Appendix 9:

CTV V Risk Based AoR Reports

Report 1: DBS&A CTV V Risk-Based AoR Delineation

Memorandum

To: Faisal Latif, Carbon TerraVault Holdings, LLC **Date:** June 7, 2024

From: Gregory Schnaar, Ph.D., P.G. (VA), Todd Umstot

Subject: CTV V Risk Based Area of Review (AoR) Delineation

At the request of Carbon TerraVault Holdings, LLC (CTV), Daniel B. Stephens & Associates, Inc. (DBS&A) has conducted modeling and data analysis to develop a risk-based Area of Review (AoR) delineation for the CTV V project in San Joaquin County, California.

Background

AoR delineation consists of determining the outermost extent of the separate-phase CO_2 plume and area of elevated pressure ("pressure front") that pose risk to underground sources of drinking water (USDWs) during the lifetime of the injection project. Elevated pressure may pose a risk to USDWs due to the potential for brine leakage from the injection zone into a USDW through a conduit if one is present (e.g., improperly abandoned well).

In most cases the AoR will at a minimum be defined by the carbon dioxide (CO_2) plume footprint and may be larger if the pressure front extends beyond the CO_2 plume. CO_2 plume extent and pressure increase are estimated based on computational modeling, and in the case of CTV V project modeling was conducted by CTV with Schlumberger ECLIPSE reservoir simulator[1].

Various methods are available to determine the pressure threshold value that defines the outermost extent of the pressure front. In general, these methods are used to define a pressure at which brine will leak upwards through an abandoned well, leak into a USDW, and endanger the USDW due to water quality impairment. Risk-based AoR delineation methods account for dilution and attenuation processes that minimize potential USDW impacts from hypothetical brine leakage. Risk-based AoR delineation strategies are supported by the U.S. EPA (2013) Class VI AoR and Corrective Action Guidance, which states (p.42):

[1] CTV ECLIPSE modeling is documented in the CTV V Class VI permit application Attachment B.

Possible methods to estimate an acceptable pressure increase for over-pressurized reservoirs include…

2. A multiphase numerical model may be designed to model leakage through a single well bore, or through multiple well bores in the formation (see e.g., Birkholzer et al., 2011). Additional pressure increases up to a certain point within an already over-pressurized injection zone may not cause an appreciable increase in fluid leakage rates through a hypothetical borehole. A sensitivity analysis may be conducted to bound the modeled leakage rates.

3. In conjunction with item #2 above, numerical or analytic ground water modeling may be conducted for the USDW to estimate how additional fluid leakage caused by the injection project is diluted within the USDW and attenuated. Dilution of fluid leakage from a borehole is impacted by the natural background flow rate of water within the USDW, which is in turn a function of the hydraulic gradient, aquifer thickness, and hydraulic conductivity. An additional pressure increase may be allowable if it can be demonstrated to the UIC Program Director that negligible degradation of the USDW would result from increased fluid leakage rates.

Risk-based methods are also discussed in Burton-Kelly et al. (2021) and Bacon et al. (2020). Generally, risk-based AoR delineation consists of three steps:

1. Model brine leakage rates through a potentially improperly abandoned well at specified pressure values within the injection zone.
2. Assuming that the improperly abandoned well is open to the USDW, model the distribution of elevated salinity within the USDW resulting from leakage for pressure value(s) modeled in Step 1.
3. Compare estimated increase in USDW salinity to established screening levels and/or background values. Confirm which pressure value(s) do not result in unallowable USDW salinity exceedance.

DBS&A performed risk-based AoR delineation by applying these steps, as described below.

Brine Leakage Modeling

The U.S. Geological Survey (USGS) MODFLOW numerical groundwater flow model was used to estimate brine leakage rates based on conservative effective well permeabilities, pressure at the location of the well, and stratigraphy overlying the sequestration zone. MODFLOW is considered an international standard for simulating and predicting groundwater conditions (USGS, 2022). Specifically, MODFLOW-2005 was used to estimate brine leakage (Harbaugh, 2005). MODFLOW is a modular three-dimensional finite-difference model and allows for numerical simulation of water flow upwards through an abandoned well and into multiple aquifers based on assigned stratigraphy and hydraulic parameters. DBS&A developed a MODFLOW model for estimating brine leakage through an abandoned well, and validated the model by comparison to estimated brine leakage rates for a single-aquifer system from (1) National Risk Assessment Partnership's (NRAP[2]) open-source Integrated Assessment Model (NRAP-Open-IAM) Multisegmented Wellbore Component ("NRAP-MSW"; Vasylkivska et al., 2022), and (2) an analytical Darcy's Law calculation of brine flux upwards through a wellbore. Results were found to be similar for the three methods. MODFLOW was chosen as the primary model for brine leakage estimation due to the capability of modeling brine discharge to multi-aquifer systems.

MODFLOW brine leakage modeling was focused on flow across large distances between the injection zone and the surface and does not consider discrete features of the flow paths such as fractures. MODFLOW assumes uniform density and temperature, which are considered acceptable; for example, NRAP-MSW (developed for support of CO_2 and brine leakage risk estimation at Carbon Capture and Storage [CCS] projects), has the same assumptions (Vasylkivska et al. 2022; Baek et al., 2021).

MODFLOW input parameters include overlying stratigraphy, aquifer properties, wellbore properties, and fluid properties. The model domain consists of a single wellbore that extends from the injection zone to the surface and surrounding aquifer and shale units. Figure 1 displays a cross-section and map of the CTV V project. Model stratigraphy was conservatively based on geologic interface elevations at the location in the vicinity of the CTV V CO_2 plume with the minimum confining zone (Capay Shale) thickness. MODFLOW modeling considered the following stratigraphic units:

- USDW (Upper Markley)
- Lower Markley
- Nortonville Shale

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[2]NRAP was developed by the Department of Energy National Energy Technology Laboratory (NETL) to support CCS project risk assessment and permitting. The National Risk Assessment Partnership (NRAP) is a multi-national laboratory collaborative research effort leveraging broad technical capabilities across the DOE complex to develop the integrated science base, computational tools, and protocols required to quantitatively assess and manage environmental risks at geologic carbon storage sites. NRAP involves five DOE national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL).

- Domengine Dissipation Zone
- Capay Shale Confining Zone
- Mokelumne Formation (Injection Zone)

Modeling considered leakage from the upper injection zone (Mokelumne Formation), which is more conservative than considering leakage form the deeper lower injection zone (Starkey Formation). An additional barrier is present above the Starkey Formation (H&T Shale), and it is a further distance from the lowermost USDW.

Table 1 presents stratigraphic unit depth and thickness. The MODFLOW grid, stratigraphic units and conceptual model are displayed on Figure 2. The grid is 2,506 meters (m) x 2,506 m on a side horizontally (8,228 feet [ft] x 8,228 ft). Grid cell size increases from the wellbore outwards; the largest cell is 100 m x 100 m (328 ft x 328 ft) and the smallest cell represents the wellbore and is 0.195 m x 0.195 m (0.64 ft x 0.64 ft).

Each stratigraphic unit was assigned as a model layer within MODFLOW, and the model was initialized at hydrostatic conditions within each layer. It was assumed that brine may leak from the wellbore along the full thickness of all aquifer units (Domengine, Upper Markley, Lower Markley). Third-type or Cauchy boundary conditions, referred to as General Head Boundary (GHB) in MODFLOW, were assigned along the outer boundary of the aquifer-unit layers, which allows for brine flux out of the domain. Average GHB cell conductance was 60 meters per day (m^2/day) in the Upper Markley, 47 m^2/day for the Lower Markley, and 22 m^2/day for the Domengine (conductance is lower for the Domengine due to the smaller aquifer thickness). Shale units (Nortonville Shale, Capay Shale) were represented by no-flow boundary conditions.

Top of injection-zone pressure was assumed to be 500 pounds per square inch (psi) above hydrostatic conditions. CTV ECLIPSE modeling results indicate that pressure increase of this magnitude will not occur outside the boundary of the CTV V CO_2 plumes for a case considering the combined pressure increase from the CTV III, CTV V and Pelican Renewables projects (Figure 3). The pressure boundary condition at the top of the injection zone is set as a MODFLOW Constant Head Boundary condition with a head of 357 meters (corresponding to 500 psi increase above hydrostatic). This value combines the pressure above the hydrostatic level at the reservoir's top (500 psi) with an additional 7 psi that accounts for the additional pressure at the mid-point depth of the reservoir layer where the head is assigned.

Additional MODFLOW input parameter values were obtained from available project documentation, standard methods, literature sources, and NRAP recommended conservative defaults as summarized in Table 2. Key parameter model assumptions included:

- MODFLOW simulations were conducted for 40 years, which is 15 years longer than the planned CTV V injection timeframe.
- Aquifer permeability (Domengine and Markley) was assumed to be 10^{-12} square meters (m^2) based on reported Domengine permeability values that range from 2 to 3 darcies ($2 \cdot 10^{-12}$ to $3 \cdot 10^{-12}$ m^2; Beyer et al., 2013).
- Borehole effective permeability was assumed to be 10^{-10} m^2, which is within or even higher than the highest range of values reported for potentially leaking abandoned wells from similar studies and is therefore conservative. For example, Celia et al. (2011) report four categories of wells for deep leakage potential ranging from "low" to "extreme." Extreme-category wells were reported to exhibit effective permeabilities from 8 to 10,000 millidarcies ($8 \cdot 10^{-15}$ to $1 \cdot 10^{-13}$ m^2).

MODFLOW results for brine flux into the aquifer units was $1.5 \cdot 10^4$ kilograms per day (kg/d) for the Domengine, 1.1 kg/d for the Lower Markley, and $2.4 \cdot 10^{-5}$ kg/d for the Upper Markley (USDW). The Domengine dissipation zone is predicted to receive the vast majority of brine leakage, as it is located nearest to the injection zone.

USDW Salinity Concentration Increase Modeling

The analytical solutions of Hunt (1978) as modified by Wexler (1992) were used to model salinity transport in the USDW ("Hunt-Wexler model"). The Hunt-Wexler model is an analytical solution of the advection-dispersion equation based on a flux source boundary condition that accounts for advection, hydrodynamic dispersion, and solute retardation and decay (retardation and decay are neglected for the case of modeling salinity). The Hunt-Wexler model assumes a uniform, homogenous flow field and an infinite aquifer in all directions. DBS&A developed custom computer code scripts to run the Hunt-Wexler model with assigned brine flux rates (from MODFLOW) as the boundary condition at the leaking wellbore. Superposition/image theory was used to establish optional top and bottom boundary conditions (e.g., to account for the presence of a shale unit underlying the USDW leakage point) and to account for time-varying brine flux. Hunt-Wexler does not account for density-driven flow and assumes isothermal conditions.

The DBS&A custom Hunt-Wexler code was verified by comparison to a similar USGS program of the Hunt solution (POINT3D; Wexler, 1992) for an infinite aquifer test problem and results were found to be identical. Hunt-Wexler solution results were also compared to USGS-MT3D numerical modeling results (Zheng and Wang, 1999) for two example test problems including (1) three-dimensional transport in a uniform flow field; and (2) a variable flux boundary condition. In both cases analytical (Hunt-Wexler) and numerical (MT3D) results were essentially identical. Hunt-Wexler solution results were also compared to numerical modeling with MODFLOW-SEAWAT (Langevin et al., 2008) that can account for potential density-driven and non-isothermal effects for a test problem with a 15,000 milligram per liter (mg/L) source released into a freshwater aquifer (density 1,000 kilograms per cubic meter [kg/m^3]). Plume modeling results were essentially identical for the Hunt and MODFLOW-SEAWAT simulations, confirming that the Hunt-Wexler solution assumptions of no density-driven flow are acceptable for these conditions.

CTV V Hunt-Wexler input parameters for aquifer properties were taken from standard conservative defaults (Table 3). The MODFLOW-predicted brine flux rate was applied as the Hunt-Wexler boundary condition, with the brine flux having an assumed total dissolved solids (TDS) source concentration of 15,500 milligrams per liter (mg/L).

CTV V Hunt-Wexler plume modeling results are presented as the increase in TDS concentrations at the base of the aquifer. Results indicate that after 40 years, 5 feet downgradient of the borehole there will be only a $3.04{\cdot}10^{-4}$ mg/L increase in TDS in the USDW for the conditions modeled (i.e., 500 psi pressure increase above hydrostatic conditions). This increase is considered negligible; however, additional data interpretation is presented below.

Sensitivity Analyses

MODFLOW/Hunt-Wexler sensitivity analyses were performed for assumed fluid properties (within the range of density and viscosity that may be encountered along the wellbore length), borehole diameter, and aquifer compressibility. Sensitivity results are presented in Table 4. MODFLOW predicted brine flux to the USDW ranges from $4.87{\cdot}10^{-7}$ kg/d to $1.42{\cdot}10^{-4}$ kg/d for all sensitivity runs, with the largest value from a run with an assumed 12-inch diameter wellbore (compared to 8.7 inches in the base case run). The corresponding TDS concentration increase for the 12-inch borehole run is $1.8{\cdot}10^{-2}$ mg/L, which is negligible. Sensitivity analyses therefore further support no appreciable leakage will occur to the USDW.

Interpretation

The linked MODFLOW/Hunt-Wexler results provide an estimate of potential elevated TDS concentration emanating from a leaking borehole. Two methods were used to interpret these modeling results in order to provide a risk-based AoR delineation:

1. Evaluate TDS concentration increase compared to regulatory groundwater quality standards
2. Evaluate TDS concentration increase compared to typical TDS variability
    a. Comparison to typical well concentration fluctuation
    b. Statistical comparison (method of Last et al., 2016)

Method 1: Comparison to Water Quality Standards

TDS has a recommended drinking-water secondary maximum contaminant (Secondary MCL) of 500 mg/L (22 CCR 64449). Secondary MCLs are not health-based standards, but are guidelines for aesthetic considerations such as taste, color, and odor. California consumer acceptance contaminant ranges for TDS are a recommended concentration less than 500 mg/L, and an upper range of 1,000 mg/L. Constituent concentrations lower than the recommended contaminant level are desirable for a higher degree of consumer acceptance, and constituent concentrations ranging to the upper contaminant level are acceptable if it is neither reasonable nor feasible to provide a more suitable water supply. Crop tolerances in the Subbasin range by crop type from 900 mg/L TDS for almonds up to 4,000 mg/L TDS for wheat, assuming a 90 percent yield (ESJGA, 2022).

CTV V is located within the Eastern San Joaquin groundwater subbasin, and shallow aquifers in the subbasin exhibit elevated TDS due to evaporated irrigation return water, entrainment of seawater in Delta deposits during sediment deposition, and impacts from underlying marine sediments (GEI, 2021; ESJGA, 2022). Median TDS in the subbasin is 520 mg/L (ESJGA, 2022). Groundwater quality data within 5 miles of the CTV V CO_2 plumes over the previous 10 years was also obtained from GAMA (2023), and median and average TDS was 310 mg/L and 505 mg/L, respectively (data shown on Figure 4).

Maximum TDS increase for the 500 psi pressure increase scenario from MODFLOW/Hunt-Wexler modeling is <1 mg/L. Significant TDS increase due to brine leakage that would cause exceedance of a regulatory standard is not predicted to occur.

Method 2A: Comparison to Aquifer TDS Variability, Observed Fluctuation

TDS at local groundwater supply wells fluctuates over time due to natural variability and other factors. An example time-series TDS chart for a local supply well is shown on Figure 4. Average TDS range (maximum TDS - minimum TDS) is 111 mg/L for wells within 5 miles of the CTV V project over the last 10-year period (GAMA, 2023). The maximum range for wells in this area and time period is 280 mg/L. From MODFLOW/Hunt-Wexler modeling presented above the maximum predicted TDS increase due to hypothetical leakage (outside of the CO_2 footprint) is <1 mg/L. These concentration increases are significantly less than the existing fluctuation in local groundwater wells; therefore, predicted maximum TDS increase would not be detectable.

Method 2B: Comparison to Aquifer TDS Variability, Statistical Analysis

Last et al. (2016) provide a statistical methodology for derivation of groundwater threshold values for analysis of USDW impacts at CCS sites. The Last et al. (2016) methodology identifies an initial (pre-injection) condition for a chemical constituent in an aquifer and a threshold value above which the aquifer would be considered negatively impacted. Initially, the authors intended to set threshold values based on the drinking water regulatory standards and guidelines, however the authors report that an NRAP stakeholder group indicated that additional threshold values were needed that could differentiate areas of no degradation from those areas that reflect some degree of change from background groundwater quality levels. Separate threshold concentrations were needed in part due to many areas (such as the Eastern San Joaquin subbasin) already exceeding drinking water regulatory guidelines.

Last et al. (2016) used the median of available concentration data as the initial condition, and the no impact threshold value was taken as the upper tolerance limit with 95 percent confidence and 95 percent coverage (UTL95-95). The UTL95-95 and 95 upper confidence limit (95-UCL) are common statistics to identify the reasonable upper-end of average background groundwater solute concentrations (U.S. EPA, 2009). The UTL95-95 threshold is expected to contain 95 percent of the distribution of all possible measurements in a population with a confidence probability of 95 percent. The 95-UCL is a value that equals or exceeds the actual average of a distribution 95 percent of the time. According to Last et al. (2016) the UTL95-95 is a good approximation of the upper limit of the background concentrations and can be used as a reasonable threshold for identification of significant change to the aquifer.

Figure 5 (reproduced from Last et al., 2016) displays an example TDS concentration histogram, the median of the population, the UTL95-95 and 95-UCL. In this example, the difference between the median TDS (341) and the UTL95-95 (452) is 111 mg/L and brine leakage due to a

CCS project that would increase aquifer concentrations more than 111 mg/L would therefore be considered to lead to exceedance of the pre-existing background threshold value.

The corresponding histogram and statistics for the Eastern San Joaquin subbasin aquifer in the vicinity of CTV V is shown on Figure 6. TDS data were obtained from GAMA (2023) for wells within 5 miles of CTV V and over the previous 10 years. Statistics including the median, UTL95-95 and 95-UCL were calculated with the U.S. EPA software ProUCL (Neptune, 2022). Median TDS is 310 mg/L, mean is 504 mg/L, 95-UCL is 564 mg/L and the UTL95-95 is 1,200 mg/L. The difference between the median and the UTL95-95 is 890 mg/L. Based on the methods of Last et al. (2016), it is assumed that the median is the initial condition within the aquifer, and the UTL95-95 is the upper range of the regional background given spatial and temporal variability. An increase of 890 mg/L would be needed to cause the median initial condition to exceed the background threshold value. An increase of 890 mg/L from brine leakage into the aquifer is not predicted to occur from the MODFLOW/Hunt-Wexler modeling. Therefore, similar to the simpler approach in Method 2A, any TDS change from leakage at the project is negligible.

