer is not available, the lowest priority test is waived. In addition, the District policy is to conduct inspections on all wells on an annual basis, including UIC wells.

2. What professional qualifications and/or experience are required by DOGGR to be an inspector?

Qualifications for the Energy & Mineral Resource Engineer are established by Human Resources and qualified candidates are then hired through a structured oral exam.

Do District staff have the necessary qualifications and/or experience?

Only candidates meeting the minimum established qualifications are eligible to interview. Once hired, new-hires go through an employee orientation, including field training with experienced field staff. This training typically lasts three-to-four months before they go into the on-call field rotation (by themselves). Field engineers are instructed to contact the District Deputy or Permitting Engineer should they encounter any field situation they are not familiar with or if they have any questions/concerns.

What types of training do inspectors access or would like to access if funds were available?

Industry training specific to California UIC wells and well testing in California. Additional data can be seen on *Page 24 of STRONGER Questionnaire.*

3. What tools do the inspectors utilize?

To name a few of the basic tools, field equipment includes a state vehicle, safety equipment (including an H2S detector and cell phone), Trimble GPS to obtain lat/long readings, equipment to verify mud weight and gel

strength on abandonments, and an office computer to input field data and generate inspection sheets prior to going into the field.

Are there additional tools that you can identify that would be useful? Hand-held GPS device, laptops with user-friendly program that could easy adapted for harsh environments in the field work with approiate training.

4. Describe the training that inspectors receive, initially, and over time as they gain more experience, including both technical and safety training.

   As a new-hire they receive HQ orientation, district orientation, office training and actual field training with an experienced field staff. They only are placed in the on-call field rotation once the District Deputy has verified that they are adequately prepared. In addition, engineering staff attends industry training on a variety of subjects through the PTTC and during industry and professional organization conferences. A PowerPoint UIC training presentation has been prepared at the District level that all field staff have seen.

5. What role do inspectors have in developing enforcement cases and to what extent are they involved in the hearing or judicial process?

   If a situation is becoming a compliance issue, the District Deputy assists them in collecting the necessary field data for enforcement cases. In general terms, the District Deputy prepares formal orders and coordinates these actions with HQ and Department and legal counsel.

B. OBJECTIVE: Understand the routine/periodic inspection program and the emergency response procedures in the District. Please describe the types of fluids that are approved for Class II wells, both for EOR and SWD, including any fluids approved for Class II injection that are not brought to the surface in connection with conventional oil or natural gas production or gas plants which are an integral part of production operations.

1. How often is each UIC permitted well inspected for aspects other than MITs? Class II ER vs. SWD wells? Please reference the database the inspection data is stored in or attach the inspection verification documentation.

   See Page 25 of STRONGER Questionnaire.

   The District maintains an Access database.

2. Is the operator given advance notice of inspection and does the operator receive a copy of the report?

   See Page 26 of STRONGER Questionnaire.

3. Describe the reporting and follow-up procedures used in the inspection program when there are violations.

   When there are violations, they are followed-up by the individual creating the violations along with notification to the District Deputy that follow-up is due via an programmed email system.

4. How is the District notified of emergency situations regarding Class II wells and related incidents such as spills?

   See Page 28 of STRONGER Questionnaire. Update: OES is called California **Emergency Management Agency**

5. What type(s) of emergency situations has/have been reported involving UIC permitted wells? Please list the ones you have received over the last five years, or the most recent examples.

   None in last 5 years

6. Describe the data management systems which are available to field inspectors in conducting routine inspections as well as providing background support for responding to complaints and emergency situations.

   District Access database.

7. How are the injections pressures on the wellhead compared with the approved Maximum Allowed Surface Pressure (MASP)? Do all the injection wells have approved MASP values in an easily accessible database? If not, how does the District verify compliance with the MASP?

   Yes, all injection wells have an approved MASP. See Question above.

PART IV: MECHANICAL INTEGRITY TESTING

A. OBJECTIVE: Understand the Mechanical Integrity Test (MIT) Program and its Implementation.

1. What type(s) of MITs are acceptable to the District for satisfying the leak/pressure test (Part 1 of MI)? Please list the test types and limitations as to applicability.

   See Page 19 of STRONGER Questionnaire.

2. What criteria are used for the pass/fail of a pressure test and why were these criteria selected?

   See Page 20 of STRONGER Questionnaire.

3. If annulus pressure monitoring (APM) is allowed to determine MI, how is MI failure determined and how often is APM recorded? Is an initial pressure test required? How many times in the last five years has failure of MI been identified by APM?

   Not allowed

4. If cement records are used to satisfy the Part 2 MI requirement, what criteria are used to determine pass/fail?

   Not used

5. Identify any logs used for the determination of MI and the limitations imposed on their use. Who makes the decision to have the operator run special log suites and who interprets the logs? How are failures determined?

   See Page 38 of STRONGER Questionnaire.

6. What is the priority schedule of wells to be tested? Are there wells tested more frequently than the standard cycle? What is the standard cycle for MITs and does it vary depending on well condition or risk of fluid migration outside of the injection zone?

   Every Year for SWD

   Every other Year for Waterflood

   Every 5 years for steamflood

7. Describe the follow-up and typical enforcement actions for MIT failures.

   Follow as per instruction that all Districts follow.

8. Who witnesses MITs and what percentage of MITs are witnessed? How is the witness documented and what documentation is required of the operator in those cases where a test was not witnessed?

   See Page 40 of STRONGER Questionnaire.

9. In the event of MIT failure, how is the operator notified to shut the well in. If all wells failing MIT are not shut in, please elaborate.

   See Page 41-44 of STRONGER Questionnaire.

10. Is the operator required to institute corrective measures for each failed MIT and what are the acceptable measures? How long is the operator given to take corrective measures?

See Page 45 of STRONGER Questionnaire.

11. If workover of the well is required as part of a repair, does the District witness the work and/or require copies of reports documenting the work?

The District will witness the repair operation. We do not witness operations that require a repair to tubing and/or packer. We do require copies of reports that document the repair work and a follow-up MIT test

12. What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed over time?

This District has had very few failures in the last 20 years. The rate is about 5 per year and has not changed.

13. What are the procedures/requirements for the operator to report a mechanical integrity failure discovered during routine operations and take corrective measures to restore MI to a well?

See Page 45 of STRONGER Questionnaire.

14. Describe the data management system used in the various components of the MIT program. The description should delineate how the system manages the program from test scheduling to follow up on failure.

Access Database that indicates when a next survey is due.

PART V: COMPLIANCE/ENFORCEMENT

A. OBJECTIVE: Understand enforcement procedures used by the District

See Page 47-53 of STRONGER Questionnaire.

1. What types of enforcement tools and legal actions are available to the District for the UIC program?

See Page 47 and page 48 of STRONGER Questionnaire.

2. What types of formal enforcement actions have been taken relative to UIC violations in the District?

No formal enforcement action has been taken in the last five years. Enforcement action taken on reporting injection is handled by our Headquarter staff.

3. Describe any differences in procedures between enforcement actions taken for "paper" violations and violations that may threaten USDWs.

   See Page 50 of STRONGER Questionnaire.

4. Does the District issue Notices of Violation (NOVs), or similar notices to the operator and attach penalties?

   Civil penalties would typically be issued following the "non-compliance" of a notice of violation.

   How many have you issued in the last five years? Please list these or the most recent examples.

   None for injection wells.

5. What are the follow up procedures to assure compliance and correction of the violation?

   ***See Page 47 and page 48 of STRONGER Questionnaire.*.**

6. How much time is granted to an operator to correct a violation that if left uncorrected could threaten a USDW? If threatening a USDW an operator can be ordered by the District to discontinue injection immediately. How much time is granted to an operator to correct a "paper" violation or one that involved the issuance of a NOV?

   Again, if a paper violation is non-reporting of injection it is typically 90 days.

7. How and when do UIC violations escalate from non-compliance into formal enforcement actions?

   See Page 47-53 of STRONGER Questionnaire.

8. What penalties have been assessed and collected on UIC violations in the past ten years?

   The District has not issued any civil penalties for UIC wells.

9. Identify and list the more prevalent UIC related problems faced by the District in providing adequate enforcement?

   N/A

B. OBJECTIVE: Understanding contamination/alleged contamination resulting from injection well operations or UIC well completion/construction practices in the last ten years.

No contamination/alleged contamination resulting from UIC well operations.

1. Please provide the policy for handling (receiving, evaluating, responding) operator reports of contamination and for reports or complaints from the general public.

2. Please provide the number of alleged USDW contamination incidents reported to the District in the past ten years. What were the causes of the contamination?

3. What actions are taken by the District when an alleged contamination report is received?

4. How many of such contamination cases were found to be actual and were proved to be a result of failure of an injection well or wells? How many were due to abandoned, unplugged wells?

5. Briefly describe the well failure, extent of contamination and remedial and/or enforcement actions taken as related to Question #3 above.

PART VI: ABANDONMENT/PLUGGING

A. OBJECTIVE: Understanding and documenting the technical aspects of plugging and abandonment (P&A) practices in the District.

See Page 55-60 of STRONGER Questionnaire.

1. Describe the plugging practices approved for each major type of well construction in the District. (Provide details on minimum plug placements, size or length; use of mud between plugs and weight; use of bridge plugs and cement retainers; standard plugs at the pay or injection zone, base of USDW, and casing stubs, etc.).

   The District complies with existing DOGGR abandonment regulations. The rods/pump and tubing (packer if an injection well) are pulled prior to commencing cementing operations. The well must be cleaned out to at least 25 feet into the uppermost perforations and cemented to at least 100 feet above the uppermost perforation, liner top, WSO, whichever is highest. This plug is then tagged with tubing and witnessed by a district field engineer to verify it meets the minimum requirements. If it does not, this plug must be upgraded until it meets the minimum requirement.

In areas of freshwater, a plug must be placed and be a minimum of 100 feet. Again, this plug is tagged to verify it meets the minimum requirements. If there is no cement behind casing, either a cavity shot or innovator shot is performed prior to cementing to ensure cement is outside the casing and across the BFW zone. A surface plug with a minimum length of 25 feet is placed last. In between these cement plugs abandonment mud must be pumped; however, the majority of the abandonments in District 2 over the last seven years have been conducted entirely with cement. Once the surface plug has been placed, the wellhead is cut-off between 5 and 10 feet below grade. If any annuli do not have cement, they are upgraded with cement. A metal ID plate is then welded to the largest string of casing and the site back-filled with clean dirt.

2. Are there UIC wells without surface casing installed? How are they plugged?

   No

3. If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed?

   If an inner string of casing is cut and pulled, a stub plug is placed from the stub to a minimum of 100 feet above the stub plug.

4. Are plug depths verified? **Yes**

   When and how?

   After the cement has hardened with coil tubing or a tubing workstring.

   Are all plugs required to be tagged?

   See Page 48-603 of STRONGER Questionnaire.

5. What percentage of UIC well pluggings are witnessed by District inspectors? What control is exercised over unwitnessed plugging operations?

   Plugs not witnessed would have to be waived by the district. The number of waived calls for abandonment operations is minimal since abandonment operations are our highest witnessing priorities.

6. Describe the process used to get an idled and an orphaned well plugged.

   The District has Idle Well Management Plan Agreements with three of the major operators who account for over 70% of the District's idle wells. We have annual project review meetings with these operators to ensure they are meeting their commitments. At these meetings we recommend idle wells that would be good candidates for abandonment based on our field observations (access issues, active slide areas, environmentally sensitive areas, etc.) Orphan wells are plugged by the Division using funding from the Hazardous Idle Deserted Well Fund (HIDWF) which is currently $2 million per year. (This fund will revert back to $1 million in FY 2012/13.) Each district identifies and proposes to HQ orphan wells they'd like to abandon. Once funding is allocated to the districts, a bid package is prepared and a contractor selected through the competitive bid process. Approval of the property owner is also required and normal abandonment procedures outlined above are required for orphan wells.

7. Does the District maintain an inventory of abandoned (orphaned) UIC wells?

   This District has no orphaned UIC wells.

8. Does the state maintain a well plugging fund that is used to plug idled **(no)** and orphaned wells? **(Yes)** Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund.

   Currently 2 million/year until FY 2012/13 then reverts back to $1 million/year, unless extended. PRC section 3258 currently authorizes expenditure of up to two million/year. Money not spent this fund within that FY offsets the next year's assessment rate.

9. How are the current plugging requirements different from those of 40 years ago?

   Same Statewide. In early 1990's, an informal agreement was made with a local water agency in which we would plug and abandon the top portion of wells in accordance with water well standards. This was done in the Oxnard field.

   Does this have an impact on corrective action requirements and how you conduct an AOR or the approval of an injection project?

   The informal agreement plug has no affect on AOR.

B. OBJECTIVE: Understand Temporary Abandonment (TA) requirements applied by the District.

See Page 63 of STRONGER Questionnaire.

1. Describe the District administrative program for TA wells and how a TA well is defined. How is a TA well different from an idled well or one that is orphaned? What limitations are imposed on the operator once TA status has been approved by the District for a given well?

2. Does the District require a mechanical integrity test to be run on a TA well before it is approved for TA status, periodically while in TA status, and before reactivation as an injection well? NA

3. Describe how TA wells are tracked and whether they are tracked as active or abandoned wells. How long may a UIC well remain in TA status before being reactivated or P&A. NA

This Division does not use the term "TA".

PART VII: COMMENTS

OBJECTIVE: Please provide any additional comments and information that you feel are relevant to this program review but were not specifically requested in the questions above.

Attached is the 2000 *STRONGER Questionnaire*

STATE REVIEW OF OIL AND NATURAL GAS ENVIROMENTAL REGULATIONS (STRONGER)

2000

PART I: GENERAL - Underground Injection Control Program

A. Statutory authorities and regulatory jurisdictions

1. Please include a copy of all statutes, rules, regulations, policies and orders applicable to the management and disposal of Class II eligible wastes, abandoned oil, gas and service wells, enhanced recovery projects, oil field NORM (naturally occurring radioactive materials) if injected into wells and water produced in connection with the production of coal bed methane.

   Public Resources Code (PRC) – Attachment 1

   California Code of Regulations (CCR) – Attachment 2

   Manual of Instruction (MOI) – The MOI is too large a document to include as an attachment. However, it will be made available during the on-site review in Bakersfield.

2. What is the statutory authority upon which your UIC program is based?

   Section 3106, PRC

3. Does this statutory authority include promulgation of rules and regulations?

   Yes, Section 3013, PRC.

4. Do the statutes relating to oil and gas or statutes pertaining to the protection of "waters of the State" contain definitions of injection, enhanced oil recovery, disposal, types of wells, hydraulic fracturing, fresh and/or usable water, and USDWs (Underground Sources of Drinking Water)?

   Yes, however, specifics to the UIC program are contained in regulation, Sections 1724.6 – 1724.10, CCR.

5. Do the statutes mandate or allow the establishment of advisory boards, regulation review boards, or other mandated vehicles designed to bring UIC program stakeholders together? If not mandated by statute, are other policies or orders issued by the agency, which brings such groups together.

   No. The Office of Administrative Law (OAL) is responsible for reviewing administrative regulations proposed by State agencies for compliance with standards set forth in California's Administrative Procedure Act, for transmitting these regulations to the Secretary of State, and for publishing

regulations in the California Code of Regulations for public review. Prior to submitting proposed regulations to OAL, the Division of Oil, Gas, and Geothermal Resources (Division) submits them to the industry's advocacy groups for review and comment. Although not related directly to the UIC program, the Division, BLM, and industry representatives formed a workgroup to review and develop statutes and regulations, as well as provide periodic updates on pertinent issues.

When field rules are changed, the Division works in partnership with the operator(s) and other agencies to develop a field rule to address a specific situation unique to that field (Section 1722(k), CCR).

6. Please provide a brief (three pages or less) historical overview of the evolution of the UIC program in your state. This should include the evolution of statutes, oil and gas production history, geology and hydrogeology, changes in agency jurisdiction, institution of injection practices and the trend of injection wells through time. Geologic maps and tables of trends are acceptable *in lieu* of rhetoric.

The California petroleum industry began in the 1870s. The Division of Oil, Gas, and Geothermal Resources (Division) was formed in 1915 to address the needs of the State, local governments, and industry by establishing statewide uniform laws and regulations. The Division supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells, preventing damage to: (1) life, health, property, and natural resources; (2) underground and surface waters suitable for irrigation or domestic use; and (3) oil, gas, and geothermal deposits. Division requirements encourage wise development of California's oil, gas, and geothermal resources while protecting the environment.

The Division's programs include: well permitting and testing; safety inspections; oversight of production and injection projects; environmental lease inspections; idle-well testing; inspecting oilfield tanks, pipelines, and sumps; contracting for hazardous and orphaned well plugging and abandonment operations; and subsidence monitoring.

To date, about 180,000 oil, gas, and geothermal wells have been drilled in California and about 88,000 are still in use. About 3,000 new wells were drilled in the State ***in 2000. Daily oil production runs about 855,000 barrels, placing California fourth among oil producing states. The estimated reserve is about 3.6 billion barrels of recoverable crude oil and can be found in eleven sedimentary basins. The majority of the*** State***'s oil and gas production occurs in the San Joaquin Basin. In fact, if Kern County (within the San Joaquin***

Basin) were a country, it would rank 25th in world in oil production for the year 2000.

About 55 percent of all oil produced in California results from injecting steam, water or gas into oil reservoirs. Since injection operations began in California in the 1940s, more than 70 billion barrels of produced water have been injected into oil and gas zones and other nonpotable aquifers without causing any known degradation of fresh waters.

Although the Division was created in 1915, regulations for oil and gas operations, including injection operations, were not adopted until 1974.

In 1983, the Division was granted primary responsibility and authority (primacy) from the Environmental Protection Agency under the provisions of the Safe Drinking Water Act. Although the Division had been regulating injection wells since the 1940s, the grant of primacy necessitated an augmentation of the existing program. This included:

- *Extension of the existing program to include the protection of subsurface waters ranging from 3,000 ppm TDS to 10,000 ppm TDS.*
- *Increased field-testing, inspection, monitoring, surveillance, and sampling to ensure mechanical integrity and the proper operation of wells.*
- *Quarterly and annual reporting covering permitting, compliance evaluation, and well testing.*
- *Increased responsibilities regarding the public's participation in injection project decisions.*
- *Consultation with other agencies and local governments regarding project proposals and modifications.*
- *Gathering and presenting engineering and geologic information for determining whether aquifers may be used for injection purposes (aquifer exemptions).*

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years.

B. Program coordination

1. Attach an agency organizational chart and identify UIC positions in permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

Organization Chart: Attachment 4.

The Division's public outreach program is designed to inform interested citizens about the program as a whole and to alert them about proposed project applications for injection wells and well modifications in their areas. Videotape, UIC information pamphlet, and other media have been created as public educational and information material. In addition, Division staff visits K-12 schools frequently to make presentations about oil, gas, and underground injection operations in the State.

The Division's web page www.conservation.ca.gov provides information on its programs, production and injection statistics, maps, publications, reports, and other information useful to the public.

2. Discuss the mechanisms in place in your state for the coordination of UIC activities and environmental protection programs, complaint and emergency response among the public, government agencies and the regulated industry.

The Division has a comprehensive memorandum of agreement (MOA) with the State Water Resources Control Board (SWRCB) (Attachment 5). This MOA outlines the procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. These procedures are intended to provide a coordinated approach that results in a single permit that satisfies the statutory obligations of both parties. The procedures ensure that construction or operation of oil, gas, and geothermal injection wells and surface disposal of wastewater from oil, gas, and geothermal production does not cause degradation of waters of the State of California.

Also, the Division has an MOA (Attachment 6) with the U.S. Environmental Protection Agency (EPA) that establishes the responsibilities and procedures used by the Division (which has primary authority) and the EPA in the administration of the UIC program. The federal UIC program corresponds closely with the Division's long-standing program of injection-project surveillance.

Complaints and emergencies for Class II wells are essentially nonexistent. If a complaint or emergency response were received, it would be directed to the appropriate district office where an engineer would complete a Report of Occurrence (Attachment 13) form. The form includes details of the emergency or complaint, location, type, volume (if spill), if the emergency situation is under control, name of person making the call, a contact person, etc. All complaints will be investigated and appropriate action taken when it is justified. Every effort will be made to resolve a valid problem and satisfy a complainant, or a complainant will be informed why a matter is not within our jurisdiction, if that is the case. The operator is notified of the complaint or emergency and the citizen who made the

complaint receives notification from the Division concerning the results of the investigation.

Complaints are classified as informal or formal:

Informal complaints are usually made by telephone or in person. When an informal complaint is received, the Division will:

- *Investigate to determine the validity of the complaint.*
- *Attempt to settle the difference between the parties involved.*

Formal complaints must be in writing and are covered by two, separate oil and gas statutes and one geothermal statute. Section 3235, PRC, provides for a complaint to the Supervisor by a person owning land or operating wells within a radius of one mile of a well or wells complained against. Section 3302, PRC, provides for a complaint to the Director of the Department of Conservation by any person operating in any oil field where an unreasonable waste of gas in any field or fields is occurring. These sections also provide that the Supervisor may initiate an investigation of wells or request a public hearing on gas wastage.

Section 3753, PRC, provides for a complaint to the supervisor or to the District Deputy, by any person, concerning possible damage by a geothermal well.

Compliance with the California Environmental Quality Act (CEQA) is a routine element in the project permitting process. The Division can approve a UIC project plan, but not the drilling of wells until CEQA requirements are met. The CEQA lead agency is usually the local agency. This agency may prepare an environmental impact report, including recommendations to mitigate impacts the project may have on the environments. As an alternative, they may prepare a declaration that the project will not cause an adverse impact on the environment. Public concerns are often addressed through these means.

3. Describe briefly the nature of the agency (Commission, Board, Appointed Head etc.) and further discuss the relationship of the oil and gas authority to the agency leadership.

The Division supervises the drilling, operation, maintenance, and plugging and abandonment of oil, gas, and geothermal wells in California. It also oversees the operation, maintenance and removal or abandonment of facilities attendant to these wells and their surrounding property. Through the enforcement of regulations, the Division encourages sound engineering practices and prudent development of hydrocarbon and geothermal resources. The Division's key customers are oil, gas, and geothermal operators; private consultants and drilling

engineers; State and federal agencies; local and regional governmental agencies; and public interest and environmental groups.

C. Staffing and funding

1. Please provide funding levels and the total staff complement for the agency or division of agency (if applicable) for the period FY 1998 to present. Please differentiate between UIC and non-UIC program funding and staffing levels. Assume fractional FTEs for staff who perform both UIC and non-UIC functions.

The chief of the Division is the State Oil and Gas Supervisor. The Division has 130 employees, including 65 professional geologists and petroleum engineers.

Although there are assigned engineers who are tasked solely with performing UIC related tasks, all engineers and most clerical staff support the UIC program, although the percentage of support will vary. The Division's UIC program is decentralized. The Headquarters office is located in Sacramento and there are six district offices located strategic to oil and gas fields. Permitting, file review, and most compliance and enforcement functions take place at the district office level. Sacramento handles the overall administrative program functions, including grant application, grant monitoring, record keeping, general data management, reporting, and program oversight and policy development (Attachment 7).

		TOTAL	TOTAL UIC	TOTAL Oil & Gas
98-99	Salaries & Benefits	$864,195.91	$194,089.76	$670,106.15
	O,E,&E	$7,692,975.59	$1,727,765.39	$5,965,210.20
	Overhead	$1,327,539.28	$298,152.05	$1,029,387.23
	TOTAL	$9,884,710.78	$2,220,007.19	$7,664,703.59
99-00	Salaries & Benefits	$7,039,310.49	$1,580,958.74	$5,458,351.75
	O,E,&E	$2,441,809.31	$548,405.95	$1,893,403.36
	Overhead	$1,300,922.61	$292,174.21	$1,008,748.40
	TOTAL	$10,782,042.41	$2,421,538.90	$8,360,503.51
00-01	Salaries & Benefits	$6,225,153.78	$1,398,107.29	$4,827,046.49
	O,E,&E	$3,058,070.80	$686,812.12	$2,371,258.68
	Overhead	$1,225,372.78	$275,206.47	$950,166.31
	TOTAL	$10,508,597.36	$2,360,125.88	$8,148,471.48
01-02	Salaries & Benefits	$3,789,571.32	$851,099.82	$2,938,471.50
(6 months)	O,E,&E	$789,911.81	$177,406.29	$612,505.52
	Overhead	$615,853.85	$138,314.62	$477,539.23

TOTAL	$5,195,336.98	$1,166,820.73	$4,028,516.25

2. Are the levels of funding and staff provided adequate for full UIC program implementation? Please discuss in reference to the trends shown in C-1.

   The Division receives an annual grant allocation from the EPA to support the UIC program. In the Primacy Award granted to the Division in 1983, a Cooperative Agreement was established that identifies the non-federal and federal participation (in funds) required between the Primacy State (recipient) and EPA. The Cooperative Agreement between the Division and the EPA established a cost share agreement set at 25 percent state (recipient) and 75 percent federal. To date, the Division has contributed over 80 percent of the funding necessary to conduct California's UIC Program. The bulk of the UIC funding comes from the Division's oil and gas assessment.

D. Data management program for agency

Describe in either flow chart form or by general description how the UIC data management system fits into the agency system, the state data base shared by other agencies having responsibility for oil, gas, water allocation and protection, and water planning for the state. Also describe the linkage that exists with any state GIS system or system affording Global Positioning capability.

The Division requires operators to file monthly reports (electronic or hardcopy) on well production and/or injection that are entered into the data management system (WellStat). About 90 percent of the monthly injection data from operators is received in an electronic format. Available information includes a list of all active injection wells, idle wells, volume injected, pressure, days injecting, shut in, and the source of fluid (production records provide the amount of fluid and disposition). The information is posted monthly on the Division's web page and printed in the Annual Report (Attachment 8).

All wells are being plotted digitally on Division maps using latitude/longitude well locations provided by the operator or by well locations arrived at by the Division using the heads-up display or GPS. Over 90 percent of all wells have been converted to a digitized location. Each well location will be tied to the WellStat database to allow web access to well production and injection information.

E. Interagency coordination

1. Please provide or summarize any memoranda of agreements or similar agreements between state agencies, or between the state and any other governmental entities (BLM, US Fish and Wildlife Service, EPA, Indian Tribes, local jurisdictions and

water management districts) which relate to UIC regulation, oil and gas waste, sharing of information, or processing of complaints.

The Division has an MOA with the SWRCB, whereby the permitting of surface wastewater disposal is regulated by SWRCB and the Division regulates any underground injection of wastewater or other fluids associated with oil and gas production (Attachment 9). Also, the Division has an MOA with the EPA regarding public notification and aquifer exemptions (Attachment 10). Furthermore, the Division has an MOA with the Bureau of Land Management (BLM) to delineate procedures for regulation oilfield operations, including UIC activities, where both the BLM and the Division have jurisdictional authority (Attachment 11).

2. Provide a flow chart, organizational diagram or other document which shows how your oil and gas program (agency) fits into the state picture with other agencies or entities having authority over portions of oil and gas regulation, oil related environmental protection, or regulation of water use and state water planning.

   Attachment 12

F. Changes in general activities since 1990

1. Excluding the changes in data management that are to be described in Section I-D and throughout the remaining sections, what significant changes have occurred within the agency or outside the agency that have affected the administration of the UIC program? New statutes or major regulatory changes?

   In 1996, Section 1724.10(j)(1), CCR, was added to include mechanical integrity testing of the casing-tubing annulus every five years.

2. Has the Congressional passage of the Safe Drinking Water Act Reauthorization (1996) and other Federal mandates caused changes in the way the UIC program is administered (i.e. Wellhead protection, Source Water Protection, Watershed Management etc.)?

   Division – No.

3. Has the SARA Title III Program of EPA and the Community Right -to Know Program (EPCRA) had an impact on your UIC program? On the ability of the regulated community to meet deadlines established in the State UIC regulations? If so, describe the impact.

   Division – No.

PART II: PERMITTING/FILE REVIEW

A. OBJECTIVE: Understand the application flow process in the state.

1. How does the Operator initiate a permit application?

   The operator files a complete project plan and/or well permit application with the appropriate district office.

   The Division requires that an operator submit a complete project plan that includes a geologic and engineering study; an injection plan, and other data listed in Section 1724.7, CCR, for onshore projects and 1748.2, CCR, for offshore projects. Requirements and surveillance procedures for injection projects are designed to ensure the injected fluid is confined to the approved zone of injection and that adjoining operations will not be affected adversely. The condition of all wells within a finite area, known as the Area of Review (AOR), is reviewed to ensure the protection of all oil and gas zones and USDWs. A thorough knowledge of the stratigraphy and subsurface conditions in the project area is essential prior to final project approval.

   Once the injection project is approved, the operator may submit an individual injection well permit applications. The application may be a permit to drill a new well or convert an existing oil and gas well to injection.

2. Who receives the application from the Operator?

   An Associate Oil and Gas Engineer in the appropriate district office receives the project or well application.

3. How and by whom are permit applications screened for completeness?

   The district Associate Oil and Gas Engineer responsible for permitting reviews the project or well application and ensures that all the required information has been submitted.

4. What is the procedure used when an application is found to be incomplete?

   The operator is notified of the deficiencies and is informed that the information must be submitted before the project can be approved. Review and evaluation by Division engineers might continue; however, the extent of the evaluation would depend upon the type of information that is available to the engineers.

5. How long is the Operator given to reply in the case of incomplete applications before they are considered null and void and how is the Operator notified?

   Each district office maintains a tickler file; however, once a letter requesting additional information is sent to the operator, no other formal follow-up occurs. It is incumbent upon the operator to complete the project or well application.

6. In the case of voided applications, is the application returned to the Operator or kept by the reviewing agency?

   The project or well application may be returned to the operator immediately if significant information is not included in the application. If the application is retained and a request for additional information was sent to the operator, there is no set time for return if the operator does not reply. It is the prerogative of the district office.

7. Upon a determination of application completeness, how is it routed and concurred upon?

   Once the permitting engineer prepares a project permit or well permit, it is reviewed by the Senior Engineer in charge of technical projects (the District Deputy in the smaller districts) and signed and approved by the District Deputy.

