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

EPA

United States Environmental Protection Agency

Underground Injection Control
Permit Application

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

I. EPA ID Number AZD980886303

		T/A	C
U			

Read Attached Instructions Before Starting

For Official Use Only

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

II. Owner Name and Address			**III. Operator Name and Address**		
Owner Name Arizona Public Service Company			Owner Name Arizona Public Service Company		
Street Address 4801 Frontage Road		Phone Number (928) 288-1206	Street Address 4801 Frontage Road		Phone Number (928) 288-1206
City Joseph City	State AZ	ZIP CODE 86032	City Joseph City	State AZ	ZIP CODE 86032

IV. Commercial Facility	**V. Ownership**	**VI. Legal Contact**	**VII. SIC Codes**
☐ Yes ☒ No	☒ Private ☐ Federal ☐ Other	☒ Owner ☐ Operator	4911 NAICS = 22112

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

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

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

		Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
☒ A. Individual	☐ B. Area	0	1	Arizona Utilities CO2 Storage Pilot

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

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

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

Latitude			Longitude			Township and Range							
Deg	Min	Sec	Deg	Min	Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
34	55	43N	110	15	31W	30	18N	20E					

XII. Indian Lands (Mark 'x')

☐ Yes
☒ No

XIII. Attachments

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

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

XIV. Certification

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

A. Name and Title *(Type or Print)* CONRAD M. SPENCER PLANT MANAGER

B. Phone No. *(Area Code and No.)* 928-288-1206

C. Signature

D. Date Signed 31 JUL 08

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

ATTACHMENTS
Underground Injection Control Permit Application
Arizona Utilities CO_2 Storage Pilot Test Project

A. **AREA OF REVIEW METHODS -** Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

For this project, the Arizona Utilities CO_2 Storage Pilot Test, a small quantity (up to 2,000 metric tons) of carbon dioxide (CO_2) will be injected into a deep saline aquifer beneath a thick confining seal formation. The maximum likely vertical and horizontal extent of the CO_2 plume has been estimated by numerical simulations of CO_2 injection at the project site, as described in the following Model Study report prepared by scientists at Lawrence Berkeley National Laboratory. This report is included in its entirety on the following pages to provide a brief introduction to the project and demonstrate the limited scale of this geologic CO_2 storage test.

As described in the Model Study report, when 2,000 metric tons of CO_2 is injected at the target depth of approximately 3,700 feet, a model with extremely high vertical permeability indicates that the top of the CO_2 plume could rise as much as 180 feet from the injection location before the plume stabilizes. It may never even reach the bottom of the seal formation. For another model with extremely high horizontal permeability, the maximum lateral extent of the CO_2 plume from the well bore is approximately 250 feet before the plume stabilizes. Leaving a large safety margin, the LBNL scientists are confident that the plume will not extend beyond a horizontal radius of 400 feet from the injection well.

The Model Study report indicates that when the 2,000 metric tons of CO_2 is injected into the target reservoir formation at a constant rate over a 15 day period: 1) injection pressure at the borehole remains significantly below fracture pressure, and 2) maximum pressure in the reservoir formation ¼ mile from the borehole rises only 10 psi, a scant 0.64% above background pressure at a depth of 3,700 feet. When injection stops at the end of the fifteenth day, pressure rapidly returns to background levels.

The Model Study report refers to an Aquifer Protection Program permit application submitted to the Arizona Department of Environmental Quality. In that permit application, Arizona Public Service Company (APS) defined the “Impact Area” as within 400 feet of the well and a “Point of Compliance” located 400 feet southwest of the well. However, <u>for the purpose of this UIC permit application, the area of review shall be a fixed radius of 1/4 mile from the well bore</u>, if that is the distance preferred by USEPA.

LBNL Model Study dated July 7, 2008.

Preliminary Modeling Study of CO_2 Injection
at the
Cholla Power Plant Site
for the
Arizona Utilities CO_2 Storage Pilot Test

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July 7, 2008

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Acronyms and Abbreviations

ADEQ	Arizona Department of Environmental Quality
APP	Aquifer Protection Program
bar	unit of pressure (1 bar = 100 kPa ≈ 14.5 psi)
CO_2	carbon dioxide
°C	degrees Celsius
°F	degrees Fahrenheit
EOS	equation of state
H_2O	water
kg/s	kilograms per second
kPa	kilopascals (thousands of pascals; 1 kPa ≈ 0.145 psi)
LBNL	Lawrence Berkeley National Laboratory
m	meters
mD	millidarcies (unit of permeability with units of area; 1 mD ≈ 0.001 μm^2)
mg/L	milligrams/liter
μm^2	millionths of a square meter (10^{-6} m^2)
MPa	megapascals (millions of pascals; 1 MPa ≈ 145 psi)
NaCl	sodium chloride (common salt)
P	pressure
ϕ	porosity
psi	pounds-force per square inch
QCO2	CO_2 injection rate
R	radius
SG	gas saturation; fraction of pore space filled with supercritical (gas phase) CO_2
S_{gr}	residual gas saturation; supercritical CO_2 trapped in capillaries of pore space
T	temperature
TDS	total dissolved solids
tonne	metric ton (1 tonne = 1 metric ton ≈ 1.1 US short ton ≈ 2,205 pounds)
TOUGH2	numerical code for modeling multiphase and multicomponent non-isothermal flow and transport processes in porous and fractured media
UIC	Underground Injection Control permit issued by the U.S. Environmental Protection Agency
WESTCARB	West Coast Carbon Sequestration Partnership
XCO2a	mass fraction of dissolved (aqueous phase) CO_2

Preliminary Modeling Study of CO_2 Injection at the Cholla Power Plant Site for the Arizona Utilities CO_2 Storage Pilot Test

1. Introduction

For the Arizona Utilities CO_2 Storage Pilot project, WESTCARB plans to inject up to 2,000 metric tons[1] of carbon dioxide (CO_2) into a deep reservoir formation beneath property owned by Arizona Public Service Company near the Cholla Power Plant. WESTCARB has performed preliminary numerical simulations to estimate the maximum extent of the injected CO_2 plume underground. The simulation results will be used to establish the Point of Compliance (POC) in the reservoir beyond which the CO_2 is not expected to migrate. This information will be incorporated into an application for a Temporary Individual Discharge permit required by the Arizona Department of Environmental Quality (ADEQ) under its Aquifer Protection Program (APP). The simulation results will also help WESTCARB develop an effective monitoring plan used to track the extent of the CO_2 plume as required by the APP. The monitoring program will likely employ vertical seismic profiling techniques.

Earth science researchers at Lawrence Berkeley National Laboratory (LBNL) have developed numerical codes for modeling the movement of fluids in geologic formations. The codes can be used to simulate the movement of CO_2 through pore space and the amount of CO_2 dissolved in the reservoir water. Reservoir variables include lithology, thickness, dip, porosity, permeability, salinity, water and gas saturation, pressure, and temperature. The simulations described below were performed by Dr. Sumit Mukhopadhyay, with support from Dr. Christine Doughty, both of whom are research scientists in LBNL's Earth Sciences Division. Short biographies are included at the end of this report.

2. Numerical Simulator

The simulations in this report are performed with the TOUGH2 (Pruess et al., 1999) numerical simulator, a general-purpose software code for modeling multiphase and multicomponent non-isothermal flow and transport processes in porous and fractured media. TOUGH2 contains various equation-of-state (EOS) modules for different fluid (liquid and/or gas) mixtures. The ECO2N EOS module (Pruess, 2005) of TOUGH2 is appropriate for simulating the injection of CO_2 into subsurface formations.

Injection of CO_2 into subsurface saline formations is expected to induce coupled processes of multiphase fluid flow, heat transfer, chemical reactions, and mechanical deformation. The ECO2N module can be used to model non-isothermal multiphase flow in the system: H_2O - NaCl - CO_2. ECO2N represents fluids as consisting of two phases: a water-rich aqueous phase (CO_2 dissolved in the formation water), referred to as "liquid," and a CO_2-rich phase referred to as "gas" (which includes the supercritical state). In addition, solid salt may also be present. The only chemical reactions modeled by ECO2N include equilibrium phase partitioning of water and carbon dioxide between the liquid and gaseous

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[1] 1 metric ton = 1 tonne ≈ 1.1 US short ton ≈ 2,205 pounds

phases, and precipitation and dissolution of solid salt. The partitioning of H_2O and CO_2 between liquid and gas phases is modeled as a function of temperature, pressure, and salinity, using the recently developed correlations of Spycher and Pruess (2005). Dissolution and precipitation of salt is treated by means of local equilibrium solubility. Associated changes in formation porosity and permeability can also be modeled.

Fluid flow is modeled by an extension of Darcy's law, with relative permeability and capillary pressure functions, collectively known as characteristic curves, introduced to model the manner in which the two fluid phases interact. Recent developments in TOUGH2 (Doughty, 2007) enable use of hysteretic characteristic curves, meaning that the drainage process, in which non-wetting-phase CO_2 replaces brine, can be distinguished from imbibition, in which wetting-phase brine replaces CO_2. All phases – gas, liquid, solid – may appear or disappear in any grid block during the course of a simulation. Thermodynamic conditions covered include a temperature range from ambient to approximately 212°F (100°C), pressures up to 8,700 psi (60.6 megapascals [MPa]), and salinity from zero to fully saturated. These parameter ranges are adequate for most conditions encountered during the injection of CO_2 into deep, high-salinity reservoirs.

3. Hydrogeology

Using data from the few existing deep wells in the vicinity of the Cholla Power Plant, Errol L. Montgomery & Associates provided LBNL with estimates of the physical properties of the geologic formations beneath the project site, which LBNL used for the simulations presented below.

The target injection zone is the Paleozoic Era Martin Formation, estimated to be at depths of 3,445 to 3,645 feet (1050 to 1,111 m), with an approximate thickness of 200 feet (61 m). The bottom portion of the Martin Formation consists of the Jerome Member, a clastic formation estimated to have higher permeability than the rest of the Martin Formation. The Precambrian basement beneath the Jerome Member has very low permeability and will serve as a seal rock that prevents downward leakage of CO_2.

Above the Martin Formation is the Naco Formation, which is estimated to have similar permeability to that of the Martin Formation and is also a candidate for CO_2 injection. The Naco Formation is about 500 feet (152 m) thick, and is located at depths of 2,945 to 3,445 feet (898 to 1,050 m). The Naco Formation is overlain by the 2,000-foot (610 m) thick Supai Formation, which contains low-permeability siltstone, mudstone, and evaporite sequences that are expected to form an effective cap that will prevent the upward migration of CO_2.

Thus, for simulating CO_2 injection, the combined 700-foot (213 m) thick section of the Naco and Martin Formations is considered to be the permeable reservoir, with confining horizons at the base of the Supai above, and the Precambrian below.

Montgomery & Associates estimated that the pressure in the Martin Formation is about 1,500 psi (10.3 MPa). This is close to the normal freshwater hydrostatic gradient of 0.433 psi/foot (9.79 kilopascals/meter [kPa/m]) and suggests that the average pressure in the Naco Formation can be estimated at 1,450 psi (10.0 MPa). However, limited drill stem test data analyzed by Sandia Technologies, LLC. suggest that the Martin Formation might be underpressured with a gradient of 0.34 psi/foot (7.7 kPa/m). This could have resulted from a short test performed in a low permeability horizon. With the concurrence of Montgomery & Associates, the normal geothermal gradient has been used to estimate the average temperature at the depths of the Naco and the Martin Formations at approximately 126-131°F (52-55°C). Under these temperature and pressure conditions, CO_2 exists in the supercritical state. This means that it is dense like a liquid, but has very low viscosity like a gas. The ECO2N module of TOUGH2 is well suited for simulating supercritical CO_2 in geologic formations under these conditions.

In this modeling study it is assumed that temperature remains constant in the entire Naco and Martin Formations. Pressure is assumed to vary with depth according to the normal hydrostatic gradient. It is also assumed that the Supai Formation at the top and the Precambrian basement at the bottom provide perfect sealing so that there is no leakage of CO_2. Permeabilities of the target formations are not accurately known, but Montgomery & Associates has estimated them to be in the range of 20-300 millidarcies (mD) (0.02-0.30 μm^2). The clastic Jerome Member is assumed to be at the upper end of this range. The dolomites and limestones in the Upper Martin and Naco Formations are assumed to have low primary (matrix) permeability, but could have high secondary (fracture) permeability.

No site-specific information is available to define the characteristic curves that control how the supercritical CO_2 phase and the aqueous phase interact. Therefore, for all but one of the simulations we use non-hysteretic generic curves based on the formulations of van Genuchten (1980) and Corey (1954), which have been widely used to model CO_2 storage in recent years. As described elsewhere (Doughty, 2007), use of non-hysteretic characteristic curves is valid for the time period in which CO_2 is being injected and the plume is growing in all directions. It is less accurate for post-injection periods, when the plume is moving upward and imbibition occurs at the trailing edge. However, it has been found that the choice of characteristic curve has less of an impact on plume evolution when geologic structures limit plume movement, as is true for some of the cases considered here. A key parameter of the characteristic curves is the residual gas saturation, S_{gr}, defined as the saturation below which gas-phase CO_2 is trapped. At the temperature and pressure of the target reservoir formation this “gas” phase is supercritical CO_2.