Results

For each of the methods described above TDS leakage into the USDW due to elevated pressure is not predicted to cause impairment outside of the CO_2 plume footprint. TDS leakage is not predicted to cause exceedance of water quality regulatory standards or guidelines or cause detectable impairment given existing concentration variability and the negligible brine flux even under conservative assumptions. For these reasons increased injection-zone pressures do not risk water supply endangerment outside of the CO_2 plume footprint and the applicable AoR is the CO_2 plume areas.

Summary and Conclusions

Risk-based AoR delineation was conducted by first simulating brine leakage through a hypothetical borehole using a MODFLOW model with conservative assumptions, and then using those results to predict TDS plume migration from the leaking wellbore into the USDW with the Hunt-Wexler model. Modeling results indicate negligible TDS increase in the USDW (<1 mg/L) that would be limited to the immediate vicinity of the wellbore. Several methods were used to interpret the modeling results and ascertain if TDS increase due to brine leakage would pose a risk to USDWs in consideration of existing aquifer water quality. Risk-based methods, including standard statistical techniques, indicate that brine leakage would not pose a risk to water supplies in the USDW.

Risk-based AoR delineation is consistent with the Class VI AoR and Corrective Action guidance, which states that "an additional pressure increase may be allowable if it can be demonstrated to the UIC Program Director that negligible degradation of the USDW would result from increased fluid leakage rates" (U.S. EPA, 2013). Methods used herein are considered conservative for the following reasons:

- Brine leakage modeling was conducted with conservative parameters and the MODFLOW model was validated against analytical calculations and tools developed by NRAP.
- Modeling accounts for the presence of the Domengine formation located between the injection zone and the lowermost USDW sand that will receive most of the leakage via an open conduit. Additional leakage dissipation occurs within the Lower Markley formation below the base of the USDW. Assumed Domengine permeability values were similar to (and slightly less than) values reported in the literature (Beyer et al., 2013).
- Assumed wellbore permeability (10^{-10} m^2) is within or higher than the highest range from similar studies (e.g., Celia et al., 2011).
- Hunt-Wexler modeling is based on standard methods consistent with U.S. EPA approaches for evaluating contaminant plume attenuation.
- Interpretation of potential TDS impacts to the local aquifers was based on review of site-specific data for the Eastern San Joaquin Subbasin. Standard methods were used in the risk-based data evaluation, including statistical methods developed by NRAP (Last et al., 2016).

Based on the risk-based analysis increased pressure from the injection project does not pose a risk to USDWs outside the CO_2 plume and therefore the applicable AoR is the CO_2 plume areas.

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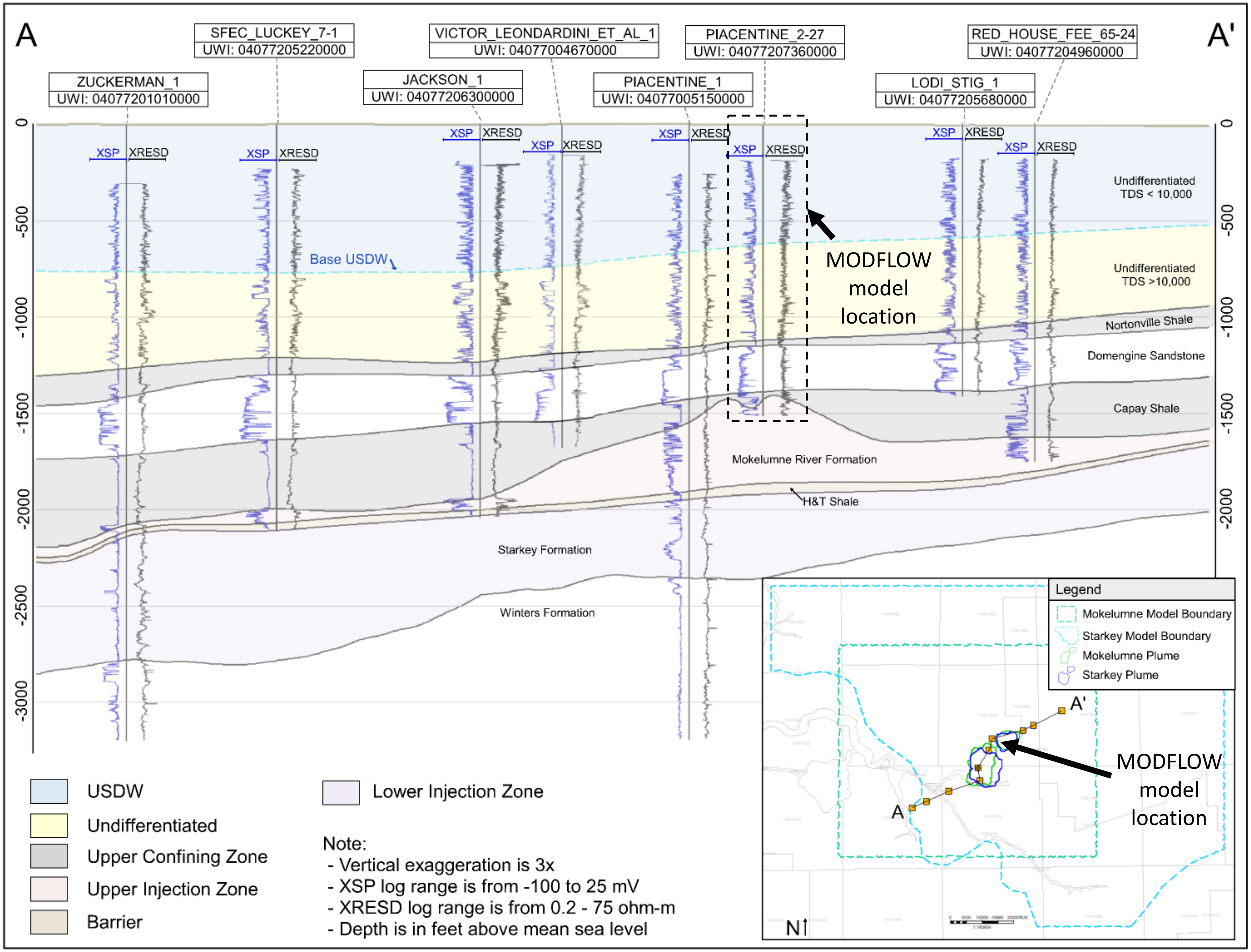
Figures



CTV V RISK BASED AOR DELINEATION

CTV V Cross Section and MODFLOW Model Location

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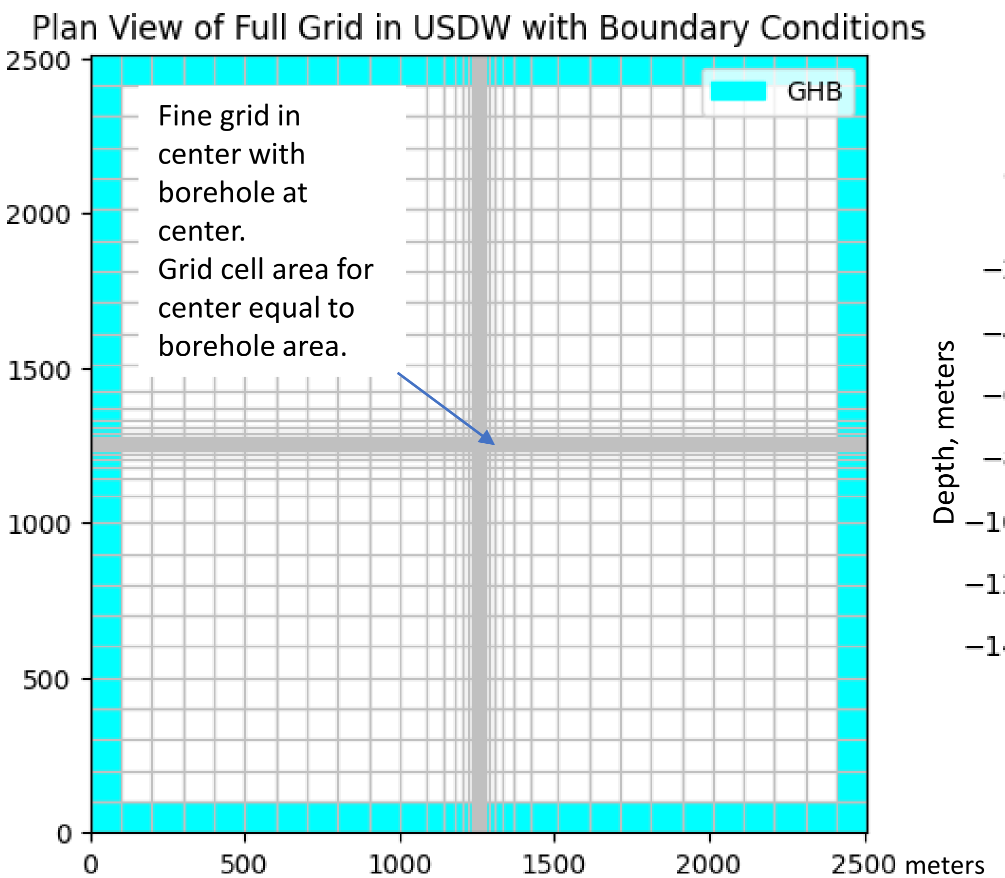
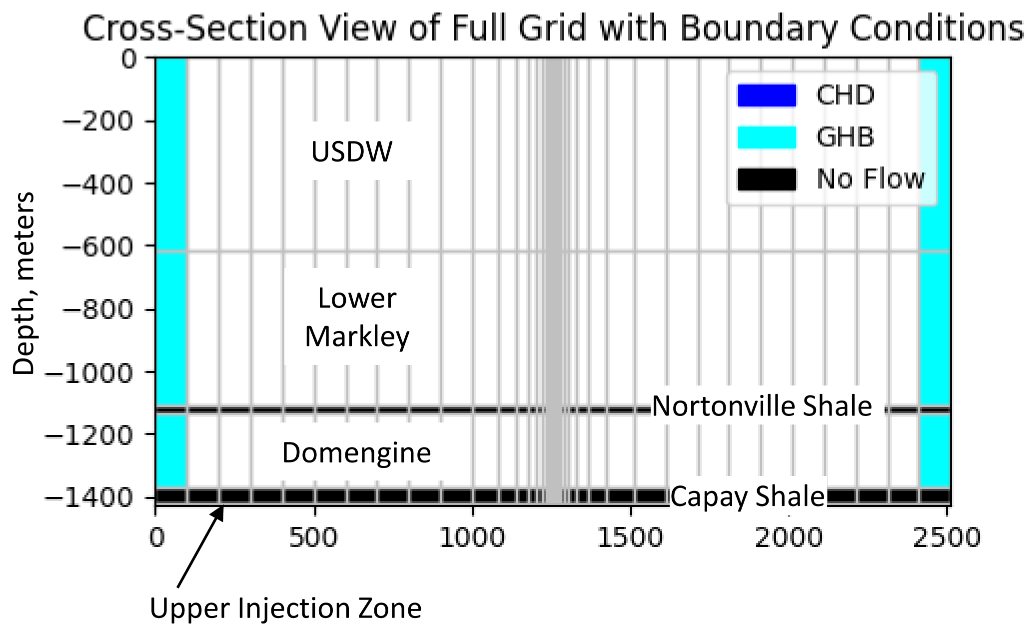
Figure 1





GHB = General Head Boundary
CHD = Specified Head Boundary

CTV V RISK BASED AOR DELINEATION

MODFLOW Grid and Conceptual Model

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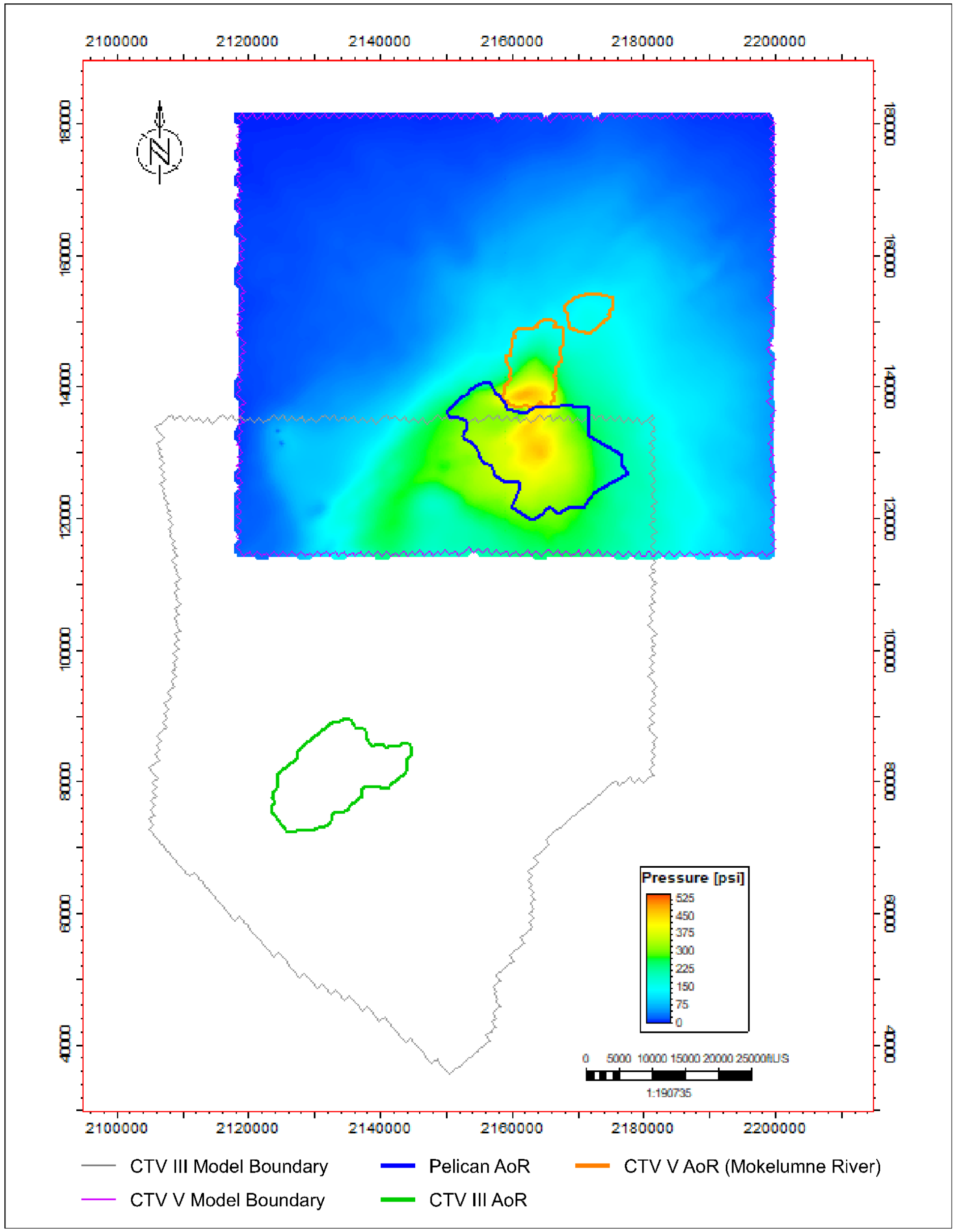
Figure 2



Note: ECLIPSE modeling results provided by CTV

CTV V RISK BASED AOR DELINEATION

Modeled Maximum Delta-Pressure Results: Combined Pelican Renewables, CTV V and CTV III Projects

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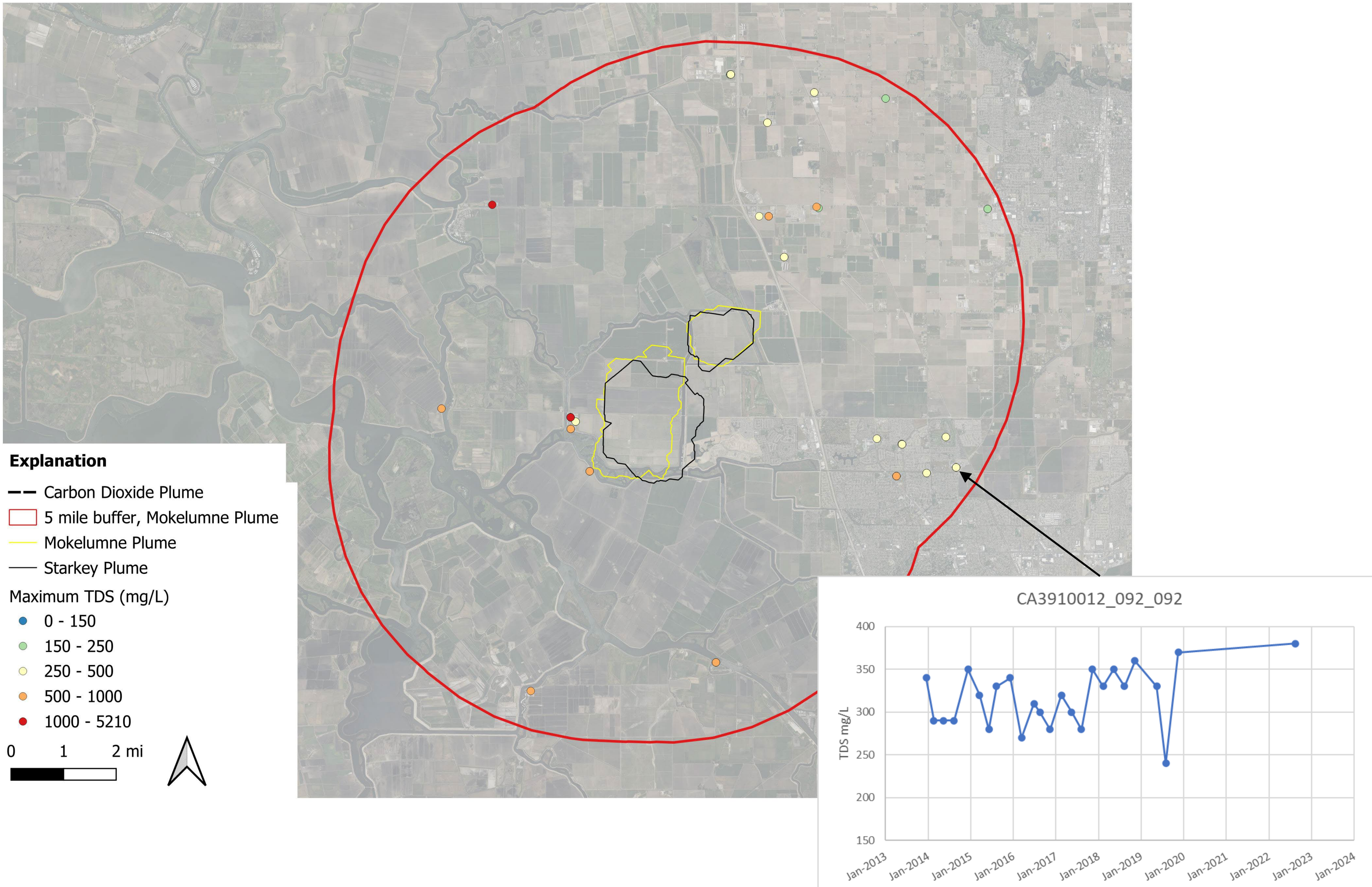
Figure 3