8. Who are the individuals responsible for reviewing the different aspects of the permit application? Technical Issues? Administrative Issues?

   Technical - ***The permitting engineer is responsible for reviewing the complete project application. In larger districts, the application is routed to the engineers with expertise in the geology or reservoir characteristics of the project area.***

   Administrative - ***A district engineer handles environmental compliance (CEQA), with support from Headquarters staff.***

9. What are the professional qualifications required for agency personnel reviewing a permit application?

   The permitting engineer is an Associate Oil and Gas Engineer that has (at least) a Bachelor's degree in geology or petroleum engineering. The permit is signed and approved by the District Deputy who is a Senior Oil and Gas Engineer in one of the four smaller district offices or a Supervising Oil and Gas Engineer in one of the two larger district offices.

10. How is an application tracked to ensure that both review and permit issuance/denial recommendation occurs in a timely manner?

Each district has its own system for tracking injection permits; however, most use the computer. The Division is mandated, via Sections 3203 and 3229, PRC, to respond to each well permit within 10 working days from the date of receipt.

11. Is the process described under questions 1-10 the same or different for amendments applications to existing permits? (Existing in the sense the permit for which amendment is sought is active.) Is the process flow different for major versus minor amendments?

The same process is used.

12. How are UIC well applications at commercial facilities handled?

Commercial facilities undergo the same project review process as all injection projects. Individual permits are issued for each well. However, permit requirements are more stringent, requiring more fluid sample analyses and reporting (especially where fluids are trucked to the injection well(s)), manned or locked gates, and the retention of trucking manifests. An important difference is that a $50,000 life-of-the-well bond must be posted for each well, unless the operator has submitted at least a $250,000 blanket bond.

13. How are the official copies of the permits stored and protected from loss?

A copy of each well record is on file in the district office and a duplicate copy is kept in offsite storage. Copies of all well records are also kept on microfilm that is maintained in each district office.

14. Does the State allow a well to be used for the disposal of both Class I and Class II fluids? Under what circumstances? How are these wells permitted and which agency acts as the principle in holding hearings?

No.

B. Objective: Understand the current file review process.

1. What is the file review strategy? (i.e.) How are wells selected for file review)? Is the compliance history a factor of selection?

A well is reviewed every time a mechanical integrity test (MIT) is performed on the well, or when the operator submits a rework notice. MITs are performed on

water-disposal wells at least once each year; waterflood wells once every two years; and steamflood wells every five years.

In addition, each injection project is reviewed with the operator annually. During the annual reviews, the entire project, including all wells within the project boundary are reviewed for compliance with permit conditions and project performance.

2. Who performs the file review and what are the qualifications of the reviewers?

   Any Division engineer can perform a file review. MITs are witnessed and approved by a field engineer. MIT results are reviewed and approved by an Associate Oil and Gas Engineer, who is in charge of UIC, who must have a Bachelor's degree in geology or petroleum engineering, with at least 2 years experience in the field.

   The Associate Engineer is also responsible evaluation and approval of rework notices and performs the annual project review with the operator.

3. Over a year period, what percentage of total UIC permits receives a file review?

   Approximately 80 percent.

4. How is the quality of file review assured and subsequently documented?

   Operating data and mechanical condition of a well are compared with permit conditions. File reviews are then documented on a database.

5. Where deficiencies are recovered during the review, what actions are taken to correct the deficiency?

   In the event a project review results in the determination that the enhanced recovery project is not fulfilling its intended purpose, project approval can be rescinded. However, this is usually an operator decision.

   Falsification of information by the operator or an operator's failure to comply with permit requirements can result in a fine and/or rescission of permit approval.

   The Division can order repair or remedial work on a well, with a deadline for compliance.

   The Division can revise permit requirements to update conditions of the project.

6. How long does it take to do an average file review of a well without complications? What are complications?

   Initial reviews can take 2-3 hours because it would entail preparing a complete casing diagram from detailed analysis of all well histories.

   Subsequent reviews (i.e., MITs, changes of casing diagram due to rework or remedial work, etc.) can take 15-30 minutes.

7. Assuming that file reviews are currently conducted on wells under permit, what action is taken toward the continued use of the well for injection while the deficiency is being corrected by the Operator? For technical deficiencies? For administrative or paper deficiencies?

   See response to question 5.

C. OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

1. What are considered to be adequate casing and cementing (surface and production, etc.) requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all USDWs? If not, how are USDWs otherwise protected?

   Sections 1722.2 – 1722.4, CCR cite casing and cement requirements for wells.

   <u>Surface casing</u> – Set at a depth of a least 10 percent of total depth with a minimum of 200' and maximum of 1,500' of casing. The casing is cemented from the casing shoe to the surface and is set into a competent bed (2^nd^ string is required if the first string is not set into a competent bed).

   <u>Intermediate casing</u> – May be required to protect oil, gas, or freshwater zones, and to seal off lost circulation or anomalous pressure zones. Casing is cemented so that all freshwater zones, oil or gas zones, and anomalous pressure intervals are covered or isolated.

   <u>Production casing</u> – If the casing does not extend to the surface, then there must be at least 100' of overlap with the next larger casing. The overlap must be cemented and a fluid entry test run.

2. What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the wells protected?

See response to question 2. Casing and cement requirements are the same for all wells (i.e., oil, gas, and injection).

Cement behind casing is not required across a USDW. There must be cement behind casing through the injection interval and 500' above the injection interval and 100' above the 3,000 mgl TDS interface. However, all intervals behind casing not filled with cement must be filled with mud. Division requirements comply with EPA standards that require wells be cased and cemented to prevent movement of fluids into USDWs.

3. Packer/ tubular goods requirements:

   a. Are packers routinely required for all newly completed and converted wells? If there are exceptions, what are the criteria used? Does an exception impose alternative requirements (i.e., more frequent MITs, annulus and pressure monitoring, limitation on injection volume)?

      Yes, see Section 1724.10(g), CCR.

      Exceptions may be made when there is:
      (1) No evidence of freshwater-bearing strata.
      (2) More than one string of casing cemented below the base of fresh water.
      (3) Other justification, as determined by the District Deputy, based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.

   b. Do permits specify the type or packer to be used?

      No.

   c. Do permits specify the use of tubing? Is lined tubing acceptable and under what conditions?

      Yes, see Section 1724.10(g), CCR. The regulations do not address lined tubing specifically; however, it is not prohibited. In areas where corrosion occurs, operators have used fiberglass tubing.

   d. Does the agency prescribe or impose restrictions on weight, grade, material, internal coating or other packer/tubing qualities?

      No, but casing and tubing must be of sufficient weight and grade, etc., to withstand collapse, burst, and tension forces (Section 1722.2, CCR).

4. Are dual completions accepted? What types?

Yes. Virtually any combination. Currently, we have dual injectors (SF/WF), dual producer/injector (OG/WF, OG/SF, OG/WD), and dual producers (two different zones). However, each dual completion is evaluated on a case-by-case basis to establish methods and conditions to protect useable waters.

5. How are the locations of USDWs determined? How often is the maps, charts or other information used for determination updated and by whom?

Most freshwater aquifers (3,000 mgl TDS or less) are known through years of permitting production wells and from in-house mapping of freshwater areas.

Historically, location of useable waters has been determined by using water analyses, E-log data, drilling records, and published geologic and reservoir reports on every oil/gas field in California.

6. How is the adequacy of the confining system determined? In those areas where confining geological deposits may consist of prominently incised channel sand fills or karst surfaces faults or other unique geologic conditions that may affect the containment of injected fluids, what buffer or insurance is provided to compensate for irregularities? How are such conditions evaluated?

Because most oil and gas fields in California have been under production for a long time, the Division has collected an abundance of information on the geology and reservoir characteristics of these fields. Much of the information available has been analyzed and interpreted into reports that are published by the Division.

Operators are required to submit data (i.e., E-logs, dipmeters, mud logs, sidewall sample logs, drilling surveys, etc.) that are used to determine zone characteristics and boundaries.

7. What types of monitoring systems are required or have been approved (flow rate and cumulative volumes, tubing pressure, annuli pressures, etc.)?

The monitoring of injection pressure and volumes is required for all injection wells. Monthly injection reports are required to be submitted to the Division.

Other monitoring systems may be required, such as graphs of time vs. injection rates or time vs. pressure, observation wells, and isobaric maps (Section 1724.10(k), CCR). In addition, periodic field inspections are made to check on surface pressures and conditions.

8. Has the compatibility of injectant/cement and injectant/formation fluid been a problem?

No.

9. How are the maximum injection pressures and rates established?

A step-rate test is performed to determine the fracture gradient (Section 1724.10(i), CCR)). The maximum allowable surface injection pressure would then be less than the fracture pressure.

A step-rate test may be waived if the proposed injection pressure is considerably below the established pressure required to fracture the zone. The Division's injection manual lists established fracture gradients for different areas in California.

10. How is corrective action handled in those cases where the approval of the application is contingent upon resolution of an adverse situation?

Before injection can commence, the conditional permit approval letter would require that all wells within the injection project area that need repair work or plugging be repaired or plugged to the satisfaction of the District Deputy.

If a well requires corrective action after injection has commenced, an informal request by phone is made with a time limit for correction, depending on the severity of the problem. A follow-up letter is sent to indicate the specific problem that needs correction. Failure to comply with the written request results in the issuance of a formal order, possible fines imposed for noncompliance, and/or recession of injection approval.

D. OBJECTIVE: To understand the Area of Review considerations and procedures.

1. How is the Area of Review determined for enhanced recovery wells or projects? For salt-water disposal wells? For commercial wells?

The Division uses the ¼-mile radius for area of review.

2. If area permits are issued, how is their area of review determined?

N/A

3. In a case where the Operator elects to withdraw the application rather than take corrective action measures, what is the subsequent course of action taken by the agency?

No action is taken; the permit or project application is canceled.

4. What authorities are open to the State where the Area of Review reveals a problem (unplugged wells or other USDW threatening situation) that is on acreage outside the Operator's control? Is the Operator's application denied if he/she has no legal status to effect corrective action?

   Application approval could be denied if some form of action cannot be implemented.

E. OBJECTIVE: Understand the administrative permit application components.

1. Prior to permit issuance, what is the public notification for applications before the agency?

   When a project application is received, a notice of receipt of application to inject/dispose of water into a specific zone is published in a local newspaper of general circulation for 3 days. The public review and comment period is 15 days. A 15-day extension can be granted if requested by the public. If there are problems that cannot be resolved through direct communication with concerned persons, the Supervisor may schedule a public hearing. All public comments at the hearing are responded to.

2. When does the public comment period start? Upon determination of completeness or after completion of technical review?

   The public comment period begins the day the notice first appears in the newspaper. The project is not announced publicly until the Division has conducted a technical review and all Division requirements have been met.

3. When and where is public hearing opportunity held on an application?

   At the discretion of the State Oil and Gas Supervisor, public hearings may be scheduled upon request of concerned persons. The notice for a public hearing is published in a local paper 30 days prior to the hearing.

4. How are the public hearings conducted (formal, informal, transcript, qualifications etc.)?

   Formal hearings are conducted with a hearing officer (usually the State Oil and Gas Supervisor) and a public recorder (optional). A recording and/or a transcript of the hearing are made and all comments are responded to, in writing, within 30 days following the hearing.

5. What criteria, conditions or circumstances would prompt a public hearing on an application?

It is the intent of the State Oil and Gas Supervisor to schedule a public hearing whenever it is requested. There is no formal set of criteria that would guide a decision whether a hearing should be held. The main intent is to let the public voice their concerns. Typically, public hearings are scheduled whenever direct communication with a person does not answer their concerns, or if a hearing is requested, as long as concerns are related sufficiently to the project.

6. In reference to hearing participation, does the agency have a definition for "significant interest" below which level the permit would automatically be issued after notification?

No, it is left to the discretion of the State Oil and Gas Supervisor.

7. How often have public comments modified the conditions of the final permit?

Very rarely are public comments received.

8. What types of financial assurance mechanisms are used in connection with UIC applications? If used, how is the adequate coverage per well determined?

Operators are required to file cash or indemnity bonds to cover drilling, redrilling, deepening, or operations permanently altering casing. Bond amounts are determined by drill depth of the well. Also, surety companies must be authorized to do business in California (Sections 3204-3206, PRC).

Wells less than 5,000' deep	***-***	***$15,000***
Wells 5,000' – 9,999' deep	***-***	***$20,000***
Wells 10,000' or deeper	***-***	***$30,000***

In addition, each commercial production-water disposal well must be covered with a $50,000 life-of-the-well bond unless the operator has submitted at least a $250,000 blanket bond (Section 3205.2, PRC).

9. In reference to question #8, what conditions is blanket surety coverage allowed?

Section 3205, PRC allows any operator who drills, redrills, deepens, or alters the casing or one or more wells to submit a blanket bond.

Operators with less than 50 wells	***-***	***$100,000***
Operators with 50 or more wells	***-***	***$250,000***

Or, an operator may post a $1,000,000 blanket bond to cover all wells, including commercial disposal and idle wells.

10. How are complaints related to the proposed permit or application recorded and filed? Is the same filing process used for complaints, which are submitted to the agency after UIC approval has been given?

    Complaints relative to proposed permits are rare because the Division addresses and responds to concerns through the public participation process prior to the issuance of permits. If a complaint were received, it would be placed in files that relate to the specific project, well, and/or in "subject" files.

F. OBJECTIVE: Understand the process for aquifer exemptions

1. How many exemptions have been requested since the inception for the program and what criteria were used for the request?

   Aquifer exemptions were listed and included in the primacy application with EPA. Essentially, the list includes all hydrocarbon-bearing zones and nonhydrocarbon zones that were being injected into at the time of the primacy application. Prior to primacy, all injection zones (hydrocarbon and nonhydrocarbon bearing) had been reviewed previously for injection through the same injection project review as now. A public notice was issued on all aquifers exempted on the primacy application.

2. How many requests have been granted/denied and, if denied, what basis or reason was given? Who issued the denial?

   Two.

3. Are minor aquifer exemptions granted? How many have been granted/denied?

   No.

4. Are certain aquifers granted exemptions in some parts of the State while the SAME aquifer is considered non-exempt in other parts of the State? If so, what criteria are used?

   No.

G. Objective: To understand the Data Management Systems Used in Review

Describe the data management system (s) used in the various components of the Permitting/File Review process as set forth in Section A-F. The description should delineate both the systems used for technical and administrative activities.

Currently, the Division is developing a Division wide Microsoft Access database that will include the unique components each district may use. This database will replace each database developed by individual districts.

The Division's WellStat is used to manage monthly reports submitted by operators. The information includes, injection volumes, pressures, days injecting, type of fluid injection, and fluid source. The Division can check for excessive injection pressures, periods of inactivity, injection volume, etc. The oil and gas program and the UIC program use WellStat for oversight.

1. When were the data management systems currently in use first put into operation?

   The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet their needs.

   In addition, production and injection data from 1977 is stored electronically.

2. Are these systems effective and efficient for the type of data management use?

   Yes. As these systems evolved over the years, they became more effective and efficient as additional functions were added. As an example, the information entered by field engineers allows UIC wells to be tracked electronically to ensure scheduled MITs are conducted and injection pressures are below the MASP, to populate reports, and to track other deficiencies.

3. What are the limitations in terms of addressing the basic regulatory needs?

   The most obvious limitation would be entering the data electronically. Historically, the Division has tracked the same information that is now being stored electronically, and in some cases hardcopy information is sufficient. However, providing this information in an electronic format vastly improves how this information is managed and used by the Division, operators, and public.

   Currently, the Division is beta testing a program that allows engineers to electronically enter data collected in the field using handheld computers. The information would then be synced to the office database.

4. Is there capability for the Operators to file some or all documentation pertaining to application submission electronically? Describe what electronic communication is currently available to the regulated community and the public.

   The Division's electronic permitting system (ePermit) is in the final stages of beta testing. Once operational, ePermit will allow operators to submit single or batch well-permit applications and receive a Division response (either a permit or denial letter) via the Internet. Lease maps, well diagrams, etc. can be added to the electronic permit application; however, notarized bond documents still will have to be submitted as hardcopy.

5. Is the agency's data management system locally (intramural) conceived or linked with other state databases?

   Although the Division's networked database is not linked to other State agencies; it is posted on the Division web site and can be accessed by the public or other agencies.

H. Changes and Modifications to Program Since 1990

Exclusive of the changes in data management described under Section G., what statutory, regulatory or policy changes have occurred during the past ten years in the UIC Permitting/File Review process? Please list or explain.

None.

PART III: INSPECTIONS

A. Objective: Understand how field operations are conducted and managed by the agency.

1. Are inspectors State employees or are they contractors?

   Full-time Division employees.

2. Do inspectors work out of an office, their homes, or other setting? Who coordinates the work of the inspectors and at level does this supervision take place (central office, district office, field supervisor working out of home)?

   The Division is configured with a Headquarters office located in Sacramento and six district offices located throughout the State and strategic to oil and gas fields. Permitting, file review, and most compliance and enforcement functions

take place at the district office level. Coordinating and scheduling the field inspector's activities in each district office is performed by an Associate Oil and Gas Engineer and supervised by a Senior Oil and Gas Engineer.

3. Do the inspectors perform all types of inspections or is there specialization of inspection responsibilities?

   Energy and Mineral Resources Engineers (EMRE) are responsible for witnessing MIT surveys, testing safety equipment, witnessing plugging and abandonment operations, etc.

   Oil and Gas Technicians (OGT) are responsible for the inspection of surface facilities, surface condition of wells, lease conditions, and check injection and tubing pressures. They do not witness mechanical integrity tests.

4. Do supervisors periodically accompany inspectors on field assignments?

   a) To observe and critique their work (please explain how often and the process?

      Yes. An Associate Oil and Gas Engineer will accompany an EMRE or OGT at least once annually.

   b) To ensure that inspections, tests required of operators and general observations of lease and well conditions meet a common standard of quality and fairness to operators?

      Yes.

   c) For other purposes (please explain how often and for what purpose(s)?

      Yes, a supervisor or Associate Oil and Gas Engineer may accompany an EMRE or OGT during enforcement cases.

5. Does the agency have a written inspection strategy, guidance manual or policy document which is available to inspectors? How are inspection priorities determined?

   Yes. The MOI is available to all Division employees. Inspections are performed regularly on all wells, but with no particular priority to operator or well unless there has been a deficiency or violation. In such cases, inspections are made more frequently until the problem is rectified and for a period thereafter to ensure continued compliance. The Division tries to achieve 100

percent inspection of all injection wells annually either through scheduled environmental lease/well inspections or during an MIT.

6. What professional qualifications and /or experience is required to be and inspector?

   Preferably, EMREs must have a minimum of a Bachelor's degree in geology or petroleum engineering; however, exceptions are made, based on experience. OGTs must have oil and gas field experience, but a Bachelor's degree is not required.

7. What training do inspectors receive? Initially upon employment? To keep trained on new regulations, industry techniques, etc.? Do inspectors receive training in safety procedures and is special safety equipment readily available?

   As mentioned above, EMREs have a minimum of a Bachelor's degree in geology or petroleum engineering and OGTs have oil and gas field experience. Each EMRE is teamed with another experienced EMRE and with an Associate Oil and Gas Engineer to receive additional training.

   Training in safety procedures is of high importance. Field engineers are trained in H2S safety, safety procedures around steam operations, rig pressure systems, safe fluid-sampling procedures, rig safety, and drivers training every four years. In addition, every EMRE is required to attend blowout equipment training.

   Protective clothing is required in the field (i.e., hard hat, steel-toed boots, and thick-soled shoes, etc.). Also, proficiency in use of medical kits, flares, gas mask for H2S, etc., is also taught.

   All Division employees are notified of statutory, regulatory, and policy changes through electronic mail and staff meetings.

   Other training consists of in-house training (videotapes), or what is provided by service companies, such as cementing companies, mud companies, well surveying companies, well equipment companies, etc.

   The Division budgets each year for college courses, conferences, seminars, and other training that is provided periodically.

8. What role do inspectors play in developing enforcement cases and to what extent are they involved in the hearing or judicial process?

EMREs carry out the documentation and follow-up inspections, including sampling and photographing violations. They are responsible for gathering all relevant information and presenting it to the District Deputy, who then takes appropriate action. In many cases, the field inspector who witnessed the field deficiency/violation would testify at a hearing as an eyewitness.

9. Is the operator compliance history and selection of wells coordinated for inspection at the field or central office level?

   Yes. Well files are maintained in each district office. All MIT and inspection activity is coordinated at the district office. Operators who have a history of certain violations may be monitored and inspected on a more frequent basis than other operators. Headquarters is informed verbally of such activity.

B. OBJECTIVE: Understand the routine/periodic inspection program in the state.

1. How often is each UIC permitted well inspected? Is there a different inspection periodicity for Class II ER than for SWDs?

   The Division attempts to inspect each UIC well annually while performing environmental lease/well inspections or through scheduled well inspections. In addition, MITs for disposal wells are performed at least once each year and waterflood wells are tested at least every two years. The Division attempts to witness most of these MITs, particularly water disposal wells, and during this time the well site is inspected also.

2. Who determines the inspection frequency for each UIC facility? Are UIC inspections done separately or are they generally coordinated with inspections of other permitted facilities on the lease?

   See response to question 1.

3. How is communication between field inspectors and the central office staff in charge of UIC permit review handled? Are inspections ever required after an Operator files an application but before technical review is completed?

   Field inspection is managed at the district office. The district communicates with the UIC program manager or Chief Deputy if needed. In addition, districts submit UIC information for US EPA reports quarterly to the UIC program manager and send a representative to the Injection Surveillance Committee meeting that is held periodically.

   Occasionally, but usually the Division does not begin inspecting a well until a permit has been issued.

4. How many UIC related inspections are conducted in an average month, which are not related to scheduled MITs? Discuss seasonal variations.

   Approximately 600 per month.

5. What does the inspector look for during a routine inspection? Is there a checklist? (Please supply a copy of forms and checklists used).

   Tubing and casing pressure, presence of a gauge, leaks (wells, pipelines, and tanks), fluid in cellars, check flow rate, general condition of equipment, general condition and cleanliness of well site, and proper well identification (Attachment 13).

6. What is the average length of time needed for a routine inspection? Include the amount of time needed for preparation, travel time, and time spent on location. Is the preparation performed by the inspection and/ or others? What review occurs during preparation?

   Preparation time per well is about 15 minutes. Average travel time to the well ranges from 15 to 60 minutes. For some wells, travel time may exceed 1 hour. Location time will range from 10 to 20 minutes per well. Time at the well site may take longer if the engineer acquires a GPS location for the well.

7. Is the operator given advance notice of inspections? How much? Does the state inspectors have statutory right on ingress and egress from leases and UIC well locations to make unannounced inspections. What restrictions apply?

   Not usually. In cases where pressure gauges are not permanently installed, the operator is notified to have a representative present to put gauges on for the inspection. Also, in cases where fluid samples are taken from an injection line or tank, the operator is notified. Short notice is emphasized in these cases to facilitate observing violations, if present. It is a misdemeanor, Section 3236 PRC, to refuse the Division access to inspect a well or lease.

8. Does the Operator receive a copy of the completed inspection report?

   No, however a letter of noncompliance is sent to the operator when violations or deficiencies are noted. The letter is sent noting all deficiencies and requesting correction before reinspection by the Division. A letter of compliance is sent after reinspection if everything is repaired adequately.

9. Are df taken during an inspection? How does the inspector log photographs? Are their written procedures designed to preserve the legal integrity of photographs for potential enforcement actions or hearings?

Yes. Each injection well has a photo taken and kept on file as identification. Photos are attached to injection reports and filed in the well file. All photos are identified with a description (i.e., well number, lease operator, well location, date, time, field inspector). Negatives are filed in a photo file with subject and date. If a digital photo is taken, the photo will be stored in the electronic database. The Division uses videotape to record well operations and violations also. The tapes are labeled appropriately and stored.

Photographs are taken whenever an enforcement action is to be taken on the well or whenever a well has a serious deficiency (i.e., leak, spill, required equipment missing, high pressure, etc.).

10. Are samples of the injectate collected routinely at some/all inspections? How are samples documented, preserved and transported? Are analyses performed by State or private laboratories?

Random samples are taken at some sites for water analysis. Sampling is also performed whenever it is necessary to check compliance. Sampling procedures have been established and are described in the Division's EPA-approved Quality Assurance Plan.

<u>Documentation</u> – When samples are collected, a sampling form is filled out that describes the sampling technique used, where the sample was collected, and information related to sample preservation and chain-of-custody.

<u>Preservation</u> – All samples are preserved according to lab recommendations; usually refrigeration at a particular temperature and/or a preservative is used.

<u>Transportation</u> – if the lab collects the sample, the sample is taken to the lab for analysis. If the Division collects the sample, the field engineer takes the sample to the lab scheduled to do the analysis. In most cases, sampling and analysis is prearranged with the lab before the sample is collected.

11. Do inspectors carry their own gauges and flow meters? How and how often are the gauges calibrated and how is this documented?

Division engineers carry no gauges and are not permitted to install gauges or operate oilfield equipment of any kind.

Operators are required to calibrate permanently affixed gauges every six months and portable gauges every two months (Section 1724.10(e), CCR).

12. What training does the inspectors received on the states QA/QC plan?

    The Division's QA/QC plan is made available to each engineer. In addition, it is contained in the Division's MOI. QA/QC training is held in-house.

C. OBJECTIVE: Understand the emergency and citizen complaint procedures.

1. How is the state notified of emergency situations regarding oil and gas lease operations? What percentages of these incidents are associated with UIC permitted wells?

   When a spill or emergency occurs, the operator is required to report the spill or emergency to the Division promptly and to the State's Office of Emergency Services (OES) and all other agencies indicated in their contingency plans. (OES is the overall State response agency to major disasters in support of local government. The office is responsible for assuring the State's readiness to respond to and recover from natural, manmade, and war-caused emergencies, and for assisting local governments in their emergency preparedness, response and recovery efforts. OES notifies all State agencies with jurisdiction over an incident. If conditions change at a spill site, the responsible party notifies OES of any significant changes. In addition, the Division will notify other agencies as necessary of any potential impacts to their jurisdiction.)

   Emergencies for Class II wells are essentially nonexistent.

2. Who communicates with the inspectors and prescribes the response? Who performs the on-scene response and coordination?

   Although most emergency and citizen complaints are handled at the district level, the gravity of the situation may require the State Oil and Gas Supervisor to be involved in the response. Usually, the districts handle most situations; however, Headquarters is kept informed.

   If a Division engineer responds to a call, the engineer will remain on site until the cleanup or repair efforts are underway and well organized. Typically, the first responder on scene is responsible to coordinate activities as the on scene coordinator until replaced.

3. How is emergency response action documented? Is there written guidance that the agency uses to insure adherence with procedures that will produce acceptable documentation for possible enforcement action?

   When a call comes in, it is forwarded to an engineer who fills out an emergency form (Report of Occurrence). The form includes details of the emergency, location, type, volume (if a spill), whether the emergency situation is under control, name of person making the call, a contact person, etc.

   Yes, the MOI.

4. What is the procedure for conducting follow-up to emergency response events?

   The site is inspected to assure that cleanup, if necessary, is proceeding in a timely manner and that any danger has been abated. Inspections continue until the problem is resolved to the satisfaction of the Division. After the incident, a report is completed and filed.

5. If the emergency requires notification of other agencies that may have their own regulatory issues to resolve (e.g. brine flow from a well into an aquifer or lake which is a public water supply), who does the notification?

   The responsible party will notify the OES as part of their initial notification. OES is the overall State response agency to major disasters in support of local government. The office is responsible for assuring the State's readiness to respond to and recover from natural, manmade, and war-caused emergencies, and for assisting local governments in their emergency preparedness, response and recovery efforts.

6. What type of emergency situation has been reported that have involved UIC permitted wells?

   Emergencies for Class II wells are essentially nonexistent. Although infrequent brine spills have occurred from tank leaks. Since tank settings have approved containment barriers to confine a spill to the area around the tank, a brine spill would not cause a significant threat.

7. What type of significant citizen complaints has been received? Are complaints responded to in accordance with a priority system or are all complaints investigated?

   Very few citizen complaints have been received. Those that have been received are usually claims about a freshwater well being contaminated. Although there is no documented evidence an injection well harmed a freshwater well, public

fears in one county were escalated to the point injection wells were essentially prohibited because of increased bonding requirements.

All reports are investigated. Priority is given to those cases that are an immediate threat to humans, wildlife, or drinking water. Cases that may be a potential threat in the immediate future would be next and, lastly, any complaint that poses no real threat to life or drinking water.

8. Is the complainant routinely contacted prior to field investigation of the alleged problem and subsequently notified of the results of the complaint investigation?

   Yes, the Division follows up a complaint with a call or a letter.

9. Is the operator notified of the complaint?

   Yes, immediately.

10. What is the typical response time to complaints?

    Response time depends upon the nature of the complaint and whether the field engineers are available (i.e., witnessing tests or other cases of higher priority). If the complaint is received during working hours, the inspection is done during the day. If the complaint is received after hours, the inspector on call will determine the severity of the complaint. If severe, he/she will inspect the site immediately; if not severe, the incident will be investigated the following workday.

11. Is the agency obligated to routinely notify Federal agencies or other state agencies when an emergency occurs? Upon such notification, are their occasions where the lead for resolution of the emergency is transferred to another agency even if the permitting authority is the transferring agency?

    See response to question 5.

12. What is the agency's policy or procedure for communicating with the news media on an emergency situation or complaint? Who is responsible?

    Inquiries from the news media (reporters, editors, etc.) are referred to the Department of Conservation's Public Affairs Office (PAO) immediately. This procedure applies to virtually all inquiries, even most of those that appear to be technical in nature. PAO staff will obtain the information requested and respond to the inquiry, or request Division staff to provide the information directly to the media contact.

D. OBJECTIVE: To understand the reporting and follow-up procedures used in the inspection program.

1. Are there a standard inspection forms for routine inspections? For complaints or emergency situations? For inspections connected to well tests?

   There is a standard form for each different type of inspection (i.e., MIT, environmental, sample collection, witness of plugging and abandonment operations, etc.). The Report of Occurrence form is used to record details of an emergency or citizen complaint.

2. Do the inspectors take field notes and if so, are there retained or destroyed? If notes are retained, where is the repository?