The residual gas saturation depends upon micro characteristics of the rock matrix, including the size and shape of the pores and the capillary connections among them. It is determined empirically from field data and laboratory analyses of core samples. For the pilot test site, residual gas saturation is unknown, so models for two assumed values of S_{gr} are described below. For our base case, $S_{gr} = 0.05$ (5%), a very small value that will provide minimal capillary trapping of CO_2 and thus yield a conservative (overly large) estimate of the extent of plume migration. A simulation for $S_{gr} = 0.25$ (25%) is also presented for comparison.

4. Numerical Model

To simulate CO_2 injection at the site, a radial-symmetric numerical grid was developed to represent the Naco and Martin Formations (see Figure 1). The model reservoir is 700 feet (213 m) thick (the combined thickness of the Naco and Martin Formations), and extends

3,281 feet (1,000 m) radially. The grid is extended radially to a distance where constant boundary conditions can be applied. That is to say, the lateral boundary is far enough from the injection point that there is little impact on the simulated pressure distribution. The grid is finer near the injection location and coarser farther away. No-flow boundary conditions are applied at the top and bottom of the model reservoir, representing the overlying and underlying seals. Initially, the entire aquifer is assumed to be at an average pressure of 1,500 psi (10.3 MPa), and simulation was performed without injection so that the hydrostatic head distribution under steady state conditions could be achieved. Temperature is maintained constant at 129°F (54°C). The initial total dissolved solids (TDS) in the model reservoir are 40,000 milligrams/liter (mg/L), assumed to be entirely NaCl. Porosity for both the Naco and the Martin Formations is assumed to be 10%. Permeability is the variable parameter for the model studies described below.

The thicknesses and permeabilities of the various lithologies within the Naco and Martin Formations at the project site are not known, so two hypothetical models were used to estimate the size, shape, and migration of the CO_2 plume over time. The model reservoir was divided into four horizontal layers (see Figure 1). At the top is a hypothetical upper Naco unit with a thickness of 250 feet (76 m). The second layer is a lower Naco unit, which also has a thickness of 250 feet. The third and fourth layers comprise the Martin Formation, which is divided into an upper unit with a thickness of 69 feet (21 m) and a lower unit with a thickness of 131 feet (40 m) that represents the Jerome Member.

For this study, it is assumed that 2,000 metric tons of CO_2 is injected over a period of 30 days with an equivalent injection rate of 2.8 tonnes per hour (0.77 kilograms/second [kg/s]). The injection interval (perforated section of the well) is 33 feet (10 m) long over the depth range of 3,681-3,714 feet (1,091-1,102 m) in the Jerome Member. (This is slightly deeper than new depth estimates mentioned in Section 3 above, but there is no significant affect on the model results presented below.)

5. Prediction of Plume Migration

5.1 Uniform permeability model accentuating upward plume movement

In the first set of simulations, it is assumed that the entire model reservoir (consisting of the Naco and Martin Formations) has a uniform permeability of 100 mD (0.1 μm^2). This model is intended to accentuate the upward movement of the plume. While not necessarily a worst case scenario, we believe that it portrays a plume that rises farther than we expect for the plume at the test site.

Part of the CO_2 injected into the reservoir will displace some of the groundwater from the pore space and occupy a portion of the pore volume as a supercritical fluid. The remainder of the CO_2, the aqueous phase, will dissolve in the formation water. For the 2,000 tonnes of injected supercritical CO_2, Figure 2 plots the quantity of CO_2 that dissolves in the formation fluid over time. The end of injection is at 10^0 (1) month. One month later, approximately half of the CO_2 has dissolved, and after 11 months 65% has dissolved.

Figure 3 shows the fraction of the pore volume occupied by the supercritical CO_2 at the end of injection, and 1 month, 3 months, 5 months, and 11 months after the end of injection (12 months after the start of injection). For example, yellow represents the cross-section area where 35-40% of the pore volume is occupied by supercritical CO_2. At the end of the injection period, the front of the plume has migrated 110 feet (34 m) horizontally and approximately 180 feet (55 m) vertically.

Though the permeability is the same in both the horizontal and vertical directions, the faster movement in the vertical direction is caused by buoyancy. At one month after the end of injection the horizontal extent of the plume is nearly unchanged. However, because of buoyancy the plume moves upward to about 280 feet (85 m) above the point of injection. By five months after the end of injection the plume is nearly immobile and supercritical CO_2 occupies less than 10% of the pore space within the plume. The remaining 90-plus percent of the pore space is occupied by formation fluid that has become saturated with dissolved CO_2. Figure 4 shows the mass fraction of dissolved CO_2, which increases to approximately 4%, the limit of CO_2 saturation in water under the temperature/pressure/salinity conditions.

The plume tends to stabilize because of competing forces when a high proportion of the CO_2 goes into solution. The remaining supercritical CO_2 in the pore space is buoyant, but the CO_2-saturated formation fluid is slightly more dense than the unaffected formation water. As a result, there is little change in the plume between 5 and 11 months after the end of injection. After 11 months the plume has moved to about 440 feet (134 m) above the point of injection, or within 140 feet (43 m) of the top of the model reservoir.

5.2 Layered permeability model (moderate case)

A set of simulations was performed to address some of the uncertainties associated with limited availability of actual permeability data for the various rock formations under consideration. The objective was to create a hypothetical model that is more geologically realistic, using horizontal layers with different permeabilities. This has the effect of enhancing horizontal migration of the plume and restricting upward migration. As shown in Figure 1, this model reservoir has the permeabilities shown in the following table.

Formation	Thickness	Horizontal and Vertical Permeability
Upper Naco	250 ft (76 m)	10 mD (0.01 μm^2)
Lower Naco	250 ft (76 m)	100 mD (0.1 μm^2)
Upper Martin	69 ft (21 m)	50 mD (0.05 μm^2)
Lower Martin (Jerome)	131 ft (40 m)	300 mD (0.3 μm^2)

Figure 5 shows the fraction of the pore space occupied by supercritical CO_2 at the end of injection, and 3, 5, and 11 months after the end of injection. At the end of the injection period, the plume has moved 165 feet (50 m) horizontally and 125 feet (38 m) vertically. As expected, for this model the horizontal CO_2 migration is greater and the vertical migration is less than for the model with uniform permeabilities. However, once again the horizontal migration stabilizes after about three months and the vertical migration stabilizes after about five months after the end of injection. Within five months the fraction of pore space occupied by supercritical CO_2 is 10% or less throughout the plume. Between five and 11 months after the end of injection there is little change in the plume. It extends upward about 340 feet (104 m) from the point of injection (about 100 feet [30 m] less than the vertical movement of the plume for the model with uniform permeabilities), and has a horizontal extent of less than 200 feet (61 m).

5.3 Layered permeability model accentuating horizontal plume movement

This set of simulations is designed to result in a broad lateral extent of the plume. While not necessarily a worst case scenario, we believe that it simulates a plume that extends farther horizontally than we expect for the plume at the test site. A four-layer model with the same thicknesses as above was used, but with anisotropic permeabilities for each layer. As shown in the table below, the horizontal permeabilities are much larger than the vertical permeabilities, and the horizontal permeability for the injection horizon has been increased to 700 mD.

Formation	Thickness	Horizontal Permeability	Vertical Permeability
Upper Naco	250 ft (76 m)	10 mD (0.01 μm^2)	1 mD (0.001 μm^2)
Lower Naco	250 ft (76 m)	100 mD (0.1 μm^2)	3 mD (0.003 μm^2)
Upper Martin	69 ft (21 m)	100 mD (0.1 μm^2)	3 mD (0.003 μm^2)
Lower Martin (Jerome)	131 ft (40 m)	700 mD (0.7 μm^2)	20 mD (0.02 μm^2)

Figure 6 shows, for a residual gas saturation of 0.05 (5%) of the fraction of the pore space occupied by supercritical CO_2 at the end of injection, and 1, 3, 5, and 11 months after the end of injection. At the end of the injection period the plume extends approximately 200 feet (61 m) horizontally and 30 feet (9 m) vertically. After 5 months from the end of injection the plume has nearly stabilized, the primary change being that increasing amounts of supercritical CO_2 dissolve in formation water that permeates into the plume. After 11 months the lateral extent of the plume is 250 feet (76 m) and the vertical extent is 50 feet (15 m) above the injection location.

Figure 7 shows the simulation results for the same model as Figure 6, but with a residual gas saturation of 0.25 (25%). The cross-sections show the fraction of the pore space occupied by supercritical CO_2 at the end of injection, and 1, 5, and 11 months after the end of injection. Once again, the plume has essentially stabilized by 5 months, and after 11 months has attained an extent of approximately 180 feet (55 m) horizontally and 20 feet (6 m) vertically above the injection location. Notice that with the higher residual gas saturation ($S_{gr} = 0.25$, rather than 0.05 in Figure 6), the plume has smaller dimensions. The reason is that, as the plume expands during injection, more CO_2 remains behind, trapped in the pore space capillaries as a supercritical gas.

For the two simulations displayed in Figures 6 and 7, the time-varying proportions of supercritical versus dissolved CO_2 are shown in Figure 8. The solid red and blue curves for $S_{gr} = 0.05$ show that for this extremely low amount of residual supercritical CO2, after 11 months there is still CO_2 dissolving into the formation water as the water moves into the base of the plume. The dashed red and blue lines for the more likely case of $S_{gr} = 0.25$, show that after 11 months from the end of injection, fluid movement within the plume has virtually ceased.

5.4 Layered permeability model with hysteresis, accentuating horizontal plume movement

When CO_2 in a plume dissolves in the formation water, or the CO_2 plume rises through buoyancy, formation water that was previously displaced moves back into pore space at the bottom of the plume. But the process is not reversible; that is, some CO_2 remains stuck in these pores. To understand the movement of fluids (CO_2 and formation water) within the plume, it is necessary to consider this hysteretic effect. (Hysteresis is also discussed at the ends of Sections 2 and 3 above.)

A simulation with hysteresis was run using the model described in Section 5.3, which emphasizes the horizontal extent of the plume. For drainage (displacement of formation water when CO_2 is injected), $S_{gr} = 0.0$. For imbibition (return of formation water when the plume rises or CO_2 is dissolved), S_{gr} is history-dependent with a maximum value of 0.25. These parameters are typical of values found in the petroleum literature, but are not necessarily correct for the present site. As shown in Figure 9, at the end of injection the plume has moved 233 feet (71 m) horizontally and 34 feet (10 m) vertically from the top of the injection location. After 11 months the plume extends to 241 feet (73 m) horizontally and 44 feet (13 m) vertically. Thus, there is only negligible movement.

When hysteresis is ignored, everything else being equal (Figure 6), the corresponding plume extent is 203 feet (62 m) horizontally and 28 feet (9 m) vertically at the end of injection, and 245 feet (75 m) horizontally and 52 feet (16 m) vertically at 11 months. Thus, there is some initial difference in predicted plume location between the two scenarios at the end of injection, but less movement of the hysteretic case post-injection, so that by 11 months after the end of injection, the predicted plume locations are similar with or without hysteresis.

6. Subsurface Pressure

6.1 Injection Pressure

A simulation was run to see if 2,000 tonnes of CO_2 could be injected over a reasonable period of time while maintaining an injection pressure below the fracture gradient, if unexpectedly low permeability is encountered in the target reservoir formation. By maintaining injection pressure below the fracture gradient, the risk of fracturing the reservoir rock, and possibly the seal above it, can be avoided.

For this simulation the TOUGH2 mesh was modified, making it much finer near the well and shifting the first nodes to the 8½-inch diameter of the wellbore so that pressure could be estimated at the wellbore rock face. Figure 10 shows the pressure at the injection location in the reservoir horizon, the Jerome Member of the Martin Formation, for 2,000 tonnes of CO_2 injected at a constant rate over periods of 7 days, 15 days, and 30 days. These periods represent injection rates of 11.9, 5.6, and 2.8 tonnes per hour (3.3, 1.6, and 0.8 kg/s), respectively. To evaluate an extreme case, permeabilities assigned to the injection horizon are much lower than for the previous models presented in this report (see table below).

Formation	Thickness	Horizontal Permeability	Vertical Permeability
Upper Naco	250 ft (76 m)	10 mD (0.01 μm^2)	1 mD (0.001 μm^2)
Lower Naco	250 ft (76 m)	100 mD (0.1 μm^2)	20 mD (0.02 μm^2)
Upper Martin	69 ft (21 m)	100 mD (0.1 μm^2)	20 mD (0.02 μm^2)
Lower Martin (Jerome)	131 ft (40 m)	**30 mD** (0.03 μm^2)	**1 mD** (0.001 μm^2)

If the maximum allowable injection pressure is assumed to be 2,300 psi (16 MPa) at the injection depth of 3,681-3,714 feet (1,091-1,102 m) based on a fracture gradient of 0.622 psi/foot (14 kPa/m), the curves in Figure 10 indicate that 2,000 tonnes of CO_2 could be injected over a period of 15 days or longer, but not over a period of 7 days. However, if the reservoir formation is found to have higher permeability, more characteristic of clastic or fractured rocks, the injection period could be less than 15 days at acceptable pressures. Injection of the CO_2 over a period of 14-21 days would be reasonable from a field operations perspective.