CTV V RISK BASED AOR DELINEATION

TDS Concentration in Groundwater Wells, Groundwater Ambient Monitoring and Assessment (GAMA) Program

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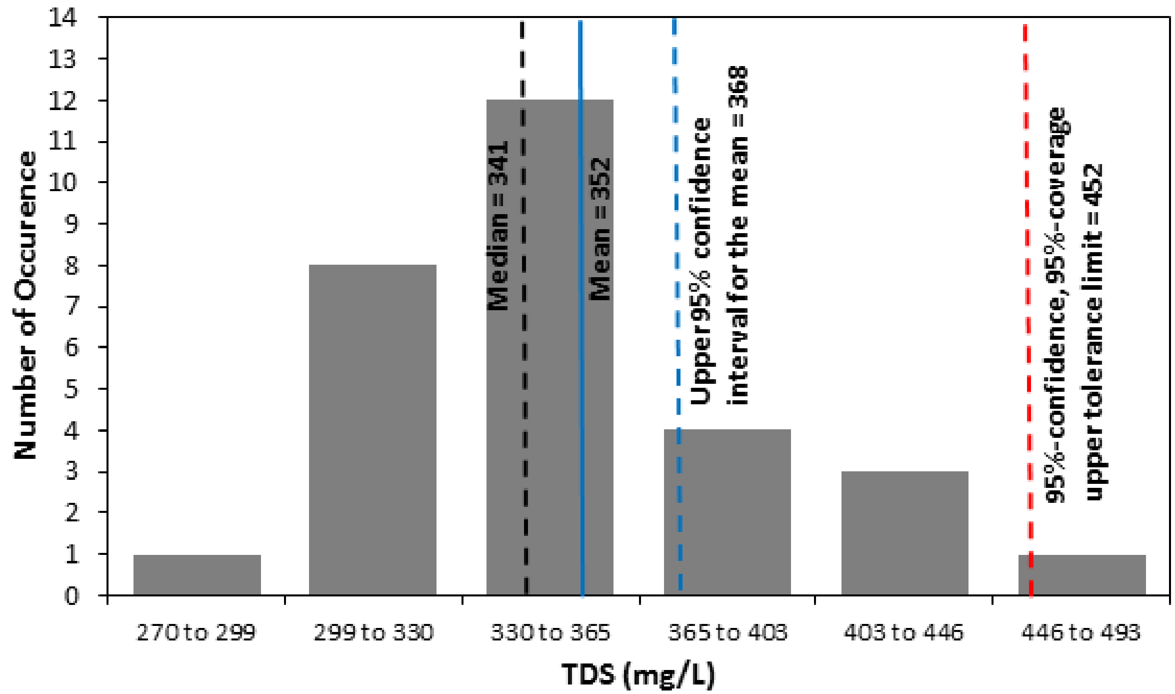
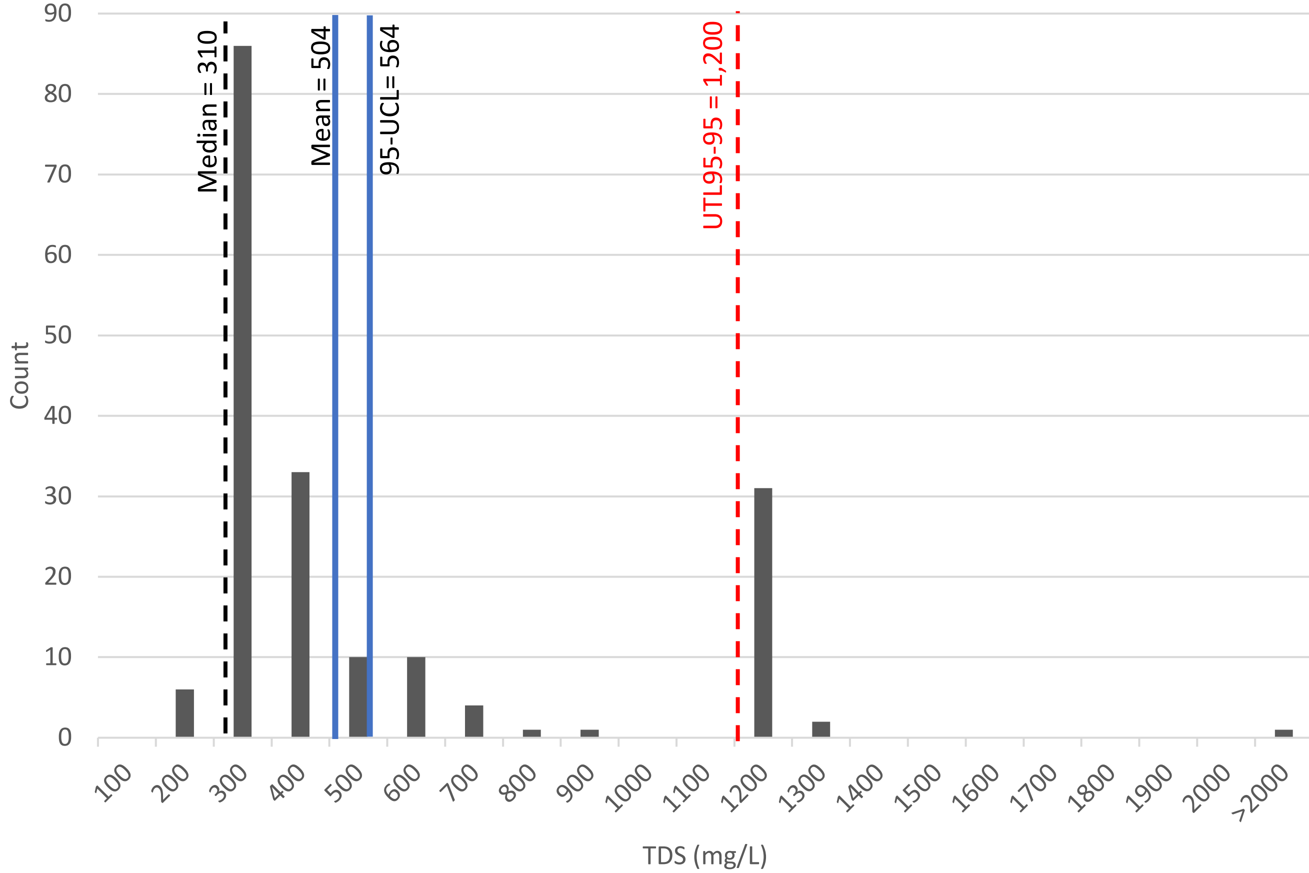
Figure 4



Source: Last et al, 2016

CTV V RISK BASED AOR DELINEATION

TDS Histogram, Median and 95-percent Upper Confidence Intervals, Literature Example



Notes:
TDS data from GAMA, within 5-miles of CTV V plume collected within previous 10 years;
95-UCL = 95% upper confidence level of the mean
UTL95-95 = 95% upper tolerance limit with 95% coverage

CTV V RISK BASED AOR DELINEATION

TDS Histogram, Median, 95-UCL and UTL95-95

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Figure 6

Tables

Table 1. MODFLOW Assumed Stratigraphy

Layer	Top Depth (ft TVD)	Layer Thickness (ft)
Upper Markley (USDW)	0	2,024
Lower Markley	2,204	1,601
Nortonville Shale	3,625	98
Domengine	3,724	761
Capay Shale	4,485	171
Mokelumne	4,656	33 [1]

Note:
[1] Mokelumne formation assigned 33 feet thickness in MODFLOW grid at bottom of domain

Table 2. MODFLOW Input Parameters

Parameters	Value	Source/Notes
Aquifer permeability (log10 m^2), Domengine and Markley	-12	NRAP default; Beyer et al., 2013. Hydraulic conductivity in MODFLOW is 1.97 m/d assuming density of 1,000 kg/m^3 and viscosity of $4.3 \cdot 10^{-4}$ Pa-s.
Wellbore permeability (log10 m^2)	-10	High end of reported ranges for leaking wellbores in previous studies (e.g., Burton-Kelly et al., 2021). Hydraulic conductivity in MODFLOW is 197 m/d assuming density of 1,000 kg/m^3 and viscosity of $4.3 \cdot 10^{-4}$ Pa-s.
Brine density (kg/m^3)	1,000	NRAP default
Brine viscosity (Pa-s)	4.30E-04	https://irc.wisc.edu/properties/ [Water, T = 151 F, P = 2860 psi]
Compressibility	5.10E-11	NRAP default
Time of simulation (years)	40	Injection + 15 years
Well radius (m)	0.11	Assumed

Table 3. Hunt-Wexler Input Parameters

Parameter	Value	Unit	Source
Hydraulic Gradient	1.00E-03	- -	Assumed
Effective Porosity	0.25	- -	Assumed
Permeability	1.00E-12	m^2	Assumed, NRAP default
Brine Density	1.00E+03	kg/m^3	Calculated
Brine Viscosity	4.30E-04	Pa*s	Calculated
Hydraulic Conductivity	1.97	m/d	Calculated from brine properties and permeability
Longitudinal Dispersivity	2.00E+01	m	Assumed
Transverse Dispersivity	2.00E+01	m	Assumed
Vertical Dispersivity	2.00E+01	m	Assumed

Table 4. Sensitivity Analysis Results

Scenario	Brine Flux, USDW (kg/d)	Comment
Base Case	$2.42 \cdot 10^{-05}$	Aquifer K = 1.97 m/d; Borehole K = 197 m/d; 8.7 in diameter borehole; $5 \cdot 10^{-7}$ specific yield
High Hydraulic Conductivity	$3.52 \cdot 10^{-05}$	Fluid density = 1,011 kg/m^3; Viscosity = $3.0 \cdot 10^{-04}$ Pa-s; Aquifer K = 2.855 m/d; Borehole Ks = 285.5 m/d
Low Hydraulic Conductivity	$9.08 \cdot 10^{-06}$	Fluid density = 991 kg/m^3; Viscosity = $1.1 \cdot 10^{-03}$ Pa-s; Aquifer K = 0.737 m/d; Borehole K = 73.7 m/d
Large Borehole	$1.42 \cdot 10^{-04}$	12 inch diameter
Small Borehole	$4.87 \cdot 10^{-07}$	4 inch diameter

K = hydraulic conductivity
kg/d = kilograms per day
Pa-s = Pascal-seconds
m/d = meters per day
kg/m^3 = kilograms per cubic meter

Report 2: Irani Engineering Abandoned Well Fluid Migration Analysis

Introduction:

Irani Engineering, Inc. has been commissioned by Carbon TerraVault LLC (CTV), a wholly Owned subsidiary of California Resources Corporation (CRC), to do a review of its proposed Carbon Sequestration project CTV III which is located West of the Union Island Gas Field in San Joaquin County in Northern California. Specifically, Irani Engineering has been tasked to review the construction of the abandoned wells which are in the vicinity of the proposed CO2 injection wells and determine if the exiting cement plugs and mud columns in these abandoned wells are sufficient barriers to prevent the migration of formation fluid (injection zone brine) from the pressurized Mokelumne River formation into the base of the USDW formation during and after CO2 injection.

Based on Irani Engineering's 39 years of experience drilling and completing gas wells in Northern California (over 1000 wells drilled), re-entering 5 old abandoned wells, existing research papers, and third party's reports of re-entry into old abandoned wells, the modeled pressure increase in the Mokelumne River formation at the well penetrations in the CTV III project region is not sufficient to induce vertical migration of fluid from the injection zone to the base of the USDW. This is based on the following –

- The positive pressure provided by the mud columns in the wellbores is well above the modeled pressure increase at these locations due to CO2 injection.
- The gel strength of the mud provides an additional resistance to fluid migration.
- Irani Engineering's operational experience in Northern California and industry experience supports that the gel based muds used in these abandoned uncased wellbores remains in the wellbore and thus provides resistance to the migration of fluids.

CO2 Sequestration Project Summary

CTV is proposing to drill and operate six Carbon Sequestration wells in Section 33, 34, T1N, R4E, and Section 5 T 1S, R4E, San Joaquin County, Northern California. The targeted injection zone is the Mokelumne River formation. The Mokelumne River formation (roughly at a depth of 5900 ft below ground level in the project area) is a massive friable sandstone formation with high porosity (average 28% in the project area) and high permeability (average 180 md in the project area). It is capped by the Capay Shale (roughly at a depth of 5700' ft below ground in the project area) which is the confining zone for the injection zone. The Domengine formation which is located above the Capay shale and extends from ~5700' to ~5200' below ground at the project area is another massive friable sandstone with high porosity (average 35% in the project area), and high permeability (average 190 md in the project area). would act as a dissipation zone in case of vertical migration of formation fluid from the proposed injection zone. The base of the USDW is estimated to be around 2500 ft below ground in the project area.

Based on CTV's modeling, three abandoned wells will fall within the boundary of the CO2 plume. These three wells will be re-entered and re-abandoned prior to injection to prevent vertical migration of CO2 from the injection zone. 43 other abandoned wells within 3 to 8 miles of the injection wells will be outside the CO2 plume but may experience increased formation pressure at the injection zone (Mokelumne River formation) due to the planned CO2 injection.

A) Well Construction Review in CTV III project region.

Irani Engineering reviewed the construction of all the 43 abandoned wells which have penetrated the Mokelumne River formation in the project region and that lie outside of the expected CO2 plume footprint.

- Five of the wells have existing cement plugs between the Mokelumne formation penetrations and the base of the USDW which would prevent the vertical migration of fluid into the USDW.
- One well has been cased and cemented through the Mokelumne penetration and the base of USDW which would prevent contamination of the USDW.
- The remaining 37 wells were abandoned with shallow set casing and cement plug depths above the base of the USDW, with mud filled wellbores and no cement plugs between the base of the USDW and the top of the Injection zone.

Table 1 tabulates the list of wells, their locations, and the modeled pressure increase at the location based on CTV's modeling efforts.

Based on CTV's modeling, the abandoned well "Sproule 1-2" (API# 04013002260) is expected to experience the maximum induced pressure increase among the set of wells, with a predicted pressure increase of 163psi in the first 5 years of injection and a peak increase of 280psi over the project life. Once injection ceases, the pressure is expected to rapidly fall and eventually return to initial conditions as pressure dissipates in the injection zone.

As the Sproule 1-2 well sees the maximum pressure increase, it will be used as a basis for further discussions in this report, and it's construction and abandonment are representative of the 37 wells described above with very shallow set casing and cement plugs above the base of the USDW. The abandoned dry hole Sproule 1-2 is located in Section 2, T 1S, R 3E, Contra Costa County. INTEX Oil Company drilled Sproule 1-2 in 1965. 12-1/4" surface hole was drilled to 474', 8-5/8", 24#, J-55 surface casing was run and cemented to surface at 474'. 7-7/8" vertical hole (maximum deviation is 2 degrees) was drilled to a total depth of 6200' using 10.8 ppg mud with mud gel strength of 39 $lb/100ft^2$. The well penetrated the base of fresh water at 525', the base of USDW at ~2443', the Domengine Sand formation at 4822', and the Mokelumne River formation at 5856'. Logging confirmed that the well was a dry hole with no commercial gas. The well was abandoned by placing a cement plug from 525' to 370' and 10' of cement plug at surface. There are no cement plugs between the top of the Mokelumne River formation and the base of the USDW in this well (see Figure 1 for 1965 Wellbore Schematic).

B. Allowable Pressure Buildup at Well penetrations

Barker (1981) first documented a basic theoretical equation to determine the maximum allowable formation pressure increase at an uncased abandoned wellbore location as a function of the wellbore and wellbore mud properties, shown below :

$$\Delta P_{Allowable} = \Delta P_H + P_G$$

Where,

ΔP_H is the positive pressure applied on the injection formation due to hydrostatic pressure of the mud column, given by –

$$\Delta P_H = (0.052 \times Inj.zone\ depth\ in\ feet \times Mud\ Density\ in\ ppg) - Initial\ Inj.zone\ \text{Pressure in psi}$$

P_G is the gel strength pressure required to be overcome in addition to the hydrostatic pressure of the mud column in order to initiate flow, given by –

$$P_g = \frac{0.00333 \times Gel\ Strength\ in \frac{lb}{100} ft2 \times Injection\ zone\ depth\ in\ feet}{Borehole\ diameter\ in\ inches}$$

This methodology is consistent with similar evaluations of allowable pressure increases associated with artificial penetrations in the area of review of Class I and Class V disposal projects.

CTV has calculated and tabulated $\Delta P_{Allowable}$, ΔP_H and P_G for 43 wells in the immediate region around the CTV III project in Table 2. The calculations assume a gel strength of 20 lb/100ft^2 for the mud for P_G, which is a reasonable worst case gel strength that could occur for the mud types used in Northern California. The ΔP_H has been calculated using three methodologies –
1) Using the recorded mud weight for the well (listed in Table 2)
2) Using the lowest mud weight of the well set (9.9 ppg at Borges No. 1 well)
3) Using the lowest mud weight of the well set with a 20% Safety factor for the calculated ΔP_H and $\Delta P_{Allowable}$

For all three methodologies the positive pressure from the hydrostatic pressure of the mud column (ΔP_H) is well above the modeled pressure increase at the well location (Table 1 and Table 2), with the ΔP_H being at minimum 26% over the modeled pressure increase at the well locations even when using the lowest mud weight of the well set and a 20% safety factor on the calculated value. The gel strength pressure (P_g) provides an additional safety factor (~10% over ΔP_H).