   Yes, inspectors take handwritten notes that usually become part of the well record.

3. If the routine UIC well inspections are a part of a comprehensive evaluation of the lease operations, are the injection well inspections cross-referenced to the permit file? Where is this done?

   Yes. The field data is entered in the database and checked to ensure the well is permitted properly, the UIC permit is active, injection pressure is below MASP, etc. The crosschecking is done in the district office.

4. Does the state have a statute or policy regarding the destruction of potentially historical files that would affect the retention of field notes? Does this mandate or policy pertain to hard copy records or records retained in electronic format or both? Who makes the judgment on record retention or the length of time records are to be kept?

   No, significant field notes are retained in the well file. Because MIT well logs are generated regularly, file space becomes an issue. To address this issue, the State Oil and Gas Supervisor established a policy that allowed districts to purge MIT well logs older than 3 years.

5. What is the lag time between the inspection and write-up of the report? Does the Central Office receive copies of the reports as hard copy or by electronic transfer?

   Less than 24. An inspection report is retained in the appropriate district well file and no copy is sent to Headquarters.

6. Where and how are inspections, and violations revealed through inspections tracked to ensure compliance deadlines are met? Is this tracking system computerized or primarily manual?

An electronic database is used to track MITs, inspections, deficiencies, violations, etc. In addition, the field engineer will check the field results against the well file and database to ensure compliance. Deficiencies and violations are logged in an electronic tickler file to ensure follow up.

7. Has the State Counsel or agency Legal Department reviewed all inspection procedures to assure the results may be used in formal enforcement actions? Are form revisions routinely reviewed by the Legal Department? In the case of the UIC program, are such form drafts sent to EPA for comment?

Yes, the Attorney's General office acts as legal counsel for the Division. An attorney has been working closely with the Division for many years and is intimately familiar with the oil, gas, and UIC programs. The attorney has attended Division management conferences and provides information and advice on proper procedures. Because form revisions were considered routine and nonsignificant, the attorney or EPA did not review them.

8. Who reviews inspectors' reports? What is the lag time between submission of the report and review? Where is the review generally done?

A district's Associate Oil and Gas Engineer in charge of UIC reviews the field reports. The Associate Oil and Gas Engineer in charge of field inspection reviews the environmental field reports (smaller districts, one engineer performs both functions). Review of the inspection report is completed within one week, depending on work priority.

9. What is the inspector's access to UIC information in the field such as permit contents, letters to operators, notices of violation, etc.?

Field inspectors have access to all information in Division files, including confidential information. Typically, the field engineer will review pertinent information before leaving for the field.

10. Where are chain of custody, photograph negatives and analysis forms filed?

Forms and photographs are filed in the injection project folders and well files.

E. OBJECTIVE: To understand the Data Management Systems Accessible to Inspectors for Conducting Field Inspections and Addressing Emergency Situations.

1. Describe the data management system (s) which are available to field inspectors in conducting routine lease and well inspections as well as providing background support for responding to complaints and emergency situations. The description should delineate how the data management system(s) available to inspector's interfaces with the systems used the other oil and gas regulatory activities.

The Division's main database file contains over 150,000 well identifications, keyed on API number (work is proceeding to enter all wells in the database). A secondary database includes field inspection tables linked by API number or by a district-generated lease number. (Lease numbers became necessary to link multiple wells together along with tank farms and sumps.) Inspectors are able to download (at a docking station) the latest copies of the databases they use before commencing their inspections. They then have available to them the tests and results of those tests from past inspections. They also have the electronic versions of reports available to them to document any emergency situation encountered. They can also generate a Word document for any event not covered by a typical form. We do not have the hard copy information in the well files available to them for review in the field. Permit requirements, casing records, and other essential information still needs to be communicated by the dispatcher who sends the inspector to a site or by a company representative at the site.

At the end of the week, field inspectors have been able to update the office's network files from their laptop databases. Because of the size and weight of the laptops, most inspectors do not use them as primary recording instruments in the field. For this reason, we have been developing PDA data tables that would be easier and more convenient to use in the field.

2. When were the data management systems currently in use first put into operation?

The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet its needs.

In addition, production and injection from 1977 is stored electronically.

3. Are these systems sufficiently effective and efficient to allow inspectors to effect retrieval of data on wells, tests, past emergency situations thus minimizing unnecessary duplication of previous findings? What limitations exist in addressing basic regulatory and response needs of the inspector?

Yes, it has improved efficiency of the Division's oversight functions and access to information. The only limitation is getting the information stored electronically.

4. Are relevant data bases and systems of other agencies having authority for water resource allocation, water protection regulation, emergency response and water resource contamination accessible to inspectors and other field office personnel (if any)?

   WellStat is available through the Division's web page. Other information is made available upon request.

5. What are the restrictions or limitations imposed on inspectors in the sharing of data with field personnel of other water resource agencies who may have cooperative functions on an investigation or may have a need to notify entities permitted by them of the findings?

   The only restriction is confidential information. The RWQCB/Division MOA allows the agency to view confidential information related to a project; however, the agency must view the information in the district office.

F. Changes and Modifications to Program since 1990

Excluding the changes in **data management** described under Section E above, what statutory, regulatory, policy or budgetary changes have occurred during the past ten years that directly affect the UIC field inspection program? Please list or explain.

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years.

PART IV: MECHANICAL INTEGRITY TESTING

A. OBJECTIVE: Understand the Types of Mechanical Integrity Tests Allowed for different UIC well completion programs.

1. What types of MITs are acceptable to the state for satisfying the leak test (Part 1 of MI)? Are some tests acceptable only for a specific set of well completion conditions? Please list the tests and their limitation as to applicability.

   A standard annular pressure test (SAPT) is required for all water-disposal and waterflood wells before commencing injection and at least once every five years thereafter. The advantages of conducting an annulus pressure test are: (1) some internal mechanical failures may be detected and (2) the well does not have to be taken out of service for monitoring to be performed.

However, internal MI can only be demonstrated partially with an SAPT because the presence of a leak in the tubing, packer, or casing may go undetected if the fluid pressure on the outside of the annulus is in equilibrium with the pressure imposed on the annulus. In such instances, pressure or fluid flow in the annulus is a better indicator of mechanical integrity failure.

The SAPT is inadequate as a sole demonstration of mechanical integrity because of given limitations, such as fluctuating injection fluid temperature, ambient air temperature, geothermal gradients, and heat transferred between fluids, tubulars, cement, and formations. In addition, the SAPT does not demonstrate that the injection fluid is entering the intended zone. Therefore, the Division utilizes the SAPT as a secondary method to monitor mechanical integrity.

2. What criteria (is, are) used for the pass/fail of a pressure test? Why were these criteria selected? Are the criteria more strict in sensitive ground water areas, wellhead protection areas, or areas of know corrosive ground waters?

A. No perforations above the packer.

   1. Hydraulic test - a minimum of 200 psi for at least 15 minutes, with a maximum pressure loss of 10 percent.
   2. Gas test - a minimum of 200 psi for at least 15 minutes, with a maximum pressure loss of 10 percent. Usually, nitrogen is used to pressurize the annular space.

B. Perforations and/or holes above packer.

   1. Fluid level (sonic) test.
      a) Must have cement behind casing (above perforations/holes).
      b) Perforations/holes must be below USDWs.
   2. Pull tubing and packer, run a bridge plug, and pressure test.

NOTE: Division approval must be obtained before the operator uses any other test method.

The ADA pressure test is a procedure that can be used for determining internal mechanical integrity in wells in which <u>the fluid level is above the base of the USDW</u> and there are known perforations and/or holes above the packer. It can also be used in tubingless wells, when such completions are allowed.

In the ADA pressure test, the fluid level in a well is measured to determine the height of the water column above the perforations. Then the pressure required to depress the column of water to the top of the perforations is calculated.

Nitrogen is then added to the annulus until the pressure no longer increases. If the test pressure stabilizes at or very close to the calculated pressure and remains constant for 30 minutes after closing the valve to the nitrogen source, no leaks in the casing above the perforations are indicated and mechanical integrity is demonstrated.

A. ***Testing Requirements***

1. ***The well should have at least 100 linear feet of cement behind the casing, immediately above the uppermost perforations/holes.***
2. ***The specific gravity or total dissolved solids (TDS) content of the water in the annulus must be known.***
3. ***There can be pressure on the tubing, but injection must be shut-in and the pressure stabilized. The well is shut-in long enough for temperatures to stabilize before the test.***
4. ***With the tubing and packer set at their normal injection depth:***
   a) ***A radioactive (RA) tracer survey must be run through tubing to demonstrate there is no leakage in the tubing or packer below the uppermost perforations/holes, or***
   b) ***The ADA pressure test may be used inside the tubing to demonstrate mechanical integrity of the tubing and packer if the distance between the injection perforations and the bottom of tubing is at least 50 feet, the water level in tubing is at least 200 feet above perforations, the fluid level is measured, and the specific gravity or TDS of fluid and the depth of perforations are known.***

B. ***Testing Requirements***

1. ***Calculate the pressure required to depress the column of water to the top of the perforations/holes:***

   Sp. gr. x 0.433 (if fresh water) = gradient (psi/ft. of head)

   Gradient x water column = psig

2. ***Pressurize the annulus (or tubing, if testing the tubing and packer) using compressed nitrogen cylinders. The number of cylinders required will depend on the volume of space above the perforations. (Be sure the hoses and the gauges are rated to handle the high pressure of the cylinders.)***

3. ***When pressure at the wellhead no longer increases, verify that gas is still flowing from the cylinder into the well, shut off the valve to the cylinders.***

4. ***Record the times and corresponding pressures. Monitor the pressure for 30 minutes. Record the pressure after 5, 10, 20, and 30 minutes. Fluid levels must be run during the test.***

3. Is the volume of fluid loss a factor in the determination of a failure?

   Yes, see answer above.

4. Is annulus pressure monitoring APM used to determine MI? How is an MI failure determined utilizing APM?

   Yes, only Part 1, see response to question 2.

5. How often is APM recorded? What is reviewed and who reviews it? Are there stricter standards imposed on wells located in special geological areas (faults, salt deposits, e.g.) or in ground water situations described under Section A-2. Above?

   It is recorded whenever this type of test is used, see response to question 2.

6. Are wells using APM required to have an initial pressure test?

   Yes, see response to question 1.

7. If other monitoring records are reviewed to establish MI, how are failures determined? If the determination of failure is different for each type of monitoring record, explain the process for each.

   Generally, no other monitoring records are used to determine mechanical integrity; however, the relationship between pressure and rate may be used as a trigger to run radioactive tracer surveys.

8. What type of technical judgment or MIT is used to satisfy Part 2 MI Fluid migration test)? If cement records are reviewed, what criteria are used to determine pass/fail?

   The Division relies on a combination of RA, temperature and spinner surveys to demonstrate external mechanical integrity. At least two of these three surveys must be employed for a complete MIT. The frequency of testing varies, depending upon the well type. After the initial MIT is conducted, water disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years.

   Cement records are never used to determine MIT.

9. Identify any logs used for the determination of MI and the limitations imposed on their use. Are logs more frequently used in areas where potential adverse geological situations are historical to past oil operations or where groundwater may be from vulnerable or artesian sources? Who interprets the logs or makes the decision to have the Operator runs special log suites? How are failures of MI determined?

See response to question 8. If a RA/temperature survey is witnessed, then the field engineer interprets the logs for pass/fail.

All injection surveys and logs submitted to the Division are reviewed and interpreted by the Associate Oil and Gas Engineer in charge of UIC.

The RA survey detects fluid movement. Any movement of fluid behind casing that migrates above the top of the injection zone behind casing is a failure. Also, any indication of fluid movement into the annulus through holes in the tubing or through a defective packer would constitute a failure.

The static temperature survey detects anomalous formation temperatures that usually indicate casing holes and/or cement failure. Any temperature anomaly is considered a failure unless proven otherwise by other tests.

A spinner survey detects changes in fluid volumes/rates. A decrease in rate (within the same size casing or tubing) usually indicates a hole in the injection string. RA surveys and temperature logs are used to verify the existence of fluid loss at points where there are rate changes.

10. What are the most common remedial actions required to correct MIT failures? Who performs the remedial action and /or plugging of the well if the Operator of the well proves to be insolvent?

The most common failure is a packer leak. The operator can remedy the failure by replacing and/or resetting the packer. The next most common failure is a casing hole.

The Division has a plugging and abandonment fund that is used to plug and abandon hazardous wells of defunct operators.

B. OBJECTIVE: Understand the Implementation of the MIT Program

1. What is the process for notifying an Operator that demonstration of MI is due? How much prior notice is given? Are tests scheduled at the Operators or states convenience?

The schedule for a Class II injection well MIT is determined by the date of the last MIT and the type of injection well (i.e., WD, WF, or SF). For new wells, an MIT is required within 90 days of commencing injection operations. The operator is responsible for scheduling the MIT and giving the Division sufficient notice to witness the test.

2. If tests are scheduled at the state's convenience, is consideration given to having an Operator run MITs on large numbers of wells in the same area in accordance with an efficient schedule?

   Normally, operators try to schedule wells in the same area to keep costs down.

3. What is the priority schedule of wells to be tested? If the general cycle for testing is five years are there wells tested on a more frequent schedule and, if so, what are the criteria?

   After the initial MIT is conducted, water-disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years.

4. How are the pressure test and fluid migration test (Part I and II of MIT) coordinated?

   These are two different tests and they are normally are not coordinated.

5. How are the MIT results filed and managed? In those cases where the well passed the test? In those cases where test failure occurred and follow-up for compliance purposes is necessary?

   Districts log MIT results in the electronic database and in the injection project file. A technical reports (T-Reports) is completed and filed in the well file for each MIT witnessed by the Division. The original copy is sent to the operator indicating the results of the test and whether any further action is necessary. The operator is required to submit all MIT logs (i.e., RA, temperature, spinner logs) to the Division. All logs are reviewed by the Division to evaluate for mechanical integrity and results are entered in the database.

6. What are the personnel (inspector) resources required to implement the MIT program? Does this vary significantly from one year to the next? During periods within the industry where economic exhilaration or depression occurs?

   The personnel resources required to implement the MIT program do not vary from year-to-year significantly.

Personnel time: ***In office maintaining compliance schedules.***
In office maintaining files.
In office preparing for MIT witnessing.
In office reviewing MIT surveys.
In field witnessing tests.

Transportation: ***Cost of transportation, including vehicles and maintenance.***

C. OBJECTIVE: Understand the procedures of witnessing a Mechanical Integrity (MI) test.

1. Who witnesses MI demonstrations and what percentages of MI tests are witnessed by State inspectors? Does witnessing vary from one producing region of the state to another?

   Normally, the operator notifies the Division of the time and date that an MIT will be conducted. Division engineers (EMRE) witness the entire MIT. The majority of MITs are witnessed. Those well tests not witnessed by the Division are reviewed when the operator submits a copy of the MIT log.

2. What do inspectors look for during an MI demonstration? Are routine inspections of the other lease facilities conducted at the same time as a visit for MIT?

   A static temperature log is run to look for anomalies in wellbore temperature that would show water going out through a hole in casing or tubing, or a packer leak.

   The RA survey shows leaks in packer, casing, tubing, and will show any fluid migration behind casing.

   The main intent is to determine if fluid is confined to the zone of injection, and to detect fluid movement at other points within the casing and tubing.

   Normally, environmental lease inspections are a scheduled event. An engineer witnessing an MIT may conduct inspections of other wells while in the area of the MIT. However, their time may be limited if they have other MITs to witness.

3. How much time is spent witnessing an average MI test? This estimate should also include travel time. Are there occasions where the Operator is not set up to do the test at the appointed time?

   From 3 to 8 hours, depending on how smoothly the equipment runs.

4. How is the witnessing of MIT documented? What documentation is required of the Operator in those cases where the test was not witnessed?

   T-Reports are completed for each MIT witnessed. The reports are filed in the well file, the database is updated, and a copy of the report is sent to the operator. The operator is required to submit a copy of the MIT log to the Division. The Associate Oil and Gas Engineer in charge of UIC evaluates the log.

5. What action does the inspector take in those cases where it is discovered that the Operator conducted a MIT prior to the scheduled time and subsequently made repairs? Does the State required documentation of the work even though the action was taken voluntarily by the Operator?

   The operator is required (project approval letters) to notify the Division anytime a loss of mechanical integrity has taken place. The operator is required to conduct an SAPT anytime the packer is pulled and submit a history (documentation) of the repair work to the Division, even if no notice is required.

D. Follow -Up on failed MI tests

1. In the event of MIT failure, how is the operator notified to shut the well in? If all wells failing MI are not shut in, please elaborate.

   When an engineer witnesses an MIT and the test fails, the field engineer informs the operator that the well must be shut-in and the well repaired. A follow-up letter is sent and a follow-up visit is made to ensure compliance.

   When the log of an unwitnessed survey is reviewed and a leak is detected, the operator is notified by phone to shut in the well. A field inspection is made to confirm compliance. If a well is not shut in when directed by the Division, a formal order may be issued.

   The following are guidelines to follow when MIT's are delinquent or fail:

   __Delinquent Mechanical Integrity Test (MIT)__

   a) Survey is determined delinquent.
   b) Operator is notified to run an MIT within 60 days.
   c) If the operator does not run the MIT within 60 days as directed, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to:
      (1) Shut-in the well within 24 hours.
      (2) Disconnect the injection line at the wellhead within 10 days.
      (3) Notify the appropriate district office when the injection line has been disconnected.

The District Deputy rescinds the permit if the MIT is not run within 90 days.

INTERNAL MECHANICAL INTEGRITY FAILURE

1) **Tubing Or Packer Failure**
   a) *Unless it is a situation where immediate damage to a USDW cannot occur, the District Deputy issues a written order to shut-in the well within 24 hours, and to repair the well within 60 days. When appropriate, the operator must file a notice and receive a permit before work is commenced.*
   b) *If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to: (1) shut-in the well within 24 hours (if the well is still active); (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.*
   c) *An MIT is required following repair if the well is returned to injection.*
   d) *The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.*

2) **Casing Failure Located Below The Packer**
   a) *If fluid is exiting a hole or cemented-off perforations (e.g., WSO) located below the packer, but within the permitted zone, no action is necessary. However, a recalculation of the maximum allowable surface pressure may be necessary.*
   b) *If fluid is exiting a hole or cemented-off perforations (e.g., WSO) located below the packer and is entering a zone that has received an aquifer exemption, but has not been permitted for injection by the Division:*
      1. *The operator must either repair the mechanical problem or amend the project to include the nonpermitted zone into the injection project by submitting the required project data within 60 days. If the operator chooses to amend the project to include the new zone, the Division will issue a revised project approval letter. No further injection is permitted until the project receives approval.*
      2. *If the operator fails to repair the well or amend the project within 60 days, the District Deputy may rescind the permit.*
      3. *An MIT is required following repair if the well is returned to injection. If the operator fails to run the MIT.*
      4. *The District Deputy must rescind the permit if the operator fails to repair the well or amend the project within 120 days.*
      5. *If fluid is exiting a hole or cemented-off perforations (e.g. WSO) located below the packer and is entering a USDW, the operator must shut-in the well immediately and:*
         a. *The operator is ordered to repair the well within 60 days.*

b. If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to disconnect the injection line at the wellhead within 10 days and notify the appropriate district office when the injection line has been disconnected.

6. *An MIT is required following repair if the well is returned to injection.*
7. *The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.*
8. *An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with technical evidence and reported to the UIC Project Manager.*

3) If a casing hole located above the packer is in the permitted interval:

a) The packer may be raised above the hole, making the hole the top perforation, or

b) Without raising the packer, the operator must demonstrate mechanical integrity or develop a monitoring program.

2) If a casing hole is located above the packer and is above the permitted interval, the operator must demonstrate MI or develop a monitoring program.

NOTE: A monitoring program should be designed as an early warning system to prevent USDW contamination. Periodic fluid level testing behind casing is one method of preventing USDW contamination.

3) If a casing hole is located above the packer and in a USDW:

a) The operator is ordered to repair the well within 60 days.

b) If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit.

c) An MIT is required following any repair if the well is returned to injection.

d) The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.

EXTERNAL MECHANICAL INTEGRITY FAILURE

Migration Outside Casing Confined To Permitted Zone

If fluid exiting the approved perforations is not confined to the perforated interval, but is confined to the permitted zone, no action may be required other than monitoring as needed. An explanation and justification of the approved condition is included in the well file, even if no action is required of the operator.

Migration Outside Casing Not Threatening A USDW

If fluid exiting the approved perforations is not confined to the permitted zone and does not pose a threat to a USDW:

1. ***The operator must repair the mechanical problem or amend the project to include the nonpermitted zone in the injection project by submitting the required project data within 60 days. No further injection is permitted until the project receives approval.***
2. ***If the operator fails to repair the well or amend the project within 60 days, the District Deputy must rescind the permit.***
3. ***An MIT is required following repair if the well is returned to injection.***

Migration Outside Casing Threatening A USDW

1. ***If fluid exiting the approved perforations is not confined to the permitted zone and is determined to pose a threat to a USDW, the operator is ordered to shut-in the well within 24 hours.***
2. ***Operator is ordered to repair the well within 60 days.***
3. ***If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well within 24 hours (if the well is still active); (2) disconnect the in the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.***
4. ***An MIT is required following repair if the well is returned to injection.***

Migration Outside Casing Invading A USDW Or Flowing To Surface.

1. ***The operator is ordered to shut-in the well immediately and make repairs within 60 days.***
2. ***If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well immediately (if the well is still active); (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.***
3. ***An MIT is required following repair if the well is returned to injection.***
4. ***An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with strong technical evidence and reported to the UIC Project Manager.***

2. Is the Operator required to institute corrective measures for each failed MI? If an alternative to effecting corrective measures is the plugging and abandonment of the well, does the State ever require the Operator to repair the well prior to plugging?

   Yes. If a well is plugged and abandoned, the permit will stipulate placement of plugs, squeezing of cement, etc. necessary to protect the environment.

3. How long is the Operator given to complete repairs?

   See response to question 2.

4. Are repairs witnessed (what percentage)?

   Depends on the type of repair. For example, the Division may witness the squeezing or placement of cement, but not witness the replacement or resetting of a packer. However, the Division will witness the follow up MIT to ensure compliance.

5. If workover of the well is required as a part of repair, does the state require copies of reports documenting the work? Does this include such activities as well fracturing or removal of scale to enhance intake capacity?

   Yes, if the repair permanently altered the casing.

6. What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed through successive five-year cycles of testing?

   The majority of wells pass MIT. The only correlation in failure rates is the age of the well and tubing/packer.

E. OBJECTIVE: Understand the data management of the MIT program

Describe the data management system(s) used in the various components of the MIT program as set forth in Section A-D. The description should delineate how the system manages the program from test scheduling to follow up on failure.

1. When was the MIT data management system currently used first put into use?

   The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet their needs.

   In addition, production and injection from 1977 is stored electronically.

2. Is RBDMS used by the State as a tool to determine when MITs should be conducted in certain areas of the State and if such tests should be conducted more frequently than five years?

   No, the Division developed its system in-house.

3. Is the MIT database used by the agency conceived as an intramural system or is it linked with other state water protection databases?

   It is a stand-alone system; however, some UIC data can be accessed from the Division's web page.

F. Changes and modifications to program since 1990

Exclusive of the changes in data management described under Section E, what statutory, regulatory or policy changes have occurred during the past ten years in the MI Testing program. Please list changes or explain.

In 1996, Section 1724.10(j)(1) of the CCR was added to include mechanical integrity testing of the casing-tubing annulus every five years.

PART V: COMPLIANCE/ ENFORCEMENT

A. OBJECTIVE: Understand enforcement procedures in the state.

1. What types of enforcement tools and legal actions (formal and informal) are available to the State? Indicate which are available through direct agency action and which are dependent upon other enforcement authorities (Attorneys General, County Attorney, or Federal)

The Division has the authority to issue orders in several specific situations. Orders may be issued to:

- ***Plug and abandon wells***
- ***Repair wells***
- ***Screen or eliminate hazardous sumps, or shut down an oil and gas production operation sustaining a hazardous sump***
- ***Discontinue unreasonable wastage of gas***
- ***Adopt a well-spacing plan***
- ***Adopt a repressuring plan to ameliorate subsidence***
- ***Unitize or pool separate producing properties***
- ***Undertake such action as is necessary to protect life, health, property, or natural resources.***

Generally, a written order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. If an emergency exists, District Deputies can obtain authorization from Headquarters to repair or plug wells or eliminate hazardous conditions without issuing a formal order or seeking bids. If a well is bonded, the surety company will also be sent a copy of the order.

Orders can be appealed to the Director of the Department of Conservation within 10 days of issue.

If the operator refuses to do the work outlined in the order, or work is not commenced in a timely manner, the Division can proceed to do the work and place a lien (Section 3423(a), PRC) on the operator's assets or property.

The Division has the authority to impose a civil penalty of not more than $5,000 for any violation of the PRC (Section 3236.5, PRC), or any implementing regulation. The penalty can be appealed to the Division.

The Division may deny permits for new wells if the operator fails to pay a civil penalty and other charges that are required by the Division, such as the oil and gas production assessment. The Division may also shut in production on a well where an unresolved violation is occurring and the civil penalty has been paid.

2. What sort of formal enforcement actions have been taken relative to UIC violations? Roughly, what percentage of enforcement actions taken by the agency does this represent?

Orders have been issued to:

- ***Rescind injection permits***
- ***Shut-in wells***
- ***Repair wells***

Civil penalties have been issued for:

- ***Not filing required records.***
- ***Not filing notice for work done.***
- ***Injection of fluid without permit.***
- ***Change of fluid stream without notice.***

Very few UIC enforcement actions have been necessary. Less than 5 percent of Division enforcement actions have focused on UIC operations.

3. What is the nature of the appeals process available to the Operator? Does the UIC staff get involved in the appeals?

The appeal must be a written statement filed by the operator, surety, or landowner with the Supervisor, District Deputy, or Director. The appeal must state that the order is unacceptable and that appeal from the order is taken to the Director under provisions of Section 3350, PRC. The appeal must be filed within 10 days of the service of the order (i.e., within 10 days following the date noted on the returned receipt acknowledging delivery of the order).

Within 20 days from the taking of the appeal, the Director must give an appellant 10 days notice in writing of the time and place of a hearing, except for good cause, and requires the Director to make a written decision with respect to the order appealed from within 20 days after hearing the evidence.

Following receipt of an appeal, the District Deputy will prepare a "fact sheet" outlining the events leading to the order, to be forwarded to the Supervisor with the appeal. This material will be submitted to the Director, who will then call for a hearing.

UIC staff would be involved during the case preparation and, most likely, to provide testimony in a hearing, if held.

4. Who evaluates field reports for violations and possible enforcement actions?

   The field engineers are well trained and knowledgeable in Division regulatory and legal requirements. Therefore, they would be the first to evaluate the field situation and make recommendations to the Associate Oil and Gas Engineer in charge of UIC. The Associate would evaluate the report and report to the Deputy.

5. How and who develops formal enforcement cases?

   Initially, the District UIC staff would work up the details to be included in any formal order. The details are a complete record of all events, inspections, observations, correspondence, etc. involving the case. The District Deputy prepares a fact sheet containing all the details about the violation and then issues the order. A copy of the fact sheet and order is sent to the State Oil and Gas Supervisor for his review.

   Civil penalties are considered, usually, after other attempts to obtain compliance have failed. Any and all attempts to contact an operator regarding operations that are out of compliance are documented, and may be presented as evidence during a hearing (if necessary). Any well locations or attendant facilities found not to be in compliance with regulations are brought to the attention of the operator on an informal basis (e.g., verbal discussions and deficiency letters). The operator is requested to submit a plan to achieve compliance within a reasonable time. If informal contact fails to bring results, then a Notice of Violation (NOV) outlining specific violations and corrective action to be taken is sent. If corrective action is not taken within 30 days, a civil penalty or other legal action is taken.

6. Who drafts the required documents and who reviews the proposed action?

   The District Deputy or his staff Senior Engineer. Mostly, the District staff prepare the documents.

7. When hearings are held on an appealed violation, what is the standing of environmental organizations or concerned citizens and their opportunity for input?

All hearings will be conducted in accordance with the Administrative Procedures Act. Headquarters will notify the operator, district office, Department of Fish and Game, and any other interested parties of the hearing outcome. Headquarters will then determine the appropriate action to take.

B. Nature and disposition of "Paper" violations versus technical and mechanical violation.

1. Is there a difference in procedures when penalties are imposed for "paper violations and for violations which may threaten USDWs? Are fines and penalties issued automatically for some violations? For all violations? For no violations?

   No. Although civil penalty amounts will vary depending upon the violation, penalty procedures are the same no matter the violation. There is no Division statute or policy that automatically imposes a penalty for a violation.

2. Does the agency issue Notices of Violation (NOV) and attached penalties? If so, who issues the NOVs and who tracks payment by the Operator?

   No violation notice or letter issued by the Division will have an attached civil penalty. However, the Division has imposed civil penalties without issuing a NOV or letter to operators habitually out of compliance (i.e., failure to file monthly injection reports) and has been subsequently warned. Civil penalties have been imposed without Division warning for well work performed without the required permit.

3. What are the follow up procedures to assure compliance and correction of the non-compliance event? Who does the follow-up and where is the report of the status sent?

   Operations found out of compliance are brought to the attention of the operator on an informal basis. A letter is sent identifying the problem and requesting that the problem be corrected within a reasonable amount of time.

   If the initial request fails to bring results, a second letter or notice is sent identifying the specific violations and that corrective action is required by a specific date, or a civil penalty may be issued. The second letter is sent via certified mail, return receipt requested. A reasonable amount of time is given to bring the operations into compliance. The second letter is identified as such, and as the final notice.

   If corrective action is not taken within the prescribed time, a civil penalty may be imposed. Civil penalties are issued in two steps: a Provisional Order Imposing Civil Penalty, and a Final Order Imposing Civil Penalty.

The district engineers perform the follow up and Headquarters is kept informed.

C. Time Allowance for Corrective Action

1. How much time is granted to an Operator to correct a "paper violation" or a violation that involved the issuance of a NOV?

   30 days.