The curves in Figure 10 demonstrate that for this model with *constant injection rates*, pressure rises during the first minute or so, plateaus for about the next 14 minutes, then starts to decline. At the end of one day, the pressure has dropped approximately 30% of the pressure differential between the peak and the pre-injection reservoir pressure. Clearly, a way to mitigate the initial pressure pulse is to start at a low injection rate and gradually increase it over the first day. It is also apparent that if CO_2 is injected at *constant pressure*, the injection rate should increase after the first couple hours.

This model scenario is instructive in several regards. It demonstrates that under low permeability conditions, the CO_2 can be safely injected over an acceptable period of time. It also provides insights into injection rate scheduling that can minimize both pressure build-up and the duration of the injection period. But these model results should not be used to establish injection rates in advance of field tests. It is important to recognize that a constant injection rate is not a desirable or practical field procedure for the duration of the injection period. Pressure and injection rate will be varied to assess reservoir conditions.

Before full-scale CO_2 injection begins, step rate injection tests will be performed with water to assess permeability and injectivity, and to establish the maximum allowable injection pressure in accordance with the Underground Injection Control (UIC) permit that will be issued by the U.S. Environmental Protection Agency working in conjunction with ADEQ. During full-scale injection, pressure and injection rate will be varied to assess bulk reservoir conditions, and pressure will be monitored continuously to maintain compliance with the UIC permit.

6.2 Formation Pressure

To estimate the rise in pressure in the reservoir formation during CO_2 injection at various distances from the injection well, the model described in Section 6.1 above was used. The 2,000 tonnes of CO_2 was injected into the Jerome Member at a constant rate over 15 days (5.6 tonnes per hour = 1.6 kg/s) so that the maximum injection pressure remains below the fracture pressure at the depth of the injection interval 3,681-3,714 feet (1,091-1,102 m). Figure 11 shows plots of pressure at the average depth of injection for different times after the start of injection. Inferences from this figure and the underlying model calculations include:

- At a constant rate of injection, the injection pressure at the borehole decreases with time.
- During injection, there is a pressure differential at the leading edge of the CO_2 plume, which is responsible for the break in slope of each of the curves. This pressure differential is driving the plume outward.
- In the formation water beyond the CO_2 plume, pressure increases gradually throughout injection.
- For this model, the CO_2 plume extends 170 feet (52 m) from the borehole by the end of injection.
- At a distance of 400 feet (122 m) from the borehole, the maximum pressure reaches 1592 psi (11.0 MPa) at the end of injection. This is 34 psi (234 kPa), or 2.2%, above the background pressure of 1558 psi (10.7 MPa).
- Calculated from the same model, but not shown in Figure 11: at a distance of 1,312 feet (400 m ≈ ¼ mile) from the borehole, the maximum pressure increase is approximately 10 psi (69 kPa), or 0.64% above background pressure.

At the end of the fifteenth day, injection stops and pressure drops rapidly to near background levels.

7. Conclusions and Discussion

The simulations described in this study use conceptual models intended to approximate both probable and extreme reservoir conditions that might be encountered at the test site near the Cholla Power Plant for the Arizona Utilities CO_2 Storage Pilot. The reservoir properties are not well known. Furthermore, there is no doubt that actual lithologic properties in the earth are more complex than can be accommodated by numerical simulations. For example, it is common for layered formations to have relatively thin beds with alternating high and low permeabilities that tend to restrict upward migration of CO_2 and channel the CO_2 in lateral directions. And it is likely that permeabilities in any individual layer are non-uniform, varying in different directions and with distance from the injection interval. There may also be fracture systems that provide secondary permeability and channel the CO_2 in one or more specific directions. Nonetheless, in spite of these limitations, simulations such as those presented in this report have proven to be invaluable for estimating the complex interactions associated with the flow of multi phase fluids in the earth.

With such limited data available for the target reservoir formation, the approach for this study was to run simulations for several parameters and models that would alternately accentuate horizontal and vertical movement of the CO_2 plume. Some of the simulations represent relatively extreme assumptions (if not quite worst case scenarios), thus providing reasonable confidence that we can estimate the maximum probable extent of the plume.

The simulations provide preliminary estimates of plume size, shape, and movement, and demonstrate that the plume stabilizes and becomes essentially immobile after a few months. The extreme case for vertical movement of the plume suggests its top could rise approximately 180 feet (55 m) from the injection location in the Jerome Member, but not reach the base of the Supai Formation. Geologically more realistic models with several layers, and permeabilities that are higher in the horizontal direction than the vertical direction, suggest that the plume will stabilize within the Martin Formation and not reach the base of the Naco Formation. The most extreme simulations that accentuate lateral movement of the plume suggest that the maximum horizontal extent could be approximately 250 feet (76 m) from the well, but using more moderate permeabilities the simulated plume does not extend beyond 200 feet (61 m).

Considering the various simplifying assumptions that have been used for the models versus the real-world complexities of geologic formation properties, we propose a “safety factor” of 2 for the moderate 200-foot (61 m) estimate of lateral plume extent. That is, we predict that the plume will not extend beyond 400 feet (122 m) horizontally from the injection well. Vertically, we expect the CO_2 plume to remain confined to the Naco and Martin Formations, and it may become immobilized before it ever reaches the reservoir seal, low permeability lithologies in the Supai Formation. In fact, many simulations suggest that it will stabilize entirely within the Martin Formation.

Simulations run to evaluate injection pressure indicate that even under unexpectedly low permeability conditions, 2,000 tonnes of CO_2 can be injected in a reasonable period of time without exceeding the fracture pressure of the reservoir formation. The models indicate that the maximum pressure in the reservoir formation beyond the CO_2 plume is very low. At a distance of 400 feet (122 m) from the injection well, the maximum pressure rise is 34 psi (234 kPa), or 2.2%, above the background hydrostatic pressure. At a distance of ¼ mile (402 m), the maximum pressure increase is 10 psi (69 kPa), or 0.64% above the background pressure. After injection stops, pressure declines rapidly.

After the project well is drilled we will run open-hole and cased-well logs, analyze core samples, perform injectivity tests, and sample reservoir fluid. This will provide an array of data for re-running the simulations with actual formation properties (e.g., depth, thickness, salinity, porosity, permeability, characteristic curves). We will again simulate the size, shape, and movement of the plume, and then use pre- and post-CO_2 injection vertical seismic profile surveys, intended to detect the actual location of the plume for comparison with the models.

8. References

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Spycher, N. and K. Pruess, 2005, CO_2-H_2O Mixtures in the Geological Sequestration of CO_2. II. Partitioning in Chloride Brines at 12–100°C and up to 600 bar, *Geochim. Cosmochim. Acta,* Vol. 69, No. 13, pp. 3309–3320, doi:10.1016/j.gca.2005.01.015.

van Genuchten, M. Th., 1980, A closed-form equation for predicting the hydraulic conductivity of unsaturated soils, Soil Science Society of America Journal, 44(5):892-898.

9. Biographies

Sumit Mukhopadhyay developed the mesh parameters and used the TOUGH2 code to calculate the simulations described above for the injection of CO_2 at the test site for the Arizona Utilities CO_2 Storage Pilot. He analyzed the results, developed the figures, and wrote a draft of this report. Dr. Mukhopadhyay has been a scientist in the Hydrogeology Department of the Earth Sciences Division at Lawrence Berkeley National Laboratory since 1998. One of his current research areas is the analytical and numerical modeling of non-isothermal, multiphase and multicomponent flow in synthetic and natural porous media.

Education
Ph.D., Chemical Engineering, University of Southern California, 1995
B.Ch.E. Chemical Engineering, Jadavpur University, Calcutta, 1987

Selected publications

Mukhopadhyay, S. and Sahimi, M., 2000, Calculation of the effective permeabilities of a heterogeneous porous medium, *Chemical Engineering Science*

Mukhopadhyay, S. and Cushman, J. H., 1998, Monte Carlo simulation of contaminant transport: I. Long-range correlations in fracture conductivity, *Transport in Porous Media*, 31, 145-181

Christine Doughty provided recommendations and guidance for the CO_2 injection simulations described in this report. Dr. Doughty has been with the Hydrogeology Department of the Earth Sciences Division at Lawrence Berkeley Laboratory since 1978. Her current research activities include the development of conceptual and numerical models for the hydrological and thermohydrological behavior of fractured and porous geological media; the development and application of techniques for inverting hydraulic well-test and tracer data to infer the distribution of hydrologic properties in heterogeneous geologic media; sand the mathematical modeling of multi-component, multi-phase fluid flow and transport in heterogeneous geologic media. For the Frio brine pilot project, she performed pre-CO_2 injection simulation modeling, then analyzed and compared post-CO_2 injection field data.

Education

Ph.D., Material Science and Mineral Engineering, Univ. of California, Berkeley, 1995.
M.S., Material Science and Mineral Engineering, Univ. of California, Berkeley, 1991.
B.S., Engineering Physics, University of California, Berkeley, 1978

Selected publications

Doughty, C. and K. Pruess, 2004, Modeling supercritical carbon dioxide injection in heterogeneous porous media, Vadose Zone Journal, 3, 3, 837-847.

Hovorka, S. D., C. Doughty, S. M. Benson, K. Pruess, and P. R. Knox, 2004, The impact of geological heterogeneity on CO2 storage in brine formations: a case study from the Texas Gulf Coast, *in* Geological storage of carbon dioxide, S. J. Baines and R. H. Worden, Editors, Special Publication 233, Geological Society, London.

John Henry Beyer is in the Earth Sciences Division at Lawrence Berkeley National Laboratory and is the Program Manager for the WESTCARB CO_2 pilot projects in Arizona and California. He communicated with Errol L. Montgomery & Associates and other Arizona CO_2 project partners to estimate geologic formation parameters for the modeling effort, then analyzed the model results and wrote the final report. Before assuming this position at LBNL, Dr. Beyer managed Public Interest Energy Research projects at the California Energy Commission, and as an independent consultant planned and managed geophysical surveys exploring for geothermal resources in the Azores, Portugal; Indonesia; and Japan. Prior to that he was the General Manager of a 50-employee company that performed electromagnetic geophysical surveys to explore for geothermal and oil resources in the United States.

Education

MBA, Golden Gate University, San Francisco, 1989
Ph.D., Engineering Geoscience, University of California, Berkeley, 1977
M.A., Geophysics, Washington University, St. Louis, 1969
B.S., Physics, Lafayette College, Easton, PA, 1966

Registration

Registered Geophysicist in California, GP-859

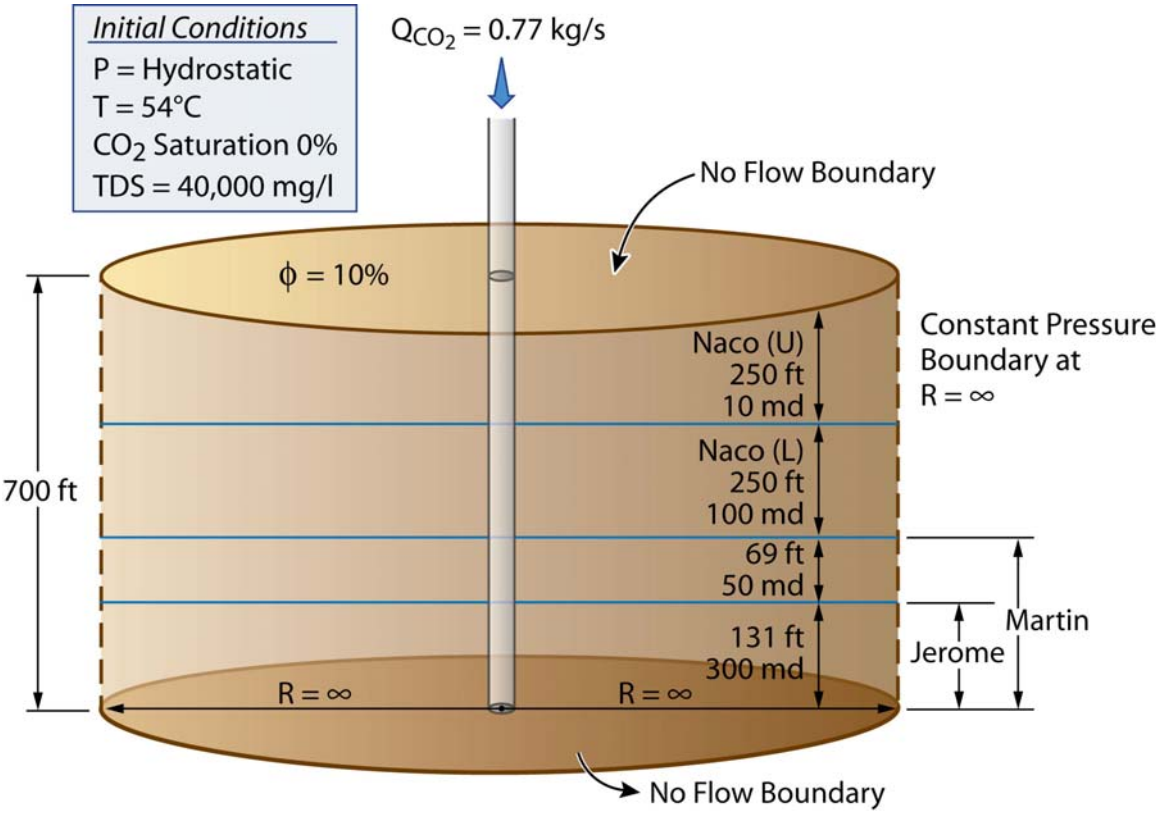

Figure 1. Schematic representation of the model reservoir used to simulate CO_2 injection at the Cholla Power Plant site.