As an example using the well that is predicted to see the highest pressure increase Sproule 1-2 -

- Assuming a normal formation gradient, the formation pressure at the top of the Mokelumne formation is initially 5856' X 0.4373 = 2561 psi.
- The calculated mud column pressure at the top of the Mokelumne formation is 5856' X 10.8X0.0519=3282 psi. which means the column of mud exerted 722 psi positive pressure (ΔP_H) over the formation pressure at the time of the abandonment.
- The mud gel strength pressure is calculated to be 0.00333*20*5856/9.875= 39 psi. Thus, the allowable pressure buildup ($\Delta P_{Allowable}$) at the location would be 761psi.

At the time of the abandonment of Sproule 1-2, in 1965, the peak expected pressure increase in the injection zone (280psi) would not have caused vertical migration of fluid (ΔP_H of mud was 722 psi at injection zone top and $\Delta P_{Allowable}$ was 761psi). Would the 280 psi pressure increase in the Mokelumne River formation cause a vertical migration of fluid to the base of the USDW 58 years (or more) after Sproule 1-2 was abandoned? Based on Irani Engineering operational experience, research papers, and other re-entry reports the answer is a resounding NO. We believe the present Sproule 1-2 wellbore is as resistive to fluid migration now as it was 58 years ago. We will discuss reasonings to support this in the next few sections.

C. Operational experience on current wellbore conditions for uncased abandoned wellbores

Irani Engineering has drilled and completed numerous wells (over 1000) in California. In addition, Irani Engineering has re-entered five old, abandoned wells in California (3 in Northern California, 2 in Central California) in the last 22 years.

Observations and brief histories of the three reentry wells in Northern California are stated below:

Community 3-1 (Section 4, T 4N, 7E, API 04-077-00072): This dry hole well was originally drilled to 3638' total depth by Amerada-Hess. The well was abandoned by cement plugs and ~11 ppg, 40 viscosity gel mud in 1943. The original hole had a 280' of 10-3/4" surface casing and the original borehole size below the surface casing was 9-5/8". We reentered this well with a 6-3/4" bit in 2002. Considerable reaming was required to make hole, which indicated a shrunken hole size with high concentration of sloughed shale and gelled up mud. Reaming indicated that we were in the original hole since reaming operation requires significantly less weight on the bit to make hole. We encountered the original mud, in a gelled up state (commonly called clabbered up mud in the Oil & Gas industry), below the surface cement plug and throughout the surface casing and the open hole portion of the well all the way to the total depth. A mixture of the original mud and new mud was observed over the rig shakers at surface as we reamed and circulated to bottom. We did not encounter any free formation water as we did not observe any formation water over the shakers. We had to use 11 ppg mud to keep the 6-3/4" hole open (the original hole was 9-5/8"). I believe the hole condition in 2002 would have prevented the vertical migration of formation fluid. See attachment A for the redrill and the original drilling histories.

Community 15-2 (Section 15, T 4N, R 7E, API 04-077-20053): This dry hole well was originally drilled to 3000' total depth by Amerada-Hess. The well was abandoned by cement plugs and ~10 ppg, 43 viscosity gel mud in 1965. The original hole had a 573' of 7" surface casing and the original borehole size below the surface casing was 6-1/4". We reentered this hole with a 6-1/4" bit in 2001. Considerable reaming was required to make hole which indicated a shrunken hole with high concentration of sloughed shale and gelled up mud. Reaming indicated that we were in the original hole since reaming operation requires significantly less weight on the bit to make hole. We encountered the original mud, in gelled up state, below the surface cement plug and throughout the surface casing and the open hole portion of the well all the way to the total depth. A mixture of the original mud and new mud was observed over the rig shakers at surface as we reamed and circulated to bottom. We did not encounter any free formation water as we did not observe any formation water over the shakers. We had to use 10 ppg mud to keep the 6-1/4" hole open. The hole was so tight that we almost got stuck at 1400'. I believe the hole condition in 2001 would have prevented a vertical migration formation fluid. See attachment B for the redrill and the original drilling histories.

Wagenet No. 5 (Section 30, T 4N, R 1E, API 04-095-20736): This dry hole well was originally drilled to 5580' total depth by H T. Hilliard. The well was abandoned by cement plugs and ~14 ppg, 44 viscosity gel mud in 1985. The original hole had a 2022' of 8-5/8" surface casing and the original borehole size below the surface casing was 7-7/8". We reentered this hole with a 7-7/8" bit in 2009. The hole was essentially closed below the cement plug at 2353'. We had to find our way around the closed portion of the hole and reenter the deeper open portion of the hole at 2450' directionally. It was very slow reaming (the re-drill history mistakenly states drilling but below the 2450' we conducted reaming operations) due to shrunken bore hole. The whole reentering operation took more than 50 days to accomplish (the original hole took 20 days to drill). We encountered severe sloughing shale issues and almost got stuck. The original mud was present in the old well hole and a mixture of the original mud and new mud was observed over the rig shakers at surface. We did not encounter any free formation saltwater as we did not observe any formation water over the shakers. We had to use 14.2 ppg mud weight to keep the hole open. I believe the hole condition in 2009 would have made the vertical migration of formation fluid an impossibility. See attachment C for the redrill and the original drilling histories.

Based on my observation of the well reentries described above I conclude the following:

1) In each re-entry, the old mud was present and was close to the surface of the wellbore below the first surface cement plug.

2) Through the visual inspection of the circulated mud during the re-entry operations, the old mud was observed throughout the entire wellbore, from below the shallowest cement plugs to the bottom of the wellbore and we did not observe any pockets of free formation saltwater during the re-entries.

3) The wellbore diameters of the re-entry wells, as expected, had shrunken, and as expected, in some intervals the wellbores were filled with sloughed shale.

4) The condition of the old wellbores would have prevented the vertical migration of formation fluid at the time of the re-entries.

Referring again to Sproule 1-2 as an example, it was drilled with 10.8 ppg mud when 9 ppg mud would have been sufficient to control the formation pressure at the Mokelumne River formation level. The extra mud weight was used to keep the hole open and prevent sloughing shale. Reduced borehole size over time would also provide further resistance to the initiation of flow of the mud column as P_G is inversely proportional to the borehole diameter. For the assessment of the wells shown in Table 2, an assumption of no borehole size shrinkage was assumed for the calculation of P_G, making the calculated values conservative.

Polk and Gary (1993, See attachment D) investigated the adequacy of mud as a sealing agent**,** with similar observations regarding sloughing shale and the presence of mud in old abandoned wellbores. In the mentioned paper, the examined wells were in Louisiana and Mississippi. Based on Irani Engineering drilling experience in Louisiana and Mississippi, the formations in the mentioned states are much more stable than California which means abandoned wells in California should potentially shrink more diameter and have more sloughing shale accumulation.

Chemours DeLisle 2017 HWDIR Exemption Application (GKS Project No.: DLC 160183) compiles and cites similar reentry observations as we have experienced **–**

"Subsurface, Inc. (1976) reentered and re-plugged the Brewster Bartle Drilling Company (British American Oil Production Company), University of Texas No. 1B (Galveston County, Texas) during 1976, at the request of Amoco and Monsanto. The 11,720-ft dry hole was abandoned with casing left in place to 11,200 ft. Cement plugs were placed from 11,000 to 11,200 ft, and from 130 to 180 ft, and also near the surface. Mud-laden fluid filled the remainder, conforming to Texas Railroad Commission plugging and abandonment requirements of 1961. During the reentry operation, drilling mud was found immediately below the surface cement plug with its properties relatively intact. A drill bit was run on tubing to 960 ft, after the upper cement plug was broken through. The well fluid was then circulated out using 12-lb/gal mud. This confirms that mud properties maintain their plugging capabilities and offer major resistance as fluid barriers. AIC (1988), in a study of well reentries originally plugged 20 to 30 years ago, found that in the Gulf Coast (Texas) and West Texas, most operators reported finding the top of the mud just below the surface plug. In the Gulf Coast, mud was generally hard, whereas in West Texas, the mud was soft.

The following comments reflect the condition of the drilling mud and/or borehole fluids encountered in the Gulf Coast:

• mud sets up like cement;
• mud sets up firm after about five years;
• mud encountered is hard and firm; and
• the top of the mud is usually just below the top cement plug"

4) In California, a vast majority of wells have been drilled using barite and gel mud system (this is the case for all the abandoned wells near CTV's project). Based on our observations, gel mud systems set up very quickly when circulation and movement of mud seizes. For example, there have been occasions during the drilling operations where due to unforeseen circumstances the mud circulation systems have broken down and remained out of service for a few days. Under the resulting static conditions, the mud system gelled up to a point where the logging equipment floated in the mud and did not get to the bottom of the hole. Staging in the hole method, which involves running drill pipe in the hole in stages and circulation and conditioning mud with extra water, had to be deployed before getting to the bottom of the hole and making the mud useable. In a gelled-up mud system, the majority of the barite particles remain permanently suspended in the mud column instead of falling to bottom, thereby retaining the essential mud weight (density) of the mud which provides the positive pressure on the formation. Also, any saltwater intrusion into gel mud system causes coagulation of the mud which makes it more like a cement slurry (in the industry we call it clabbered up mud). The notion that formation saltwater can migrate through these kind of mud systems is thus not realistic.

Based on these observations, a realistic and likely picture of the current condition of the uncased wellbores in the project area is that of a wellbore that has shrunken in diameter, filled with clabbered up mud and a long column of sloughed shale on bottom (see attached Figure 2 for illustration of Sproule 1-2).

D) Potential for penetrations to allow fluid migration from Injection zone to the USDW

As described in the previous section, the present condition of an uncased wellbore in the project area would be a shrunken wellbore, filled with gelled up mud, and sloughing shale on bottom. Would a wellbore with gelled up mud, sloughing shale and shrunken wellbore diameter allow fluid migration from the Injection zone to the base of the USDW? We have considered three scenarios in answering that question.

Scenario 1: The mud and sloughing shale are still in some state of liquid form. In this case, as an example, for Sproule 1-2, the mud column would exert a ΔP_H of 722 psi over the initial Mokelumne River formation pressure which is more than 340% of the expected 163 psi pressure as the result of 5years of CO2 injection and more than 200% of the expected 280 psi peak pressure increase. Even assuming the lowest drilling mud weight of any wells in the vicinity (9.9 ppg at Borges No. 1 well), the ΔP_H calculates to be +450 psi, 200% more than 163 psi pressure increase at 5yeats of injection and 60% more than the 280 psi peak pressure increase expected. In addition, the gel strength pressure, provides additional resistance to the inducement of fluid flow. No vertical movement of fluid is expected in this scenario.

In the region, Hilmar's MW-1D and MW-2D monitoring wells (associated with Class I disposal Project# R9UIC-CA1-FY15-2R) which were drilled in 2023 per EPA's mandate, the base of USDW was squeezed in both wells with cement slurry. It took more than 1000 psig positive pressure at surface to initiate flow. Cement slurry looks a lot like gelled up mud with similar viscosity. Since the hydrostatic gradient of cement slurry is much higher than mud (0.81 psi/ft for 15.8 ppg cement slurry compared to 0.52 psi/ft for 10 ppg mud), it stands to reason to expect an even higher pressure for squeezing gelled up mud into the base of the USDW. For example, at MW-1D we squeezed ~890 linear feet of 15.8 ppg cement slurry into the base of the USDW at 1750' with the initial injection pressure of 1100 psig (see the attached history for MW-1D). Assuming 890' of 10 ppg gelled up mud column in the wellbore with a similar viscosity as the cement slurry, the squeeze pressure could have been as high as ~ 1368 psig as shown in the calculations below:

<u>Surface Squeeze Pressure for mud column instead of cement slurry:</u> 15.8 ppg (cement slurry weight) X 890' (column of cement slurry) X 0.05194 (conversion factor) – 10 ppg (mud slurry weigh) X 890' (assuming column of mud instead of cement slurry) X 0.05194 (conversion factor) + 1100 psig (Squeeze pressure at surface) = 1368 psig.

Scenario 2: The mud is in a solid form. In this case, the column of solid mud and sloughing shale exert minimum, if any, positive hydraulic delta Pressure to the Mokelumne formation, and instead behaves as a low permeability column of material. **Polk and Gary's (1993)** model for analyzing vertical movement of formation fluid from the Lower Tuscaloosa to the USDW assumed that the barite in the mud would settle on bottom which is a very conservative approach compared to the relatively solid suspended barite mud column seen in the re-entry wells. Polk and Gary's model showed that at 158 psi delta-Pressure there was no vertical migration of fluid from the lower Tuscaloosa formation to the base of USDW due the low permeability of the sloughing shale, and mud cake. Test of mud cake by **Gary and Polk (1984)** showed permeability of 0.2 x 10^{-8} to 8 x 10^{-9} cm/sec which is lower than the EPA's low permeability threshold of 1 x 10^{-7} cm/sec.

As mentioned above, **Polk and Gary's (1993)** settled mud column model was very conservative. A model using solid column of mud with suspended barite would be even more resistant to the vertical migration of fluid. Even though, the permeability of mud in deep wells has not been measured, we would expect the permeability to be closer to 10^{-9} CM/Sec (which is lower than EPA's low

Scenario 3: This scenario assumes, despite strong arguments in Scenario 1&2, a vertical movement of formation has been initiated. Would it contaminate the base of the USDW? Based on CTV's core analysis and log calculations for the project area, the Mokelumne formation estimated average permeability is 180 md, the average Domengine permeability is 191 md, and the average USDW permeability is 50 md. At Sproul 1-2, the bottom of the Domengine formation is about 330' above the top of the Mokelumne formation, the base of the USDW is about 3300' above the top of the Mokelumne formation. Physics would dictate that fluid would travel through the path of least resistance which in this case would be the Domengine formation not the base of the USDW and as such the Domengine would serve as the dissipation zone for any brine flow from the Injection

E) Formation Pressure Increase due to Injection:

Irani Engineering has performed the annual MIT tests for several Class I and II injection wells in California for many years. I have noticed that in all the cases, the actual formation pressure increases in the injection zone, if any, are substantially smaller than the predicted increase from numerical models used for estimating the AOR. I believe, high permeability massive sands with a strong water drive characteristic such as the Mokelumne River formation, dissipate the pressure faster than what the numerical models are predicting which further diminishes the chances for brine leakage from the injection zone to shallower zones.

F) Conclusion:

On the bases of the scientific papers discussed in this report, the reports of the re-entries into old abandoned wells by other operators, my own personal experience of drilling numerous wells and reentering 5 abandoned old wells in California, and most importantly the properties of the mud's used in the drilling of wells in the CTV III project area, I conclude that CTV's CO2 injection project will not be a source of contamination to the USDW.

Saeed Irani

Saeed Irani
President Irani Engineering, Inc.
Registered Petroleum Engineer

October 12, 2023

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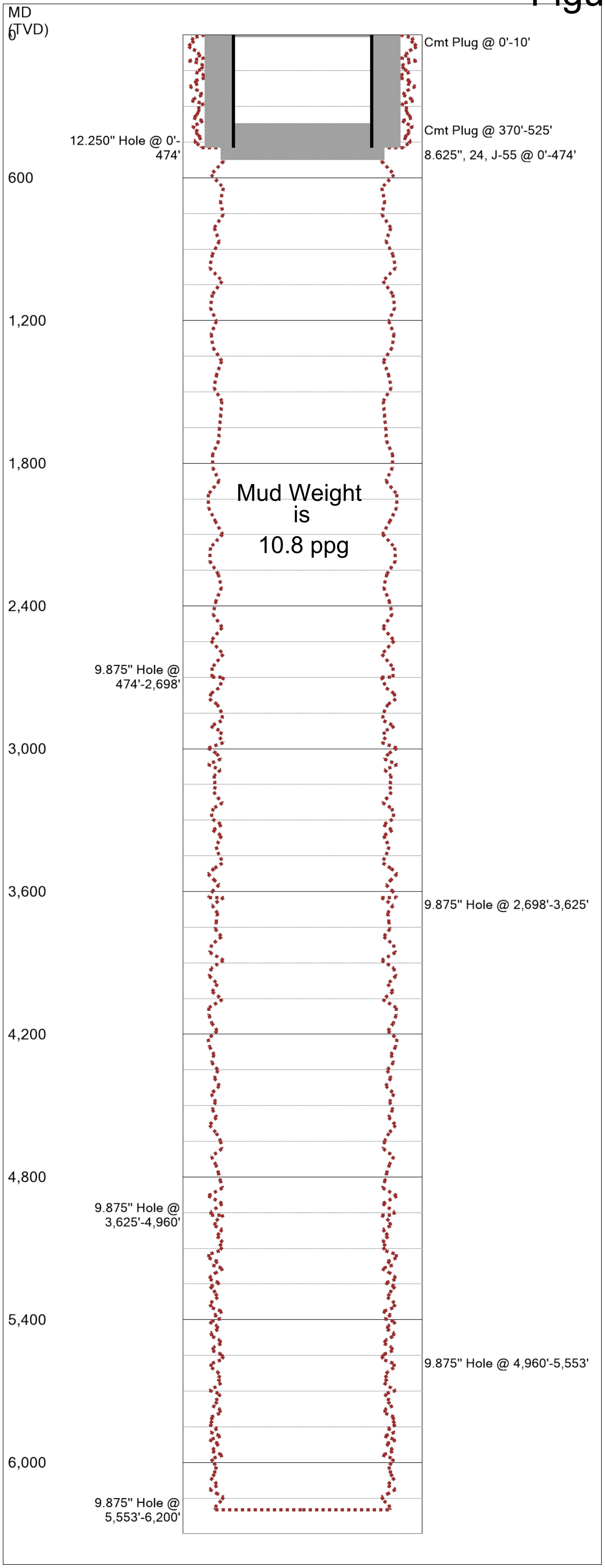
FIGURES

Figure 1



Wellbore configuration in 1965 post abandonment

Last Updated: 2/24/2022 03:36 PM

Field Name	Lease Name	Well No.
ANY FIELD	INTEX OIL INC	SPROULE_1-2

County	State	API No.
CONTRA COSTA	CALIFORNIA	04-013-00226-0000

Version	Version Tag
0	

GL (ft)	KB (ft)	Section	Township/Block	Range/Survey
7.0	13.0	2	S	E

Operator	Well Status	Latitude	Longitude
INTEX OIL INC	DRY & ABANDONED	+37.871150000	-121.607860000