2. How much time is granted to an Operator to correct a violation (condition) that if left uncorrected could threaten a USDW? Please provide a range of situations and associated time allowances.

   This could vary. If the threat is imminent, corrective action is immediate. However, if it is an implied threat, the operator has 30 days to correct the violation. Examples:

   Imminent threat to USDW – a hole developed in an injection well and fluid was exiting across a USDW zone. The well was shut in and well work to repair the hole was completed immediately.

   Threatens USDW – violations such as high injection pressures, i.e., pressures greater than MASP, but less than fracture pressure, or pressures needed to raise the injection fluid to the base of the USDW), would require urgent attention. The Division informs the operator of the violation verbally, a follow up field inspection may not occur for 30 days.

3. How much time is allowed the inspectors to perform follow-up inspections and report submission on C-1 and C-2?

   Whatever it takes to ensure compliance. How quickly an inspector follows up depends on the several factors, mostly severity of the violation and well location. Operators may have up to 30 days after service of an order to comply with the order. If an operator fails to commence or complete the necessary work and the violation threatens a USDW, the inspector will follow up as soon as possible following the compliance period stipulated in the NOV.

D. Flow from Non-Compliance to Enforcement Action

1. How and when are field violations escalated into formal enforcement actions?

   Generally, a written order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. Any well locations or attendant

facilities found not to be in compliance with regulations is brought to the attention of the operator on an informal basis (e.g., verbal discussions and deficiency letters). The operator is requested to submit a plan to achieve compliance within a reasonable time. If informal contact fails to bring results, then a NOV outlining specific violations and corrective action to be taken is sent. If corrective action is not taken within 30 days, a civil penalty or other legal action is pursued.

2. Are Operator bonds and license revocations (if applicable) reviewed as a part of initial enforcement action and under what conditions are bonds called in?

   Yes. Generally, bonds are forfeited when an operator fails to plug and abandon a well or wells, but can also be forfeited for other reasons, such as failure to clean up a spill or screen a sump associated with a well. In addition, the Division may deny permits for new wells if the operator fails to pay a civil penalty and other charges that are required by the Division, such as the oil and gas production assessment. The Division may also shut in production on a well where an unresolved violation is occurring.

3. Is there coordination with other State or local agencies (RCRA, NPDES, EPCRA, SDWA etc.?

   There may be coordination with EPA if the division is unable to achieve compliance or coordination of the operator. In addition, the Division MOA with the SWRCB outlines the procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. These procedures are intended to provide a coordinated approach that results in a single permit that satisfies the statutory obligations of both parties. The procedures ensure that construction or operation of oil, gas, and geothermal injection wells and surface disposal of wastewater from oil, gas, and geothermal production does not cause degradation of State waters.

4. What actions have been taken in response to enforcement actions? What penalties have been assessed and collected on UIC violations?

   Penalties have been issue and collected on just about every type of violation. Fines for failure to file records, filing fraudulent reports, failure to file for a permit, change in fluid stream without notifying the Division, plug and abandon wells without a permit, inject without approval, inject non-Class II fluids, etc.

5. How and who determines when the non-compliance event has been successfully resolved and the Operator can reactivate the well? Is this accomplished by formal order from the agency or by other communication?

The inspector will revisit a site to determine whether the violation was corrected. Once a violation is corrected, the Division will follow up with a letter.

6. Identify and list the more prevalent UIC related problems faced by the State in providing adequate enforcement?

   The Division has adequate field presence to insure compliance; however, addition staff could be place in the field to witness more MITS.

E. State/ Federal Enforcement Action Interface

1. Describe the existing cooperative relationship with the EPA Region on UIC violations. Are significant non-compliance events being reported to EPA?

   The Division has an excellent working relationship with the EPA and keeps them informed on UIC related issues. Only one or two significant non-compliance events have occurred in California since primacy was granted in 1983.

2. Has the agency ever requested EPA to take over enforcement on an UIC violation? Has EPA ever over filed on a case during enforcement proceedings by the state? If so, what was the result?

   No to all of the above.

F. Contamination/alleged contamination resulting from injection well practices or associated activities in the last ten years.

The purpose of these questions is to determine the extent of reports of alleged and proven USDW contamination resulting from "current" UIC practices or practices associated with UIC well completion and construction.

1. Estimate the number of alleged USDW contamination incidents reported to the State in the past ten years. Were any of these associated with such activities as hydraulic fracturing, zone acidizing or other well stimulation activity?

   None.

2. What actions are taken by the state when an alleged contamination report is received?

   N/A

3. How many of such contamination cases were found to be actual and were proved to be as a result of failure of an injection well or wells? How many were due to abandoned, unplugged injection wells?

   N/A

4. As related to question #3 and to the degree possible, briefly describe the well failure, the extent of contamination and any remedial and /or enforcement actions taken?

   N/A

G. Changes in Compliance or Enforcement Capability Since 1990

What statutory, regulatory, or policy changes have occurred during the past ten years in the agency's compliance/enforcement program? Have these changes been generated at the state level or by changes in the EPA Class II UIC regulations or State primacy agreement?

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years. This change occurred in response to EPA's requirement that two conditions of an MIT must be met. The Division codified regulations to ensure there is no significant leak in the casing, tubing, or packer (this is referred to as <u>internal mechanical integrity</u>) of an injection well.

PART VI: ABANDONMENT/PLUGGING

A. OBJECTIVES: Understanding and documenting the technical aspects of Plugging and Abandonment (P&A)

1. For each major type of well construction, what techniques of plugging are approved? (Give detail on minimum plug size or length: use of mud between plugs and weight: use of bridge plugs; standard plugs at the pay or injection zone, base of freshwater or casing stubs etc;).

Approved plugging techniques are usually the same for injection and production wells, however, there are different requirements for cased vs. open hole. The majority of cement plugs in open hole or in cased hole are place through tubing into a mud-filled hole. The placement of a plug with a bailer is permitted only at a depth no greater than 3,000 feet. However, the bailer method is seldom used. See Sections 1723 – 1723.8, CCR, for specific plugging and abandonment requirements.

1723. Plugging and Abandonment--General Requirements

(a) Cement Plugs. In general, cement plugs will be placed across specified intervals to protect oil and gas zones, to prevent degradation of usable waters, to protect surface conditions, and for public health and safety purposes. At the discretion of the district deputy, cement may be mixed with or replaced by other substances with adequate physical properties.

(b) Hole Fluid. Mud fluid having the proper weight and consistency to prevent movement of other fluids into the well bore is placed across all intervals not plugged with cement, and poured into all open annuli from the surface.

(c) Plugging by Bailer. Placing of a cement plug by bailer is not permitted at a depth greater than 3,000 feet. Water is the only permissible hole fluid in which a cement plug shall be placed by bailer.

(d) Surface Pours. A surface cement-pour is permitted in an empty hole with a diameter of not less than 5 inches. Depth limitations are determined on an individual well basis by the district deputy.

(e) Blowout Prevention Equipment. Blowout prevention equipment may be required during plugging and abandonment operations. Any blowout prevention equipment and inspection requirements are prescribed on the permit to abandon.

(f) Junk in Hole. A diligent effort is made to recover junk when such junk may prevent proper abandonment either in open hole or inside casing. In the event that junk cannot be removed from the hole and fresh-saltwater contacts or oil or gas zones penetrated below cannot therefore be properly abandoned, cement is downsqueezed through or past the junk and a 100-foot cement plug is placed on

top of the junk. If it is not possible to downsqueeze through the junk, a 100-foot cement plug is placed on top of the junk.

1723.1. Plugging of Oil or Gas Zones

(a) Plugging in an Open Hole. A cement plug is placed to extend from the total depth of the well or from at least 100 feet below the bottom of each oil or gas zone, to at least 100 feet above the top of each oil or gas zone.
(b) Plugging in a Cased Hole. All perforations are plugged with cement, and the plug extends at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
(c) Special Requirements. Special requirements may be made for particular types of hydrocarbon zones, such as:
(1) Fractured shale or schist;
(2) Massive sand intervals, particularly those with good vertical permeability; or
(3) Any depleted productive interval more than 100 feet thick.
As a minimum for an open-hole abandonment, the special requirement consists of a cement plug extending from at least 100 feet below the top of the oil or gas zone to at least 100 feet above the top of the zone.
As a minimum for a cased-hole abandonment, the special requirement consists of a cement plug extending from at least 100 feet below the top of the zone to at least 100 feet above the top of the perforations, the top of the landed liner, the casing cementing point, the water shutoff holes, or the zone, whichever is highest.
(d) Bridge Plug. A bridge plug above the lowermost zone in a multiple-zone completion may be allowed in lieu of cement through that zone if the zone is isolated from the upper zones by cement behind the casing.

1723.2. Plugging for Freshwater Protection

(a) Plugging in Open Hole.
(1) A minimum 200-foot cement plug is placed across all fresh-saltwater interfaces.
(2) An interface plug may be placed wholly within thick shale if such shale separates the freshwater sands from the brackish or saltwater sands.
(b) Plugging in a Cased Hole.
(1) If there is cement behind the casing across the fresh-saltwater interface, a 100-foot cement plug is placed inside the casing across the interface.
(2) If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug is placed inside the casing across the fresh-saltwater interface.
(3) Notwithstanding other provisions of this section, the district deputy may require or allow a cavity shot immediately below the base of the freshwater sands.

In such cases, the hole is cleaned out to the estimated bottom of the cavity and a 100-foot cement plug is placed in the casing from the cleanout point.

(c) Special Plugging Requirements. Where geologic or groundwater conditions dictate, special plugging procedures are required to prevent contamination of usable waters by downward percolation of poor quality surface waters, to separate water zones of varying quality, and to isolate dry sands that are in hydraulic continuity with groundwater aquifers.

1723.3. Plugging at a Casing Shoe

If the hole is open below a shoe, a cement plug extends from at least 50 feet below to at least 50 feet above the shoe. If the hole cannot be cleaned out to 50 feet below the shoe, a 100-foot cement plug is placed as deep as possible.

1723.4. Plugging at the Casing Stub

When casing is recovered from inside another casing string (or strings), and the outer string (or strings) is cemented opposite the casing stub, a 100-foot cement plug is required on the casing stub. A plug on the casing stub will generally not be required when casing is recovered in open hole or from inside another casing string that is not cemented opposite the casing stub.

1723.5. Surface Plugging

The hole and all annuli is plugged at the surface with at least a 25-foot cement plug. The district deputy may require that inner strings of uncemented casing be removed to at least the base of the surface plug prior to placement of the plug.

All well casing is cut off at least 5 feet below the surface of the ground. In urban areas, as defined in Section 1760(e), a steel plate at least as thick as the outer well casing is welded around the circumference of the outer casing at the top of the casing, after division approval of the surface plug.

1723.6. Recovery of Casing

(a) Approval to recover all casing possible will be given in the abandonment of wells where subsurface plugging can be done to the satisfaction of the district deputy.

(b) The hole is full of fluid prior to the detonation of any explosives in the hole. Only a licensed handler with the required permits shall utilize such explosives.

1723.8. Special Requirements

The supervisor, in special cases, may set forth other plugging and abandonment requirements or may establish field rules for the plugging and abandonment of wells. Such cases include, but are not limited to:

(a) The plugging of a high-pressure saltwater zone.

(b) Perforating and squeeze-cementing previously uncemented casing within and above a hydrocarbon zone.

2. Does the state have any geological standards, tables or other technically based policy documents available to field staff which are used as a guide in plugging wells?

American Petroleum Institute publications and the MOI.

3. Are there wells with no surface casing? How are they plugged?

None.

4. If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed?

A 100 foot plug is required above the casing stub; however a plug on the casing stub will generally not be required when casing is recovered in open hole or from inside another string that is not cemented opposite the casing stub.

5. Are plug locations verified? When and how? Are inspectors present to witness the plugging?

The Division requires witnessing the tag of the:

- ***Base of freshwater plug.***
- ***Zone plug (open or case hole).***
- ***Mudding placement between plugs.***
- ***Cavity shot.***

The Division may witness the tag or placement of the:

- ***Shoe plug.***
- ***Casing stub plug.***
- ***Surface plug.***

1723.7. Inspection of Plugging and Abandonment Operations

Plugging and abandonment operations that require witnessing by the division is witnessed and approved by a division employee. When discretion is indicated by these regulations, the district deputy determines which operations are to be witnessed.

(a) Blowout prevention equipment--may inspect and witness testing of equipment and installation.

(b) Oil and gas zone plug--may witness placing and shall witness location and hardness.

(c) Mudding of hole--may witness mudding operations and determine that specified physical characteristics of mud fluid are met.

(d) Freshwater protection:

(1) Plug in open hole--may witness placing and shall witness location and hardness. Plug in cased hole--shall witness placing or location and hardness.

(2) Cementing through perforations--shall witness cementing operation.

(3) Cavity shot--may witness shooting and shall witness placing or location and hardness of required plug.

(e) Casing shoe plug--shall witness placing or location and hardness.

(f) Casing stub plug--shall witness placing or location and hardness.

(g) Surface plug--may witness emplacement and shall witness or verify location.

(h) Environmental inspection (after completion of plugging operations)--shall determine that division environmental regulations (California Administrative Code, Title 14, Subchapter 2) have been adhered to.

6. What percentage of well plugs is witnessed? If all wells are not witnessed by inspectors, is there a priority system, which determines those plugs to be witnessed in all cases (producing wells, injectors, D&A)?

   About 80% of all plugs are witnessed. It is a priority to witness the base of fresh water plugs first, zone plugs second, shoe plugs and stub plugs third and non-critical plugs (such as across blank pipe opposite injection zones, damaged casing, etc.) last. All surface plugs are witnessed. The type of well is rather irrelevant to our priorities unless it's something like a mandatory squeeze of an injection well to seal off vertical migration.

7. Are plugs required to be tagged and if so, is the tagging witnessed? Is plug tagging required by regulation, elective on the part of the agency, or limited to certain geological or hydrogeological situations?

   Yes, Division regulations require witnessing and tagging of plugs. See response to question 5.

8. What control is exercised over unwitnessed plugs?

When a well is plugged and abandoned, the operator has 60 day to submit the complete record of operations to the Division (Section 1724 – 1724.1, CCR). These records are required to include all cement plugs, amount of cement, details of the cement job where tubing was hung, pump pressure, etc. An engineer reviews the submitted records and adds them to the well file. For unwitnessed plugs placed in a hole prior to the arrival of an inspector, the field inspector can check the tour reports at the well before plugging and abandonment is complete.

B. Understand the non-technical aspects of P&A and how this activity is integrated with the remainder of the program.

1. How are P&A reports coordinated with the permitting/area of review process?

   They are not coordinated with the area of review (AOR) process. An AOR is performed during the permit approval process for an injection project and/or injection well. The plugging and abandonment of a well subsequent to an AOR are engineered

2. Where are plugged and abandoned injection wells tracked? In the Central or district office? By whom?

   The tracking of plugged and abandoned wells is done by district office staff using the WellStat database.

3. What is the flow of activity starting with the Operators notice to the agency of an intention to plug a well through the submission of the final report?

   The operator submits a Notices of Intention to Abandon Well (permit application) to the appropriate Division district office. The notice is date stamped and the statutory 10-day (working days) clock starts in which the Division must respond to the operator regarding their permit application (Section 3229, PRC).

   The permit application is reviewed by the Division for completeness and to determine whether the proposed plugging and abandonment program is satisfactory. The application must include:
   a. The total depth of the well to be abandoned.
   b. The complete casing record of the well, including plugs.
   c. Such other pertinent data as may be required.

   If the proposed program meets Division requirements, a permit to plug and abandon the well is issued. Division requirements, including what operations the Division will witness, are listed on the permit. The plugging and abandonment operations must begin within one year of receipt or the notice will be cancelled.

The operator is required to submit plugging and abandonment history of all work performed within 60 days of completing required work. The history must describe the work in detail, including volumes of cement used, tops and bottoms of plugs, perforations, junk, locations of cavity shots and perforations used for squeeze-cementing operations, slurry compositions, etc.

Within 10 days after receiving the history of work performed, the Division must issue a final approval of abandonment letter to the operator that includes a statement that cleanup of surface is approved and that all well records have been filed.

If all provisions have not been met, the operator is notified that a final approval of abandonment cannot be issued until the work has been completed properly. A formal order is prepared in cases where the omitted requirements are serious and the operator has not remedied the situation.

4. Is P&A information incorporated into the data management/tracking system? How current is this information and how often are newly P&A wells available in a report?

   Yes. The information is current and available on the Division's web page (WellStat, Weekly Summary, Annual Report, etc.).

5. What is the State's action when an abandoned well is discovered? Please describe the process used to get the well plugged.

   Plugging and abandonment may be ordered whether or not damage is threatened or occurring, Section 3237 or 3755, PRC. Generally, this procedure is used when a well becomes "orphaned". The procedure may also be used as a result of a complaint, or when the District Deputy seeks to plug and abandon a well because it is a threat to the environment or public safety.

   Wells that require formal action fall into two general categories: (a) damaging (Section 3224, PRC) or deserted wells (Section 3237, PRC); and (b) hazardous or idle-deserted wells (Sections 3250-3259, PRC). These wells may be either unbonded or bonded in varying amounts. The procedures for handling these two categories of wells differ slightly and are discussed in the following sections.

   The purpose of an order is to notify all affected parties of the Division's intent to enter a property and plug and abandon a well. As required by the PRC, it is an order to allow entry and abandonment, subject to the right of appeal as specified in Section 3255(c), PRC. Prior informal contact with property owners is made for the purpose of explaining the operations to be performed. This provides better understanding, cooperation, and support from the public in such matters.

If the landowner wishes to dispute the Division's intention to enter the property to plug and abandon a well, the landowner may appeal the order to the Director.

Before a formal order is issued, the following is done:

1. *Every reasonable effort is made to have the operator (if active) comply with our requirements.*
2. *The well is inspected*

Headquarters' permission and review is required prior to issuance of orders to plug and abandon wells. Generally, Headquarters gives the order number to the district office, along with any instructions that Headquarters deems necessary.

Copies of the orders are sent out as follows:

1. *(Original) to owner, operator, or referee in bankruptcy*
2. *Headquarters*
3. *District file (1 to the well record; 1 to the Chronological file of orders).*
4. *Landowner. A cover letter is included to inform the landowner that they have no financial responsibility.*
5. *Surety (if well is bonded). A cover letter is included to inform the surety of the option to arrange to have the work done and that it would be to the surety's financial advantage to do so, as a "cost incurred" charge would be added to the cost of any work arranged by the Division.*
6. *Interested parties (if deemed appropriate by the District Deputy).*
7. *Regional Coastal Commission office if a well is within the Coastal Zone. If extensive road building or vegetation removal is required for access to a well, a Coastal Commission permit may be required. If specific advice regarding the need for a permit is not received from a Regional Coastal Commission office within two weeks, it may be presumed that a permit is not required.*
8. *Local government agency (also inquire as to the existence of a bond). Some local governments require operators to file life-of-the-well bonds. Along with a copy of the formal order, local governments are sent a letter inquiring as to the existence of a bond. If a bond exists, it is pursued as a source of funds to cover the costs of work performed by the Division.*

Copies of all formal orders sent to the surety or operator must be by certified mail, return receipt requested.

6. Does the State maintain an inventory of abandoned wells? Does the State maintain a well plugging fund that is used to plug wells with no responsible party? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund.

Yes, it's posted on the Division's web page. Where no operator can be located, Division statute currently identifies a $1 million fund for plugging and abandonment contracting.

C. **OBJECTIVE: Understand the Temporary Abandoned (TA) Well Status Program used by the State.**

1. Does your UIC program include a separate formalized (by statute or regulation) administrative program for temporarily abandoned wells and how is a TA well defined. Please provide a summary of the limitations on the Operator once TA status has been approved by the agency for a given well.

   The Division administers an idle-well program that is similar to a temporarily abandoned well program. A major difference is an active well can become idle without Division approval. Because the term temporarily abandoned implies that a well has been disregarded by the operator, the Division uses the term "long-term idle" instead.

   Long-term idle means any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last 10 or more years. A long-term idle well does not include an active observation well. Long-term idle wells are categorized as 5, 10, or 15 year-idle wells (the amount of time since last production).

   If an injection well is idle for two or more years, the approval for injection is rescinded. Since idle injection wells are not subject to the normal MIT schedule, by virtue of them being idle, they are subject to the idle-well testing guidelines.

   The object of the idle-well program is to elevate an operator's awareness of its idle-well inventory and to have idle wells that have no apparent future use plugged and abandoned by the responsible party, at no cost to the State. If the operator does not have specific plans for the well or wells, does not respond to Division inquiries, has wells located in unstable terrain, or has junked holes, the wells are ordered plugged and abandoned.

2. Please provide a copy of any regulations or policies on TA wells that your agency has issued in the past five years.

   See Sections 3008 and 3206, PRC.

3. Does the agency require a mechanical integrity test to be run on a TA well before it is reactivated to an injection well?

If the permit to inject has been rescinded because the well was idle for two years and the operator wants to commence injecting again, the Division requires the operator to reapply for a new permit to inject. The new permit will stipulate the MIT requirements.

4. Describe how TA's wells are tracked and whether they are tracked as a part of the active or abandoned well regimes?

   Long-term idle wells are tracked through WellStat.

D. OBJECTIVE: Understand the Data Management System Used in the Plugging and Abandonment Program.

1. When was the data management system currently used first put into operation?

   1977.

2. Is there capability for the Operators and field inspectors to file some or all of the documentation pertaining to well pluggings and abandonments electronically? Describe what electronic communication is available to the regulated community, other state and federal agencies and the public.

   Not yet, but were working on it (see previous comments on ePermit).

3. Is the agency's data management system locally (intramural) conceived or linked with other state databases?

   WellStat is networked so districts and Headquarters have access to the information. In addition, WellStat is posted on the Division web page, thereby, providing access to p&information to other agencies, industry, and the public.

E. Changes and Program or Policy Since 1990

Exclusive of the changes in data management described under Section D., what statutory, regulatory, or policy changes have occurred during the past ten years to address abandonment of wells and financing of orphan wells?

Prior to 1998, long-term idle well bonding requirements would not provide sufficient funds should a long-term idle well be determined to be orphaned and the Division ordered plugging and abandonment.

The 1998 legislation also increased the annual funding amount the DOGGR can spend for the plugging and abandonment of orphaned wells to $1 million for 5 years. Previously, where no operator can be located and the DOGGR had determined a well to be orphaned, statute identifies a $500,000 fund for the DOGGR to access in contracting for the clean up. In 1994, the Legislature approved an increase from $350,000 to $500,000.

Legislation was passed in 1998 that gave operators a set of options to cover the liability its long-term idle wells. First, an operator could take out a $1 million blanket bond to cover all their operations, including idle wells. Second, operators could choose to pay the annual idle well fee, but on an increased scale reflecting relative hazards: for wells idle less than 10 years the fee is $100; for wells idle 10-15 years the fee is $250; and for wells idle for over 15 years, the fee is $500. Third, operators may take out a $5,000 bond for each individual idle well; fourth, operators may establish an escrow account for each idle well that must be worth $5,000 after 10 years (any interest earned in the escrow account will be returned to the operator); and fifth, operators may establish an idle well management plan that requires operators to eliminate a certain percentage of long-term idle wells (10 years or longer) on an annual basis. For purposes of the plan, eliminate means to return to production, plug and abandon (clean-up), or turn that well into an injection or observation well. An operator choosing the Plan would not be subject to any additional idle well fees or bonding requirements. If they failed to meet their annual goals for plan implementation, they would immediately be required to secure idle well bonds or establish an escrow account for the wells.

The Division also increased bonding amounts for active wells by $5,000. Individual well bonds increased to $15,000 for wells less than 5,000 feet in depth; $20,000 for wells between 5,000 and 10,000 feet; and $30,000 for wells in excess of 10,000 feet. The intent with this 1998 change is that plugging and abandoning costs for a well has increased. The previous rates were established in statute in 1976.

The 1998 bill also increased the amount of annual funding the Division could spend for the plugging and abandonment of orphaned wells to $1 million. Previously, where no operator can be located and the Division had determined a well to be orphaned, statute identifies a $500,000 fund for the Division to access in contracting for the clean up. In 1994, the Legislature approved an increase from $350,000 to $500,000.

PART VII: PUBLIC OUTREACH

A. OBJECTIVE: Understand the Public Outreach Mechanisms used by the State

1. How is the public informed about UIC issues and the promulgation of new regulations and amendments to existing regulations?

   Notices for all new and modified injection projects are published in a local newspaper for 3 consecutive days. The laws and regulations regarding UIC are available for review in any district office, on the Division web page, and at most public libraries. If there are significant comments or concerns, then the Division schedules a public hearing. Local governments and operators are notified of changes or additions to Division policy by written notices. General information on the Division's UIC program is available for operators, local and county governments, and the general public through the Division's web page, informational video, and pamphlet.

2. How is the regulated community identified and informed about UIC requirements?

   1. ***Upon submission of injection permits, the Division informs operators of all requirements in the permit.***
   2. ***"Notice to Operators" is sent to all operators operating in the State whenever there is new Division policy.***
   3. ***Changes to Division programs are posted on its web page.***

3. If used, are mailing lists kept up to date? How often do general mailings occur? Are special mailings sent on specific UIC issues? Who do the mailings go to?

   Yes. They are used whenever a special mailing is sent out. Yes, special mailings have been used for UIC; the latest was in 1996 for changes made to the program regarding MIT requirements. Mailings go to all operators.

4. Please indicate any local, regional. Or national interest groups included in the mailing lists?

   IOGCC, GWPC, API, various county governments, and industry organizations.

5. Which of these groups have shown an active interest in UIC issues? Have any groups shown concerns over UIC well completion practices including hydraulic fracturing of the injection zone?

   Local groups and GWPC.

agencies in your Public Outreach activities? Has there been any decrease in interest by other agencies in UIC regulatory activities? Please list and explain changes.

None to all of the above.

PART VIII: REVIEW OF WATER REUSE MANDATES AND POLICIES

This set of general questions is designed to describe the states efforts to use various categories of wastewater including those associated with the oil industry and UIC Class II wells.

1. Does the state have any statutes, regulations or policies mandating or precluding the reuse of wastewater from the following:

   a. Low level chloride (less than 3000 TDS) produced water from oil field operations that could be returned to the surface or ground water regime?

      Division response – no.

   b. Low level chloride water produced from coal bed methane?

      N/A.

2. Which agency in your state would have to give the Operator permission to either reuse water produced under (1) or return it to the environment through wells? Is reuse taking place at the current time? If so, describe.

   If reuse means to use the produced water for domestic purposes, the Division does not regulate this activity.

PART IX: REVIEW OF COAL BED METHANE PROGRAM (If Applicable)

This section is non-applicable to California. There is no coal bed methane production in the State.

A. Statutory Authorities and Regulatory Jurisdictions

1. Please include a copy of all statutes, rulers, regulations, policies and orders applicable to the production of coal bed methane (CBM) and the wastes derived from the production of coal bed methane.

APPENDIX B3

FIELD DATA TABLES

Field Data Tables for All Districts

These tables provide summary information collected during the review process for each district. These data were collected combining information from the *California Oil and Gas Fields* publication to identify well field information, and the 2008 CDOGGR annual reports for current status on the wells. The fields listed below include the largest in terms of water injection volumes and/or the number of injection wells, but are not a complete list of fields in each district.

District 1

Field Name	Disc. year	BFW (feet)	Injection Zone Average Top Depth (feet)	TDS Injection Zone Minimum (mg/L)	Enhanced Recovery (ER) Type	Initial ER date & status	Well Count/Type and Comments
Wilmington	1932	1600	2000-5850	28000+	wf/sf/af	1954 active	842 wf, 3 wd, 7 sf
Inglewood	1932	200-350	950-9000	30100-42600	wf/cs	1953 active	249 wf, 2 wd TDS=30,100 at 1500 ft
Long Beach	1921	1800-2500	2000-7500	28750	wf	1964 active	88 wf, 0 wd
Santa Fe Springs	1919	1000	2000-9100	7500-31200	wf	1961 active	63 wf, 0 wd
Montebello	1917	1600	2000-7650	14037-25677	wf	1960 active	66 wf, 0 wd
Beverly Hills	1900	500	2500-10800	21500-26000	wf	1968 active	32 wf, 2 wd
Seal Beach	1924	1800	2610-8100	28000-31645	wf	1961 active	12 wf, 10 wd
Torrance	1922	1550-1770	2800-4200	23300-27435	wf	1958 active	48 wf, 2 wd
Huntington B.	1920	1000-2400	1800-4600	21000-31000	wf/sf	1962 active	181 wf, 2 wd
Brea Olinda	1880	0-1300	1200-5000	9,000+	wf/sf/cs	1964 active	47 wf, 10 wd Formation Water Resistivity = 1.0-1.5 @ 1800 ft.
Richfield	1919	800-3200	2000-7950	6609-6850	wf/cs	1944 active	64 wf, 0 wd
Coyote, East	1909	50-1250	2500-5500	10959-20542	wf/CO_2	1968 active	21 wf
Las Cienegas	1961	400-800	2500-64200	17100-26500	wf/GI	1965 active	33 wf
Rosecrans	1924	2000-4800	3750-9100	26200-34300	wf	1968 active	12 wf
L.A. Down Town	1969	300	2000-4800	14721-24876	wf	1966 active	8 wf Had a surface leak in an inj. well.