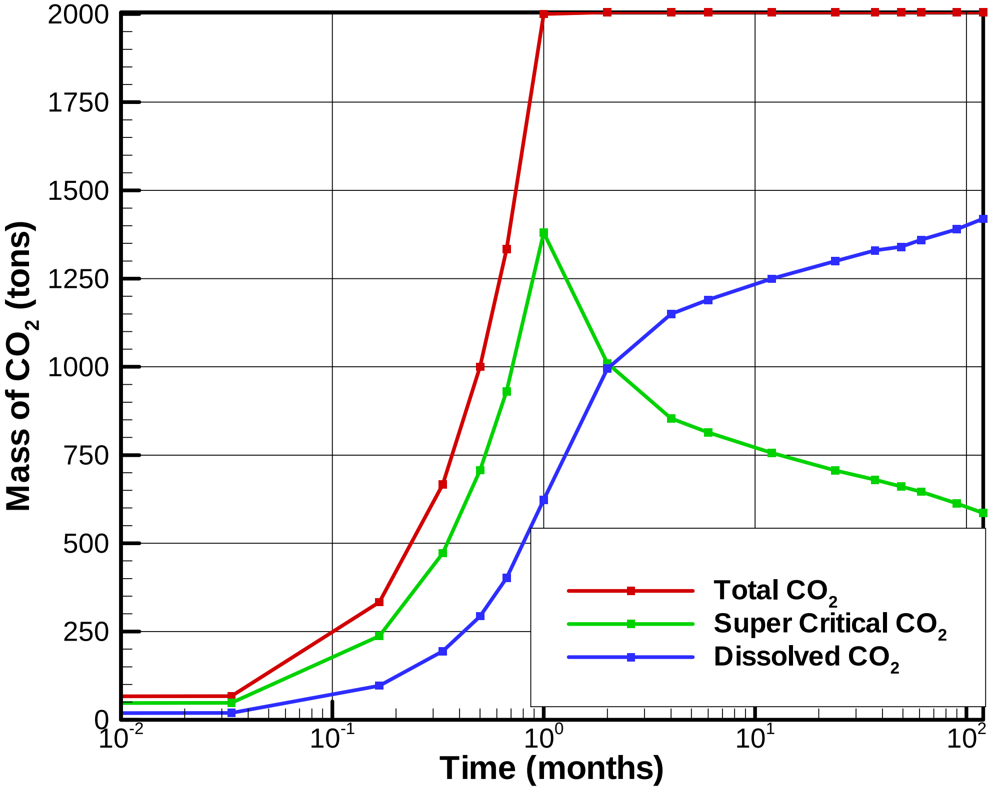

Figure 2. Distribution of injected CO_2 mass between supercritical and dissolved phases as a function of time with the residual supercritical CO_2 saturation $S_{gr} = 0.05$. The figure also shows the total mass of CO_2 in the system. 2,000 tonnes of CO_2 was injected over one month in the Jerome Member. Simulations were performed with a uniform permeability of 100 mD (0.1 μm_2) for the entire model reservoir consisting of the Naco and Martin Formations. Note the logarithmic scale for time, where 100 (1) month is the end of injection.

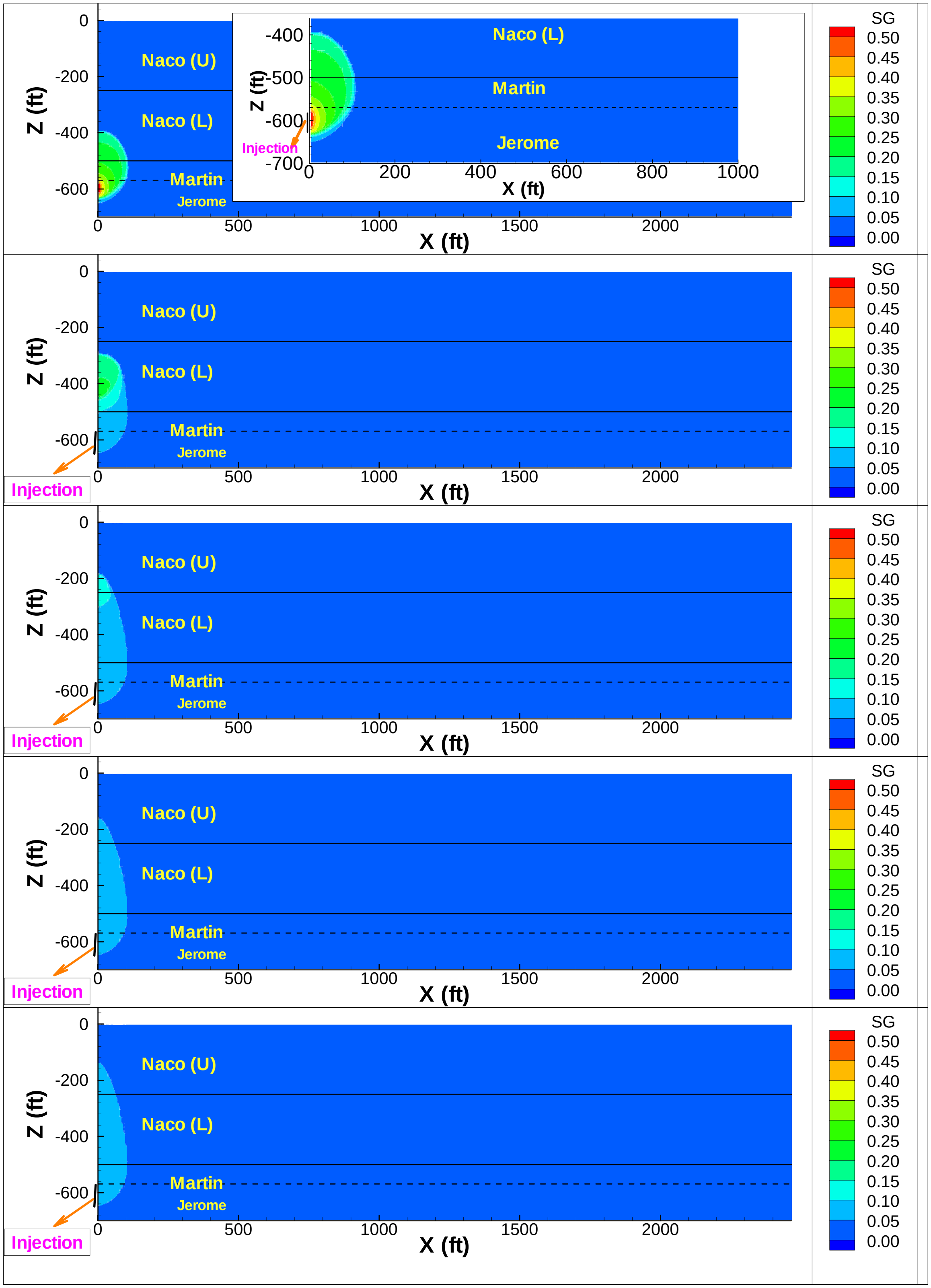

Figure 3. Cross-sections showing the fraction of the reservoir pore space filled by supercritical CO_2 at 0, 1, 3, 5, and 11 months (top to bottom, respectively) after the end of injection with the residual supercritical CO_2 saturation $S_{gr} = 0.05$ (5%). All layers have isotropic permeability = 100 mD (0.1 μm^2).

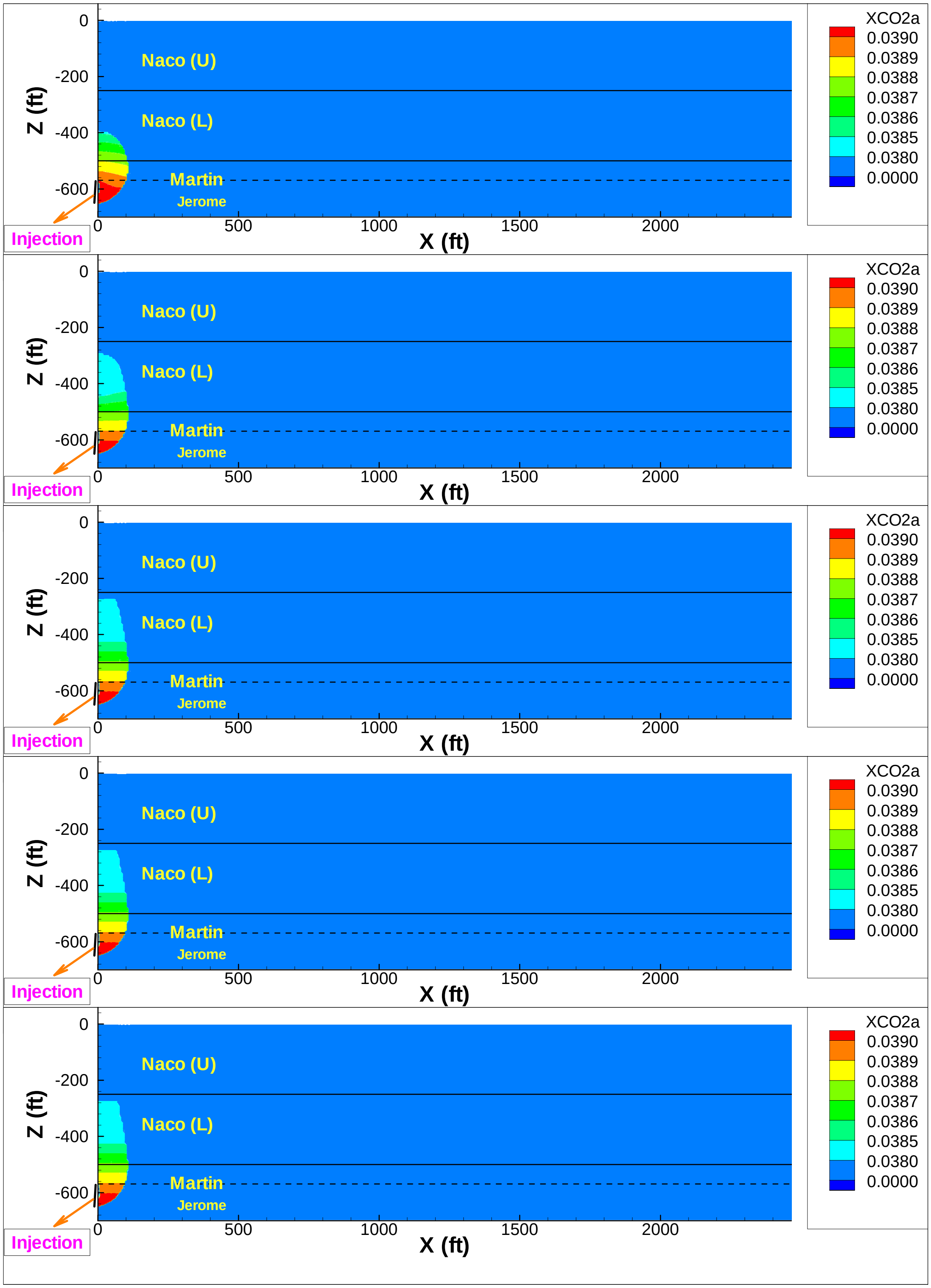

Figure 4. Cross-sections showing the mass fraction of dissolved (aqueous phase) CO_2 at 0, 1, 3, 5, and 11 months (top to bottom, respectively) after the end of injection with the residual supercritical CO_2 saturation $S_{gr} = 0.05$ (5%). All layers have isotropic permeability = 100 mD (0.1 μm^2).