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

Prop Num	Spud Date	Comp. Date
	3/30/1965	4/6/1965

Additional Information

Other 1	Other 2	Other 3	Other 4

Prepared By	Updated By	Last Updated
Chamba	Chamba	2/24/2022 3:36 PM

Hole Summary

Date	Diam. (in)	Top (MD ft)	Bottom (MD ft)	Memo
3/30/1965	12.250	0	474	
4/1/1965	9.875	474	2,698	Dev. 2698' 0°
4/2/1965	9.875	2,698	3,625	Dev. 3485' 1°
4/3/1965	9.875	3,625	4,960	Dev. 4153' 1°
4/4/1965	9.875	4,960	5,553	Dev. 4960' 1°
4/5/1965	9.875	5,553	6,200	Dev. 6200' 2°

Tubular Summary

Date	Description	O.D. (in)	Wt (lb/ft)	Grade	Top (MD ft)	Bottom (MD ft)
3/31/1965	Surface Casing	8.625	24.00	J-55	0	474

Casing Cement Summary

C	Date	No. Sx	Csg. O.D. (in)	Top (MD ft)	Bottom (MD ft)	Memo
	3/31/1965	150	8.625	0	474	

Cement Plug Summary

C	Date	No. Sx	O.D. (in)	Top (MD ft)	Bottom (MD ft)	Memo
	4/6/1965		8.625	0	10	Cmt Plug @ Surface-10'
	4/6/1965	100	10.250	370	525	Cmt Plug @ 370'-525'

Figure No. 2

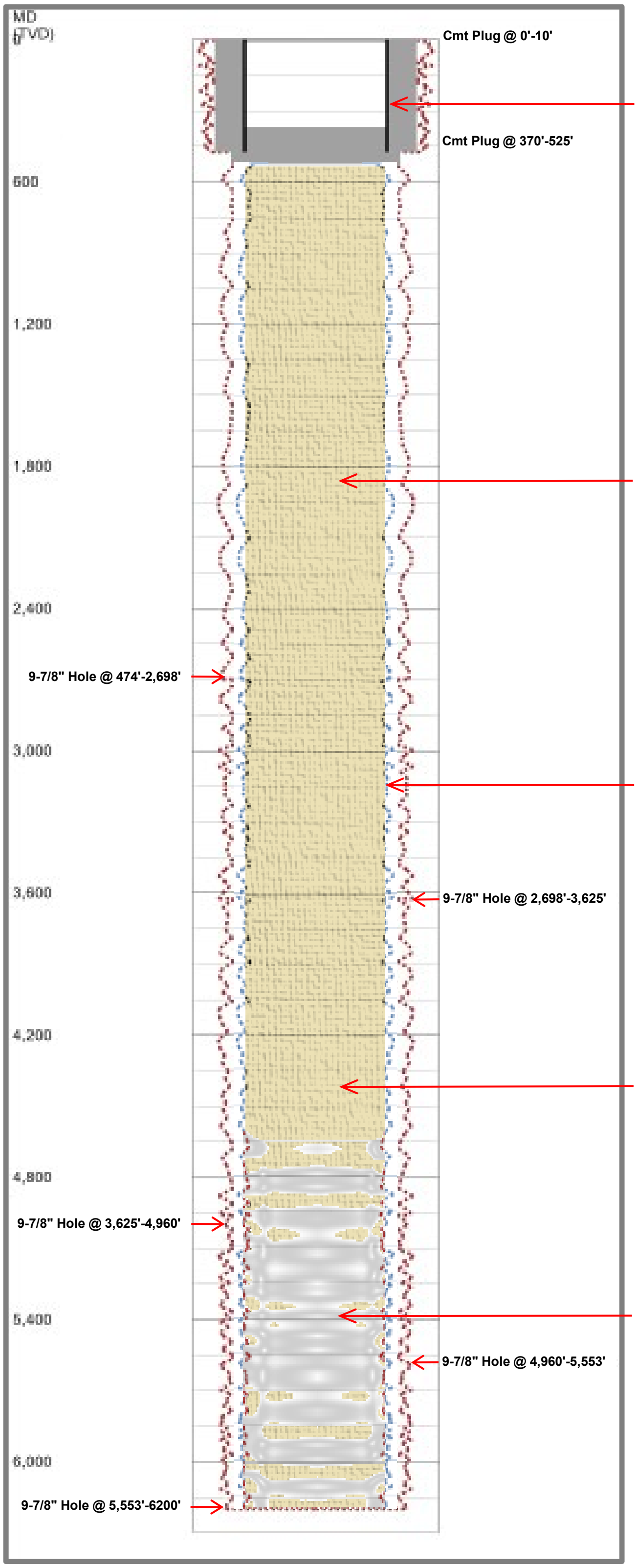
Sproule No. 1-2

API No. 0401300226-00

Sec 2, T 1S, R 3E, MD B&M, Contra Costa Co., CA

Elevation: +7' Ground, +20' KB Depiction of Wellbore in 2023

This is a vertical well.

Installation	Depth & Description	OD	ID
	**8-5/8", 24#, J-55 STC Csg at 474'** **(Cemented to surface with 150 sacks of cement)**	**8.625"**	**7.972"**
	Clabberd up Mud (original mud weight was 10.8 ppg)		
	Shrunken Wellbore		
	Clabberd up Mud		
	Sloughed Shale		

TABLES

Table 1: List of 43 wells in the immediate CTV III project area outside of the CO_2 plume, and the modeled pressure increase at the well locations after 5years of injection, and the peak predicted pressure increase.

Wellname	API12	Latitude (ºN)	Longitude (ºE)	Modeled Pressure increase in 5yr, psi	Maximum modeled Pressure Increase, psi
SPROULE_1-2	040130022600	37.87108	-121.60893	163	280
PERRY_1	040132002500	37.85817	-121.62473	147	262
DALTON_FARMS_1	040130027300	37.9227	-121.58209	145	244
SPROULE_1	040130023100	37.85457	-121.61131	144	262
ROSA_1	040132010600	37.9057	-121.61977	142	254
TURNER_1	040770030700	37.85254	-121.53986	141	260
BIGELOW_1-27	040132021700	37.89906	-121.62938	130	234
CALPAK_10-3	040770030500	37.85613	-121.52026	126	241
CALIF_PACKING_CORP_1	040770030400	37.85475	-121.51499	123	237
WOODWARD_ISLAND_UNIT_20-1	040130027400	37.92299	-121.56098	122	220
WOODWARD_ISLAND_UNIT_20-1	040130027401	37.92299	-121.56098	122	220
SPROULE_1	040130023200	37.84549	-121.61234	118	227
CALPACK_1	040772000900	37.85962	-121.50472	117	229
THORPE_1	040770042100	37.9209	-121.50451	111	200
HAYES_1-7	040132027600	37.94161	-121.58373	103	191
ALLIED_PROPERTIES_ET_AL_1	040770000100	37.90657	-121.49056	103	196
BIXLER_1-14	040132036100	37.93518	-121.61557	103	202
MCCULLOCH_LAMB_1	040770030600	37.86707	-121.4844	103	208
ARNAUDO_18-1	040132031000	37.93842	-121.57694	97	187
R_M_FARMS_1	040772068100	37.85201	-121.48801	97	216
SIGNAL_ALLIED_PROPERTIES_1	040770041800	37.94344	-121.52666	95	188
CALIFORNIA_PACKING_CORP_1	040770030900	37.83209	-121.50993	95	233
ALLIED_PROPERTIES_1	040770042000	37.94043	-121.50881	90	181
MANTELLI_1	040772014500	37.9293	-121.49651	89	180
PACIFIC_STATES_1	040770042200	37.92082	-121.48868	89	183
RIVERVIEW_INV_CO_1	040772049500	37.95377	-121.53835	88	182
HACKEL_FERGUSON_1	040770031100	37.82151	-121.49591	88	230
WM_C_FERGUSON_1	040770031200	37.82126	-121.49942	85	230
NORRIS_GRUNAUER_1	040772016700	37.81657	-121.49803	83	230
HOC_SHELL_SORENSEN_1	040770031000	37.81622	-121.48467	78	223
KRONER_1-35	040772037400	37.8086	-121.51119	75	224
WICO_BANKHEAD_1	040770031300	37.79663	-121.52454	74	225
OHLENDORF_UNIT_2_1	040772035900	37.80368	-121.48268	70	222
PESCADERO_1	040770032100	37.80255	-121.45388	66	217
PESCADERO_1_RD1	040770032101	37.80255	-121.45388	66	217
L_COCHRAN_20-1	040772041000	37.83321	-121.45104	65	195
L_COCHRAN_20-1_RD1	040772041001	37.83321	-121.45104	65	195
HALL_1	040770034000	37.78811	-121.4593	64	219
OHLENDORF_UNIT_1_1	040772034800	37.79097	-121.46852	62	217
DUSINA_1	040772014700	37.77692	-121.49012	62	221
GETTY_DUSINA_1	040772008700	37.77713	-121.48145	62	223
BORGES_1-7	040772041700	37.77989	-121.46532	62	220
GONSALVES_1	040772055800	37.77272	-121.47054	58	218

Table 2: List of 43 wells in the immediate CTV III project area with their recorded hole sizes, mud weights during abandonment, formation depths, and calculated ΔP_H, P_G and $\Delta P_{Allowable}$ using - 1) the recorded mud weight 2) lowest mud weight of the well set 3) Applying a 20% Safety factor on calculated ΔP_H and $\Delta P_{Allowable}$ using lowest mud weight of the well set

							Using Recorded Mud Weight			Using Lowest Mud Weight (9.9ppg) of Well Set			Applying 20% Safety factor		
Wellname	API12	Hole Size, inches	Mud wt in Pounds per gallon (ppg)	Injection zone Depth, ft	USDW Depth, ft	Initial Formation Pressure in Injection Zone, psi	ΔP_H, psi	P_G, psi	$\Delta P_{Allowable}$, psi	ΔP_H, psi	P_G, psi	$\Delta P_{Allowable}$, psi	ΔP_H, psi	P_G, psi	$\Delta P_{Allowable}$, psi
BORGES_1-7	040772041700	7.875	9.9	5,278	2,523	2,308	404	44	448	404	44	448	323	35	358
ALLIED_PROPERTIES_1	040770042000	6.25	9.9	5,576	2,480	2,438	427	59	486	427	59	486	341	47	388
GETTY_DUSINA_1	040772008700	7.875	10.0	5,498	2,480	2,404	449	46	495	421	46	467	337	37	373
BIGELOW_1-27	040132021700	6.75	9.9	5,960	2,392	2,606	456	58	514	456	58	514	365	46	411
L_COCHRAN_20-1	040772041000	6.25	10.1	5,429	2,589	2,374	472	57	529	415	57	473	332	46	378
L_COCHRAN_20-1_RD1	040772041001	6.25	10.1	5,429	2,559	2,374	472	57	529	415	57	473	332	46	378
SPROULE_1	040130023100	8.75	10.2	5,599	2,456	2,448	516	42	558	428	42	471	343	34	376
CALPACK_1	040772000900	12.25	10.2	5,698	2,687	2,492	525	31	555	436	31	467	349	25	373
ROSA_1	040132010600	9.875	10.0	6,231	2,424	2,725	509	42	551	477	42	518	381	34	415
RIVERVIEW_INV_CO_1	040772049500	8.75	10.1	6,047	2,597	2,644	525	46	571	463	46	508	370	37	407
HOC_SHELL_SORENSEN_1	040770031000	8.75	10.4	5,290	2,652	2,313	542	40	582	405	40	445	324	32	356
PERRY_1	040132002500	8.625	10.4	5,449	2,408	2,383	558	42	600	417	42	459	334	34	367
PESCADERO_1	040770032100	8.75	10.8	4,654	2,544	2,035	573	35	609	356	35	391	285	28	313
OHLENDORF_UNIT_2_1	040772035900	9.625	10.4	5,640	2,713	2,466	578	39	617	432	39	470	345	31	376
SIGNAL_ALLIED_PROPERTIES_1	040770041800	6.25	10.4	5,708	2,516	2,496	585	60	645	437	60	497	349	48	398
TURNER_1	040770030700	15	10.4	5,741	2,570	2,511	588	25	613	439	25	465	351	20	372
MCCULLOCH_LAMB_1	040770030600	8.75	10.4	5,807	2,501	2,539	595	44	639	444	44	488	355	35	390
GONSALVES_1	040772055800	7.875	10.7	5,256	2,531	2,298	620	44	664	402	44	446	322	35	357
HALL_1	040770034000	8.5	10.7	5,330	2,527	2,331	629	41	670	408	41	449	326	33	359
CALPAK_10-3	040770030500	8.75	10.6	5,652	2,544	2,472	638	43	680	432	43	475	346	34	380
WM_C_FERGUSON_1	040770031200	10.625	10.7	5,376	2,634	2,351	635	33	668	411	33	445	329	26	356
DUSINA_1	040772014700	8.75	10.6	5,555	2,664	2,429	627	42	669	425	42	467	340	34	374
SPROULE_1	040130023200	6	10.7	5,515	2,473	2,412	651	61	712	422	61	483	338	49	386
WOODWARD_ISLAND_UNIT_20-1	040130027400	8.75	10.6	5,930	2,572	2,593	669	45	714	454	45	498	363	36	399
WOODWARD_ISLAND_UNIT_20-1	040130027401	8.75	10.6	5,930	2,572	2,593	669	45	714	454	45	498	363	36	399
PACIFIC_STATES_1	040770042200	9.625	10.7	5,656	2,483	2,473	668	39	706	433	39	472	346	31	377
R_M_FARMS_1	040772068100	8.875	10.7	5,714	2,518	2,499	674	42	717	437	42	480	350	34	384
KRONER_1-35	040772037400	8.75	10.8	5,678	2,589	2,483	700	43	742	434	43	477	348	34	382
BIXLER_1-14	040132036100	6.75	10.4	6,801	2,507	2,974	697	66	763	520	66	587	416	53	469
SPROULE_1-2	040130022600	9.875	10.8	5,856	2,443	2,561	722	39	761	448	39	487	358	31	390
OHLENDORF_UNIT_1_1	040772034800	8.75	11.0	5,533	2,689	2,420	739	42	781	423	42	465	339	34	372
ALLIED_PROPERTIES_ET_AL_1	040770000100	7.875	11.0	5,727	2,494	2,504	765	48	813	438	48	486	351	38	389
HACKEL_FERGUSON_1	040770031100	8.75	11.2	5,354	2,638	2,341	771	40	811	410	40	450	328	32	360
HAYES_1-7	040132027600	7.875	10.5	7,374	2,563	3,225	794	62	856	564	62	626	451	50	501
ARNAUDO_18-1	040132031000	7.875	10.7	6,851	2,544	2,996	809	57	866	524	57	582	419	46	465
CALIFORNIA_PACKING_CORP_1	040770030900	8.75	11.4	5,499	2,589	2,405	849	41	890	421	41	462	337	33	370
NORRIS_GRUNAUER_1	040772016700	8.75	11.5	5,353	2,623	2,341	854	40	894	410	40	450	328	32	360

CALIF_PACKING_CORP_1	040770030400	8.5	11.4	5,646	2,542	2,469	872	44	915	432	44	476	346	35	381
DALTON_FARMS_1	040130027300	8.75	11.1	6,482	2,554	2,835	900	49	949	496	49	545	397	39	436
THORPE_1	040770042100	8.75	11.7	5,671	2,505	2,480	964	43	1,006	434	43	477	347	34	381
MANTELLI_1	040772014500	8.5	11.8	5,602	2,742	2,450	981	43	1,025	429	43	472	343	34	378
WICO_BANKHEAD_1	040770031300	9.875	11.9	5,565	2,785	2,434	1,003	37	1,041	426	37	463	341	30	370
PESCADERO_1_RD1	040770032101	8.75	10.8	4,470	2,544	1,955	551	34	585	342	34	376	274	27	301

Attachment A

Assessment of Environmental Implications of Abandoned Oil and Gas Wells

D.L. Warner and **C.L. McConnell**, U. of Missouri-Rolla

Summary

A detailed study was made of the potential for abandoned oil and gas wells in the Lower Tuscaloosa sand of Mississippi and Louisiana to act as conduits for movement of saline water from the Lower Tuscaloosa into underground sources of drinking water (USDW's). Finite-difference numerical modeling determined the extent that water might be forced from the Lower Tuscaloosa sand into a USDW as a result of injection into the Lower Tuscaloosa. Within the range of conditions modeled, water from the Lower Tuscaloosa never traveled into a USDW. On the basis of the modeling, we concluded that it is unlikely that abandoned oil and gas wells in the Lower Tuscaloosa would serve as conduits for water movement from the trend into a USDW. The procedures developed in this study should be readily applicable to analysis of the potential for abandoned wells to act as pathways for contaminant flow into USDW's in other oil and gas producing areas of the country.


Warner


McConnell

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Introduction

Purpose and Scope of Study. Because of the increasing focus by U.S. regulatory agencies on abandoned oil and gas wells, the U. of Missouri-Rolla conducted research to assess the potential for abandoned oil and gas wells in the Lower Tuscaloosa sand oil-producing trend of Mississippi and Louisiana to act as conduits for flow of saline water from the Lower Tuscaloosa into USDW's.

Fig. 1 shows locations of selected wells from oil fields in the Lower Tuscaloosa sand. The Lower Tuscaloosa sand trend extends for about 135 miles from south-central Mississippi northwest into eastern Louisiana and for about 100 miles from north to south.[1]

The study included assembly of geologic and engineering data to formulate numerical models to simulate the range of flow conditions through abandoned wells in the Lower Tuscaloosa trend. The final step in the study was the actual numerical simulation of flow conditions for these abandoned wells. The simulations performed are believed to represent conditions throughout the Lower Tuscaloosa sand and the conclusions should be applicable to all abandoned Lower Tuscaloosa sand wells. The study is intended as an example that can be replicated in other oil- and gas-producing areas with similar conditions. To conduct such a study, sufficient information concerning the subsurface geology and hydrology, oil production history, and historic well construction and abandonment practices must exist or be possible to obtain to develop a realistic computer model. Also, geologic and hydrologic conditions that are sufficiently consistent over some area or distance are needed for the model to be represent enough cases to make modeling worthwhile. One would not be likely to conduct such modeling where every injection well required formulation of a new model.