District 2

Field Name	Disc. year	BFW (feet)	Inj. zone avg. top depth (feet)	TDS inj. zone min. (mg/L)	ER type	Initial ER date & status	Well Count/Type and Comments
Ventura	1919	750	3680-12010	15219	wf	1956 active	260 active/112 inactive wf, 0 salt water disposal (swd) wells
Placerita	1920	500	600-1700	3800	wf/sf/sc	1954 active	3 wf, 16 wd, 76 sf, 44 sc
San Miguelito	1931	200	6803-14257	27200	wf	1955 active	80 wf, 0 wd
Aliso Canyon	1918	100-800	4150-7437	2900-15000	wf	1976 active	3 wd, 7wf, 100 gs
Bardsdale	1892	550	2000-6500	5100-33300	wf	N/A active	3 wd, 3wf
Del Valle	1940	100-1150	3800-9700	13700-21800	wf	1959 inactive	5 wd
Eureka Canyon	1893	1250	200-1800	1000-2200	none	N/A	2 wd
Holser	1942	None	1000-6540	1400-2700	cs	1965 inactive	2 wd
Honor Ranch	1950	1150	3800-6481	10300-24800	wf/gs	1957 active	3 wd, 34 gs
Hopper Canyon	1894	0-100	1000-2780	700-6000	none	N/A	2 wd
Montalvo West	1917	1600	2200-7650	14037-25677	wf	1964 active	6 wd, 4 wf
Newhall	1876	100-1400	145-3000	4300	wf	1963 inactive	4 wd
Newhall-Potrero	1937	0-300	6500-14200	6000	pm/wf	1944 inactive	3 wd
Oak Canyon	1941	2500	2750-9800	9540-11850	wf	1972 active	1 wd, 4 wf
Oak Park	1969	400	800-1500	7200	wf/cs	1971 inactive	3 wd
Ojai	1866	100	1544-5500	1700-26000	cs/wf/pm	1948 inactive	15 wd
Oxnard	1937	1800	2176-10200	5400-23900	cs/wf	1963 active	8 wd, 22 sc
Ramona	1943	100-350	2498-2900	9400-17800	none	N/A	5 wd,
Rincon	1927	none	3400-13000	9900-25600	wf	1963 active	4 wd, 64 wf
Santa Clara Ave.	1972	1750	8630-9000	39000	none	N/A	2 wd
Saticoy	1955	None	8570-9035	17100	wf	1963 active	0 wd, 9 wf
Sespe	1887	0-100	600-5400	1700-18500	wf	1962 inactive	15 wd, 5 wf
Shiells Canyon	1911	200	1000-6600	4300-35900	wf/sf	1949 inactive	4 wd, 4 wf
So. Mountain	1916	0-1650	3500-7500	8977-35739	wf/sf	1956 active	11 wd, 9 wf
Tapo Canyon So.	1953	500-600	1800-2200	1500-17600	cs/wf	1964 inactive	1 wd
Tapo North	?	0-400	1000-2000	5100-6800	wf	1951 inactive	1 wd
Temescal	1926	none	2200-2950	34000	wf	1964 inactive	2 wd

District 3

Field Name	Disc. year	BFW (feet)	Inj. zone avg. top depth (feet)	TDS inj. zone min. (mg/L)	ER type	Initial ER date& status	Well Count/Type and Comments
San Ardo	1947	950-1000	2000-2400	4300-6000	wf/sf/sc	1963 active	28 wf, 164 sf, 14 sc, 24 wd
Orcutt	1901	250-1250	1400-9676	15000-21500	wf	1963 active	64 wf, 7 wd, 33 sc
Cuyama So.	1949	2000-2620	1830-7500	15000-21500	wf	1955 active	44 wf, 5 wd, 3 pm
Lompoc	1903	400	2250-2750	4860-8090	pm	1929 inactive	12 wd , 1 pm
Arroyo Grande	1906	700-1200	750-3100	2000-19125	sf/sc/pm	1965 active	22 wd, 60 sf, 23 sc, 4 pm
Casmalia	1905	None ?	1275-3953	6278-15000	none	N/A	9 wd
Zaca	1942	1400	3500	5134	wf, sc	1953 inactive	11 wd
Cat Canyon	1908	0-1400	1750-6000	3765-30000	wf/sf/sc/pm	1954 active	38 wd, 37 wf, 19 sf, 2 pm

District 4

Field Name	Disc. year	BFW (feet)	Inj. zone avg. top depth (feet)	TDS inj. zone min. (mg/L)	ER type	Initial ER date& status	Well Count/Type and Comments
Belridge South	1911	None ?	400-8200	13900-40000	wf/sf/sc	1963 active	1940 wf, 1536 sf, 330 sc, 30 wd
Kern River	1899	2500	400-4700	500-5382	wf/sf/sc	1961 active	14 wf, 1582 sf, 7420 sc, 64 wd
Midway-Sunset	1890	None?	200-8700	1550-38000	wf/sf/sc/pm	1954 active	23 wf, 2040 sf, 4853 sc, 2 pm, 197 wd
Elk Hills	1919	None ?	1120-9500	4560-32400	wf/pm	1957 active	249 wf, 64 pm, 72 wd
Cymric	1909	None?	1000-3400	4844-25967	sf/sc	1963 active	570 sf, 1086 sc, 22 wd
Poso Creek	1929	2200	1800-3400	220-1400	sf/sc	1965 active	28 sf, 129sc, 60 wd
Lost Hills	1913	None?	200-6020	15500-38000	wf/sf/sc	1946 active	905 wf, 288 sf, 244 sc, 79 wd
Round Mountain	1927	200	1250-2600	1400-2700	wf/sf	1960 active	14 wf, 16 sf, 32 wd
Kern Front	1912	2500	2290 avg.	500-1100	sf/sc	1964 active	4 wf, 128 sf, 3 sc, 21 wd
Buena Vista	1909	None?	1800-5300	10100-40317	wf/sf/sc	1954 active	44 wf, 1 sf, 1sc, 32 wd
Belridge North	1912	None?	600-8550	10100-42000	wf/sf/sc	1955 active	354 wf, 36 sf, 12 sc, 4 wd
Mount Poso	1926	1800	1140-2575	650-3300	sf	1964 active	22 sf, 43 wd
McKittrick	1896?	None?	300-9100	2000-28200	wf/sf/sc	1962 active	11 wf, 190 sf, 112 sc , 29 wd
Tejon	1935	1800	2000-5400	940-17200	wf	inactive	2 wf, 13 wd
Rosedale Ranch	1945	3100	3500-4900	12100-30000	wf/sc/pm	Inactive	18 wd
Edison	1928	4000*	400-4730	532-17810	sc/wf	1964 active	99 sc, 20 wd, 1 wf *1350' minimum depth.
Fruitvale	1928?	3000	3000-4500	900-10800	wf	1962 active	9 wf, 42 wd
Ant Hill	1944	850	2300-3500	3500-4700	wf	Inactive	2 wd , 2.2 million bbls injected in 2008
Yowlumne	1974	4000**	10400-13300	14000-15000	wf	active	37 wf , 0 wd ** 1600' minimum depth

District 5

Field Name	Disc. year	BFW (feet)	Inj. zone avg. top depth (feet)	TDS inj. zone min. (mg/L)	ER type	Initial ER date& status	Well Count/Type and Comments
Coalinga	1887	1300	500-4600	3300-5400	wf/sf/sc	1952 active	623 wf, 970 sf, 369 sc, and 8 wd
Raisin City	1941	750	4680-6260	22500-48800	none	N/A	20 wd wells.
Burrel	1943	1400	6500	40900	none	N/A	1 wd
Coalinga East	1938	2100	7400-8000	2300-19600	pm/wf	1950 inactive	3 wd, 4 wf
Helm	1941	1300-1700	6100-7990	22200-40900	wf	1961 inactive	10 wd
Jacalitos	1941	550	3400	9400-11800	pm/wf	1945 active	3 wd, 4 wf
Pleasant Valley	1943	2300	6644-9144	2500-15700	none	N/A	2 wd
Riverdale	1941	1500-1850	6800-7930	23900-42700	none	N/A	4 wd
San Joaquin	1947	1050-1150	7000	21100	none	N/A	1 wd
Vallecitos	1944	100-500	420-5350	1100-8200	none	N/A	1 wd
Van Ness Slough	1988	2250	6650	40900	none	N/A	1 wd

District 6

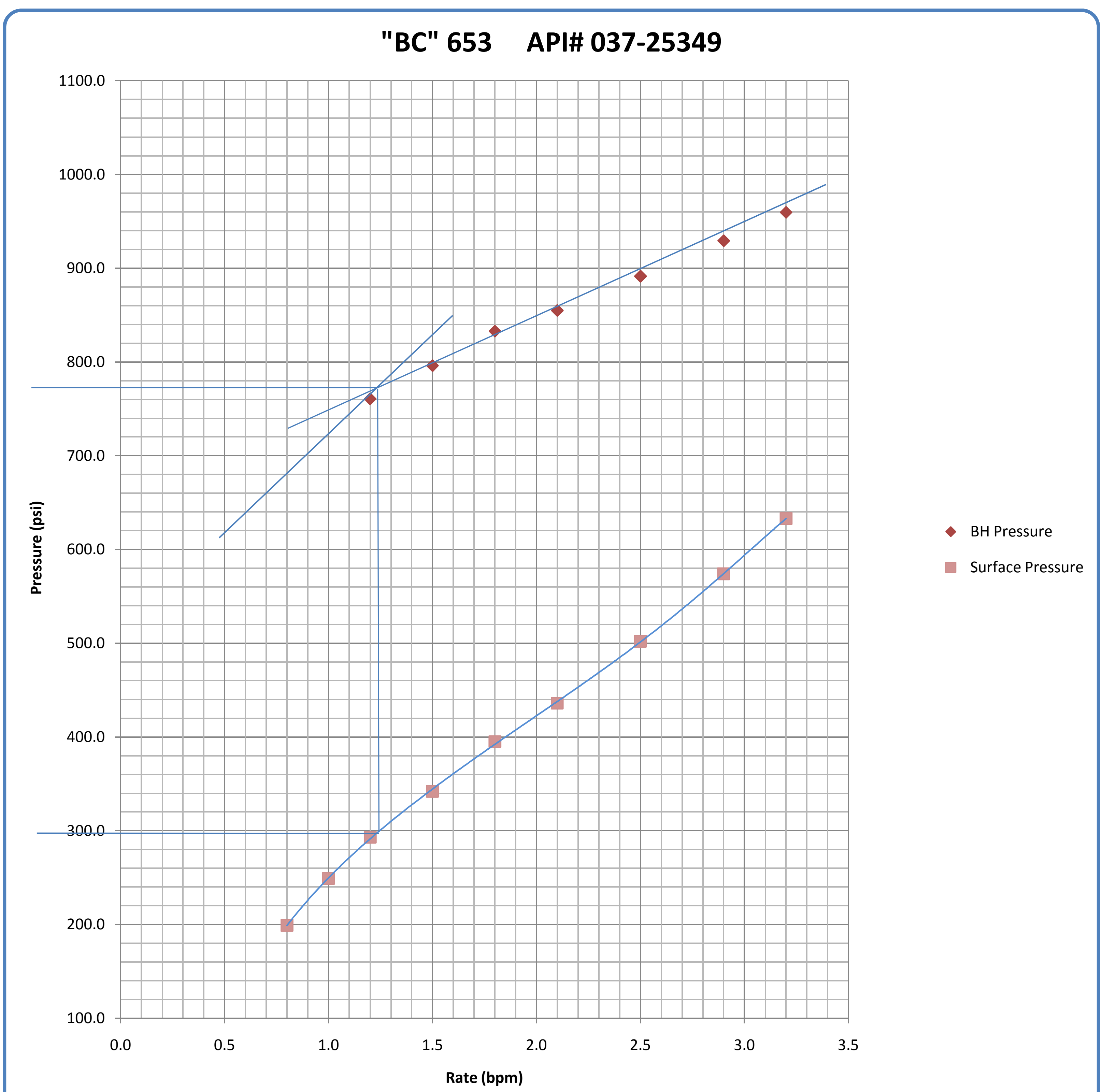
Field Name	Disc. year	BFW (feet)	Inj. zone avg. top depth (feet)	TDS inj. zone min. (mg/L)	ER type	Initial ER date & status	Well Count/Type and Comments
Grimes Gas	1960	1100	4900-8800	16823	None	N/A	3 wd
Kirkwood	1958	2000	2400-4020	2100	None	N/A	2 wd
La Honda	1956	150	1120-2500	19700-41000	None	N/A	1 wd
Lindsey Slough	1962	2500-3000	1100-10828	860-21000	None	N/A	7 wd
Livermore	1967	200	900-5300	3400-9400	None	N/A	2 wd
Lodi Gas	1943	1700	2280-2515	1863-3424	None	N/A	2 wd
Main Prairie Gas	1945	2700	630-8300	68-17120	None	N/A	0 wd one new well under permit review
Malton-Blk Butte	1964	1500-1800	1550-4950	18000-21600	None	N/A	2 wd
Millar Gas	1944	2900-3200	3875-82450	1700-10440	None	N/A	1 wd
Oil Creek	1955	None	1860-2090	25300	None	N/A	1 wd
Ord Bend Gas	1943	1200	3660	15400	None	N/A	1 wd
Rio Vista Gas	1936	1900-2900	2950-9650	7700-24000	None	N/A	5 wd
Sherman Isl. Gas	1965	800	4770-6700	1810-10000	None	N/A	1 wd
Sutter City Gas	1952	1200-1700	1440-6620	2200-27000	None	N/A	1wd
Sycamore Gas	1956	7501	1480-7370	N/A	None	N/A	0 wd
Union Island	1972	300	9700	39900	None	N/A	1 wd
Willows-Beehive	1938	850-1500	2095-7350	1710-18400	None	N/A	1 wd

APPENDIX B4

SAMPLE SRT RESULTS FOR INGLEWOOD AND LAS CIENAGAS

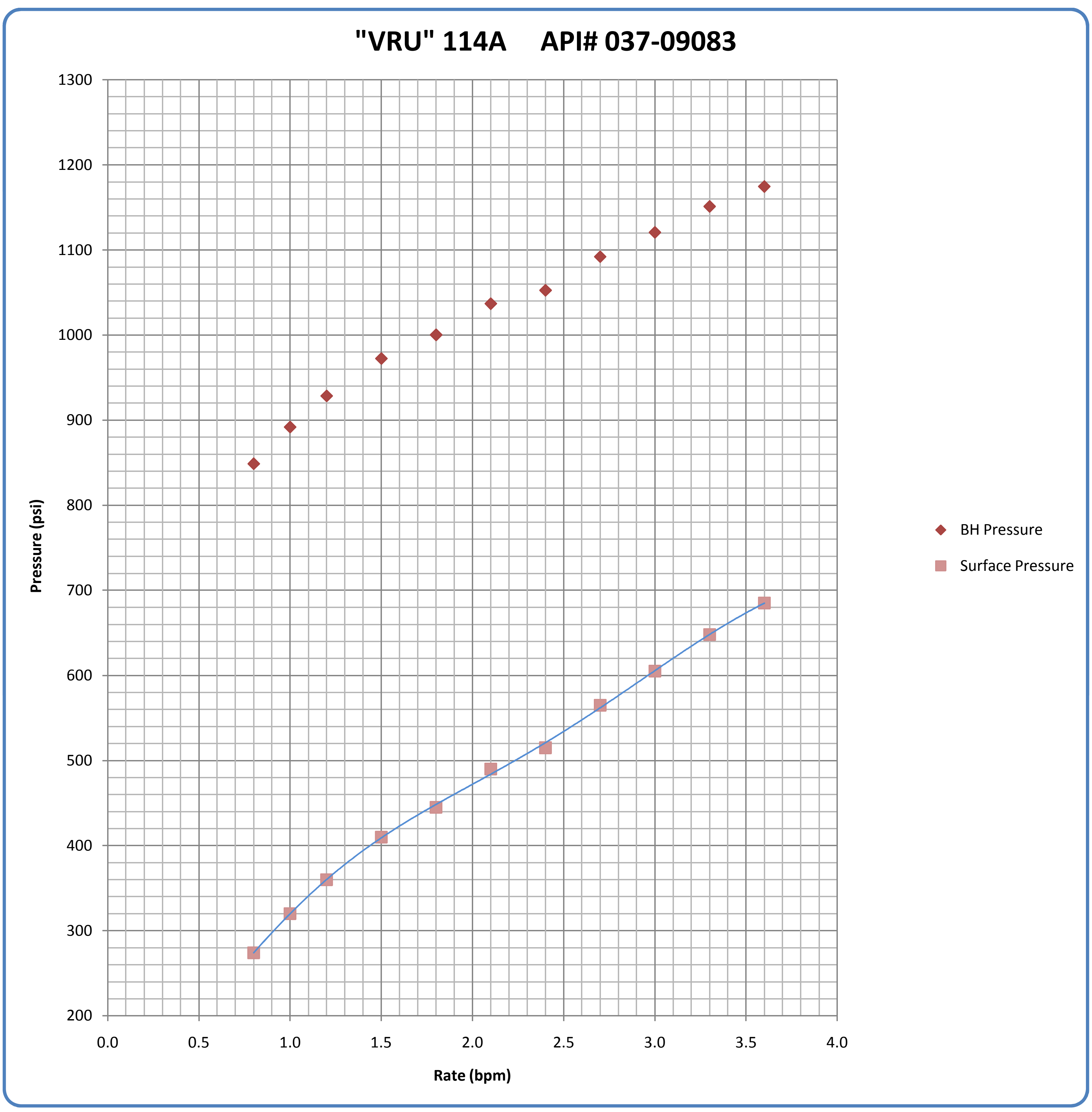
"BC" 653 API# 037-25349						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
140	2.441	1556	1120	775	0.69	1.5" Dia. for 20" x

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	20.0	0.0	0.0	512.8
1	0.8	33.6	199.0	6.5	5.1	680.2
2	1.0	42.0	249.0	9.8	8.0	724.0
3	1.2	50.4	293.0	13.8	11.4	760.6
4	1.5	63.0	342.0	20.9	17.9	796.1
5	1.8	75.6	395.0	29.2	25.8	832.8
6	2.1	88.2	436.0	38.9	35.1	854.9
7	2.5	105.0	502.0	53.7	49.7	891.4
8	2.9	121.8	574.0	70.7	66.8	929.3
9	3.2	134.4	633.0	84.8	81.4	959.6
ISIP	0.0	0.0	385.0	0.0	0.0	877.8



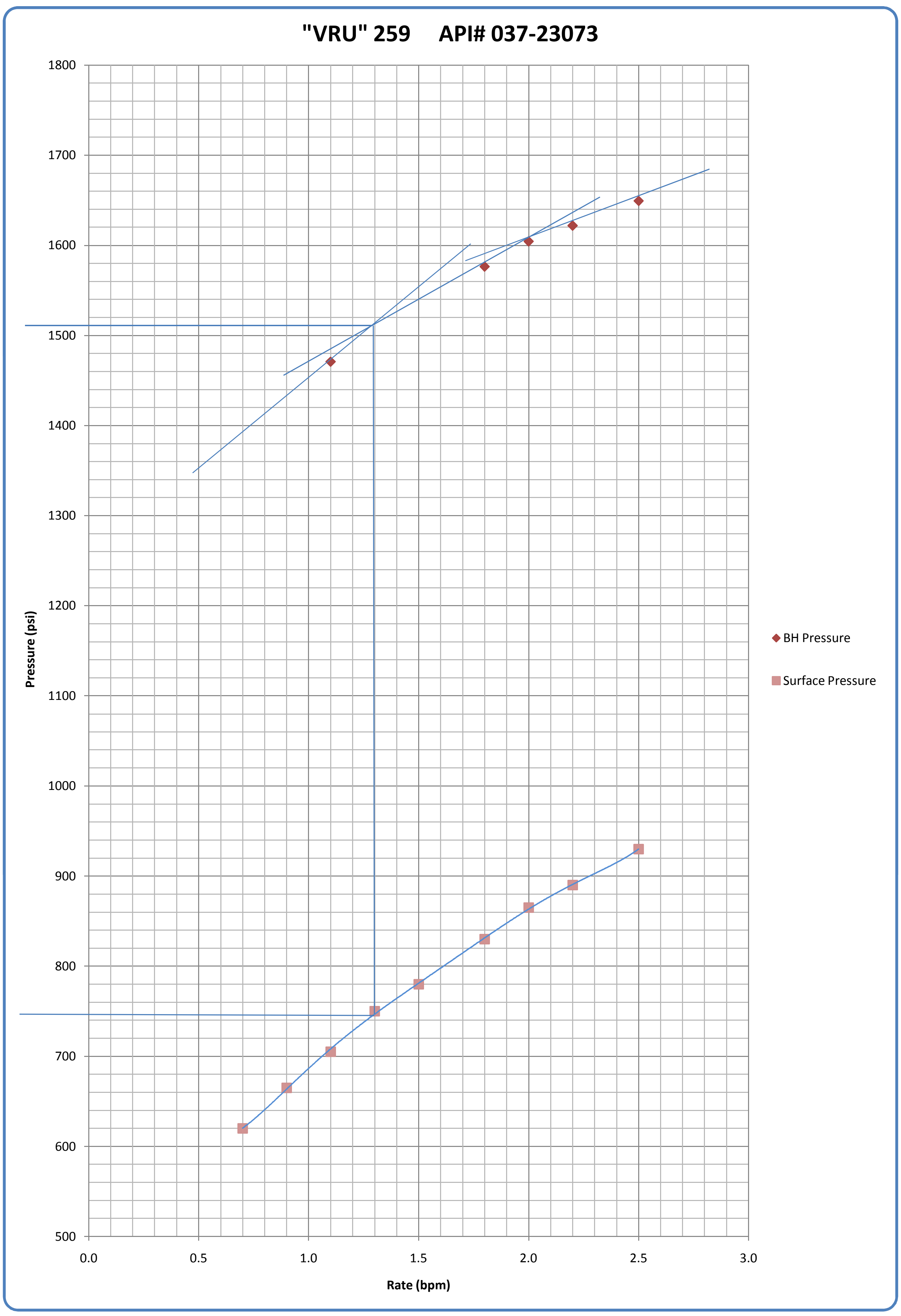
"VRU" 114A API# 037-09083						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
140	2.441	1339	1319		0.00	No side Pocket

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	120	0.0	0.0	700
1	0.8	33.6	274	5.6	0.0	849
2	1.0	42.0	320	8.5	0.0	892
3	1.2	50.4	360	11.9	0.0	928
4	1.5	63.0	410	17.9	0.0	972
5	1.8	75.6	445	25.2	0.0	1000
6	2.1	88.2	490	33.5	0.0	1037
7	2.4	100.8	515	42.9	0.0	1053
8	2.7	113.4	565	53.3	0.0	1092
9	3.0	126.0	605	64.8	0.0	1121
10	3.3	138.6	648	77.3	0.0	1151
11	3.6	151.2	685	90.8	0.0	1175
ISIP		0.0	510	0.0	0.0	1090



"VRU" 259 API# 037-23073						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
140	2.441	1724	1770	1510	**0.85**	No side pocket

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	430	0.0	0.0	1209
1	0.7	29.4	620	5.6	0.0	1393
2	0.9	37.8	665	9.0	0.0	1435
3	1.1	46.2	705	13.0	0.0	1471
4	1.3	54.6	750	17.7	0.0	1511
5	1.5	63.0	780	23.1	0.0	1536
6	1.8	75.6	830	32.4	0.0	1576
7	2.0	84.0	865	39.4	0.0	1604
8	2.2	92.4	890	47.0	0.0	1622
9	2.5	105.0	930	59.5	0.0	1649
ISIP	0.0	0.0	790	0.0	0.0	1569



The Hazen - Williams Equation

The Hazen - Williams equation is an empirical formula which relates the flow of water in a pipe with the physical properties of the pipe and the pressure drop caused by friction. When used to calculate the pressure drop using US customary units, the equation is:

$$P = (4.52\ Q^{1.852}) / (C^{1.852}\ d^{4.8655})$$

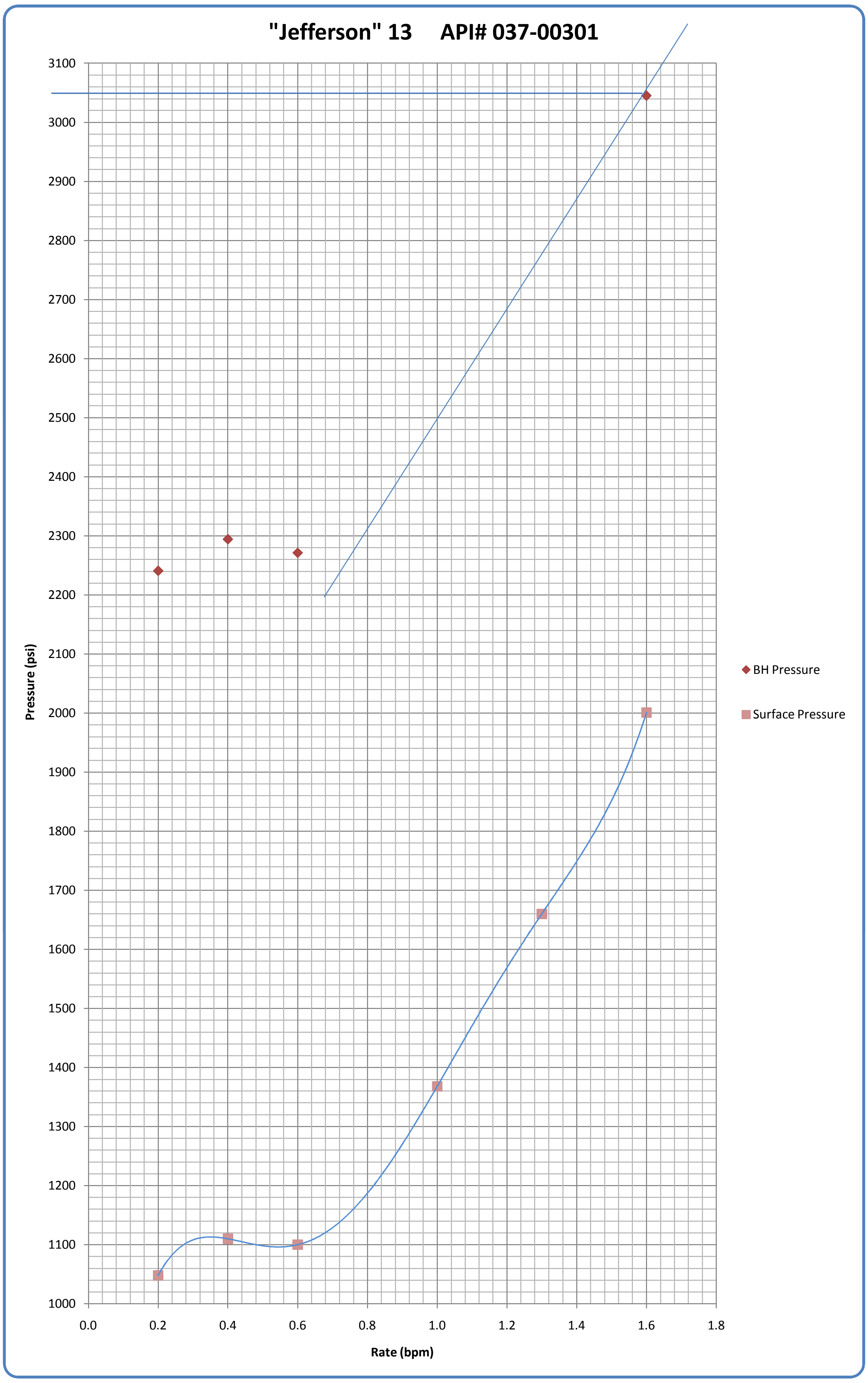
where **P = pressure drop (psi/foot)**
Q = flow rate (gpm)
C = roughness coefficient (dimensionless)
d = inside pipe diameter (inches)

Some typical roughness coefficients for common materials are listed below:

Material	Roughness Coefficient
Fiber Glass Pipe	150
Steel, New	140 - 150
Polyethylene - PE, PEH	140
Very smooth Metal Pipe	140
Brass	130 - 140
Cooper	130 - 140
Acrylonite Butadiene Styrene - ABS	130
Polyvinyl Chloride - PVC	130
Cast Iron, New	130
Cast Iron, 10 years old	107 - 113
Cast Iron, 20 years old	89 - 100
Cast Iron, 30 years old	75 - 90
Cast Iron, 40 years old	64 - 83
Corrugated Metal	60

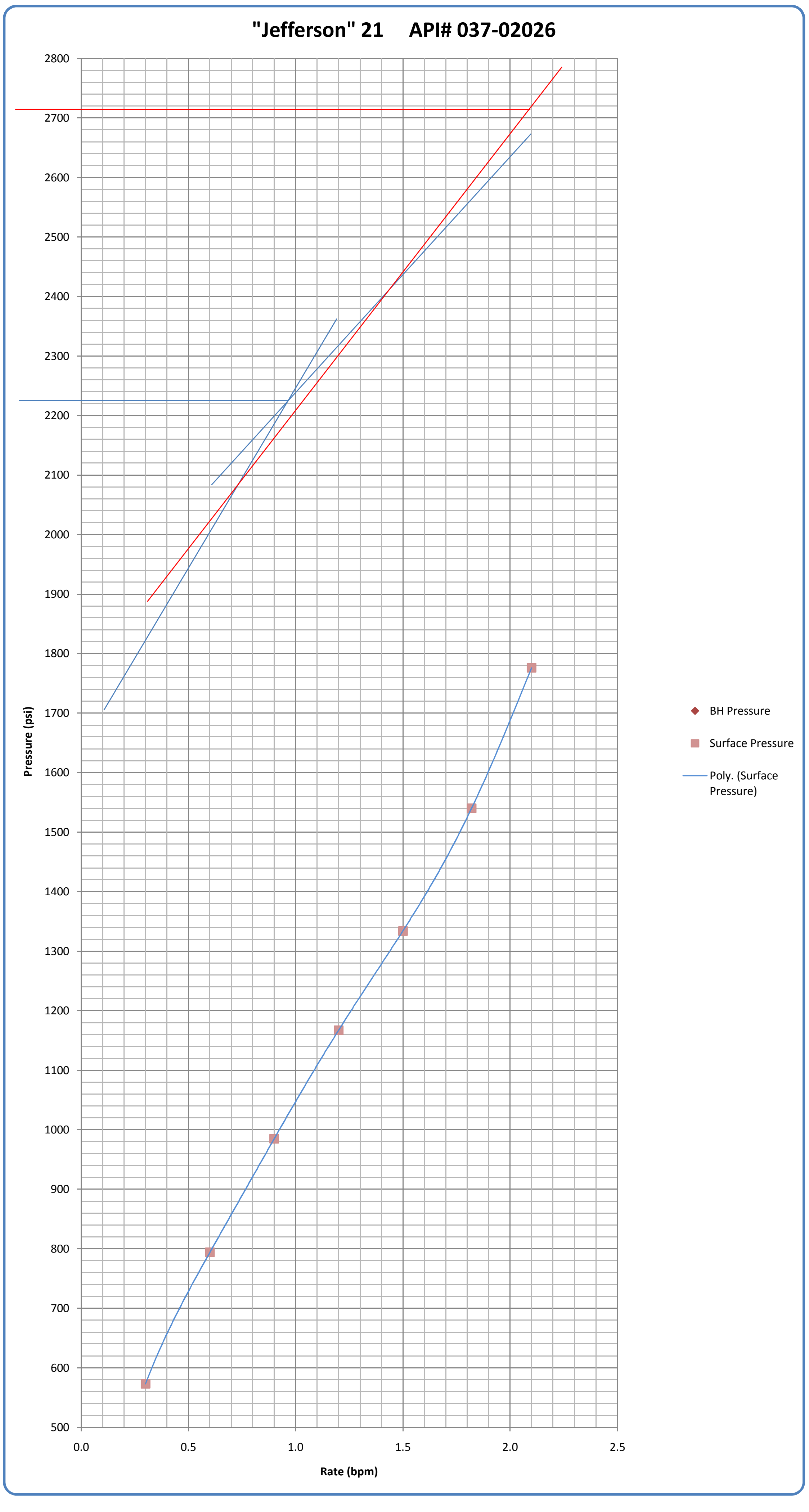
"Jefferson" 13 API# 037-00301						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
110	2.041	2688	2718	3043	1.12	No Side Pocket