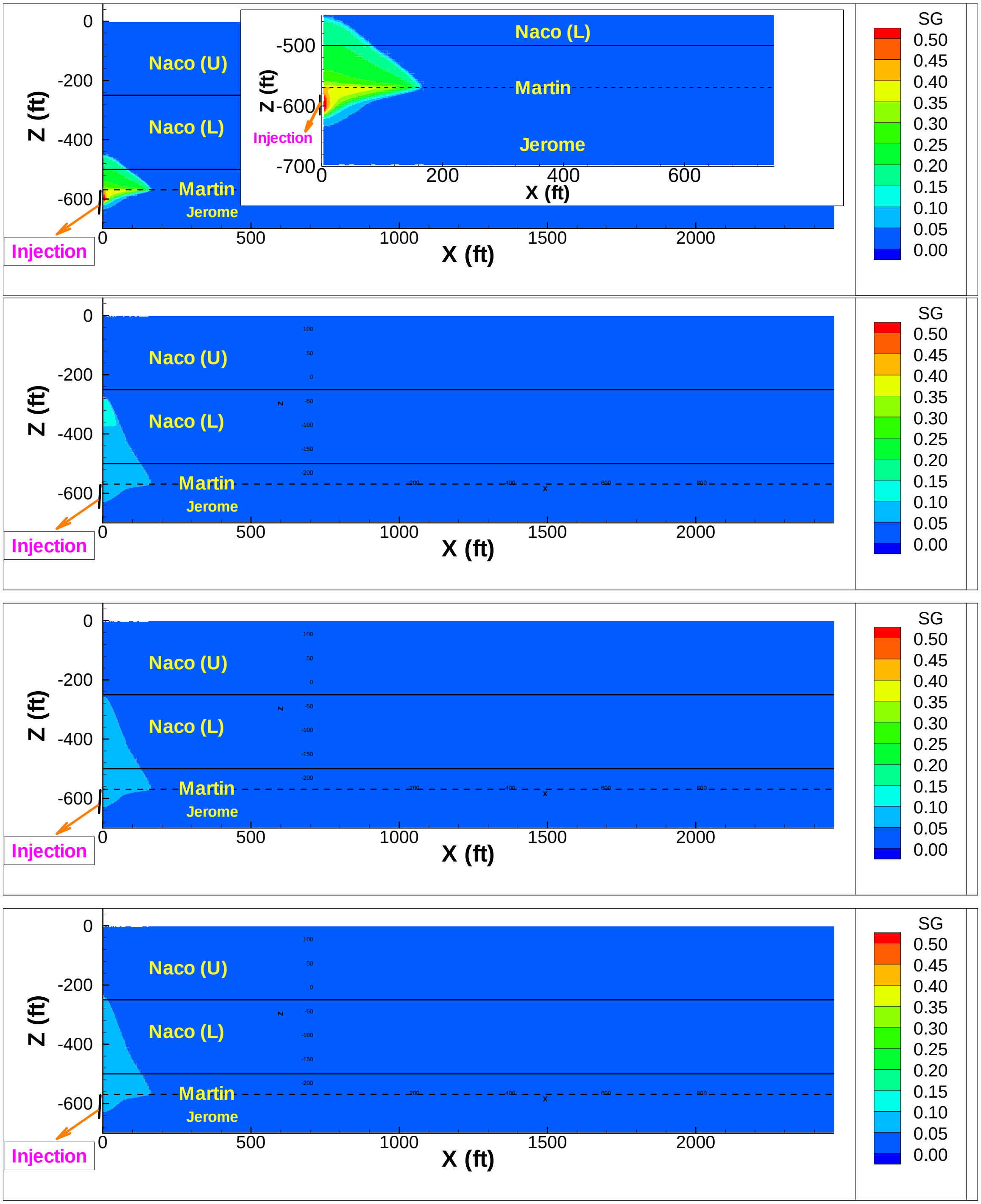

Figure 5. Cross-sections showing the fraction of the reservoir pore space filled by supercritical CO_2 at 0, 3, 5, and 11 months (top to bottom, respectively) after the end of injection with $S_{gr} = 0.05$ (5%). The four layers have isotropic permeabilities (equal in horizontal and vertical directions) of: Naco (U) = 10 mD, Naco (L) = 100 mD, Upper Martin = 50 mD, and Jerome Member of Martin = 300 mD.

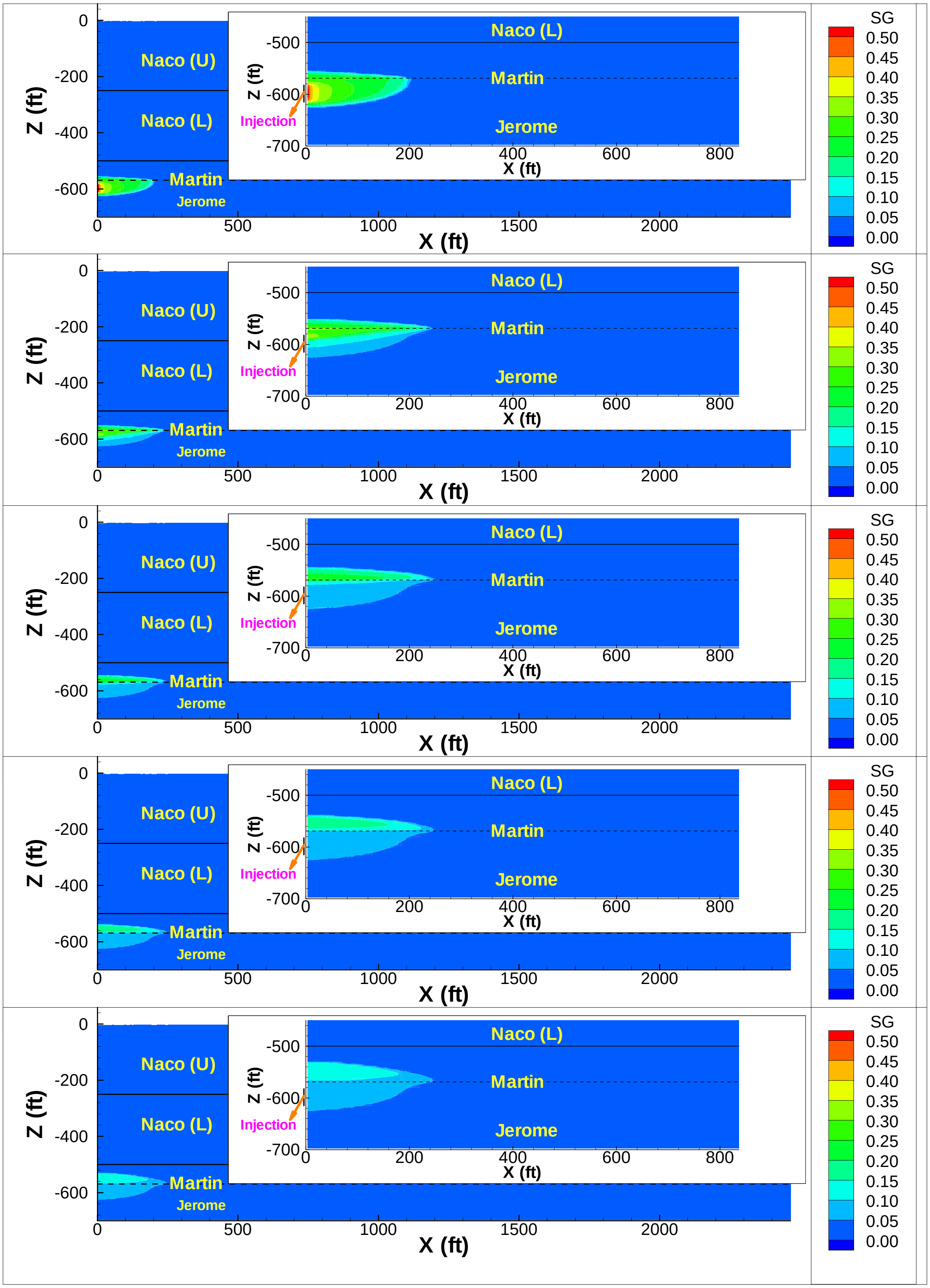

Figure 6. Cross-sections showing the fraction of the reservoir pore space filled by supercritical CO_2 at 0, 1, 3, 5, and 11 months (top to bottom, respectively) after the end of injection, with the residual supercritical CO_2 saturation $S_{gr} = 0.05$ (5%). The four layers have anisotropic permeabilities that are high in the horizontal direction, as described in Section 5.3.

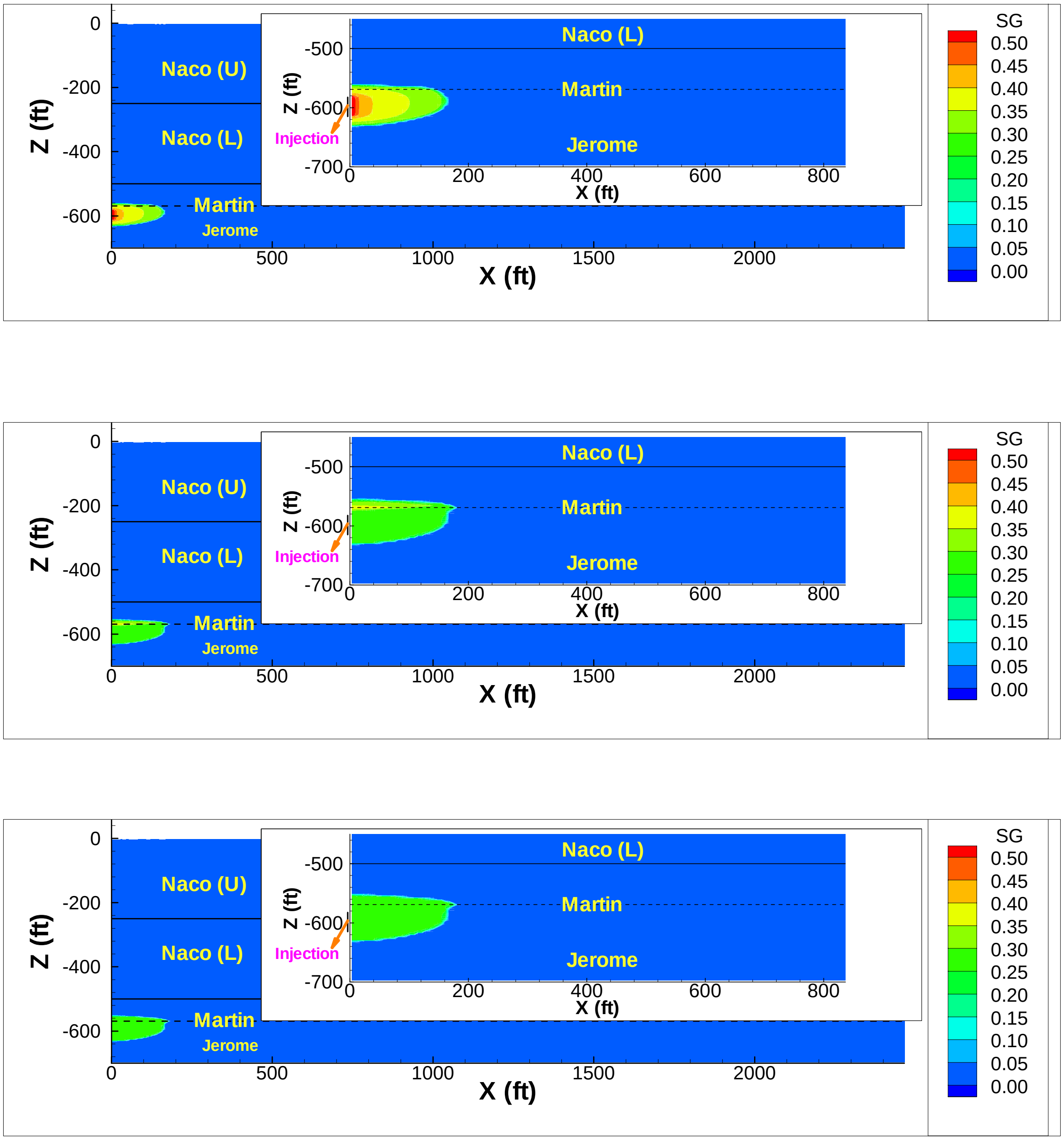

Figure 7. Cross-sections showing the fraction of the reservoir pore space filled by supercritical CO_2 at 0, 5, and 11 months (top to bottom, respectively) after the end of injection with the residual supercritical CO_2 saturation $S_{gr} = 0.25$ (25%). The four layers are the same as in Figure 6. They have anisotropic permeabilities that are high in the horizontal direction, as described in Section 5.3.