Previous Work. Ward *et al.*[2] performed the first numerical modeling work on the movement of fluids through an abandoned well. Ward *et al.* modeled the leakage of injected contaminants through an abandoned unplugged borehole. The work demonstrated the capability of the SWIFT III[3] model for such investigations, but has no direct application to the problem studied here. Ward *et al.*'s investigation involved tracking wastes moving from an injection well to and up through an abandoned well. The problem here involves tracking the movement of native saline water from a saline-water-bearing aquifer in response to the pressure created by an injection well. Although significant differences exist in the details of the two problems, most procedures in setting up the models and data input are the same. In the modeling of injected waste movement, the injected fluid was tagged and tracked and no attention was given to the native saline water residing in the injection reservoir. In this problem, the injection fluid was assumed to the same as the native saline water and all the water that moved up the borehole was considered a potential contaminant to USDW.

Warner[4] modeled the response of a specific existing abandoned well in the West Mallalieu oil field to injection through a nearby water-injection well.

Javendel *et al.*[5] developed an analytical model of the abandoned well problem. While this model cannot be used to determine the effect of an abandoned well on the quality of groundwater in a USDW, it allows calculation of the gross amount of water that can flow into an abandoned well and thus provides a means to compare the results of numerical modeling of the flow into an abandoned well with a much simpler analytical calculation. The Javendel analytical model was used to verify the accuracy of flow results obtained from the numerical model during calibration.

Abandoned Well Problem

Thousands of wells have been drilled and abandoned during the 130-year history of the U.S. petroleum industry. Regulations for plugging these wells, nonexistent in the early days of the industry, have evolved over the years to their present effective level. Thus, an unknown but large number of abandoned wells exist that may be unplugged or inadequately plugged by today's standards.

As a result of incidents in which abandoned wells were implicated as sources of groundwater contamination, such wells are often considered indiscriminately to be potential pathways for contamination of a USDW. Contamination can result from interaquifer flow of natural formation water or by transmission of injected fluids from the injection reservoir to a USDW.

The relative contamination potential of such wells actually ranges from highly likely

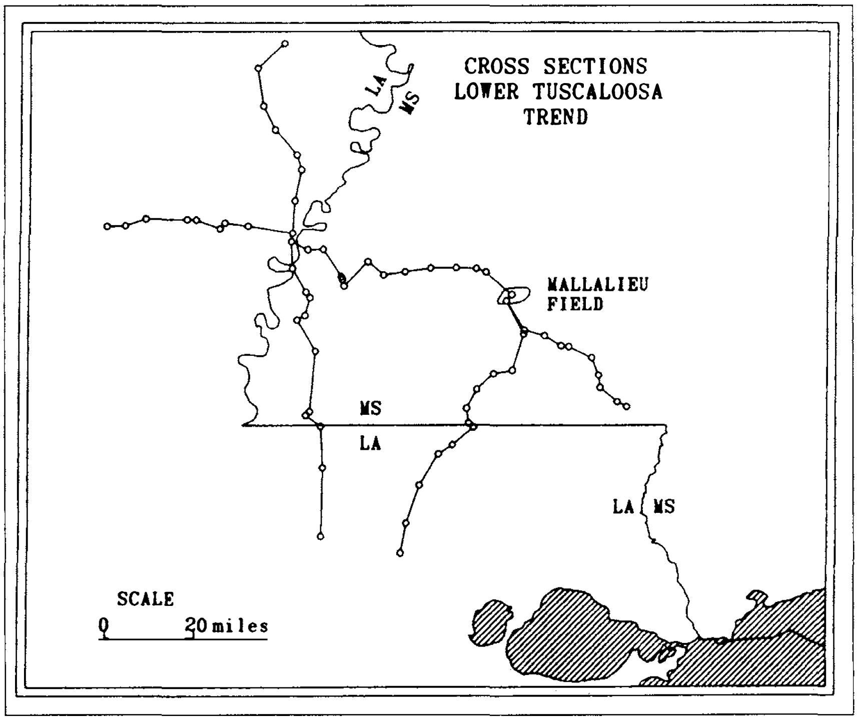

Fig. 1—Map showing locations of wells used in Lower Tuscaloosa trend study.

"Thus, an unknown but large number of abandoned wells exist that may be unplugged or inadequately plugged by today's standards."

to impossible, depending on a complex set of well factors and geologic and hydrologic circumstances. The relative contamination potential of an abandoned well or wells in a particular geologic and hydrologic setting can be analyzed qualitatively by understanding the factors involved. Warner[6] listed and discussed these factors, which include well age, depth, type, and construction; well plugging and abandonment history; and the hydrogeologic conditions at the wellsite.

Review of these general well characteristics often can establish that a well has no contamination potential because its physical condition, hydrogeology, or perhaps both, prevent migration of saline water or other liquids from aquifers containing waters with >10,000 mg/L of dissolved solids into USDW's. In such cases, no further investigation of the well is necessary.

In instances where an abandoned well does have possible pathways for natural brines or injected fluids to migrate into USDW's and where the hydrogeology is amenable to interaquifer flow, quantitative analysis with numerical computer models may predict whether such interaquifer flow is likely. This paper documents both qualitative and quantitative evaluation of abandoned oil and gas wells in the Lower Tuscaloosa trend of Mississippi and Louisiana.

General Description of Numerical Model

Modeling for this research project was carried out with the SWIFT III numerical code. SWIFT III,[3] the result of more than 10 years of model evolution, is a revised and improved version of a code originally developed for the U.S. Geological Survey specifically for injection-well modeling. Predecessor codes include SWIP,[7] SWIPR,[8] SWIFT,[9] and SWIFT II,[10,11] all publicly available through the Natl. Technical Information Service, Arlington, VA, and the Natl. Energy Software Center, Argonne, IL.

The SWIFT III code is a fully transient, 3D, finite-difference numerical code that solves the coupled equations for fluid flow, transport of chemicals that do not decay radioactively, transport of radionuclides, and heat transport. According to Prickett *et al.*[12] the SWIP (or SWIFT) type models are the latest and most comprehensive models available. No comparable numerical model is known to exist today for the type of modeling carried out in this research project.

Geology and Petroleum Production in the Lower Tuscaloosa Trend

Fig. 2 depicts a generalized stratigraphic column of the Mallalieu field, Lincoln County, MS. Strata shown in Fig. 2 range in age from the Cretaceous Lower Tuscaloosa sand at the base to the Eocene Cook Mountain and Sparta sand units at the top of the column. At the Mallalieu field and elsewhere in southern Mississippi and in southeastern Louisiana, Strata of Oligocene through Holocene Age overlie the Cook Mountain and Sparta.

The only geologic unit that has produced oil or gas in the study area is the Lower Tuscaloosa sand. This fact is of practical importance, because there are no younger and shallower or deeper and older producing units in the many Lower Tuscaloosa fields into which oil- or gas-producing wells have been drilled and abandoned. The possibilities for interaquifer flow through abandoned wells that must be considered are limited because it is not necessary to be concerned about significant number of wells other than those drilled to the Lower Tuscaloosa sand.

The fact that the Lower Tuscaloosa is the only producing formation also restricts the manner in which wells have been drilled, completed, and abandoned. Lower Tuscaloosa oil production began in the early 1940's, and fields are now in the very late stages of petroleum recovery. For example, The Mallalieu and Little Creek fields are undergoing tertiary oil recovery by CO_2 injection. By the 1940's, when drilling in the Lower Tuscaloosa trend began, the technology and regulation of well construction and abandonment had already advanced considerably over practices in the early 1900's. The actual practices used are covered in the next section.

Cross sections developed for the study[1] show correlation of the strata throughout the Lower Tuscaloosa oil-producing trend. The cross sections show the remarkable continuity of the overall geologic units within the study area. Very rapid changes in stratigraphy occur within major geologic units, even between wells in the individual oil fields, but the major units remain present throughout the trend. The cross sections show that, while all the geologic units of interest differ in thickness and lithologic detail in any one of the oil fields for which a log is shown, the section in the Mallalieu field is as representative as any that could be selected. Therefore, the stratigraphic section for the Mallalieu field (Fig. 2) was selected for modeling purposes.

Uncased Well Scenario. Fig. 3 shows the conditions of the uncased well scenario. This scenario is very straightforward in that sur-

TABLE 2—PRESSURE BUILDUPS AND FLOWS WITH TIME FOR A 20-B/D INJECTION RATE AND LOWER TUSCALOOSA SAND PERMEABILITY OF 2 md, UNCASED ABANDONED WELL SCENARIO

Time Since Injection Began (days)	Δp of BHP, Injection Well (psi)	Δp at Bottom of Abandoned Well (psi)	q Into USDW (B/D)	q Into Abandoned Well (B/D)	q Into Upper Tuscaloosa (B/D)
0.01	80.2	0	0	0	0
0.1	122.2	0	0	0	0
1.0	159.7	0	0	4.89×10^{-11}	6.7×10^{-12}
10.0	201.4	2.8	0	3.01×10^{-8}	5.0×10^{-10}
100.0	239.1	26.9	0	7.40×10^{-7}	3.6×10^{-8}
1,000.0	277.2	63.2	0	2.47×10^{-6}	1.7×10^{-7}
2,000.0	288.5	74.4	0	3.26×10^{-6}	2.5×10^{-7}
3,650.0	298.1	84.0	0	4.19×10^{-6}	3.4×10^{-7}

likely be in the lower portion of the Wilcox sand where brine injection could render the water more corrosive. An arbitrary depth of 6,000 ft within the lower Wilcox was selected as the possible location of such a corroded casing interval.

Wellbore Properties of Settled Mud Solids and Formation Materials

Procedures described in Ref. 1 were used to calculate that, in the uncased well scenario, a 154.5-ft-thick column of sloughed shale would be present at the bottom of the hole overlain by a 4,620-ft column of settled mud solids (**Fig. 5**). The porosity of the sloughed shale column was assumed to be that of the in-place material (3%). The permeability of the sloughed shale was assumed to be 0.1 md. The porosity and permeability of the settled mud solids column was assumed to be 84% and 1.0 md, respectively.[1] The 84% settled mud solids porosity is high compared with values normally associated with sedimentary materials. This value is believed to be reasonable, however, for the settled drilling mud including hydratable clays known to be used in the area.

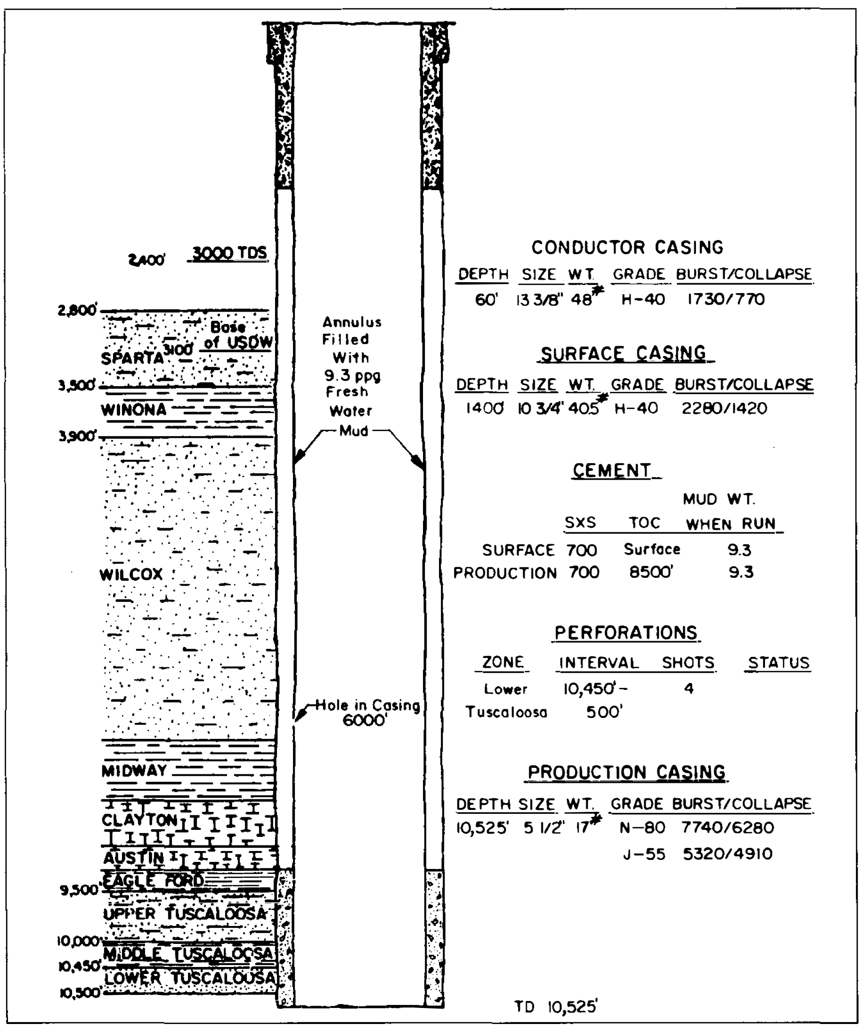

Fig. 4—Illustration of cased abandoned well scenario, Lower Tuscaloosa trend.

In the cased well scenario, a cement sheath extended from bottomhole to 8,500 ft. A 200-ft-thick sloughed shale column was calculated to be present on top of the cement and a 3,740-ft-thick settled mud column on top of the sloughed shale (**Fig. 6**). The sloughed shale and mud solids were assumed to have the porosity and permeability values given for the uncased well scenario.

Modeling of Two Regional Scenarios

Uncased Well Scenario. A 3D 47×20-node$\times10$-layer model grid was designed for simulation of the uncased well scenario. The *x-y* grid nodes were spaced logarithmically to provide an efficient gridding system. Because the geologic units were treated as if they were homogeneous and areally infinite, the flow field was symmetric and only half of the grid was present in the *y* dimension. The injection and abandoned wells were located 500 ft apart and roughly centered along the *x* boundary. The *x-y* extent of the grid was 10×10^5 by 9×10^5 ft and was established by trial and error to be large enough to avoid significant boundary effects during the 10-year modeling period.

Fig. 5 shows the 10 model layers used in the vertical, or *z*, dimension. The layers were selected to discriminate both the major hydrogeologic units and the sloughed shale and settled mud layers in the borehole. For example, the Lower Tuscaloosa sand, Layer 10, is one 50-ft-thick layer, while the Middle Tuscaloosa is divided into Layers 8 and 9 to reflect the top boundary of the sloughed shale. Similarly, the top of Layer 5, in the Wilcox sand, identifies the top of the column of settled mud solids. **Table 1** lists the model parameter values used in simulation runs for the uncased abandoned well scenario. Two permeability values (2 and 30 md) were used as the likely lower and upper permeability limits for the Lower Tuscaloosa sand.

More than 20 calibration runs were performed for the uncased well scenario simulations. Each simulation required 9 megabytes of core storage and about 4 hours of CPU time. Although no exact analytical solution exists for the scenario modeled here, the modeling results were compared with the fully confined, infinite in horizontal extent, homogeneous, and isotropic case for verification. The actual model results should be

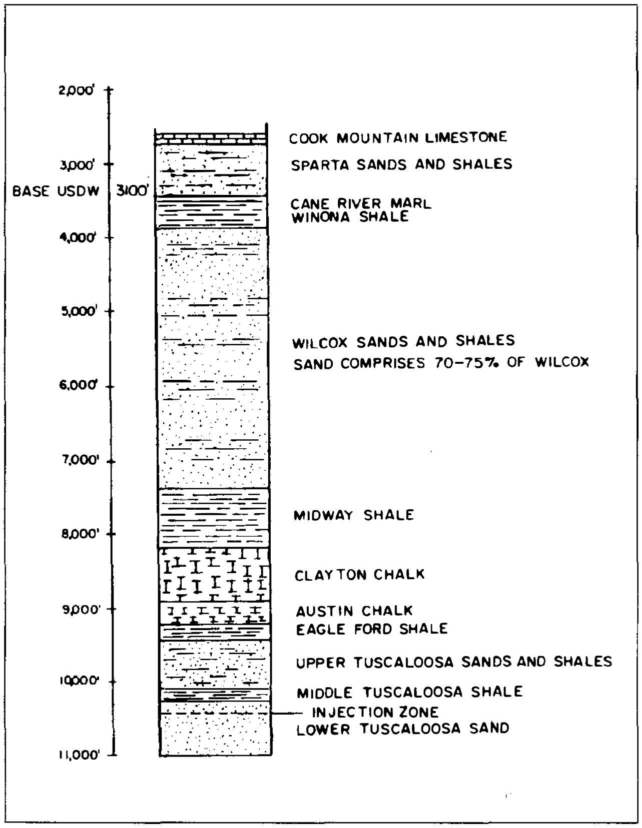

Fig. 2—Generalized stratigraphic column, Mallalieu field, Lincoln County, MS.

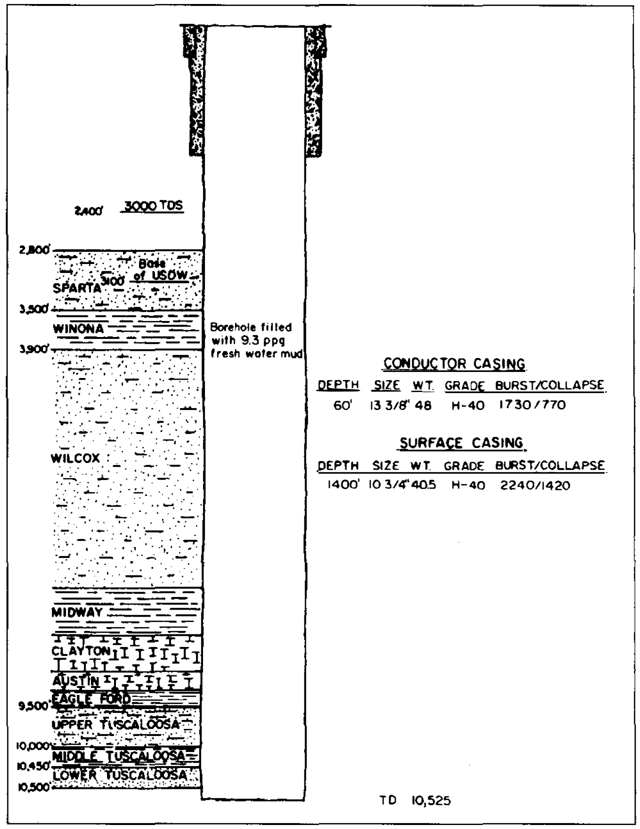

Fig. 3—Illustration of uncased abandoned well scenario, Lower Tuscaloosa trend.

face casing typically was set to about 1,400 to 1,500 ft and cemented to the surface. The remainder of the hole needed to reach the Lower Tuscaloosa sand was left open until the Lower Tuscaloosa was reached and its thickness and production capability assessed. If the Lower Tuscaloosa sand was present and sufficiently thick and promising, the well was cased. If the Lower Tuscaloosa sand was missing, thin, or otherwise unlikely to be economically productive, the well was plugged and abandoned with the drilling mud in the hole and no casing other than the surface casing. Many such abandoned wells contain cement plugs. However, in the worst case, a well might not contain anything other than drilling mud upon abandonment. This worst case scenario was selected for modeling.