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	213	0.0	0.0	1409
1	0.2	8.4	1048	3.2	0.0	2241
2	0.4	16.8	1110	11.6	0.0	2294
3	0.6	25.2	1100	24.6	0.0	2271
4	1.0	42.0	1368	63.5	0.0	2500
5	1.3	54.6	1660	103.2	0.0	2753
6	1.6	67.2	2001	151.6	0.0	3045
ISIP	0.0	0.0	995	0.0	0.0	2191



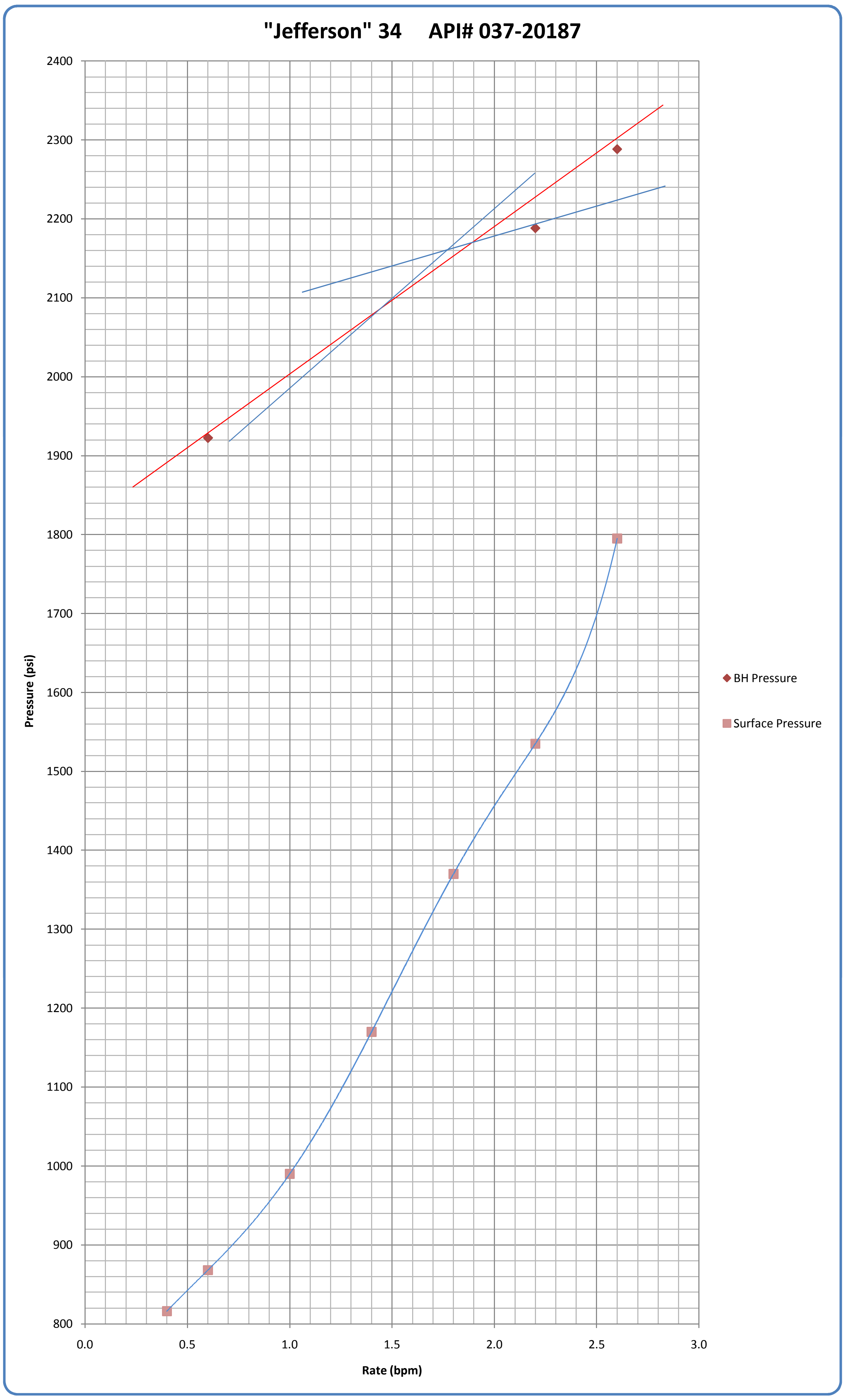
"Jefferson" 21 API# 037-02026						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
110	2.041	3437	2853	2711	0.95	No Side Pocket

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	224	0.0	0.0	1479
1	0.3	12.6	573	8.7	0.0	1820
2	0.6	25.2	794	31.5	0.0	2018
3	0.9	37.8	985	66.8	0.0	2174
4	1.2	50.4	1167	113.8	0.0	2309
5	1.5	63.0	1334	172.0	0.0	2417
6	1.82	76.4	1540	246.1	0.0	2549
7	2.1	88.2	1776	320.7	0.0	2711
ISIP	0.0	0.0	920	0.0	0.0	2175



"Jefferson" 34 API# 037-20187						
Hazen-Williams Equation Variables			Effective TVD (feet)	BH Fracture Pressure (psi from graph)	Fracture Gradient (psi/foot)	Side Pocket Description
Roughness Coefficient (dimensionless)	Inside Pipe Diameter (inches)	Tubing Length (feet)				
110	2.041	4335	2487	2288	**0.92**	No Side Pocket

Step Rate Data						
Step #	Rate (bpm)	Rate (gpm)	Pressure (psi)			
			Surface Pressure	Tubing Pressure Drop	Side Pocket Pressure Drop	BH Pressure
Start	0.0	0.0	750	0.0	0.0	1844
1	0.4	16.8	816	18.8	0.0	1892
2	0.6	25.2	868	39.7	0.0	1923
3	1.0	42.0	990	102.4	0.0	1982
4	1.4	58.8	1170	190.9	0.0	2073
5	1.8	75.6	1370	304.1	0.0	2160
6	2.2	92.4	1535	440.9	0.0	2188
7	2.6	109.2	1795	600.8	0.0	2288
ISIP	0.0	0.0	0	0.0	0.0	1094



The Hazen - Williams Equation

The Hazen - Williams equation is an empirical formula which relates the flow of water in a pipe with the physical properties of the pipe and the pressure drop caused by friction. When used to calculate the pressure drop using US customary units, the equation is:

$$P = (4.52\ Q^{1.852}) / (C^{1.852}\ d^{4.8655})$$

where **P = pressure drop (psi/foot)**
Q = flow rate (gpm)
C = roughness coefficient (dimensionless)
d = inside pipe diameter (inches)

Some typical roughness coefficients for common materials are listed below:

Material	Roughness Coefficient
Fiber Glass Pipe	150
Steel, New	140 - 150
Polyethylene - PE, PEH	140
Very smooth Metal Pipe	140
Brass	130 - 140
Cooper	130 - 140
Acrylonite Butadiene Styrene - ABS	130
Polyvinyl Chloride - PVC	130
Cast Iron, New	130
Cast Iron, 10 years old	107 - 113
Cast Iron, 20 years old	89 - 100
Cast Iron, 30 years old	75 - 90
Cast Iron, 40 years old	64 - 83
Corrugated Metal	60

APPENDIX B5

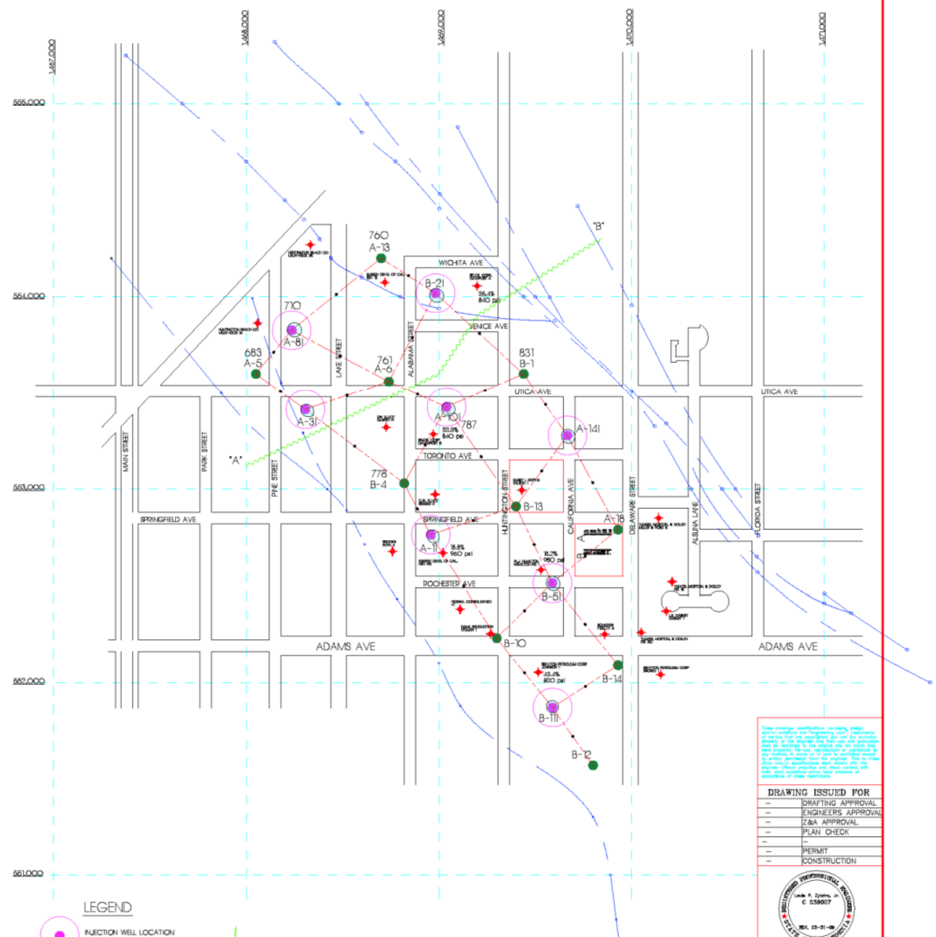
Angus Drill Site Power Point Presentation
Formal Order 1007

Angus Drill Site

A proposed waterflood project in the Springfield area of the Huntington Beach Oil Field

Cross Section
Injection Well Bottom Hole Location
1/4 Mile AOR
MAP#134
1" = 500'
WC/RL 9/16/08
Angus Petroleum Corp.
Drillsite
YORKTOWN
AVE
UNION
WICHITA
VENICE
UTICA
TORONTO
SPRINGFIELD
ROCHESTER
QUINCY
ADAMS
LOMA
PORTLAND
OSWEGO
NASHVILLE
13TH
12TH
HUNTINGTON
DELAWARE
FLORIDA
BEACH
MAIN
PARK
PINE
DOUGLAS
WESLEY
School
Surety Oil Co
E.A. Parkford
The Hampton Oil Co
(Brown)
(Johnson)
Yinker, Morton & Dolley

Angus Drill Site
Area of Review



LEGEND

A-31	INJECTION WELL LOCATION 100' RADIUS (SHOWN)
B-1	PRODUCTION WELL LOCATION
	ABANDONED WELL DOG QUESTIONABLE ABANDONMENT
	SECTION CUT LINE "A" TO "B"
	HYDROSTATIC LIMITS OF INJECTION DISTRIBUTION PRESSURE (2600' VSS DATUM & 800 PSI STATIC RESERVOIR PRESSURE)
43.4% 820 PSI	DISTANCE FROM INJECTOR IN PERCENT PRESSURE AT A KNOWN POINT BASED ON INJECTION DISTRUBUTION PROFILE

N

DRAWING ISSUED FOR	
—	DRAFTING APPROVAL
—	ENGINEERS APPROVAL
—	Z&A APPROVAL
—	PLAN CHECK
—	—
—	PERMIT
—	CONSTRUCTION

REGISTERED PROFESSIONAL ENGINEER
Louis P. Zylstra, Jr.
C 039007
EXP. 03-31-09
STATE OF CALIFORNIA

APPROVED BY: LOUIS P. ZYLSTRA, JR. PE
REGISTERED CIVIL ENGINEER
STATE OF CALIFORNIA C039007
EXPIRES MARCH 31, 2009

Z & A
ZYLSTRA & ASSOCIATES
ENGINEERING
CIVIL
CONSTRUCTION
COLD-FORMED STEEL
MARINE
COMM/RES STRUCTURES

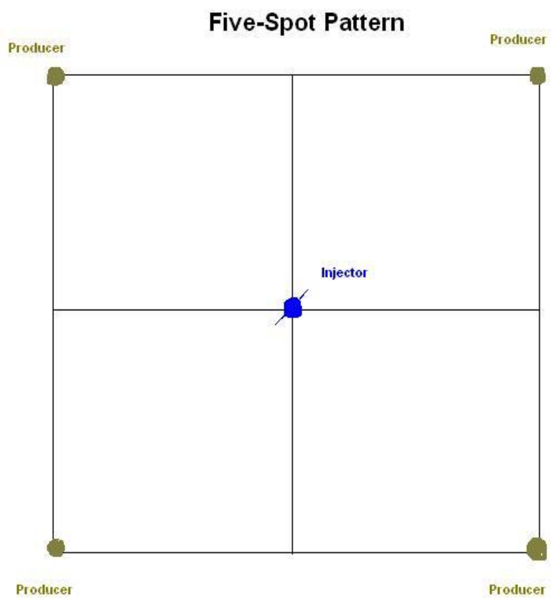
S1

SPRINGFIELD PROJECT
H.B. OILFIELD
LOWER BOLSA
WELL LOCATION MAP

Job #: 108-089
Dated: 10/26/08
Scale: 1"=200'-0"
Drwg #: CA108-089

Five-Spot Pattern

Four Quadrants



One Quadrant

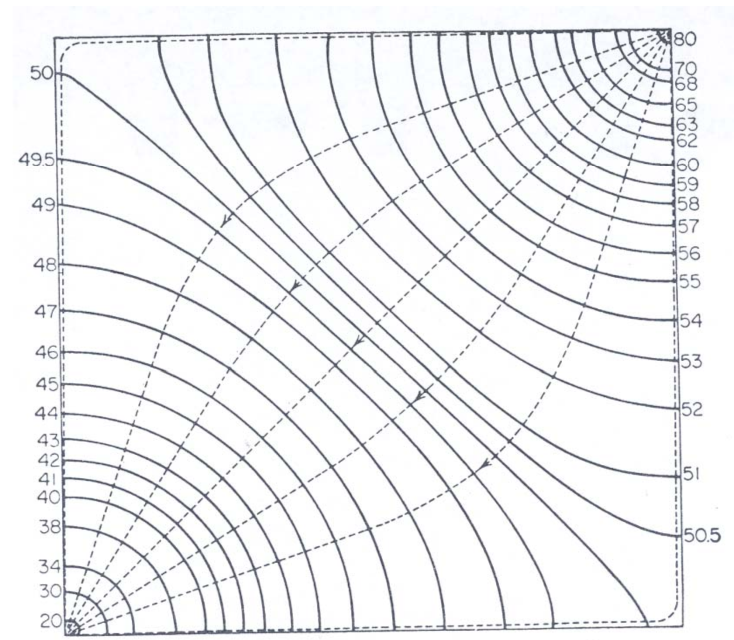


Fig. 44.16—The steady-state, homogeneous-fluid equipressure contours and streamlines in a quadrant of a five-spot network element. Numbers represent percentages of the total pressure drop.

Equipressure Contour and Streamline Network for a Five-Spot Pattern (from the Petroleum Engineering Handbook, page 44-15)

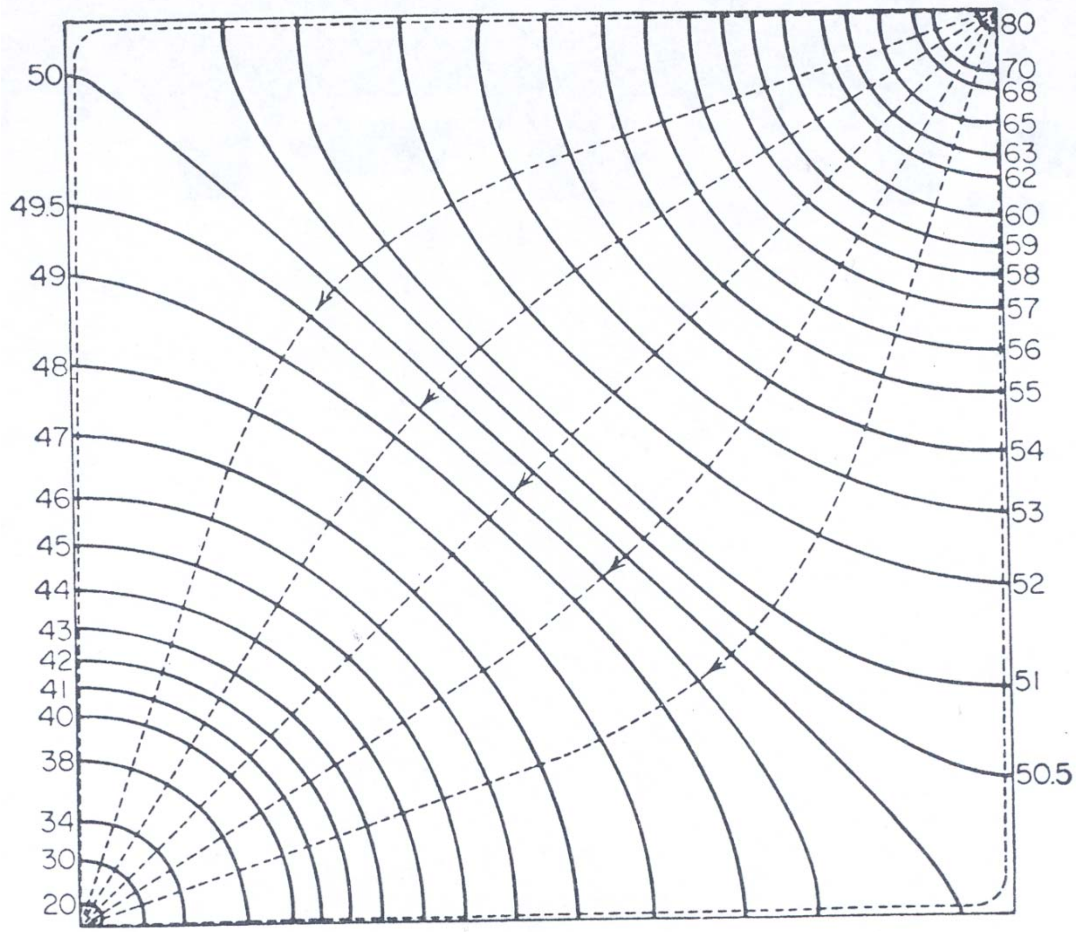


Fig. 44.16—The steady-state, homogeneous-fluid equipressure contours and streamlines in a quadrant of a five-spot network element. Numbers represent percentages of the total pressure drop.

How were the equipotential lines discovered?

1. Analogy between Ohm's Law and Darcy's Law.
2. A Scale Electric Model of a Five-Spot Network is Built.
3. Model's Electric Voltage is Analogous to Zone Pressure.
4. Use a Pair of Search Electrodes to Locate Equipotential Lines.
5. Plot the Equipotential Lines on a Map.
6. And That is How We Get ……

Equipressure Contour and Streamline Network for a Five-Spot Pattern

Planar View

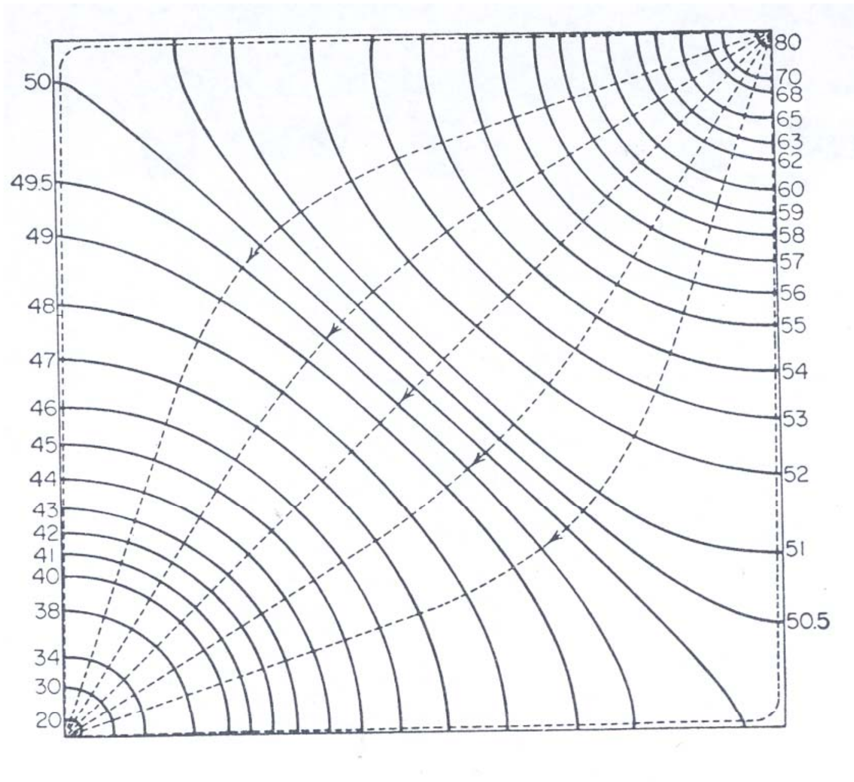
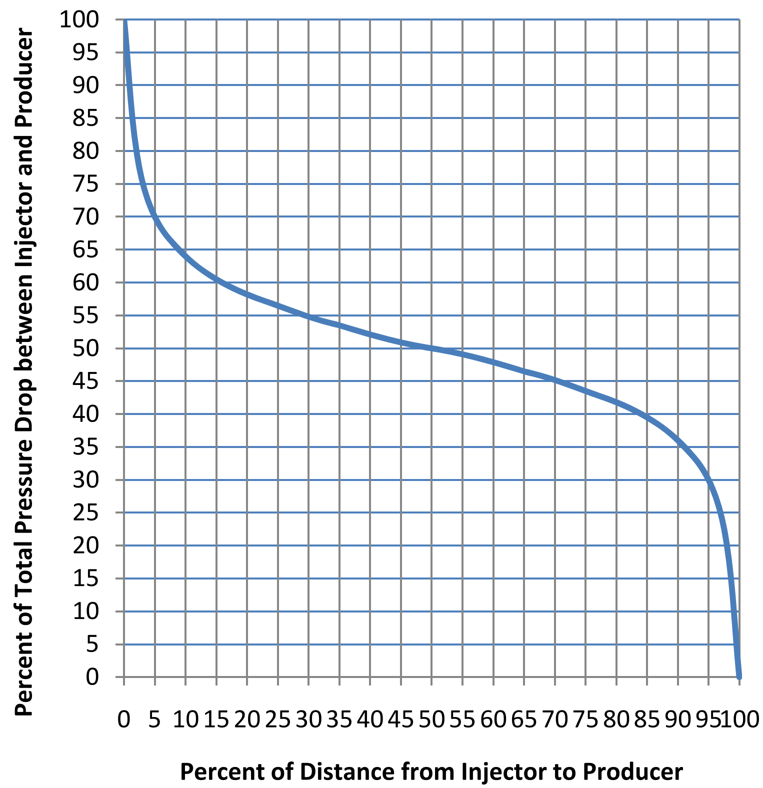
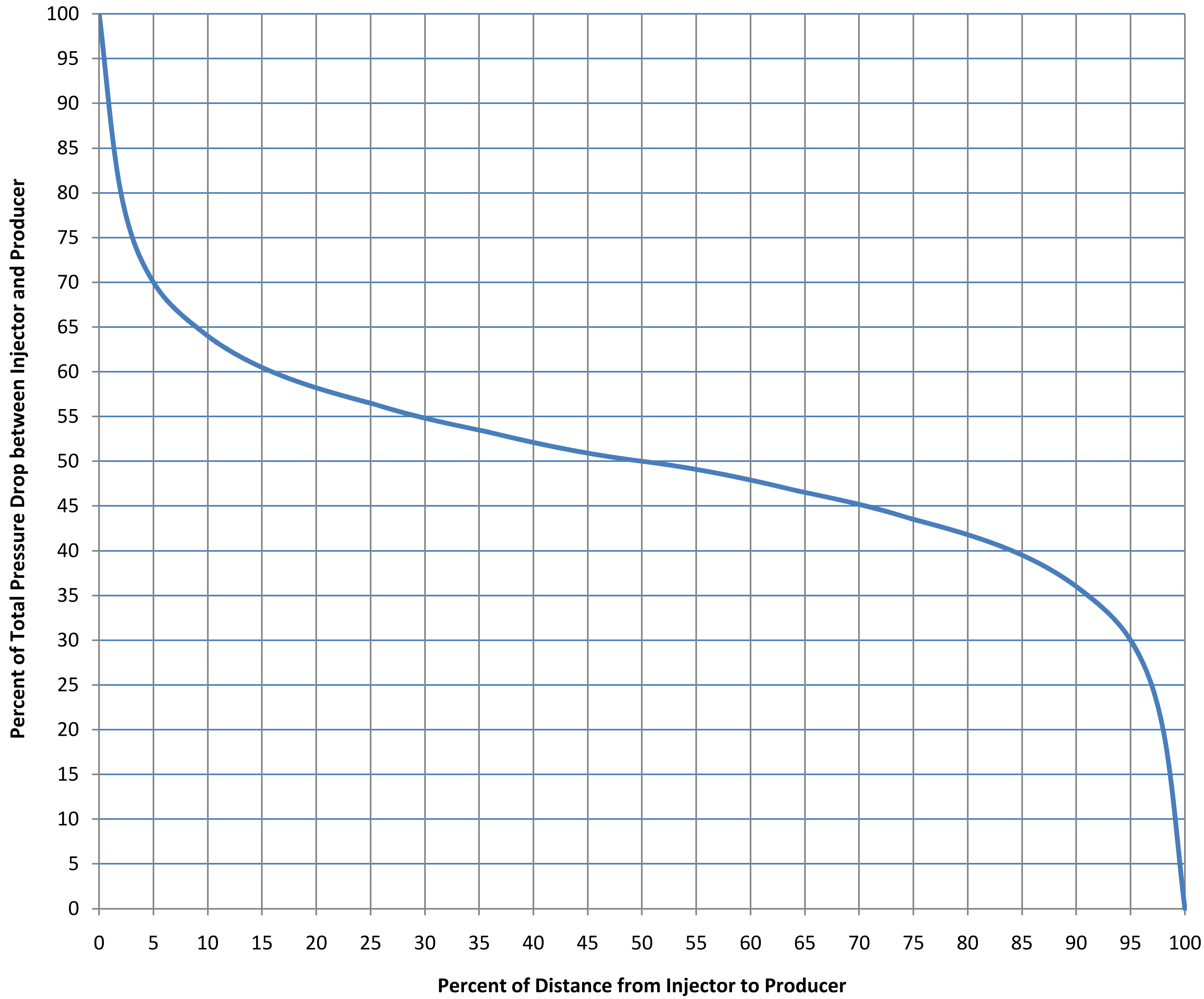


Fig. 44.16—The steady-state, homogeneous-fluid equipressure contours and streamlines in a quadrant of a five-spot network element. Numbers represent percentages of the total pressure drop.

Cross Section View





Percent of Total Pressure Drop between Injector and Producer
100
95
90
85
80
75
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
0 5 10 15 20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100
Percent of Distance from Injector to Producer

Assumptions

1. The equipressure and streamline network for a five-spot pattern is in effect.
   a. Homogeneous Injection Zone – Physical Parameters are constant.
   b. Injection Zone is flat.
   c. The system has reached Steady State – Dynamic equilibrium.