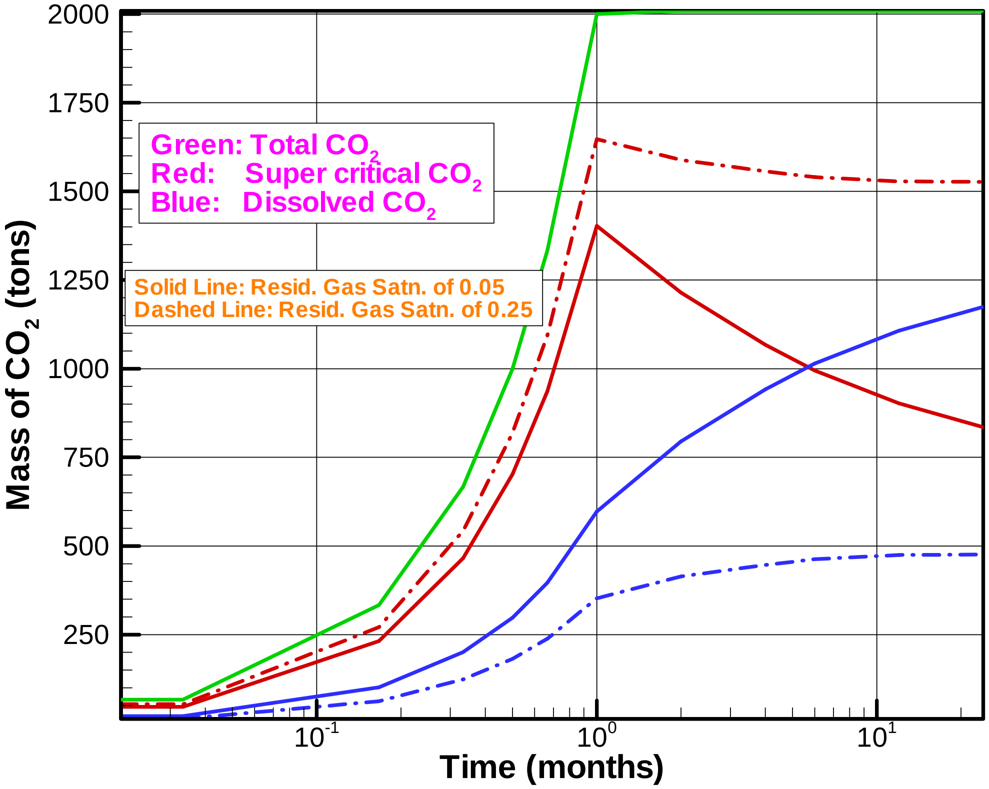

Figure 8. Distribution of injected CO_2 mass between supercritical and dissolved phases as a function of time for the simulations with high horizontal permeability described in Section 5.3 and shown in Figures 6 and 7. For the solid red and blue lines, residual supercritical CO_2 saturation $S_{gr} = 0.05$ (5%). For the dashed red and blue lines, residual supercritical CO_2 saturation $S_{gr} = 0.25$ (25%). The green line shows the total mass of CO_2 in the system. Note the logarithmic scale for time, where 10^0 (1) month is the end of injection.

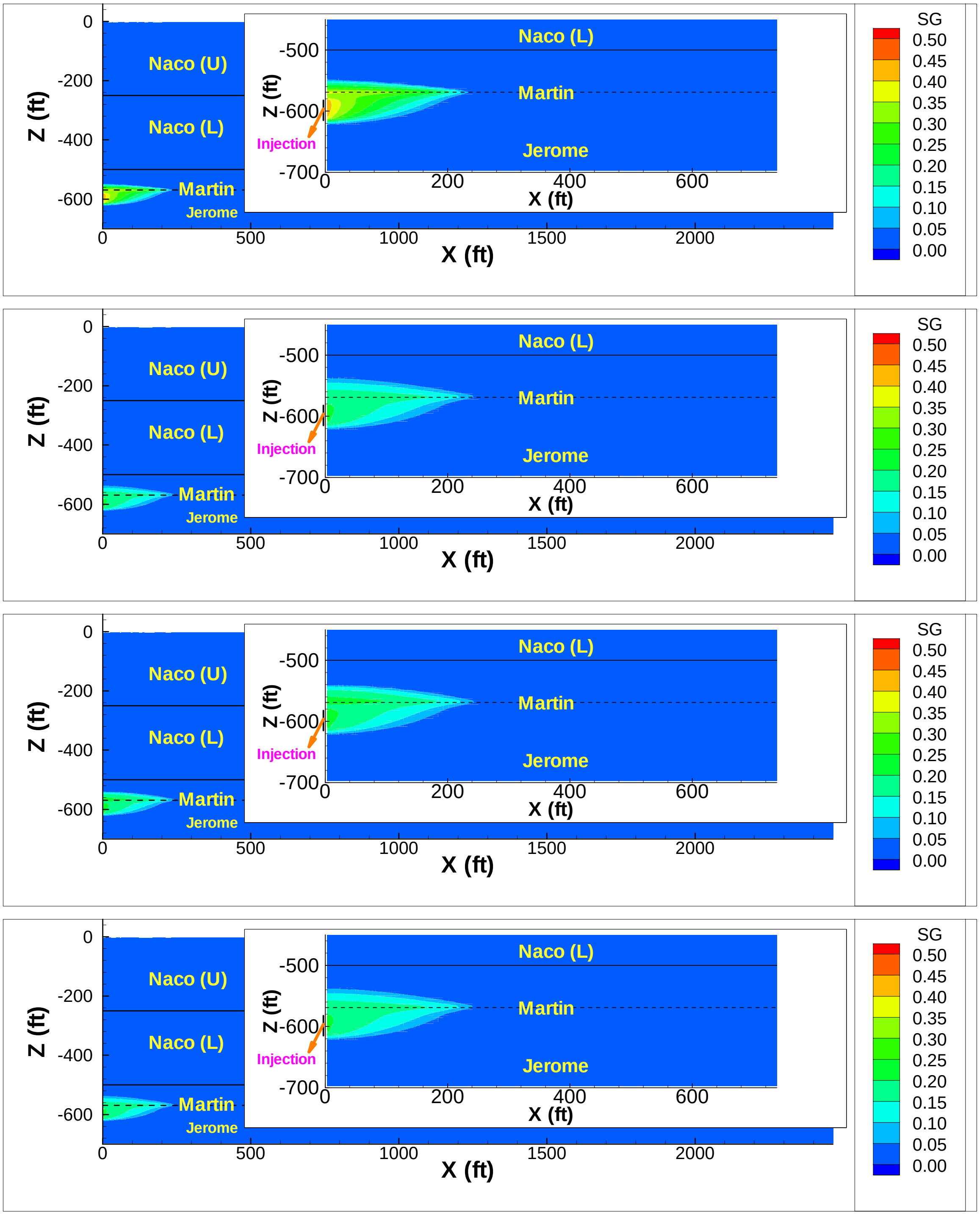

Figure 9. Cross-sections showing the fraction of the reservoir pore space filled by supercritical CO_2 at 0, 1, 5, and 11 months (top to bottom, respectively) after the end of injection. The residual supercritical CO_2 saturation $S_{gr} = 0$ for drainage, and is history-dependent with a maximum value of $S_{gr} = 0.25$ (25%) for imbibition. The four layers have anisotropic permeabilities that are high in the horizontal direction, as described in Section 5.3. Capillary hysteretic effects are included in this simulation for comparison with Figure 6, which does not include hysteresis.

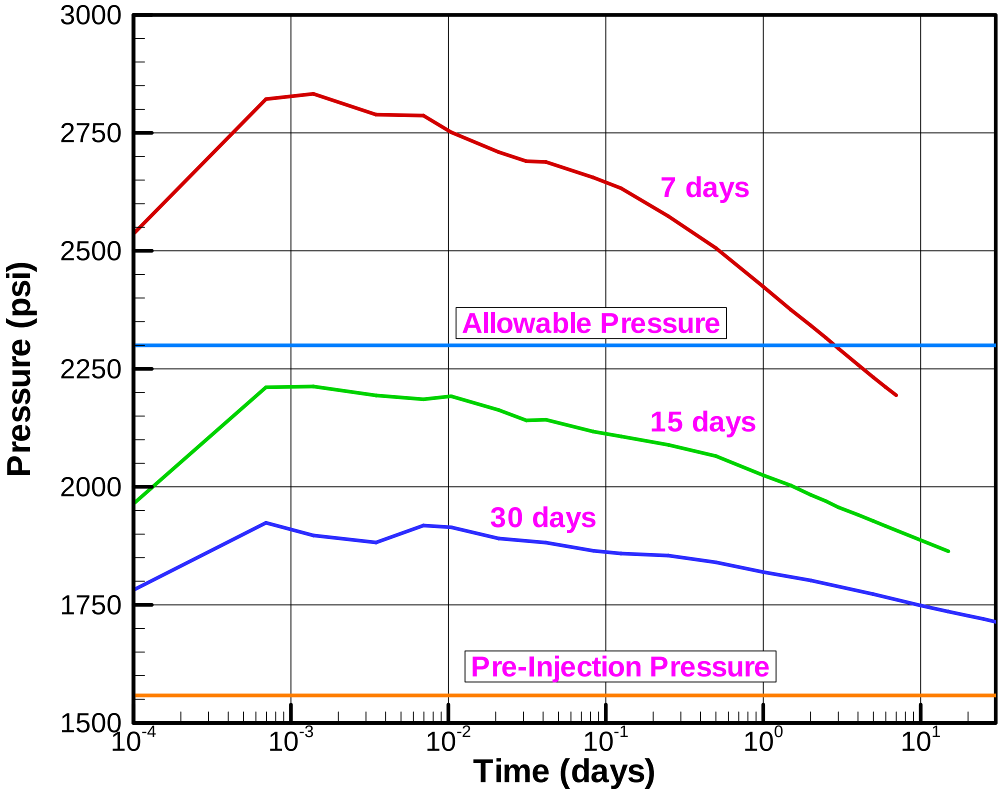

Figure 10. Pressure at the wellbore surface of the injection horizon (Jerome Member) if 2,000 tonnes of CO_2 is injected at a constant rate over 7, 15, and 30 days (11.9, 5.6, and 2.8 tonnes per hour, or 3.3, 1.6, and 0.8 kg/s, respectively). The injection horizon is assumed to have a horizontal permeability of 30 mD and a vertical permeability of 1 mD. These permeabilities are lower than for other models presented above to evaluate a "worst case" scenario.

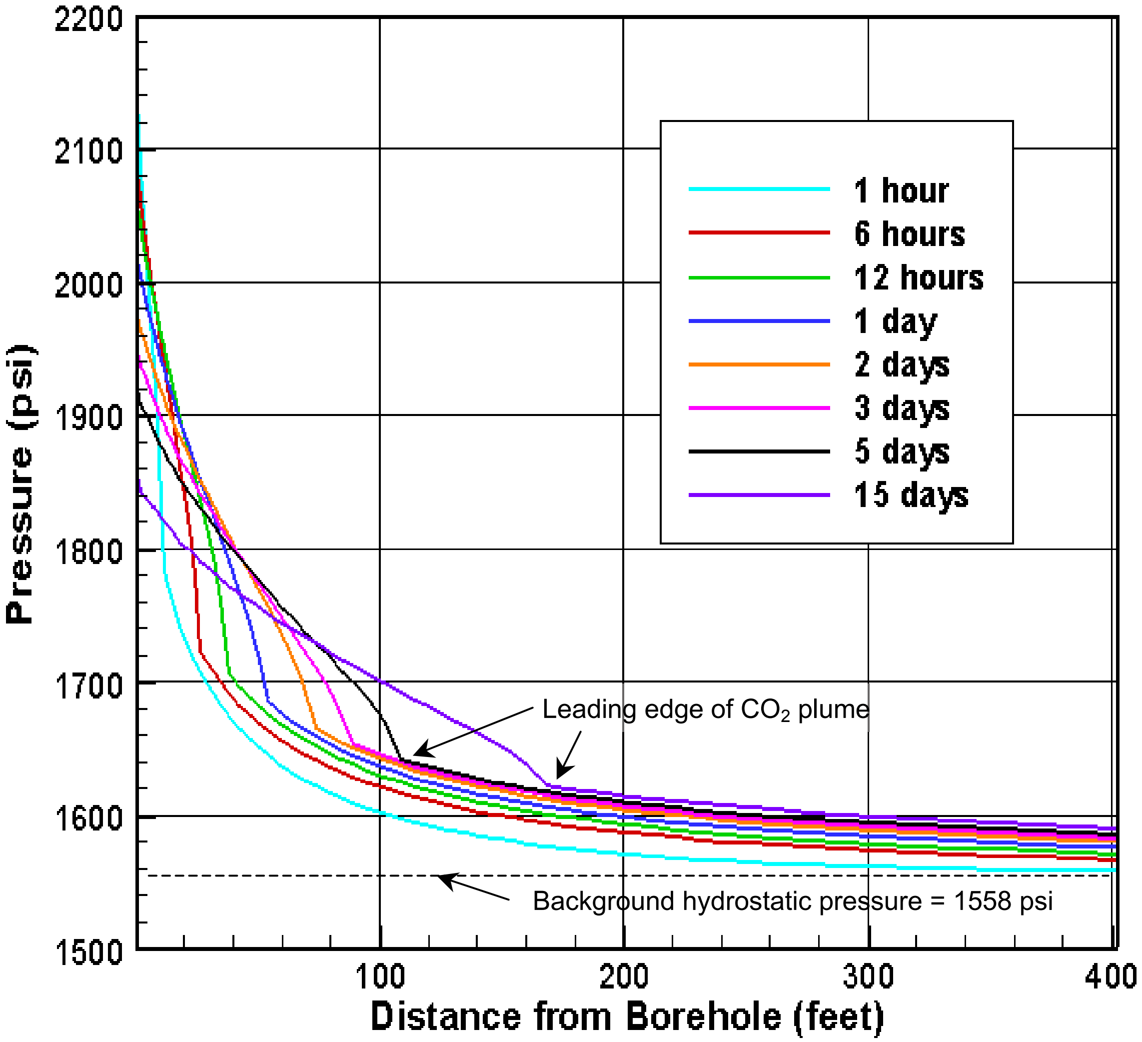

Figure 11. Pressure in the reservoir formation at horizontal distances from the injection well at different times after the start of CO_2 injection. The geologic model is the same as in Figure 10 above, with 2,000 tonnes of CO_2 injected at a constant rate over 15 days (5.6 tonnes per hour = 1.6 kg/s).