Cased Well Scenario. When a Lower Tuscaloosa sand well was drilled and the sand found to be present and likely to be sufficiently productive, the well was cased with production casing through the Lower Tuscaloosa (**Fig. 4**). The production casing was cemented at the bottom with about 2,000 ft of cement. The remainder of the annulus behind the production casing was left mud filled.

Of course, if the casing remained intact, no possible threat to groundwater resources existed. However, the casing could have corroded to the extent that it breached, creating a pathway to formations behind the casing. According to Michie,* the incidence of casing corrosion in the Lower Tuscaloosa sand is very low. If corrosion were to occur, however, Michie* judged it would most

*Personal communication with T.W. Michie, Michie and Assocs., New Orleans (1988).

"...abandoned oil and gas wells in the Lower Tuscaloosa trend of Mississippi and Louisiana are unlikely to serve as conduits for movement of water from the Lower Tuscaloosa into a USDW."

TABLE 1—MODEL PARAMETERS, UNCASED ABANDONED WELL SCENARIO

Model Layer	Permeability, k_x and k_y, $k_z = k_x \times 10^{-1}$ (darcies)	Porosity (%)
1	1	35
2	2.5×10^{-8}	3
3	1	30
4	1	30
5	1	30
6	2.5×10^{-8}	3
7	0.1	23
8	2.5×10^{-8}	3
9	2.5×10^{-8}	3
10	2×10^{-3} or 3×10^{-2}	25
Drilling mud	1×10^{-3}	84
Sloughed shale	1×10^{-4}	3
Empty borehole	3.7×10^{8} (10^{9} ft/D)	100
Other Parameters		
Water compressibility, psi^{-1}	3×10^{-6}	
Rock compressibility, psi^{-1}	5.5×10^{-1}	
Fluid specific weight, lbm/ft^3	67.3	
Viscosity, cp	1	

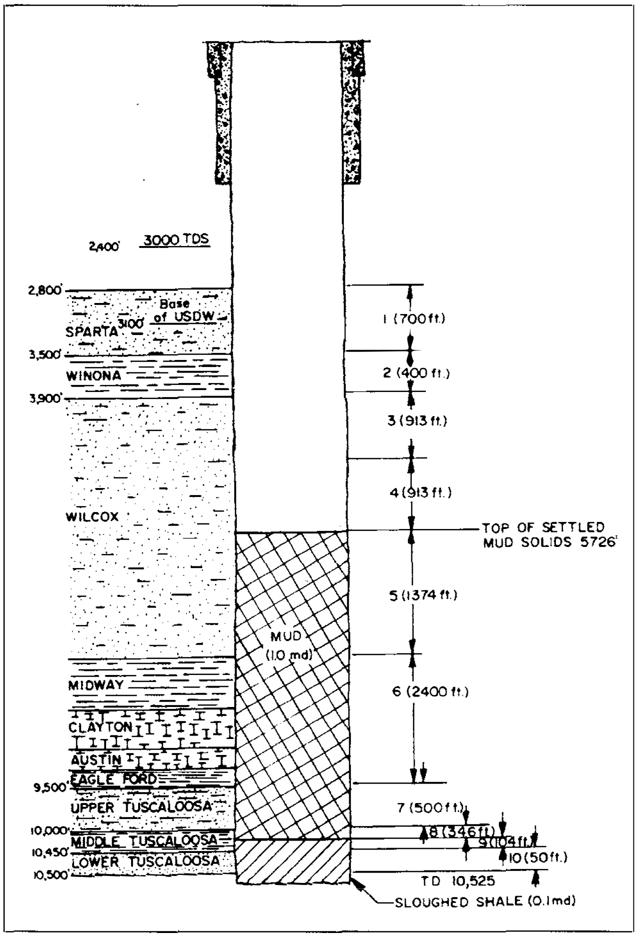

Fig. 5—Illustration of uncased abandoned well scenario, Lower Tuscaloosa trend, showing finite-difference model layers.

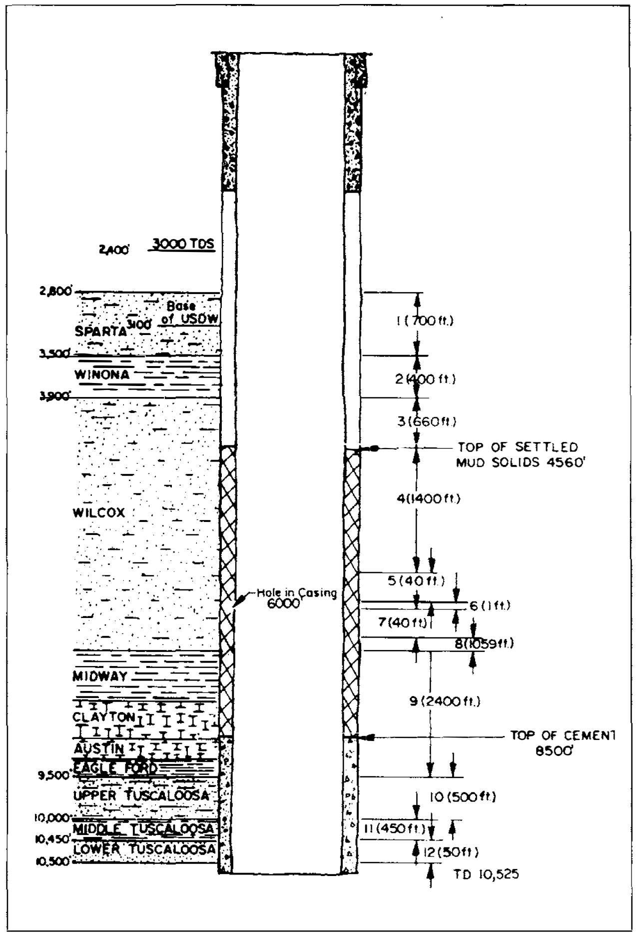

Fig. 6—Illustration of cased abandoned well scenario, Lower Tuscaloosa trend, showing finite-difference model layers.

TABLE 3—PRESSURE BUILDUPS AND FLOWS WITH TIME FOR A 200-B/D INJECTION RATE AND LOWER TUSCALOOSA SAND PERMEABILITY OF 30 md, UNCASED ABANDONED WELL SCENARIO

Time Since Injection Began (days)	Δp of BHP, Injection Well (psi)	Δp at Bottom of Abandoned Well (psi)	q Into USDW (B/D)	q Into Abandoned Well (B/D)	q Into Upper Tuscaloosa (B/D)
0.01	84.0	0	0	0	0
0.1	110.8	0	0	0	0
1.0	133.1	2.3	0	7.13×10^{-9}	0
10.0	162.8	21.0	0	2.82×10^{-7}	5.0×10^{-9}
100.0	186.4	43.4	0	1.26×10^{-6}	6.6×10^{-8}
1,000.0	13.1	70.3	0	2.81×10^{-6}	2.0×10^{-7}
2,000.0	221.0	78.2	0	3.53×10^{-6}	2.7×10^{-7}
3,650.0	227.6	84.8	0	4.38×10^{-6}	3.5×10^{-7}

TABLE 4—PRESSURE BUILDUPS AND FLOWS WITH TIME FOR A 600-B/D INJECTION RATE AND LOWER TUSCALOOSA SAND PERMEABILITY OF 30 md, UNCASED ABANDONED WELL SCENARIO

Time Since Injection Began (days)	Δp of BHP, Injection Well (psi)	Δp at Bottom of Abandoned Well (psi)	q Into USDW (B/D)	q Into Abandoned Well (B/D)	q Into Upper Tuscaloosa (B/D)
0.01	252	0	0	0	0
0.1	332.6	0.1	0	0	0
1.0	399.5	6.9	0	1.67×10^{-7}	9.9×10^{-11}
10.0	488.7	63.2	0	6.6×10^{-6}	1.6×10^{-8}
100.0	559.5	130.3	0	3.0×10^{-5}	2.0×10^{-7}
1,000.0	640.1	211.5	0	6.6×10^{-5}	6.0×10^{-7}
2,000.0	664.4	235.8	0	8.3×10^{-5}	8.1×10^{-7}
3,650.0	684.9	256.3	0	1.0×10^{-4}	1.1×10^{-6}

the same as those calculated with the analytical equation during early response time. Then, the pressure buildup should be less than or equal to the confined analytical solution, depending on the amount of leakage into the abandoned well. The close agreement between modeled and analytical solution results indicated that the model was correctly assembled and the results were valid.

Tables 2 and 3 show the simulation results for the uncased well scenario. Tables 2 and 3 list the Δp at the bottom of the injection well [bottomhole pressure (BHP)], the Δp at the bottom of the abandoned well, the flow rate, q, of saline water into the groundwater zone (USDW), the flow rate through the sloughed shale, and the flow rate into the Upper Tuscaloosa. Tables 2 and 3 differ with regard to the Lower Tuscaloosa permeability values (2 and 30 md) and injection rates (20 and 200 B/D). These values represent the range of likely permeabilities and injection rates.

To study the effect of increasing the injection rate on flow up the abandoned well and into the Upper Tuscaloosa, a simulation was performed with an injection rate of 600 B/D and an injection-zone permeability of 30 md. The 600 B/D injection rate was selected because it was the maximum that could be used in the simulation without computing a BHP that would be above the anticipated fracture pressure of the Lower Tuscaloosa sand. **Table 4** shows the results. The simulation showed no flow into the USDW zone at the 600-B/D injection rate. Flow rates less than 10^{-2} B/D should be considered too small to be meaningful. For practical purposes, such rates indicate that no measurable flow is occurring.

The highest flow rate shown in Tables 2 through 4 is 1×10^{-4} B/D into the abandoned well. Most likely, none of this negligible amount of saline water will enter the USDW because it will be diverted into other formations before reaching that level.

Cased Well Scenario. A 3D 48×22-node× 12-layer model grid was designed for simulation of the cased well scenario. Because the geologic units were treated as if they were homogeneous, isotropic, and areally infinite, the flow field was symmetric and only the upper half of the grid was present in the Y dimension. The injection well and the abandoned well were 500 ft apart and roughly centered along the x boundary. The x-y extent of the grid was 3.4×10^5 by 2.1×10^5 ft and was established by trial and error to be large enough to prevent significant boundary effects during the 10-year modeling period.

Fig. 6 shows the 12 model layers used in the z dimension. The layers were selected to discriminate the hydrogeologic units; the cement, sloughed shale, and settled mud layers behind the casing; and the corroded casing interval. **Table 5** lists the values for the model parameters used in simulation runs for the abandoned cased well scenario.

TABLE 5—MODEL PARAMETERS, CASED ABANDONED WELL SCENARIO, LOWER TUSCALOOSA TREND

Model Layer	Permeability, $k_x=k_y=k_z$ (darcies)	Porosity (%)
1	1	35
2	2.5×10^{-8}	3
3	1	30
4	1	30
5	1	30
6	1	30
7	1	30
8	1	20
9	2.5×10^{-8}	3
10	0.1	23
11	2.5×10^{-8}	3
12	2 or 30×10^{-3}	25
Drilling mud	1×10^{-3}	84
Empty borehole	3.7×10^{8} (10^9 ft/D)	100
Other Parameters		
Water compressibility, psi^{-1}	3.6×10^{-6}	
Rock compressibility, psi^{-1}	5.5×10^{-6}	
Fluid specific weight, lbm/ft^3	67.3	
Viscosity, cp	1	

More than 10 calibration runs were performed for the cased well scenario simulation. Each simulation required 14 megabytes of core storage and about 4 hours CPU time. Although no exact analytical solution exists for the scenario modeled here, the modeling results were compared with the fully confined, infinite in horizontal extent, homogeneous, and isotropic case for calibration. The actual model results should equal the analytical solution through the early transient phase. Then, the pressure buildup should be less than or equal to the confined analytical solution, depending on the amount of leaking into the abandoned well. The close agreement between modeled and analytical solution results indicated that the model was valid.

Tables 6 and 7 show the simulation results for the cased well scenario. The tables differ with regard to the Lower Tuscaloosa permeability values (2 and 30 md) and the injection rates (20 and 200 B/D). These values represent the range of likely permeabilities and injection rates. Tables 6 and 7 list the Δp of the BHP at the injection well and the flow rate into the abandoned well. The flow of saline water vertically from the Wilcox formation through the Winona shale and Cane River Marl and into the USDW was zero for all these simulations.

As in the uncased well scenario, flow rates of less than 10^{-2} B/D should be considered highly inaccurate. For practical purposes, such rates indicate that no measurable flow is occurring.

Conclusions

On the basis of the modeling performed, we concluded that abandoned oil and gas wells in the Lower Tuscaloosa trend of Mississippi and Louisiana are unlikely to serve as conduits for movement of water from the Lower Tuscaloosa into a USDW. In the scenario of the uncased well, essentially no water was found to move vertically through the sloughed shale/settled mud column and no measurable amount of water that did penetrate the settled mud column reached the Sparta, which is the USDW in the Mallalieu field area. In the cased well scenario, essentially no water moved through the settled mud sheath into the Wilcox formation and none of the water that did flow into the Wilcox moved vertically through the Wilcox and the Winona-Cane River into the Sparta.

The procedures developed in this study should be readily applicable to the analysis

TABLE 6—PRESSURE BUILDUPS AND FLOWS WITH TIME FOR A 200-B/D INJECTION RATE AND LOWER TUSCALOOSA SAND PERMEABILITY OF 30 md, CASED ABANDONED WELL SCENARIO

Time Since Injection Began (days)	Δp of BHP, Injection Well (psi)	q Into Abandoned Well (B/D)
0.01	44.7	0
0.1	70.4	0
1.0	84.5	1.6×10^{-5}
10.0	115.8	3.7×10^{-4}
100.0	132.9	7.8×10^{-4}
1,000.0	149.5	1.2×10^{-3}
2,000.0	154.6	1.4×10^{-3}
3,650.0	158.4	1.5×10^{-3}

TABLE 7—PRESSURE BUILDUPS AND FLOWS WITH TIME FOR A 20-B/D INJECTION RATE AND LOWER TUSCALOOSA SAND PERMEABILITY OF 2 md, CASED ABANDONED WELL SCENARIO

Time Since Injection Began (days)	Δp of BHP, Injection Well (psi)	q Into Abandoned Well (B/D)
0.01	23.5	0
0.1	61.9	0
1.0	98.1	1.1×10^{-6}
10.0	145.1	8.7×10^{-6}
100.0	177.3	5.6×10^{-5}
1,000.0	207.8	1.2×10^{-4}
2,000.0	215.4	1.4×10^{-4}
3,650.0	221.3	1.6×10^{-4}

of the potential for abandoned wells to act as pathways for contaminant flow into USDW's in other oil- and gas-producing areas. Modeling such as that described here is a very powerful tool for classification of abandoned wells. While this type of modeling is not a trivial exercise, and the necessary data are not routinely available, the information produced can return the necessary investment many fold by diverting concern from unwarranted areas and thus avoiding unnecessary regulatory effort.

Acknowledgments

We thank the American Petroleum Inst. for financial support for the research documented in this paper. Shell Oil Co. commissioned the stratigraphic study of the Lower Tuscaloosa trend as a separate but essential part of the project. B.E. Esquinance, Shell Offshore Inc., developed the well scenarios described. Nina K. Springer, Exxon Production Research Co., developed the method for estimating the characteristics of settled mud and sloughed shale in abandoned wells, used in the study. Bill Freeman, Shell Oil Co., chaired the API Issues Group overseeing this study. We express our appreciation to that group for its helpful suggestions and input to the study.

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SI Metric Conversion Factors

bbl	×	1.589 873	E−01	=	m^3
cp	×	1.0*	E−03	=	Pa·s
ft	×	3.048*	E−01	=	m
ft^3	×	2.831 685	E−02	=	m^3
lbm	×	4.535 924	E−01	=	kg
mile	×	1.609 344*	E+00	=	km
psi	×	6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **A Quantitative Assessment of the Environmental Implications of Abandoned Oil and Gas Industry Wells: Lower Tuscaloosa Trend, Mississippi and Louisiana,** received for review Sept. 2, 1990. Revised manuscript received Dec. 8, 1992. Paper accepted for publication Feb. 24, 1993. Paper (SPE 20692) first presented at the 1990 SPE Annual Technical Conference and Exhibition held in New Orleans, Sept. 23-26.

JPT

Attachment B

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

WELL SUMMARY REPORT

API NO. **04-077-00072**

Operator	Well				
Lodi Gas Storage, LLC	**"Community" 3-1**				
Field **Lodi Gas**	County **San Joaquin**	Sec. **4**	T. **4N**	R. **7E**	B.&M. **M.D.**

Location (Give surface location from property or section corner, street center line)
1,400' North and 130' East from the Southwest corner of Section 4

Elevation of ground above sea level **+81.00'**

California Coordinates (if known):

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

Commenced drilling (date): **September 14, 2002**
Completed drilling (date): **September 27, 2002**

Total depth: (1st hole) **2,900'** (2nd) (3rd)

Depth measurements taken from top of: ☐ Derrick Floor ☐ Rotary Table ☒ Kelly Bushing
Which is **+14.00** feet above ground

Commenced production/injection (date):

Present effective depth **2,789'**

Junk

Production mode: ☐ Flowing ☐ Pumping ☐ Gas lift

Name of production/injection zone(s)

GEOLOGICAL MARKERS	DEPTH

Formation and age at total depth: **Domengine-Eocene**
Base of fresh water: **1,850'**

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

CASING AND CEMENTING RECORD (Present Hole)

Size of Casing (API)	Top of Casing	Depth of Shoe	Weight of Casing	Grade and Type of Casing	New (N) or Used (U)	Size of Hole Drilled	Number of Sacks or Cubic Feet of Cement	Depth of Cementing (if through perforations)	Top(s) of Cement in Annulus
10-3/4"	surface	280'	45#		U	15"	200 sx	shoe	surface
7"	surface	2,838'	23#	J-55/LT&C	N	9-1/2"	345 sx	shoe	1,300'

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

Logs/surveys run? ☒ Yes ☐ No If yes, list type(s) and depth(s).
SED from 1,556'-300'; EMI from 2,000'-900'; FMI from 1,400'-200'; "Platform Express" from 2,875'-280'.