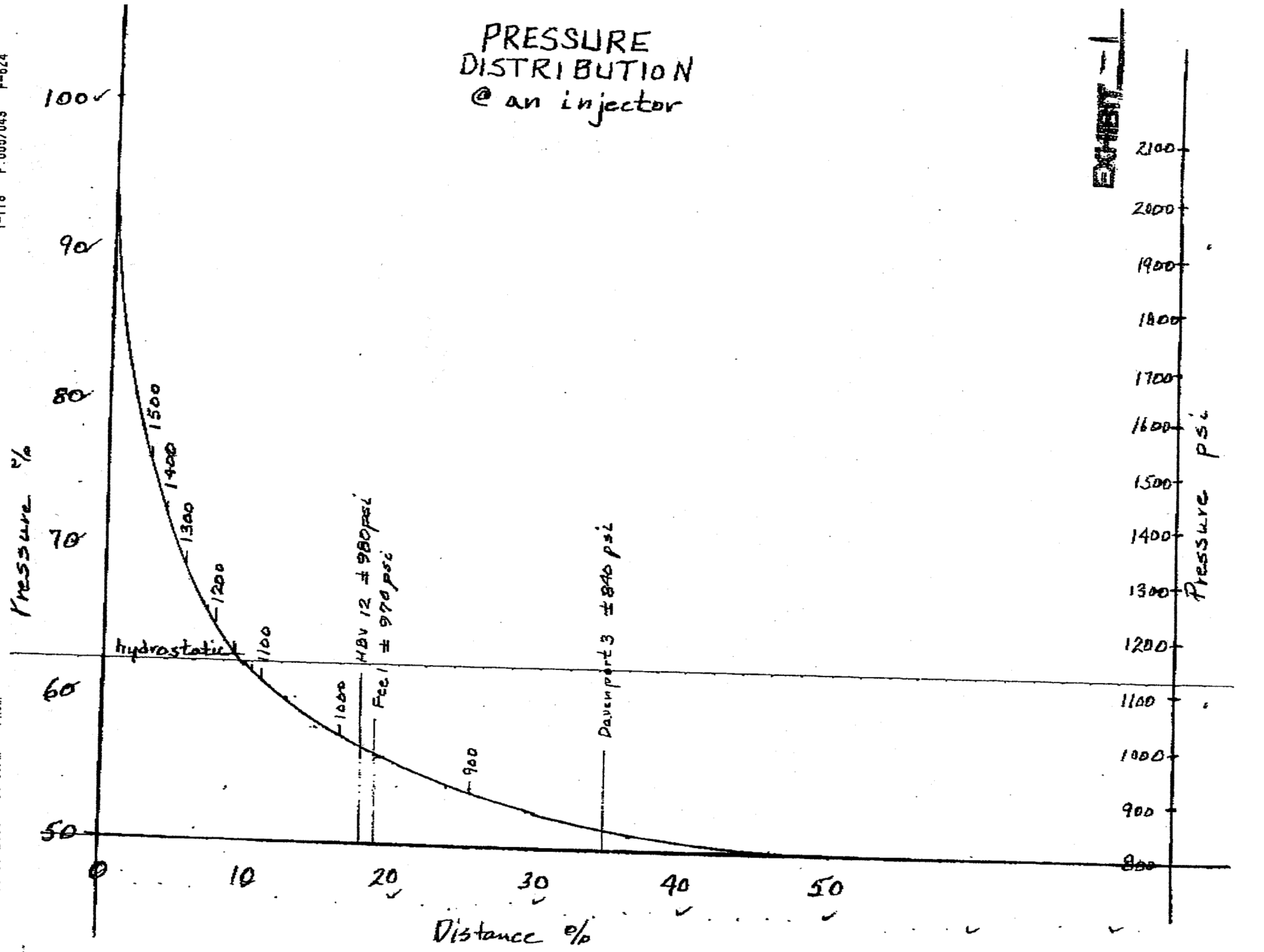
2. Pressure at the injection well is 2100 psi.

3. Pressure at production well is 0 psi.

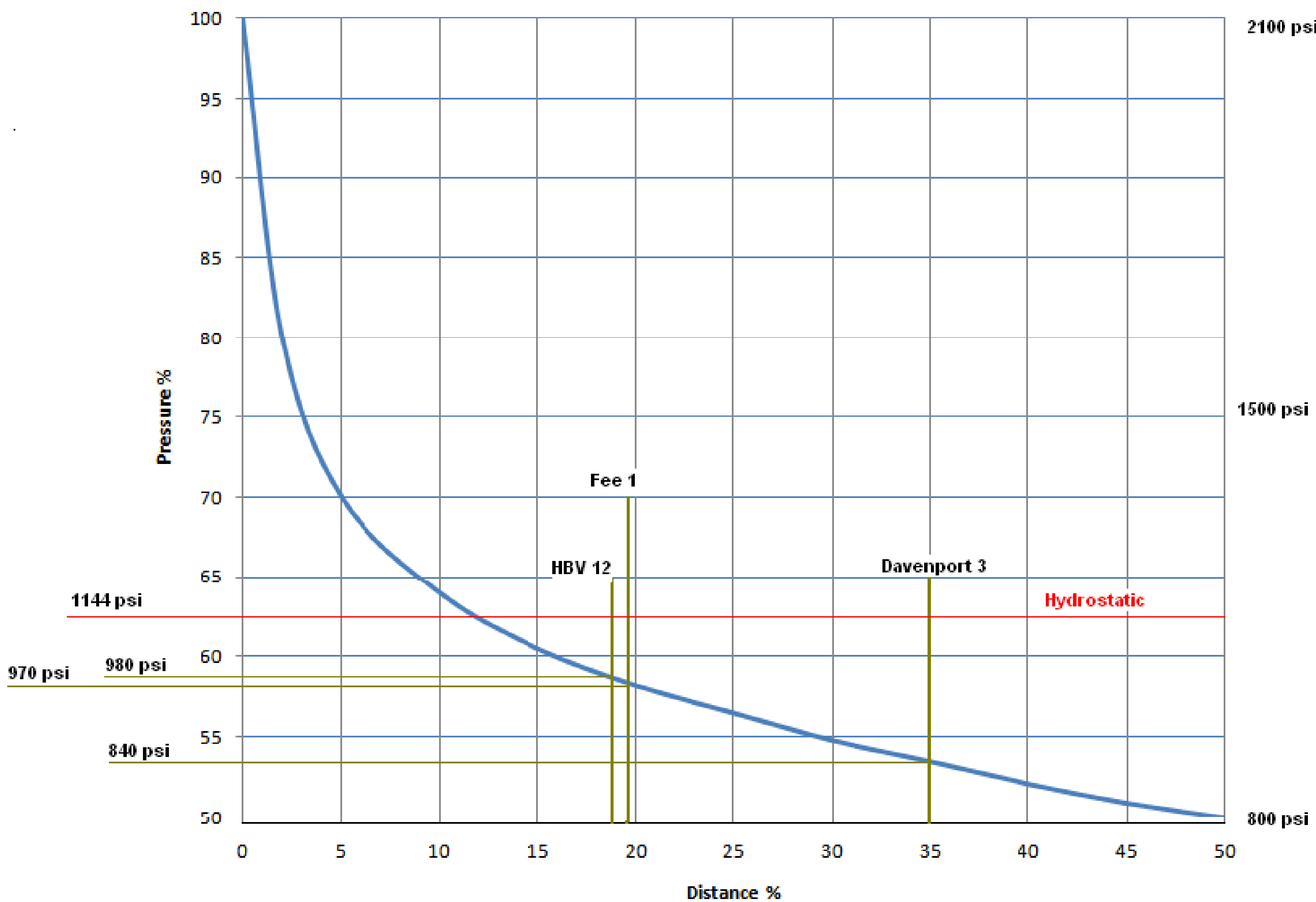
4. Top of the Injection Zone is 2600’ vss.

5. Hydrostatic Pressure is 1144 psi – Zone Fluid 0.44 psi/ft.

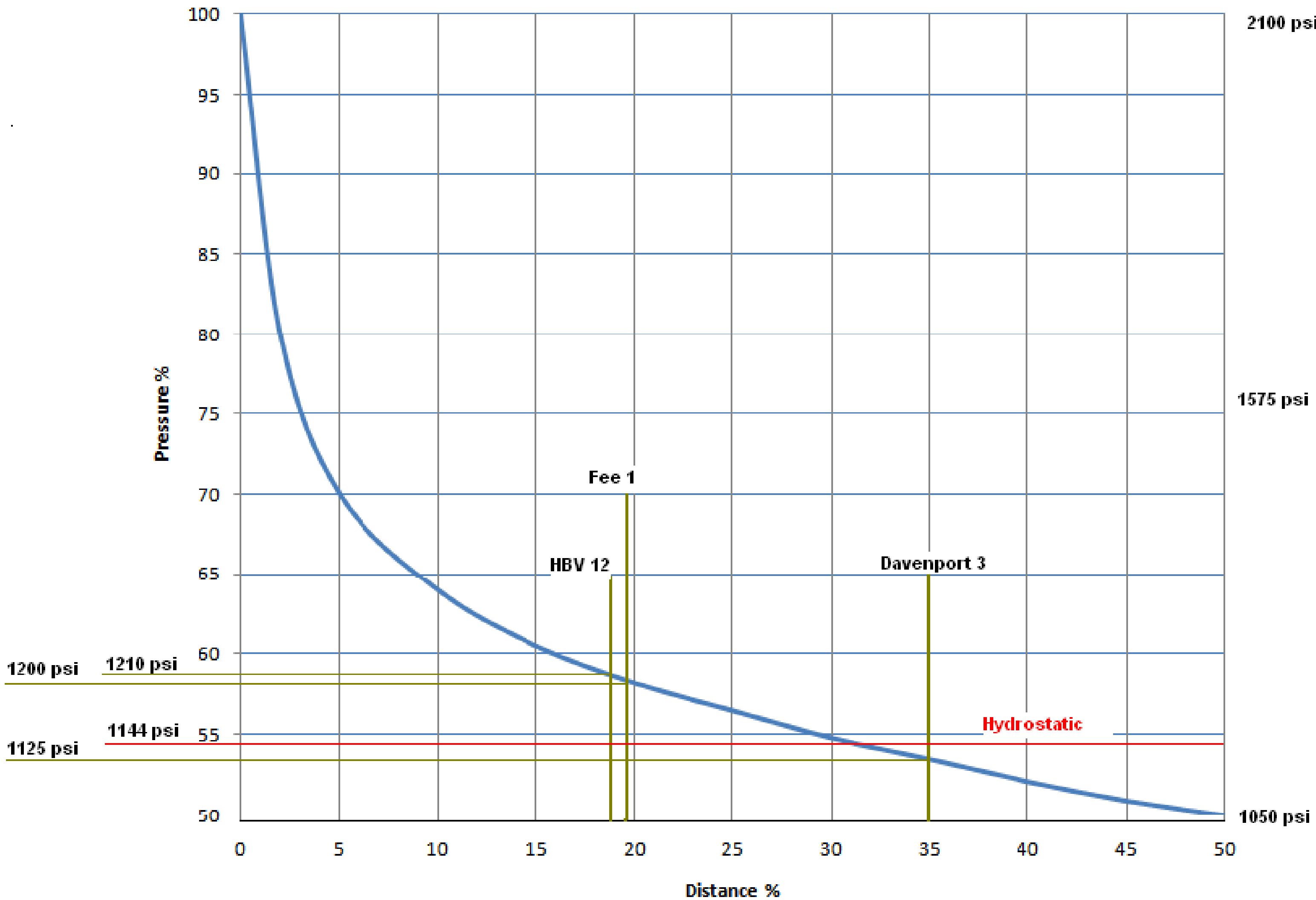
PRESSURE DISTRIBUTION @ an injector



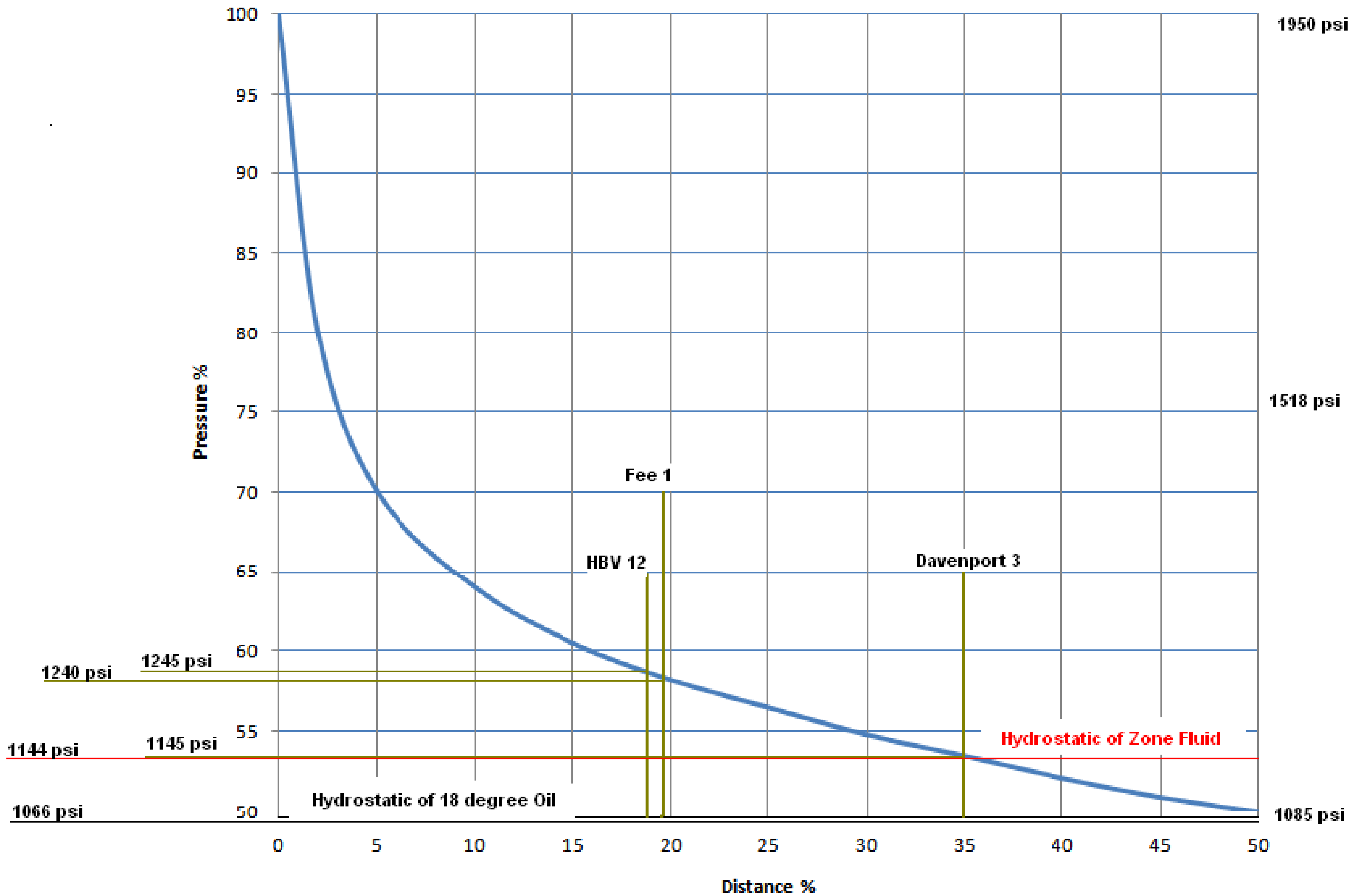
Applicant's Interpretation



DOGGR Interpretation #1



DOGGR Interpretation #2



Calculations for DOGGR Interpretation #1

Injection Well Pressure is 2100 psi @ formation face.

Production Well Pressure is 0 psi @ formation face.

Total pressure change = ΔP = 2100 psi – 0 psi = 2100 psi

ΔP at 50% contour line = (0.5)(2100 psi) = 1050 psi

Zone pressure at 50% contour line = ΔP at 50% + Production Well Pressure

= 1050 psi + 0 psi

= 1050 psi

Note: ΔP and Zone pressures are the same because Production Well Pressure is assumed to be 0 psi.

Calculations for DOGGR Interpretation #2

Injection Well Pressure is 1950 psi @ formation face. (2600')(.75 psi/ft.) = 1950 psi
Production Well Pressure is 220 psi @ formation face. (500')(.44 psi/ft.) = 220 psi

Total pressure change = ΔP = 1950 psi – 220 psi = 1730 psi

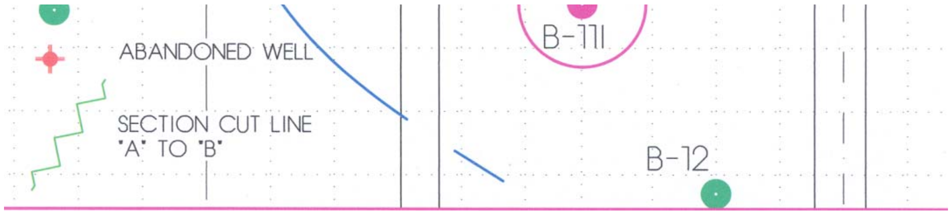
ΔP at 50% contour line = (0.5)(1730 psi) = 865 psi

Zone pressure at 50% contour line = ΔP at 50% + Production Well Pressure
= 865 psi + 220 psi
= 1085 psi

Note: ΔP and Zone pressures are <u>NOT</u> the same because Production Well Pressure is <u>NOT</u> assumed to be 0 psi.

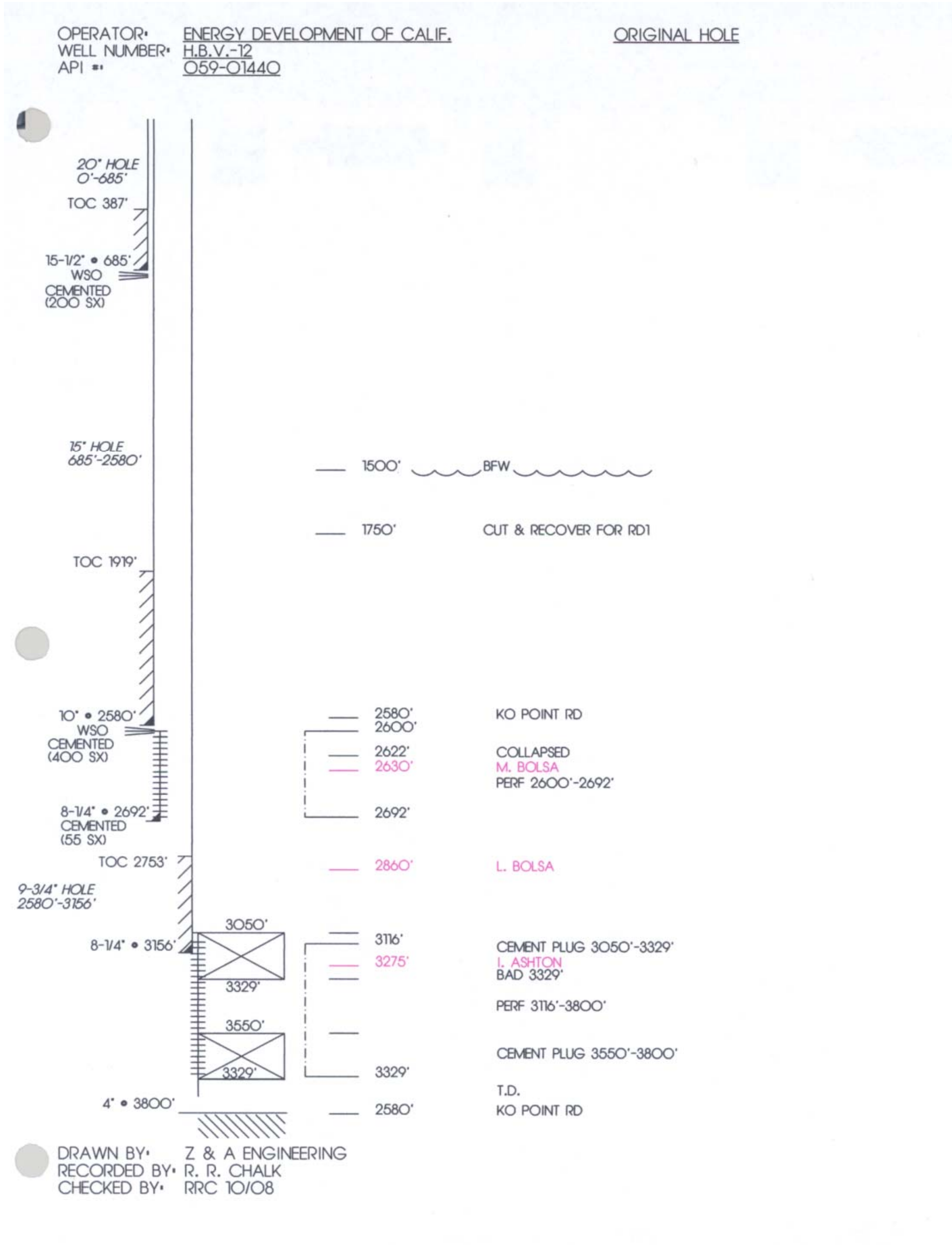
Note: Injection Well Pressure is reduced from 2100 psi to 1950 psi, but Zone pressure at 50% contour line increases because Producing Well Pressure is 220 psi.

Close-up of the Three Wells



"HBV" 12

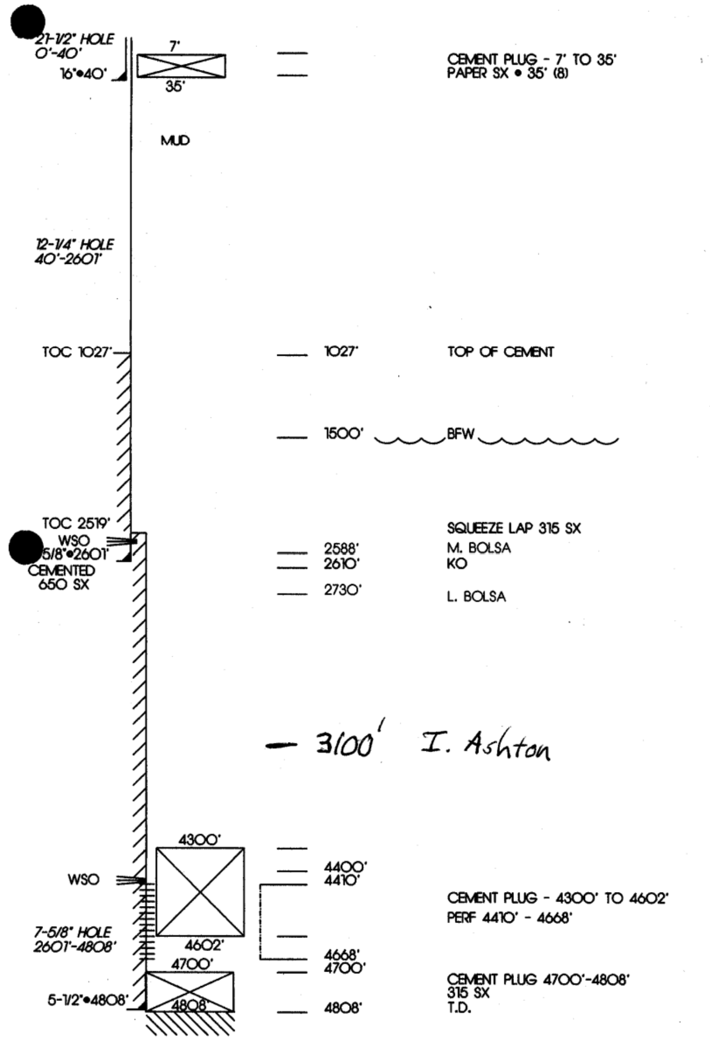
Abandoned June 1976



“Fee” 1

Abandoned February 1966

OPERATOR: W. J. HAMILTON
WELL NUMBER: HAMILTON FEE #1
API #: 059-01838

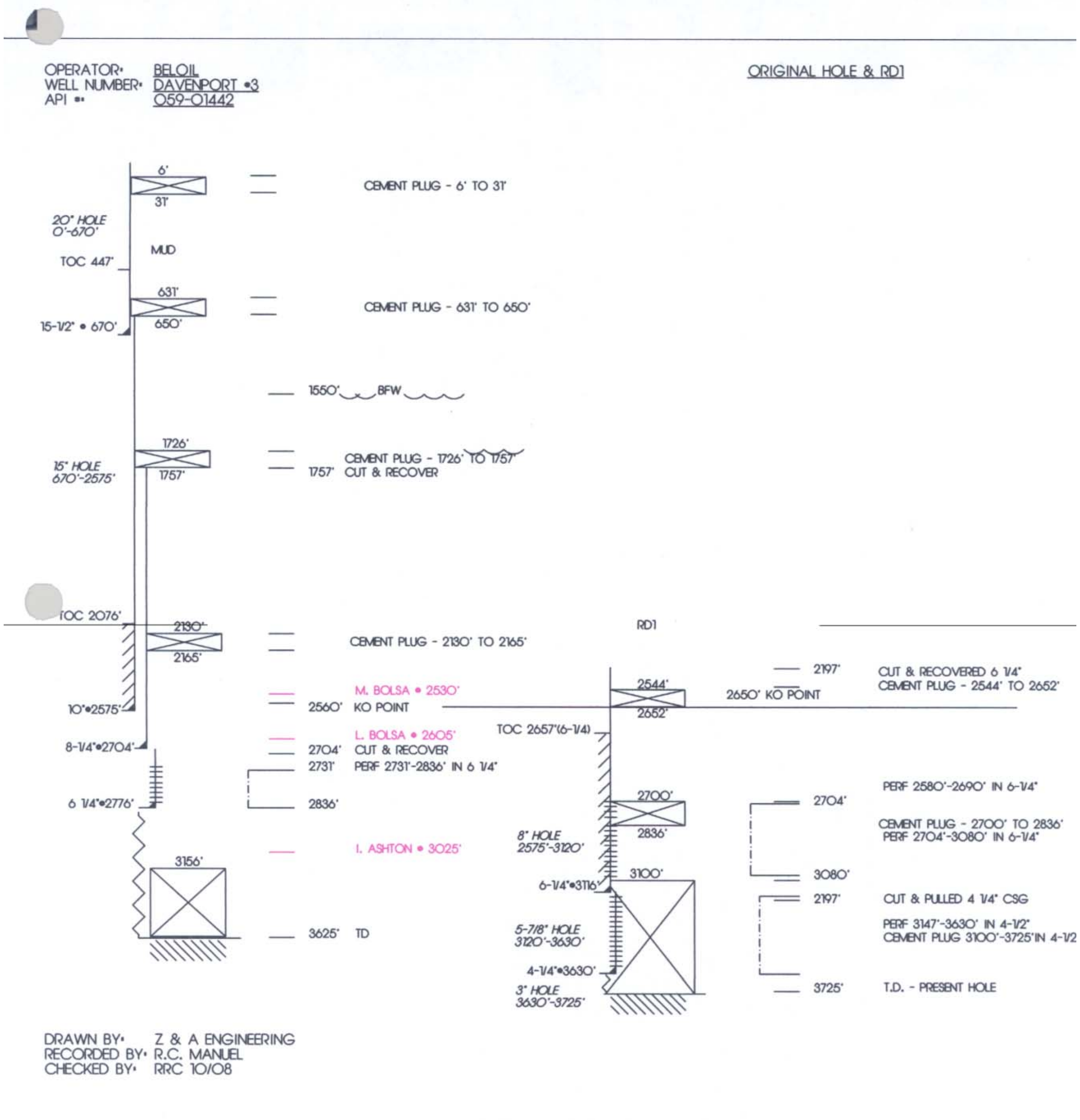


JUNK IN ORIGINAL HOLE
6-5/8" LINER 2765'-2515'

DRAWN BY: Z & A ENGINEERING
RECORDED BY: R. R. CHALK
CHECKED BY: RRC 3/19/08 & 10/17/08

"Davenport" 3

Abandoned October 1940



DEPARTMENT OF CONSERVATION

Managing California's Working Lands

Division of Oil, Gas, & Geothermal Resources

801 K STREET • MS 20-20 • SACRAMENTO, CALIFORNIA 95814

PHONE 916 / 445-9686 • **FAX** 916 / 323-0424 • **TDD** 916 / 324-2555 • **WEB SITE** conservation.ca.gov

ORDER NO. 1007

by

Elena M. Miller

STATE OIL AND GAS SUPERVISOR

DATED

October 6, 2010

Plains Exploration & Production Company (PXP)

Inglewood Field

Los Angeles County

On September 28, 2010, water was found to be leaking into the Culver City Park known as "The Boneyard". City staff excavated over the water leak and uncovered the Atlantic Oil Company "Block" 1 well. The well was found to be leaking water and gas. PXP immediately shut-in several of the nearby injection wells and the water and gas flowing to the surface were significantly reduced. Water samples were collected and tested. Preliminary fluid sample analyses indicate the fluid is similar to fluids being injected by PXP: pH: 7.40, resistivity: 0.199 ohm meter (corresponding 25,000-30,000 ppm Chloride).

The State Oil and Gas Supervisor (Supervisor) has determined that there is a connection between PXP injection operations in the Inglewood field and the water leak from, or near the Atlantic Oil Company "Block" 1 well. Section 3106 of the Public Resources Code (PRC) states: "The supervisor shall so supervise the drilling, operations, maintenance, and abandonment of wells and the operation, maintenance, and removal or abandonment of tanks and facilities attendant to oil and gas production, including pipelines not subject to regulation pursuant to Chapter 5.5 of Part 1 of Division 1 of Title 5 of the Government Code that are within an oil and gas field, so as to prevent, as far as possible, damage to life, health, property, and natural resources; damage to underground oil and gas deposits from infiltrating water and other causes; loss of oil, gas, or reservoir energy, and damage to underground and surface waters suitable for irrigation or domestic purposes by the infiltration of, or the addition of, detrimental substances." In addition, in reference to underground injection projects, Title 14, Section 1724.10 (h) of the California Code of Regulations states: "Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notices from the Division. Project data shall be available for periodic inspection by Division personnel."

Therefore, to protect public health and safety in furtherance of the authorities cited above, and acting pursuant to PRC Sections 3224 and 3226, the Supervisor orders that all injection immediately cease within ¼ mile radius, in the injection zone(s), from the Atlantic Oil Company "Block" 1 well until the time that the Supervisor is satisfied that the cause of the leak is determined and remediated.

With permission from the Division, injection may be conducted for the limited purpose of conducting testing while this order is in effect.

This order may be appealed by filing a written statement with the Supervisor or district deputy that the order is not acceptable within ten (10) days of receipt of the order. Upon receipt of an appeal, the Director will schedule a public hearing pursuant to Section 3351 of the PRC.

Elena M. Miller
State Oil and Gas Supervisor

by Robert S Habel
Robert S. Habel
Chief Deputy State Oil and Gas Supervisor

cc: DOGGR-HQ
Cindy Traxler, Counsel
L. Pearlman, Deputy Atty. Gen.