B. MAPS OF WELL/AREA AND AREA OF REVIEW - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I
The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

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

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

There is only one injection well, the CO_2 Injection Well, located on the project site for which the permit is sought: a 200 x 300-foot drill pad on property owned by Arizona Public Service Company near their Cholla Power Plant between Holbrook and Joseph City, Arizona. The edge of this drill pad is the “facility property boundary,” as shown in Figure 1 at the end of this attachment. While APS has extensive land holdings in the vicinity of the project site, the other property is devoted to power plant operations unrelated to proposed well and CO_2 injection project. Only the drill pad is dedicated for use by the West Coast Carbon Sequestration Partnership (WESTCARB) for the Arizona Utilities CO_2 Storage Pilot Test.

The proposed CO_2 Injection Well for the project is located approximately 270 feet southeast of the edge of the Fly Ash Pond for the APS Cholla Power Plant. The southeastern end of an earthen dam along the southwestern edge of the Fly Ash Pond is located about 570 feet southwest of the proposed CO_2 Injection Well. (See Figure B1.) The Fly Ash Pond and associated Dam is the only discharge structure located within one mile of the proposed well. There are no hazardous waste treatment, storage, or disposal facilities within one mile of the project site.

Within the area of review (1/4 mile from the CO_2 Injection Well) there are no producing wells, injection wells, springs, mines (surface or subsurface), quarries, residences, faults that are known or suspected, nor public water systems. Within the Area of Review there are five monitoring wells associated with the Fly Ash Pond. Wells located within one mile of the proposed CO_2 Injection Well are described in a Technical Memorandum included at the end of Attachment G. Figure 4 in this Technical Memorandum is a map showing the location of the wells and other features.

This application is not for an area permit, and there is no distribution manifold applying injection fluid to wells in the area, nor to system monitoring points.

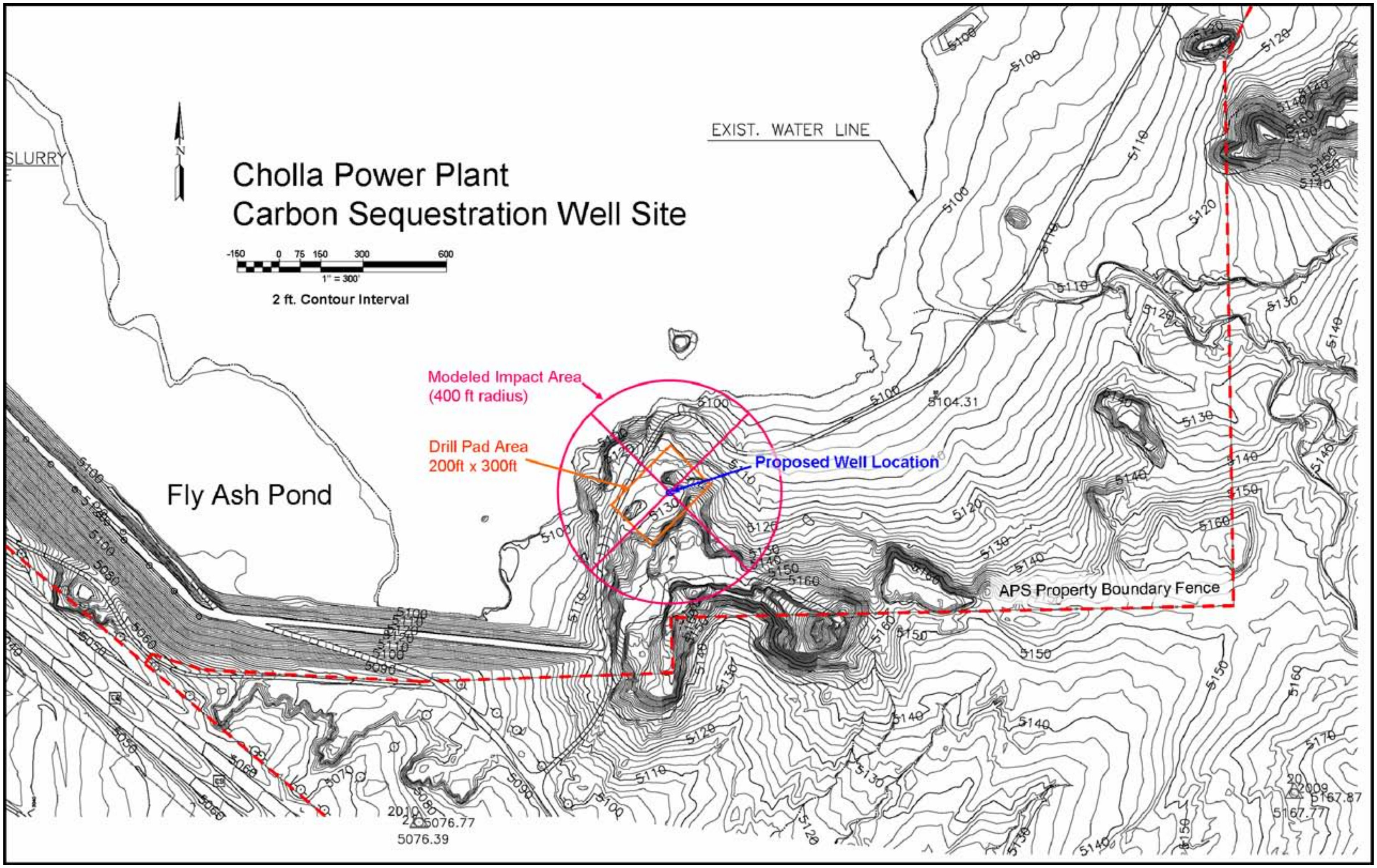

Figure B1. WESTCARB Arizona Utilities CO_2 Storage Pilot project site and CO_2 Injection Well location, adjacent to APS Cholla Power Plant fly ash pond.

C. CORRECTIVE ACTION PLAN AND WELL DATA

C. CORRECTIVE ACTION PLAN AND WELL DATA –Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

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

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

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

There are no existing wells within the area of review (1/4 mile radius from the CO_2 injection well) that penetrate the proposed injection zone. Consequently, no corrective action plan is required pursuant to 40 CFR §144.55 and 40 CFR §146.7.

Note regarding Attachments D, E, F, and G:

These four attachments all concern the hydrogeology in the vicinity of the project site. Most of the information necessary to address the topics in Attachments D, E, F, and G is presented in a Technical Memorandum entitled *Summary of Hydrogeologic Conditions in Support of a Temporary Individual Aquifer Protection Permit, CO_2 Sequestration Pilot Project, Arizona Public Service Corporation*, prepared by Errol L. Montgomery & Associates, Inc., a water resource consulting firm based in Tucson, Arizona.

Presented below is a brief response to the topics of interest in the four attachments which, to avoid redundancy, refers to figures and text in the Technical Memorandum. Then the Technical Memorandum is presented in its entirety to provide a coherent understanding of the underground source of drinking water (USDW) in the vicinity of the project site and the relationship of the USDW to the CO_2 injection zone.

D. **MAPS AND CROSS SECTION OF USDWs** -Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

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

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA -** Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

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

A geologic cross-section showing the projected location of the CO_2 Injection Well is presented in Figure 2 of the following Technical Memorandum. Note that the vertical exaggeration is approximately 51 to 1. The location of the cross-section is shown in Figure 1 in the Technical Memorandum. The interpreted geologic column in the vicinity of the project site is shown in Figure 3 of the Technical Memorandum. Structural relief is minor, so this is representative of the geologic section significantly beyond the Area of Review.

The underground source of drinking water (USDW) in this area of northeastern Arizona is known as the Regional C-Aquifer, indicated on the geologic cross-section (Technical

Memorandum Figure 2) as the Kaibab-Coconino-Schnebly Hill Formations and on Figure 3 as the Coconino Sandstone and Schnebly Hill Formation. The target CO_2 injection formation is more than 2,000 feet below the base of the Regional C-Aquifer in the horizon shown on the cross-section as Mississippian and Devonian Carbonates. In Figure 3, the primary target injection formation is labeled as the Martin Formation. A secondary injection target is the overlying Naco Formation.

As described in the Technical Memorandum, in the vicinity of the project site the Regional C-Aquifer comprises the Coconino Sandstone and Schnebly Hill Formations; the Kaibab Formation is absent. At the project site the Coconino Sandstone is ~400 feet thick over a depth range of approximately 210-610 feet, and the Schnebly Hill Formation is ~300 feet thick over a depth range of approximately 610-910 feet (see Table 1 in the Technical Memorandum). The altitude of the top of groundwater in the C-Aquifer is shown in Figure 5 and 6 in the Technical Memorandum, with flow to the northwest. Sedimentary formations in the Colorado Plateau of northeastern Arizona are nearly flat-lying with regional dip estimated to be 1 degree or less to the north.

As described in the Technical Memorandum on pages 5-6 and shown in Figure 7, TDS in the Regional C Aquifer in the vicinity of the project site is estimated to be in the range of 1,000-2,000 mg/L. Dissolved solids concentrations in the C-Aquifer are attributed to halite evaporite horizons in the underlying Supai Formation.

The only anticipated disturbance of the Regional C-Aquifer is the drilling of the proposed CO_2 injection well through it. Well drilling and construction procedures are designed to minimize the impact that the well will have (see Attachments L and M). Fresh water drilling mud will be used to drill through the Regional C-Aquifer into the top of the confining Supai Formation. Then, before reaching the Supai evaporites, the well will be cased and cemented from within the top of the Supai Formation to the surface to prevent the movement of groundwater among horizons within the Regional C Aquifer through the annular space outside the well casing.

It is highly unlikely that the USDW (the Regional C-Aquifer), will be affected by the CO_2 project. The CO_2 will be injected below the 2000-foot-thick Supai Formation, which is expected to be an effective seal that prevents the upward migration of CO_2. At least 1,500 of the total 2,000 feet of Supai Formation sediments are comprised of low-permeability siltstone, mudstone, and the evaporite minerals.

The target formation for CO_2 injection is the clastic Jerome Member of the Martin Formation (in the Mississippian and Devonian carbonates on the geologic cross-section), which lies immediately above granite basement. A secondary target is the Naco Formation, which overlies the Martin Formation beneath the confining Supai Formation. Water quality in the Martin and Naco Formations beneath the project site is unknown, but is expected to be significantly above 10,000 mg/L. In any case, before CO_2 is injected into any reservoir formation, water samples will be obtained and analyzed. TDS must be above 10,000 mg/L for CO_2 injection to take place, to ensure that no USDW in the area will be affected.

Fracture pressure in the target reservoir formations is unknown because there are no data from the few offset wells in the vicinity of the project site. Before CO_2 is injected, a step-rate injection test will be performed to determine a maximum safe injection pressure such that the reservoir and seal formations will not be fractured. Please see Attachment I, Formation Testing Program, for a description of the step-rate injection test.

Errol Montgomery & Associates
Technical Memorandum
July 23, 2008.

ERROL L. MONTGOMERY & ASSOCIATES, INC.
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Dennis H. Shirley, P.G.
Jeffrey J. Meyer
Janis K. Blainer-Fleming
Hale W. Barter
Gregory L. Wallace

TECHNICAL MEMORANDUM

DATE: July 23, 2008 **Project – 1263.03**

TO: John Boyer, ARIZONA PUBLIC SERVICE

FROM: Dennis H. Shirley, P.G.
ERROL L. MONTGOMERY & ASSOCIATES, INC.

REGISTERED GEOLOGIST
CERTIFICATE NO.
26393
DENNIS H.
SHIRLEY
Date Signed 7-23-08
ARIZONA, U.S.A.
Expires 09/30/2010

cc: John Beyer, WESTCARB
Rob Trautz, EPRI
Danny Gradle, ARIZONA PUBLIC SERVICE

SUBJECT: **SUMMARY OF HYDROGEOLOGIC CONDITIONS IN SUPPORT OF AN UNDERGROUND INJECTION CONTROL PERMIT, CO_2 SEQUESTRATION PILOT PROJECT, ARIZONA PUBLIC SERVICE CORPORATION**

SUMMARY

This technical memorandum was prepared by Errol L. Montgomery & Associates, Inc. (Montgomery & Associates) on behalf of Arizona Public Service Corporation (APS) in support of an Underground Injection Control (UIC) permit application submittal to the Environmental Protection Agency, Region IX. The UIC permit application is associated with the Arizona Utilities CO_2 Storage Pilot Project to drill a test well to evaluate the potential for sequestration of carbon dioxide (CO_2) into deeply buried sedimentary strata at the APS Cholla Generating Station (Cholla), located near Joseph City, Arizona.