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

Name	Title	
Lodi Gas Storage, LLC	**Petroleum Engineer**	
Address **23265 N. State Rt. 99, W. Frontage Rd.**	City/State **Acampo, CA**	Zip Code **95220**
Telephone Number **(209) 368-9277**	Signature	Date **October 18, 2002**

OG100 (1/98/GSR/1M)
Printed on recycled paper.

SUBMIT IN DUPLICATE

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

HISTORY OF OIL OR GAS WELL

Operator Lodi Gas Storage, LLC Field Lodi Gas County San Joaquin

Well "Community" 3-1 Sec. 4 T. 4N R. 7E M.D. B.&M.

A.P.I. No. 04-077-00072 Name Irani Engineering (Person submitting report) Title Petroleum Engineer (President, Secretary, or Agent)

Date Oct. 18, 2002 (Month, day, year)

Signature

Address 23265 N. State Rt. 99, Acampo, CA 95220 Telephone Number (209) 368-9277

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

Date

2002

9-14 Moved in and rigged up Hexadyne Rig #1. Welded on 10-3/4" stub. Welded on 10-3/4" SOW X 11" 3M casing head and tested welds to 1500 PSIG. Installed BOPE and tested CSO rams to 1100 PSIG-OK. Made up 9-5/8" bit and BHA. Ran in hole.

9-15 Tested BOPE to 750 PSIG-OK (witnessing of BOPE test waived by DOG). Drilled out cement from 98'-275'. Ran 9-5/8" washover shoe and washed over cement from 275'-347'. Installed Geolog mud loggers at 280'. Reamed to 499'. Mud weight 9.5/71.

9-16 Reamed to 1,139'. Mud weight 11.5/86.

9-17 Reamed to 1,358'. Mud weight 11.6/87.

9-18 Reamed to 1,501'. Mud weight 11.6/87.

9-19 Reamed to 1,565' (sidetracked hole). Mud weight 12/90.
Halliburton ran SED from 1,556'-300'.

9-20 Drilled 7-7/8" hole to 1,875'. Mud weight 11/82+.

9-21 Drilled to 2,000'. Mud weight 11/82+.
Halliburton ran EMI from 2,000'-900' and FMI from 1,400'-200'.

9-22 Directionally drilled to 7.06' South and .53' West from SHL at 2,149'. Mud weight 10.8/81.

9-23 Halliburton equalized 70 sx of Class "G" cement premixed with 0.75% CFR-3 and 2% CaCl2 from 2,142. Drilled cement with 6-3/4" bit to 1,955'. Directionally drilled to Northeast (re-entered old hole at ~2,100'). Reamed to 2,398'. Mud weight 11/82.

9-24 Reamed to 2,900'. Ran 9-1/2" hole opener to 2,012'. Mud weight 11/82.

9-25 Ran 9-1/2" hole opener to 2,900'. Mud weight 11/82.
Schlumberger ran "Platform Express" from 2,875'-280' and MDT at 2,361'. Stuck MDT at 2,361'.

9-26 Stripped over and recovered MDT tool. Ran in hole to 2,900'. Circulated and conditioned mud and hole. Laid down DP and BHA. Began running casing.

9-27 **7" casing at 2,838'.** Ran 64 joints (2,840.57') of new 7" 23# J-55 LT&C 8RT R3 casing equipped with and including differential fill-up/float shoe and collar. Placed one centralizer per joint from 2,745'-1,750'. Pumped 20 BBLs of mud flush ahead and cemented shoe at 2,838' (float collar at 2,789') with 345 sx of "WCHT" cement premixed with 3% CaCl2, 0.75% CFR-3 and 0.15% SuperCBL. Dropped plug and displaced to float collar with water. Tested casing to 2500 PSIG. Had good returns. Bled back (float held). Calculated TOC at 1,300'. Nippled down BOPE. Cut 7" casing 3' below ground level. Cut off 10-3/4" SOW X 11" 3M casing head and cut 10-3/4" casing 4' below ground level. Placed 12" cap over both casings. Cleaned mud pits and released rig at 3:00 PM.

Attachment C

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

HISTORY OF OIL OR GAS WELL

Operator Lodi Gas Storage, LLC   Field Lodi Gas   County San Joaquin

Well "Community" 15-2   Sec. 15   T. 4N   R. 7E   M.D. B.&M.

A.P.I. No. 04-077-20053   Name Irani Engineering (Person submitting report)   Title Petroleum Engineer (President, Secretary, or Agent)

Date Jan. 24, 2002 (Month, day, year)

Signature

Address 1822 W. Kettleman Lane, Suite 3, Lodi, CA 95242   Telephone Number (209) 368-9277

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

Date

2001

11-15 Moved in and rigged up Hexadyne Rig #5.

11-16 Welded 7" casinghead on top of stub. Installed BOE and tested. Witnessed and approved by DOG.

11-17 Made up BHA and bit. RIH. Tagged hard cement at 421'. Drilled out cement to 565'. Mud Weight 9.0 ppg. POOH. Made up the following BHA. 6-1/4" shoe, 5-3/4" washpipe, stab, DC, stab, DC, stab, BS, Jars, 14 Hw's. Drilled cement plug from 565' to 640'. Reamed open hole to 689'.

11-18 Reamed open hole to top of cement plug at 1657'. Drilled cement plug from 1657' to 1875'. Mud weight 9.5 ppg.

11-19 Drilled cement plug to 1889'. POOH. Changed wash over shoe. Drilled cement plug to 1896'. Reamed open hole 2745'. Mud weight 10.0 ppg.

11-20 Reamed open hole to 2890'. Mud weight 10.0 ppg. Circulated. POOH. Laid down BHA. Ran open-ended drill pipe to 2890'.
Equalized 75 sacks Class G cement premixed 0.1% SuperCBL at 2890'. Located top of cement plug at 2595'.
Equalized 75 sacks Class G cement premixed 0.1% SuperCBL at 2595'. Located top of cement plug at 2316'.
Equalized 75 sacks Class G cement premixed 0.1% SuperCBL at 2316'. Located top of cement plug at 2137'.
Equalized 120 sacks Class G cement premixed 0.1% SuperCBL at 2137'. Located top of cement plug at 1643'. Witnessed and approved by DOG.

11-21 Equalized 60 sacks Class G cement premixed 3% CaCl2 at 646'. Located top of cement plug at 600'. Placement was witnessed and approved by DOG. Equalized 25 sacks Class G cement at 600'. Located top of cement plug at 550'. Equalized 20 sacks Class G cement at 550'.
Cut casing 5' below ground. Plugged casing with 30 lineal feet of cement. Welded steel plate on stub. Abandoned well on November 21, 2001. Released rig.

Attachment D

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

HISTORY OF OIL OR GAS WELL

Operator Lodi Gas Storage, LLC   Field Kirby Hill Gas   County Solano

Well "Wagenet" 5   Sec. 30   T. 4N   R. 1E   M.D. B.&M.

A.P.I. No. 095-20736   Name Irani Engineering (Person submitting report)   Title Petroleum Engineer (President, Secretary, or Agent)

Date 9/16/09 (Month, day, year)

Signature

Address P. O. Box 230, Acampo, CA 95220   Telephone Number (209) 368-9277

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

Date
2009

4/22 Welded on extension 8-5/8" casing. Set in and welded 11" 3M X 8-5/8" SW wellhead. Tested welds to 1,500 psig.

4/28 MIRU PG Rig #2. Installed BOPE. Tested blind rams and casing to 1,500 psi. Made up BHA and RIH. Tagged plug at 100'. Drilled out cement to 281'.

4/29 Drilled cement to 402'. RIH to 1,510'. Drilled out cement to 1,543'. RIH to 1,718'. Drilled out cement to 1,771'. Tested BOPE, witnessed and approved by DOG. Drilled out cement to 2,000'. POOH and laid down BHA. Made up directional BHA. RIH to 2,000'. Changed the hole to 13.0 ppg mud. Directional tools failed. POOH.

4/30 Repaired directional tools. RIH to 2,000'. Drilled out cement to 2,060'. Drilled to 2,280', mud 13.0 ppg.

5-01 The hole packed off. POOH to 1,850'. Raised mud weight to 13.5 ppg. Staged in hole and reamed to 2,280'. Directionally drilled 7-7/8" hole to 2,505', mud weight 13.5 ppg. POOH. Made up new BHA. RIH. Circ. and conditioned mud at 2,055'.

5/02 Reamed to 2,505'. Circulated and conditioned mud at 2,505'. POOH to 1,700'. RIH and reamed to 2,505. Circulated and raised mud weight to 13.7 ppg. Circulated, wiped hole and POOH. Rigged up loggers.
Halliburton ran **EMI** from **2,495'-2,022'**. POOH. Made up directional BHA. Directionally drilled 7-7/8" hole to 2,640', mud weight 14.0 ppg.

5/03 Drilled to 3,029', mud weight 14.0 ppg.

5/04 Drilled to 3,191'. POOH. Changed bit. RIH. Directionally drilled 7-7/8" hole to 3,316', mud weight 14.0 ppg.

5/05 Drilled to 3,630', mud weight 14.0 ppg.

5/06 Drilled to 3,992', mud weight 14.0 ppg.

5/07 Drilled to 4,214', mud weight 14.0 ppg.

5/08 Drilled to 4,324', mud weight 14.0 ppg. POOH. RIH with open-ended drill pipe to 2,560'.
Cement Plug @ 2,560'. Equalized 140 sacks Class G cement with 2% CaCl2 and 0.75% CFR-3 (16.5 ppg) at 2,560'. POOH and WOC. Made up BHA and RIH. WOC.

5/09 Tagged TOC at 2,141'. POOH. Made up directional BHA. Polished off cement to 2,256'. POOH.

5/10 RIH with open-ended drill pipe to 2,249'.
Cement Plug @ 2,249'. Equalized 90 sacks Class G cement with 2% CaCl2 and 0.75% CFR-3 (16.5 ppg) at 2,249'. POOH. Made up BHA. RIH to 2,100'. Circulated and conditioned mud. POOH. Made up directional BHA. RIH to 1,810'. WOC.

5/11 RIH. Tagged cement at 2,100'. Directionally drilled 7-7/8" hole to 2,476', mud weight 14.0 ppg.

5/12 Drilled to 2,557', mud weight 14.0 ppg. Rigged up loggers.
Halliburton ran **EMI** from **2,551'-2,022'**. POOH. Made up directional BHA and RIH to 2,557'.

5/13 Directionally drilled 7-7/8" hole to 2,830', mud weight 14.1 ppg. Circulated bottoms up and POOH.

5/14 RIH with open-ended drill pipe to 942'. POOH. Made up directional BHA and RIH. Directionally drilled 7-7/8" hole to 2,851', mud weight 14.1 ppg. POOH. Changed bit. Directionally drilled 7-7/8" hole to 3,000, mud weight 14.1 ppg.

5/15 POOH. RIH with open-ended drill pipe to 2,998'. Circulated clean.
Cement Plug @ 2,998'. Equalized 159 sacks G cement with 1% CaCl2 and 0.5% CFR-3 at 2,998'. Circulated at 2,530'.
Cement Plug @ 2,530'. Equalized 181 sacks G cement with 2% CaCl2 and 0.75% CFR-3 at 2,530'. Circulated at 1,905'. Made up BHA and RIH. Tagged TOC at 2,100'. Circulated and cleaned hole to 2,140'. Drilled cement to 2,190'. POOH.

5/16 **Schlumberger** ran **USIT/GR** from **1,628'-290'**. Rigged down loggers. Made up directional BHA. RIH to 1,153'. POOH. Repaired directional tools. RIH to 2,190'. Directionally drilled 7-7/8" hole to 2,324', mud weight 14.0 ppg.

5/17 Drilled to 2,475', mud weight 13.9 ppg. POOH to 1,600'. Reamed to 2,022. POOH. Ran gyro survey from surface to 2,010'. POOH with wireline. RIH with open-ended drill pipe to 2,467'. Circulated clean and rigged up cementers.

5/18 **Cement Plug @ 2,467'**. Equalized 120 sacks Class G cement with 2% CaCl2 and 0.75% CFR-3 (16.5 ppg) at 2,467'. POOH and WOC. Made up BHA and RIH. WOC. Tagged TOC at 2,130'. Polished cement to 2,260'. POOH and made up directional tools. Directionally drilled 7-7/8" hole to 2,274', mud weight 13.9 ppg.

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

HISTORY OF OIL OR GAS WELL

Operator Lodi Gas Storage, LLC Field Kirby Hill Gas County Solano

Well "Wagenet" 5 Sec. 30 T. 4N R. 1E M.D. B.&M.

A.P.I. No. 095-20736 Name Irani Engineering Title Petroleum Engineer
(Person submitting report) (President, Secretary, or Agent)

Date 9/24/09
(Month, day, year)

Signature

Address P. O. Box 230, Acampo, CA 95220 Telephone Number (209) 368-9277

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

Date
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5/19 Time drilled to 2,249', mud weight 14.0 ppg.
5/20 Time drilled to 2,268', mud weight 14.0 ppg. Drilled to 2,412', mud weight 14.0 ppg.
5/21 Drilled to 2,450', mud weight 14.0 ppg. Hole packed off. POOH to 2,360'. Circulated and reamed to 2,450'. Drilled to 2,536', mud weight 14.0 ppg. POOH to 2,436'. Worked directional tools and attempted to find the old hole to 2,450'. POOH to surface. Changed MM and BHA tools and RIH.
5/22 RIH to 2,224'. Worked directional tools to 2,290'. Time drilled 7-7/8" hole to 2,317', mud weight 14.0 ppg.
5/23 Time drilled to 2,322'. Directionally drilled to 2,353. POOH and changed MM. RIH to 2,319'. Reamed to 2,505'. Directionally drilled 7-7/8" hole to 2,518', mud weight 14.0 ppg. POOH to 1,877'. Closed bag. Shut down.
5/26 Staged in hole. Circulated and reamed to 2,518'. Directionally drilled 7-7/8" hole to 2,534', mud weight 14.0 ppg.
5/27 Drilled to 2,607. POOH. Cleaned bit. RIH. Drilled to 2,666', mud weight 14.0 ppg. POOH. Changed jets. RIH.
5/28 Drilled to 2,978', mud weight 14.0 ppg.
5/29 Drilled to 3,229', mud weight 14.0 ppg.
5/30 Drilled to 3,526', mud weight 14.0 ppg.
5/31 Circulated and POOH. Changed bit. Directionally drilled 7-7/8" hole to 3,540', mud weight 14.0 ppg. POOH. Picked up bull nose hole opener. RIH and attempted to run hole opener unsuccessfully. POOH. Laid down hole opener. Made up directional BHA. Directionally drilled 7-7/8" hole to 3,574', mud weight 14.0 ppg.
6/01 Drilled to 3,726', mud weight 14.2 ppg.
6/02 Drilled to 3,819', mud weight 14.2 ppg.
6/03 Drilled to 3,944', mud weight 14.2 ppg. POOH. Changed bit. Attempted to drill with PDC bit unsuccessfully.
6/04 POOH. Changed bit. Directionally drilled 7-7/8" hole to 3,986', mud weight 14.2 ppg. POOH. Changed drilling line and jets.
6/05 Drilled to 4,162', mud weight 14.2 ppg.
6/06 Drilled to 4,391', mud weight 14.2 ppg.
6/07 Drilled to 4,459', mud weight 14.2 ppg. POOH. Changed bit. Attempted to drill with PDC bit unsuccessfully. POOH. Changed bit. Directionally drilled 7-7/8" hole to 4,489', mud weight 14.2 ppg.
6/08 Drilled to 4,736', mud weight 14.2 ppg.
6/09 Drilled to 4,946', mud weight 14.2 ppg.
6/10 Drilled to 5,162', mud weight 14.2 ppg.
6/11 Drilled to 5,229'. Circulated and POOH. Changed bit. Directionally drilled 7-7/8" hole to 5,277', mud weight 14.2 ppg.
6/12 Drilled to 5,463'. Wall stuck drill pipe, while sliding. Worked pipe free. Drilled to 5,478', mud weight 14.2 ppg.
6/13 Drilled to 5,524'. POOH. Laid down directional BHA. RIH. Drilled 7-7/8" hole to 5,573', mud weight 14.2 ppg.
6/14 Drilled to 5,752', mud weight 14.2 ppg.
6/15 Drilled to 5,800' (TD), mud weight 14.2 ppg. Circulated and wiped hole to shoe. POOH for E-logs.
Schlumberger ran **AIT/SP/GR/NL/DL/MCFL/GPIT/FMI/CDI** from **5,797'-2,021'**.
6/16 **Schlumberger** ran **UIT/CBL/VDL/GR** from **2,015'-50'**. Made up BHA. Circulated and wiped hole. Laid down DP.
6/17 Laid down DP, HW's and BHA. Rigged up power tongs.
5-/2" casing @ 5,800'. Ran 134 joints of 5-1/2", 15.5#, K-55, LT&C, SMLS new casing equipped with PDF shoe at 5,800', PDF collar at 5,760' and 3 flag joints. Placed 111 centralizers from top of second joint. Cemented casing shoe at 5,800' with 650 sacks Pozimax 50-50 cement with 2% gel premixed with 3% KCl, 1% Halad-322, and 0.15% SuperCBL followed by 510 sacks of Class G cement premixed with 3% NaCl, 0.75% Halad-322, 0.2% Halad-344 and 0.15% Super CBL (ramped up from 15.8 to 16.4 ppg). Dropped plug and displaced with 6% KCl water. Did not bump plug. Float held. CIP @ 06:30 pm. Had cement to surface. Set casing in slips. Nippled down BOP. Cut casing and nippled up tubing spool.
6/18 Cleaned mud pits. Released rig (09:00 am).