Certified Mail Receipt No. 7006 0810 0005 0961 7077

APPENDIX B6

Injectivity Plot Variance Letter
March 2011 Injectivity Plots

DEPARTMENT OF CONSERVATION

DIVISION OF OIL, GAS AND GEOTHERMAL RESOURCES

4800 STOCKDALE HWY. • SUITE 417 • BAKERSFIELD, CALIFORNIA 93309
PHONE 661 / 322-4031 • **FAX** 661 / 861-0279 • **WEBSITE** conservation.ca.gov

July 1, 2009

Mr. Darryl Gunderson
AERA ENERGY LLC
P. O. Box 11164
Bakersfield, CA 93389-1164

Re: INJECTIVITY PLOT VARIANCE - REVISED

Dear Mr. Gunderson:

Following a June 29, 2009 meeting between the Division of Oil, Gas, and Geothermal Resources (Division) and your representatives, some changes to this Division's May 25, 2009 variance approval letter have been made. Effective immediately, this letter supersedes that letter and the new conditions of this variance are as follows:

Continued use of injectivity plots, in lieu of standard radioactive surveys, on your North and South Belridge fields Diatomite zone waterflood wells are approved provided:

a) It applies solely to waterflood wells completed in the Diatomite zone in North or South Belridge oilfields, and;

b) It applies solely to wells where a radioactive survey tool cannot get to 100 feet or less from the uppermost effective open perforation in the well unless specifically justified and approved by this Division, and;

c) It applies only to wells that have documented evidence that the reason a radioactive survey tool cannot get to the minimum required depth is due to mechanical casing damage, and;

d) The aforementioned casing damage is a direct result of subsidence of the formation, and;

e) Each well meeting the conditions listed herein must be individually requested and pre-approved by this Division prior to implementing this variance, and;

f) Wells exceeding an injectivity value of 3.0 shall be considered as possibly having failed casing integrity and shall be shut-in immediately until such time as they are evaluated in conjunction and consultation with this Division and sufficient cause and justification is determined to return the well to injection. Wells exceeding an injectivity value of 4.0 shall be considered as having failed casing integrity and shall be shut-in until repaired.

During the June 29, 2009 meeting, these conditions were re-emphasized and agreed upon as necessary requirements in order to be accepted under this variance. In addition, these following conditions remain in effect as per the original variance:

g) All injectivity plots, including those that demonstrated failure of the test, are to be submitted to this Division, and;

h) All injectivity plots submitted to this Division shall be annotated, when appropriate, to explain any anomalies or unusual trends associated with the plot, and;

i) Documentation, including graphs presented at the May 11, 2009 meeting, showing the relationship of the injectivity value to the Diatomite zone, shall be submitted to this Division within 30 days, and;

j) All pressure measuring devices shall be calibrated no less than once every 6 (six) months and shall be available at the well site during all tests witnessed by Division personnel, and;

k) Contractors performing tests on all wells that are witnessed by Division engineers shall have a written and/or visual summary of the most current wellbore conditions on site for reference by all personnel.

These conditions are effective immediately but are subject to revision or rescission at any time upon notification by this Division. Any violation of these conditions may constitute grounds for individual well injection and/or variance termination.

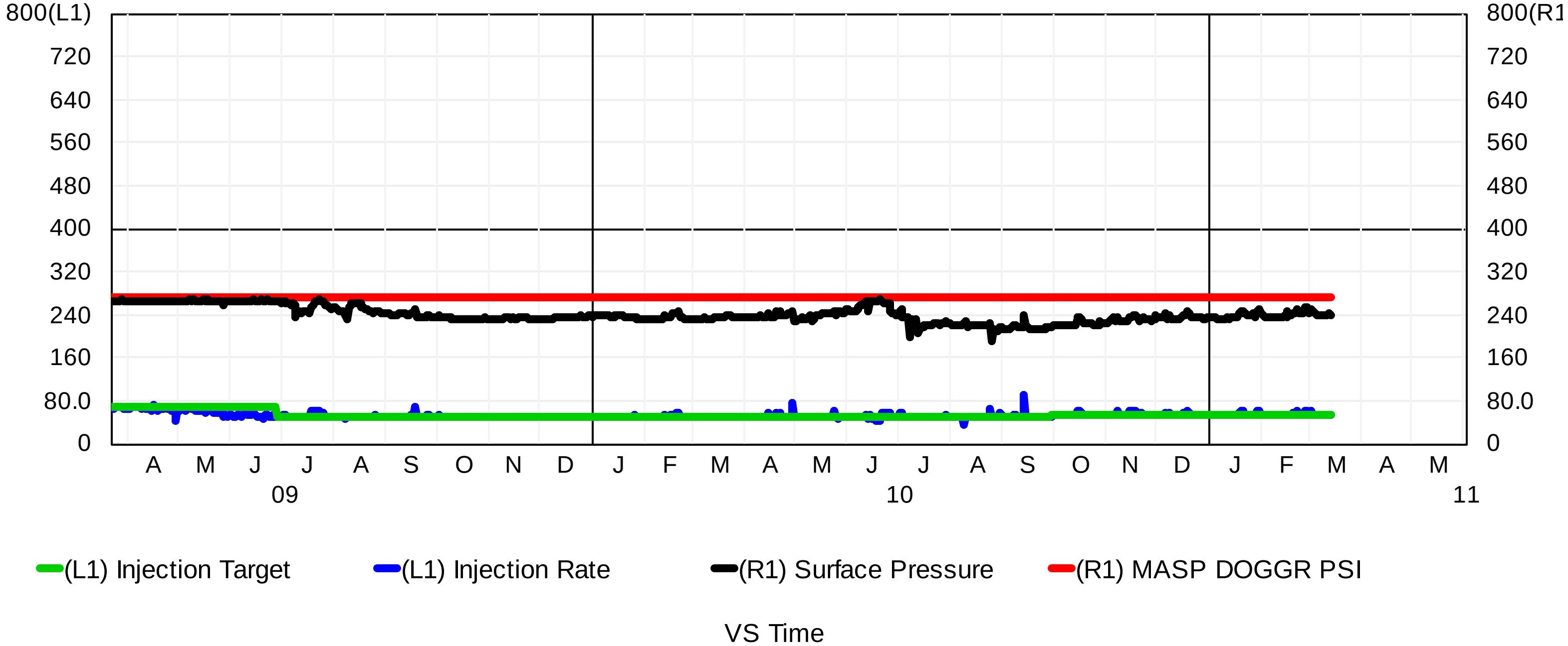
If you have any questions, please contact this office.

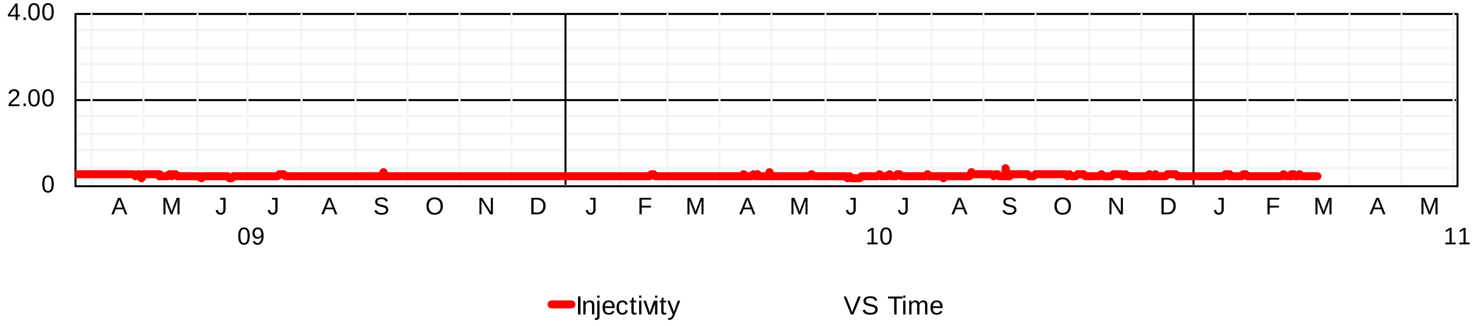
Sincerely,

David Mitchell
Senior Oil and Gas Engineer

Aera Energy LLC - Diatomite Water Injector 3/15/2011

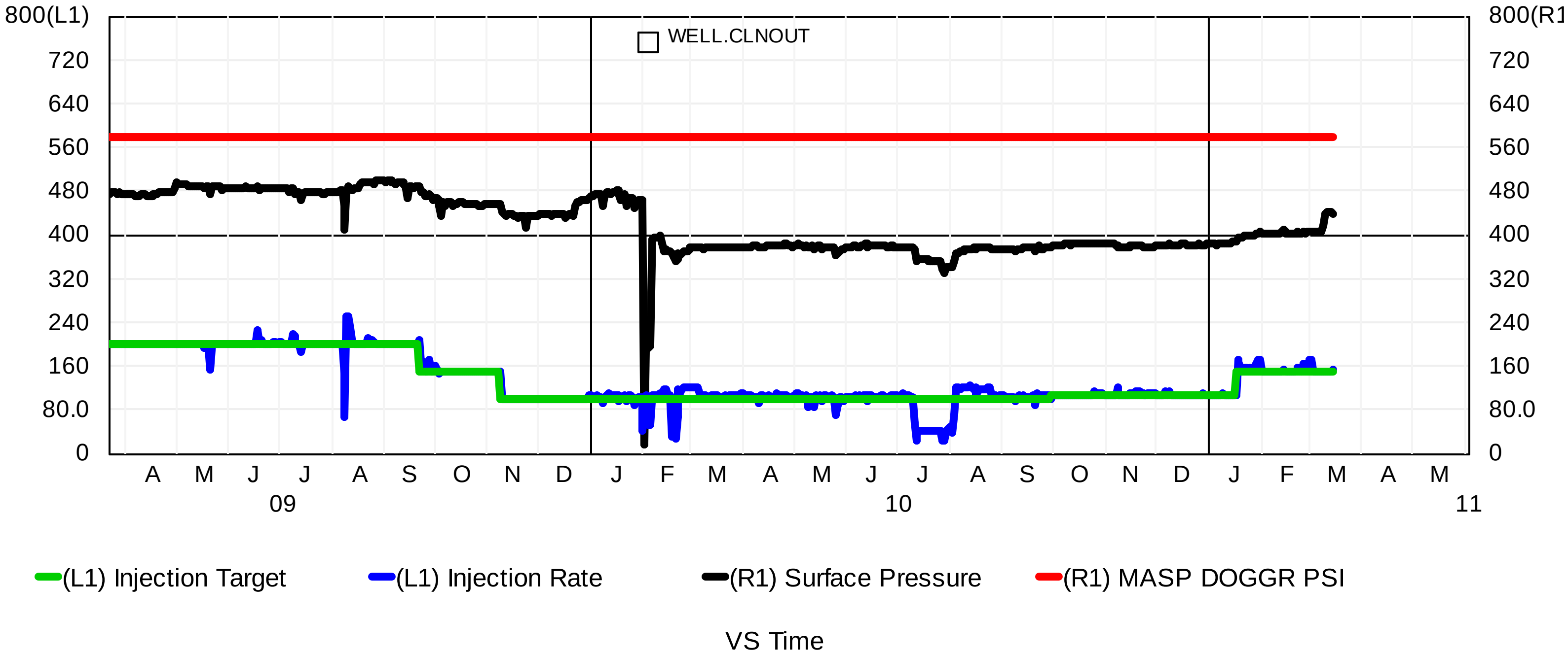
Well Name:61AX-30 API Well NBR:0402986064 SECTION:30 TOWNSHIP:T28S RANGE:R21E

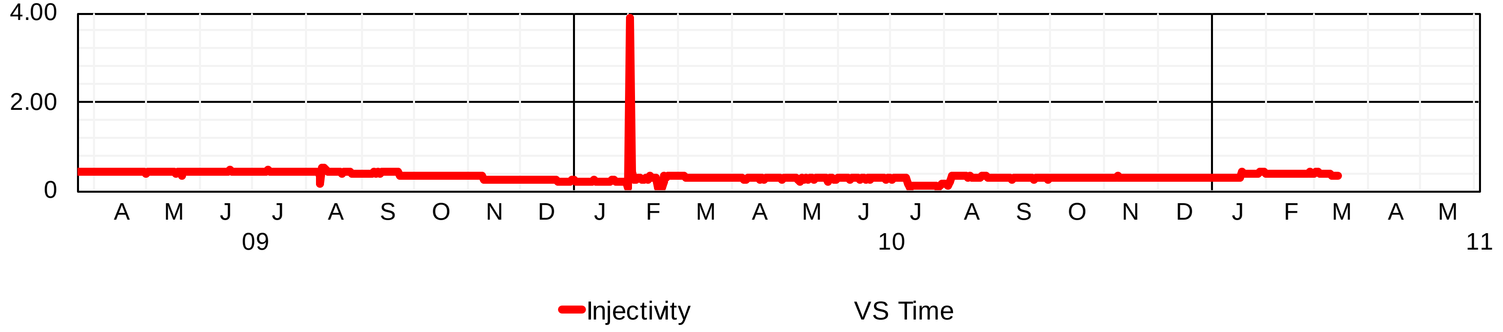




Aera Energy LLC - Diatomite Water Injector 3/16/2011

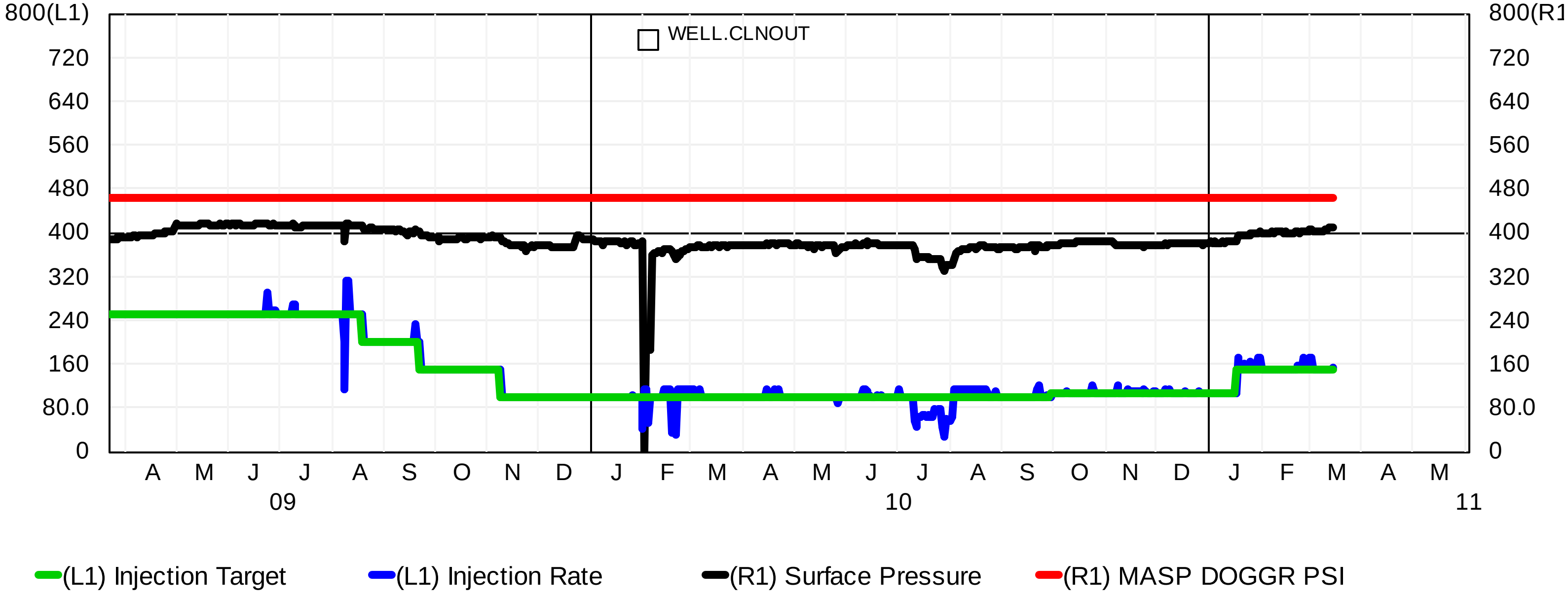
Well Name:76WBL-19 API Well NBR:0403033950 SECTION:19 TOWNSHIP:T28S RANGE:R21E

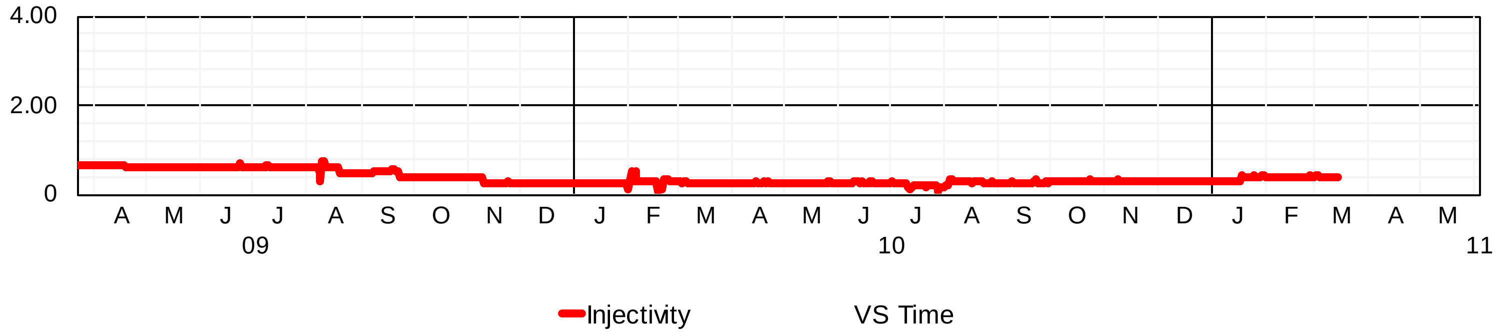




Aera Energy LLC - Diatomite Water Injector 3/16/2011

Well Name:76WBS-19 API Well NBR:0403033950 SECTION:19 TOWNSHIP:T28S RANGE:R21E





APPENDIX B7

Kern River Field Letter to Operator
Kern River Field Report on Operations

STATE OF CALIFORNIA-RESOURCES AGENCY

GEORGE DEUKMEJIAN, *Governor*

DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

4800 STOCKDALE HWY., SUITE #417
BAKERSFIELD, CALIFORNIA 93309
(805) 322-4031

WATER DISPOSAL PROJECT
Kern River Field
Santa Margarita Zone

#34000030

September 23, 1986

Mr. C. D. Fiddler
Chevron U.S.A. Inc.
P.O. Box 1392
Bakersfield, Ca. 93302

Dear Mr. Fiddler:

It has been determined from recent tests that the Santa Margarita zone in Kern River field is being supercharged in several areas. Our studies indicate the supercharging may be related to injection volumes and seems to be controlled more by stratigraphic/paleoecologic parameters; resulting in permeability variations in the zone, than from structurally confining influences.

In order to alleviate this situation, injection into supercharged zones shall be terminated based upon the following schedule:

All wells with wellhead pressure exceeding 100 psi, after being shut-in for 24 hours, shall cease injection by November 30, 1986.

All wells with wellhead pressure exceeding 0 psi, after being shut-in for 24 hours, shall cease injection by March 31, 1987.

Our records indicate the following wells would be subject to this order:

Well No.	Sec., T/R	Initial Inj. Pressure	24-hr. Shut-in Pressure	Test Date
D2-4	4/29/28	500	120	7/23/86

This order does not preclude injecting into the Santa Margarita zone where supercharging is not present, or the possibility of re-entering supercharged areas should the condition subside.

Yours truly,

E. A. Welge
Deputy Supervisor

By Hal Bopp
Hal Bopp
Senior Oil & Gas Engineer

cc: EPA
RWQCB

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

No. T 486-792

DIVISION OF OIL AND GAS

Report on Operations

Water Disposal Project
Kern River Field
Santa Margarita Zone

C. D. Fiddler
CHEVRON U.S.A. INC.
P. O. Box 1392
Bakersfield, CA 93302

Bakersfield, Calif.
September 5, 1986

Your operations at well D2-4, API No. 029-75051, Sec. 4, T29S R.28E, M.D. B.& M. Kern River Field, in Kern County, were witnessed on 7-23-86. Mr. Floyd Leeson, representative of the supervisor, was present from 1130 to 1330. There were also present Ken Johns, Wireline operator.

Present condition of well: 9 5/8" cement 1860', perf. 1504'-1614'. TD 1861'.

The operations were performed for the purpose of demonstrating that the injection fluid is confined to strata below 1504'.

DECISION: THE OPERATIONS ARE APPROVED AS INDICATING THAT THE INJECTION FLUID IS CONFINED TO STRATA BELOW 1504' AT THIS TIME.

Deficiency:

A pressure fall off test was run on this well during which the pressure did not fall off below 120 psi in over 24 hours. Injection approval is cease immediately.

Note:

Santa Margarita injection wells for Kern River Field are being reviewed for possible zone fill up. Kern River operators will be kept notified of all future decisions regarding their injection wells.

FL:jk

cc: RWQCB
UIC

M. G. Mefferd, State Oil & Gas Supervisor

By [signature]

E. A. Welge, Deputy Supervisor

OG109 (9/83/CSR1/15M)

APPENDIX B8

District 6 UIC Rescinded Permits 2000-2010

District 6 UIC Projects/Injection Permits Rescinded

SUMMARY

Date	Operator	Project Title/Well	Reason
October 9, 2001	Laymac Corporation	French Camp Gas Field, Post-Eocene Zone, Water Disposal Project / "Reynolds & Carver-Long" 1	injection well deemed idle.
September 13, 2002	Calpine Natural Gas, L.P.	Rio Vista Gas Field, Perry Anderson Sands - Martinez Formation, Water Disposal Project / "Perry Anderson" 19	Operator no longer intend to use well for injection - well producing gas.
September 13, 2002	Calpine Natural Gas, L.P.	Main Prairie Gas Field, Mokelumne River Formation, Water Disposal Project / "Edward Wineman" 3	Operator no longer intend to use well for injection - well plugged & abandoned.
September 13, 2002	Calpine Natural Gas, L.P.	Main Prairie Gas Field, Mokelumne River Formation, Water Disposal Project / "Midland WI" 2	Annual injection survey not conducted since August 17, 1999. Operator no longer intend to use well for injection.
September 21, 2004	Oxy Resources California, LLC	River Island Gas Field, Winter Formation, Water Disposal Project	Project never activated. Operator no longer intend to inject into project.
October 1, 2004	Vintage Petroleum, Inc.	Kirkwood Gas Field, Kione Formation, Water Disposal Project / "R.H.L. Brackenbury et al" 3	Project idle for two years.
November 16, 2004	Key Production Company, Inc.	Willows-Beehive Bend Gas Field, Kione Formation, Commercial Water Injection Project / "Dracula" 1	Project inactive for two years.
March 5, 2009	Vintage Petroleum California, LLC	Lathrop Gas Field, Azevedo Zone, Water Disposal Project / "J. Ratto" 18-1	Injection well idle for over two years. Mechanical integrity test not conducted since September 20, 2004.

DEPARTMENT OF CONSERVATION
STATE OF CALIFORNIA

CALIFORNIA CONSERVATION

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

801 K STREET
MS 20-20
SACRAMENTO
CALIFORNIA
95814-3530

PHONE
916/445-9686

FAX
916/323-0424

TDD
916/324-2555

INTERNET
consrv.ca.gov

GRAY DAVIS
GOVERNOR

October 9, 2001

Mr. Jon Crawford
LAYMAC CORPORATION
1717 28th Street
Bakersfield, CA 93301

Subject: Water Disposal Well "Reynolds & Carver-Long" 1

Dear Mr. Crawford:

The Division of Oil, Gas, & Geothermal Resources has been reviewing its list of idle wells, and your well "Reynolds & Carver-Long" 1 is listed as idle because, at most, it only injects one month out of the year. The volumes injected are very small, and indicate that this water disposal project does not constitute a viable project. Therefore, the Division is rescinding the water disposal project approval.

Because this well has not injected for six consecutive months, it will be considered idle under Section 3206 and you must comply with the Division's regulations. This well must be covered by one of the four options listed in Section 3206 that includes the following: an idle well fee, escrow account, well bond, or idle well management plan. Please let this office know by November 1, 2001 what option Laymac Corporation will follow.

If you have any questions please call me at (916) 322-1110.

Sincerely,

Robert S Habel

Robert S. Habel
District Deputy

CALIFORNIA CONSERVATION

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

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GRAY DAVIS
GOVERNOR

DEPARTMENT OF CONSERVATION

STATE OF CALIFORNIA

September 13, 2002

Eric F. Hadsell, Agent
Calpine Natural Gas, L.P.
2692 Amerada Road
Rio Vista, CA 94571

RE: Inactive Water Disposal Projects and Well

As you are aware, the Division of Oil, Gas, and Geothermal Resources (Division) regulates the injection of U.S. EPA Class II fluids in California. An annual injection project review meeting with injection well operators and Division staff is part of the regulatory program. On September 4, 2002, Tim Kustic, Associate Oil and Gas Engineer with the Division met with Rand George with Calpine Natural Gas, L.P. (Calpine), to discuss Calpine injection projects.

Since Calpine no long intends to inject into the following projects, the project approval for these projects are herby rescinded.

Field	Formation	Well	Well Status
Rio Vista	Perry Anderson Sands	"Perry Anderson" 19	Producing Gas
Main Prairie	Mokelumne River	"Edward Wineman" 3	Abandoned

Additionally, since Calpine no long intends to inject in to the "Midland WI" 2 well and the annual injection survey has not been conducted since August 17, 1999, approval to inject into this well is rescinded. All lines to the well must be disconnected. Should Calpine desire to reactivate this well, it will be necessary to submit a form OG107 (Notice of Intention to Rework) for this well. This well was part of the Rio Vista Gas – Mokelumne River disposal project. The project remains active because of continued injection into the "Midland Fee Water Injection" 1 well.

If you have questions, please contact Tim Kustic at (916) 322-1110.

Sincerely,

Robert S Habel

Robert S. Habel
District Deputy

Cc: Project File

DEPARTMENT OF CONSERVATION

STATE OF CALIFORNIA

CALIFORNIA CONSERVATION

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

District 6

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ARNOLD
SCHWARZENEGGER
GOVERNOR

September 21, 2004

Denny L. Brown
OXY RESOURCES CALIFORNIA, LLC
P.O. Box 82576
Bakersfield, CA 93380-2576

RE: **River Island Gas Field, Winters Formation, Water Disposal Project**

Dear Mr. Brown:

As you may be aware, the Division of Oil, Gas, and Geothermal Resources (Division) regulates the injection of U.S. EPA Class II fluids in California.

In a September 18, 2002 letter the Division approved the above referenced water disposal project. This project was never activated. Since at this time, Oyx Resources California, LLC no longer intends to inject into this project and the project has been inactive for two years, the project approval is herby rescinded.

If you have questions, please contact me at (916) 322-1110.

Sincerely,

Tim Kustic
Associate Engineer
District 6

DEPARTMENT OF CONSERVATION

STATE OF CALIFORNIA

CALIFORNIA CONSERVATION

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES

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ARNOLD SCHWARZENEGGER
GOVERNOR

October 1, 2004

Sharon Shelton, Agent
Vintage Petroleum, Inc.
P.O. Box 609
Rio Vista, CA 94571

RE: Kirkwood Gas Field, Kione Formation, Water Disposal Project

Dear Ms. Shelton:

Since the above referenced injection project has been idle for over two years, the Division of Oil, Gas, and Geothermal Resources (Division) is rescinding project approval. Any future injection into this project will require prior approval from the Division.

Injection lines to the "R.H.L. Brackenbury et al" 3 (API# 103-00048) well, which was used for injection into this project, must be disconnected.

If you have questions, please contact our office.

Sincerely,

Tim Kustic

Tim Kustic
Associate Oil & Gas Engineer

DEPARTMENT OF CONSERVATION
STATE OF CALIFORNIA

CALIFORNIA CONSERVATION

DIVISION OF OIL, GAS, & GEOTHERMAL RESOURCES
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ARNOLD SCHWARZENEGGER
GOVERNOR

November 16, 2004

Mike Wolfe, Agent
KEY PRODUCTION COMPANY, INC
555 University Ave., Ste. 13
Sacramento, CA 95825

RE: Key Production Company, Inc., Willows-Beehive Bend Gas Field
Kione Formation, Commercial water Disposal Project

Dear Mr. Wolfe:

As you may be aware, the Division of Oil, Gas, and Geothermal Resources (Division) regulates the injection of U.S. EPA Class II fluids in California. It is Division Policy to rescind approval of all injection projects that have been idle for two or more years. Reactivation of such a project may require full project-application review, at the discretion of the District Deputy.

In a March 19, 2002 letter the Division approved the above referenced water disposal project. This project has been inactive since October 2002. Since the project has been inactive for two years, project approval is hereby rescinded. Lines to the injection well, "Dracula" 1, must be disconnected and the well shut –in.

If you have questions or which to reactivate this project, please contact me at (916) 322-1110.

Sincerely,

Tim Kustic

Tim Kustic
Associate Engineer

Cc: Project File
Well File

STATE OF CALIFORNIA, RESOURCES AGENCY

ARNOLD SCHWARZENEGGER, GOVERNOR

OIL, GAS & GEOTHERMAL

DEPARTMENT OF CONSERVATION

DIVISION OF OIL, GAS AND GEOTHERMAL RESOURCES

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March 5, 2009

Richard Oringderff, Agent
VINTAGE PETROLEUM CALIFORNIA, LLC
9600 Ming Ave., Ste. 300
Bakersfield, CA 93311

RE: "J. Ratto" 18-1, Azevedo Zone, Lathrop Gas Water Disposal Project

Dear Mr. Oringderff:

As you are aware, the Division of Oil, Gas, and Geothermal Resources (Division) regulates the injection of U.S. EPA Class II fluids in California.

Since the above referenced well has been idle for over two years and a mechanical integrity test has not be conducted since September 20, 2004, approval to inject fluid into this well is hereby rescinded.

All injection lines to the above referenced well must be disconnected. Should Vintage Petroleum, Inc. desire to reactivate this well, it will be necessary to submit a form OG107 (Notice of Intention to Rework) for this well.

As of March 4, 2009 our office rescinds this **project** approval.

If you have questions, please contact me at (916) 322-1110.

Sincerely,

Pam Ceccarelli

Pam Ceccarelli
Associate Engineer

Cc: Bruce Johnson, P.O. Box 609, Rio Vista, CA 94751