The APS Cholla site was selected for the Arizona Utilities CO_2 Storage Pilot Project based on previous siting study prepared by Montgomery & Associates in conjunction with West Coast Regional Carbon Sequestration Partnership (WESTCARB) summarized in a draft report dated June 26, 2007 entitled:

REGIONAL GEOLOGIC AND HYDROLOGIC CHARACTERIZATION
NORTHERN ARIZONA SALINE FORMATION CO_2 STORAGE PILOT
COLORADO PLATEAU REGION OF NORTHERN ARIZONA

Based on screening of regional geologic and hydrologic conditions and considerations of land access and permitting, a site at or in the vicinity of the Cholla Power Plant was selected for a pilot project. Two important factors were pivotal in selecting the Cholla Area for further consideration. First, the Cholla Area is the most favorable area in the Colorado Plateau under consideration in lands outside of the Navajo Nation and Hopi Indian reservation. Oil and gas test wells drilled in this area indicate that most of the Cholla Area appears favorable for supercritical carbon dioxide storage. A second key factor supporting pilot project implementation in the Cholla Area was based on water quality of the regional aquifer (C-Aquifer) in the Coconino/De Chelly Sandstone. Groundwater wells penetrating the regional aquifer indicate an extensive area of poor quality groundwater exists just north of and roughly parallel to the Little Colorado River in this region. Total dissolved solids in groundwater range from approximately 20,000 to 70,000 milligrams per liter in this area due to the presence of evaporative salts in the underlying Supai Formation. The highly saline conditions present in the uppermost aquifer in the northern Cholla Area give reason to believe that underlying groundwater in deeper sedimentary formations will be saline. This memorandum briefly describes geologic and groundwater conditions and current water uses in vicinity of the proposed pilot site.

GEOLOGIC SETTING

The proposed pilot well site is located about 4 miles east-southeast from Joseph City, Arizona, and about 2.5 miles east of the Cholla Generating Station (**Figure 1**). This site is located within the Colorado Plateau physiographic province of Arizona, which is a generally low-relief high-altitude landmass interspersed with buttes, mesas, deeply incised canyons, and volcanic peaks. The Colorado Plateau in northeast Arizona is underlain by a thick sequence of nearly flat-lying sedimentary strata. Stratigraphy and structural geology of potential CO_2 reservoir units are reasonably well known and correlated between outcrop and widely-spaced deep exploration wells across the area (**Figure 2**). The Colorado Plateau includes the area drained by the Colorado River and its tributaries, the Green, San Juan, and Little Colorado Rivers.

Stratigraphy

The sedimentary section is inferred to be about 3,600 to 3,800 feet thick in the vicinity of the Cholla Power Plant. A deep exploration well designated as the Cree #1 Scorse well (Arizona Oil and Gas Conservation Commission well number 460) is located about 2 miles southeast from the proposed test site and penetrates the entire sedimentary section. Based on data from this well and regional geologic interpretation, the inferred stratigraphy at the proposed test site is summarized as follows (**Table 1** and **Figure 3**):

Chinle Formation The Triassic Chinle Formation, comprised primarily of mudstone and claystone, has been largely removed by erosion at the proposed test site and most of the area to the south. The local soil, however, is derived from the sandy, pebble conglomerate of the basal Shinarump member of the Chinle Formation which surrounds the site.

Moenkopi Formation The Triassic Moenkopi Formation, about 210 feet thick, has upper and lower silty sandstone members with a Middle Moqui member composed of claystone and gypsum. At the proposed test site, the Moenkopi Formation is exposed on the land surface.

Coconino Sandstone The Permian Coconino Sandstone, 400-500 feet thick at the test site, may be generally described as a cross-bedded quartz arenite. This sandstone crops out over large portions of the Colorado Plateau south of the Little Colorado River, and is an important potable aquifer where it contains groundwater of acceptable chemical quality (C-Aquifer).

Schnebly Hill Formation The Permian Schnebly Hill Formation is a very-fine-grained sandstone, about 300 feet thick, that is hydraulically connected to the overlying Coconino Sandstone.

Supai Formation The Permian-Pennsylvanian Supai Formation, about 2,000 feet thick, is comprised of four members, including, in descending order: the Corduroy member, Fort Apache Limestone member, Big A Butte member, and Amos Wash member. The upper Corduroy member is primarily clayey siltstone and shale, and is expected to have an aggregate 100-200 feet of halite interspersed with the fine-grained deposits at the proposed test site (Rauzi, 2000). Some halite also occurs in the Big A Butte member; however, the Big A Butte, and the underlying Amos Wash member, are primarily siltstone and mudstone with secondary sandstone and dolomite. The 20-foot thick Fort Apache Limestone member is insignificant except as a stratigraphic marker bed.

Halite beds are present in the upper part of the Supai Formation at depths of about 1,200-1,500 feet (Rauzi, 2000). These salt beds have adversely affected groundwater quality in portions of the overlying C-aquifer, and are expected to have contributed salinity to groundwater in formations underlying the Supai Formation. Due to the fact that at least 1,500 of the total 2,000 feet of Supai Formation sediments are comprised of low-permeability siltstone, mudstone, and evaporite minerals, the Supai Formation would form an effective **confining seal** for carbon dioxide injected into underlying formations.

Naco Formation The Pennsylvanian Naco Formation is the uppermost injection target. According to Rauzi (1996), the Naco Formation is about 500 feet thick at the proposed test site (**Table 1**). The Naco is a marine-shelf deposit (Blakey and Knepp, 1989). In the Cholla Area, the Naco Formation may be about 50 percent limestone and sandstone and 50 percent mudstone and claystone. Assuming a 500-foot total thickness, the Naco would contain about 250 feet of limestone and sandstone.

Martin Formation The Devonian Martin Formation is the primary injection target for this pilot project. The Martin Formation is expected at a depth of about 3,445 feet below land surface at the proposed test site, and is projected to be about 200 feet thick (Rauzi, 1996; **Table 1**). The nearest exposure of the Martin Formation is about 60 miles southwest, along the Mogollon Rim. There, the lower Beckers Butte member of the Martin is “quartz sandstone to granule conglomerate with minor dolomite and shale”, up to 130 feet (40 m) thick. The upper Jerome member, up to 535 feet (165 m) thick, is composed of dolomitic mudstone in the bottom one-third of the member, and “dolomite or limestone having a skeletal wackestone or packstone texture” in the upper two-thirds (Beus, 1989). In the vicinity of the test site the Jerome member may become increasingly sandy as a nearshore facies.

Precambrian Rocks The Precambrian rocks of the Colorado Plateau region comprise a diverse group of igneous, metamorphic, and sedimentary rocks and are generally well consolidated and thus not thought to have sufficient porosity to warrant consideration as injection targets.

Geologic Structural Features

The Cholla Area is situated near the southern end of the Black Mesa basin, near the southern edge of the Colorado Plateau (**Figure 1**). From the edge of the Plateau, about 40 miles south of Cholla, to the structural center of Black Mesa basin, about 70 miles north, the sedimentary rocks have a fairly consistent 1 degree northward dip. This regional dip is interrupted by local folding and one major structure, the Holbrook anticline, located about 20 miles south of Cholla **(Figure 1)**.

Regional structural geology along an east-west transect through the Cholla vicinity consists of a very broad synclinal structure centered roughly on the Little Colorado River, likely a southern extension of the Black Mesa Basin (**Figure 2**). The proposed test site is located on the eastern limb of the syncline, near where the Martin Formation is thought to pinch out between the overlying Naco Formation, and the underlying Precambrian basement rocks. East of the Cholla area, small folds and the large wedge of Supai Formation evaporites are superimposed on the broad synclinal limb (**Figure 2**). The Naco Formation is also thought to pinch out farther east beneath the thickest section of evaporates. Local structural flexures on the top of the Coconino Sandstone have been identified in the vicinity of the proposed test site (**Figure 4**). The site is located at the eastern edge of a gently plunging northwest-southeast trending synclinal / anticlinal pair. These localized structures are superimposed on the regional northward dip of the Coconino Sandstone, which is about 50 feet per mile in the Cholla area (Mann, 1976).

HYDROGELOGIC SETTING

The hydrologic features in the vicinity of Cholla are characterized by intermittent and ephemeral streams with fairly abundant groundwater in the Coconino Sandstone. The Little Colorado River, an intermittent stream, lies adjacent to the proposed test site (**Figure 1 and 4**). A couple of surface impoundments also exist in the vicinity of the proposed test site; however these surface water bodies are man-made and are related to operations of the Cholla Plant.

Occurrence and Movement of Groundwater

Small amounts of groundwater may be present in shallow alluvium or the Moenkopi Formation in the vicinity of Cholla; however neither of these deposits represents a viable potable supply aquifer due to the limited extent of alluvium and the low permeability of the Moenkopi. Regional groundwater underlying the Cholla area occurs in the C-aquifer system which is used as water supply for the Cholla Power Plant and for municipal and domestic use (**Figure 5**). Recharge to the C-Aquifer occurs at altitudes above 6,000 feet along the Mogollon Rim and the Defiance Plateau (**Figure 1**). From those high areas, groundwater moves directly down-gradient north-northwest to discharge from Mississippian rocks at Blue Springs, near the confluence of the Colorado and Little Colorado Rivers, at an altitude of about 3,150 feet. Little vertical recharge occurs to Paleozoic rocks north of the Little Colorado River because of confining seals in Mesozoic rocks, notably the Triassic Chinle Formation.

Confining head in the Martin Formation is projected to be about 3,000 feet in the area of the test site. This projection was originally based on altitudes of springs 60 to 80 miles distant, and construction of a potentiometric surface that conforms to the springs' altitudes (i.e., the potentiometric surface in the aquifer must be higher than the discharge points). Subsequently, reported shut-in pressures of 1,300-1,600 psi in the Martin Formation have been found in several oil test records. These reported pressures correspond well with those previously estimated.

The total head of 3,000-4,000 feet is sufficient to move groundwater across most structures with little influence on direction of movement. C-Aquifer groundwater-level altitudes in the Cholla area indicate a generally west-northwest flow direction (**Figure 6**). The directions of groundwater movement in the older Paleozoic rocks are believed to be similar to those in the Permian strata.

Chemical Quality of Groundwater

Water quality of the C-aquifer in the Cholla area is highly variable. Groundwater in the area south of the Little Colorado River is generally good with low total dissolved solids (TDS). Groundwater in the area north of the Little Colorado River has been found to have TDS concentrations in excess of 2,000 mg/L (**Figure 7**; Mann, 1976). This extensive area of poor quality groundwater extends to the west roughly parallel to the Little Colorado River, and is attributed to the presence of evaporative salts in the underlying Supai Formation. Saline water that is thought to have been present in much of the area south of the Little Colorado River has been flushed out by past and present discharge to the Little Colorado River.

Very few water quality data are available for rocks underlying the C-Aquifer in the project area. It is assumed that the halite deposits affecting the C-Aquifer in the Cholla area also create saline conditions in the underlying formations (Devonian through Pennsylvanian). In estimates prepared for the Southwest Regional Carbon Sequestration Partnership, Steve Rauzi (personal communication) of the Arizona Geological Survey estimated a total dissolved solids (TDS) concentration of 30,000 parts per million in the Naco Formation. The estimate was based on expected downward movement of highly saline groundwater from the Supai Formation and the possible presence of connate water in the limestones of the Naco Formation. No exploration well test data were found for dissolved solids concentrations in Martin Formation groundwater in, or near, the Cholla Area. The basis for anticipating high-salinity groundwater is the same as

Rauzi's logic for the Naco Formation; downward movement of poor quality groundwater from the Supai Formation, and possible connate water in the Martin marine carbonates. Altitude of head in the very saline groundwater in the Supai Formation is about 500-800 feet above the projected altitude of head in the Martin Formation. Thus, some downward movement of saline groundwater would be expected to occur.

EXISTING WELLS IN THE VICINITY OF PROPOSED CHOLLA TEST SITE

An inventory of wells in the vicinity of the test site was compiled from Arizona Department of Water Resources (ADWR) well databases and the Oil and Gas well files obtained from the Arizona Geological Survey. The completed inventory contains 87 wells: 61 exploration or monitor wells, 16 stock, domestic, or other supply wells, and 10 industrial or irrigation wells (**Figure 4** and **Figure 6**; **Table 2**). Of these wells, 54 appear to be completed in the Moenkopi Formation, 20 in the Coconino Sandstone, 5 in the Supai Formation or Precambrian basement, and 8 well records did not have enough data to make a determination. All stock-domestic or public supply wells were assumed to be completed in the Coconino Sandstone even if the total depth of the well appeared to be above the top of the Coconino Sandstone, except for one well that did not have any total depth information (55-552166; well inventory number 81 on **Table 2**).

Three of the potable wells of record are located a little more than ½ mile from the proposed test site (well numbers 59, 70, and 71 in **Table 2**). Two of these are to the south-southwest and the third is west-southwest from the proposed test site (**Figure 4**). Only one of these wells was drilled after the enactment of the 1980 Groundwater Code (i.e., ARS §45) and has been registered with ADWR registration number (55-541134). Therefore, it is possible two of these wells have been destroyed or abandoned. The next closest potable well west-northwest from the proposed test site is about 1.2 miles away (55-201626; well inventory number 10 in **Table 2**; **Figure 4**). However, review of well registration records indicates that this well is actually located in Section 2 of Township 11 North, Range 14 East.

REFERENCES

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TABLE 1. PROPOSED TEST WELL SITE INFERRED STRATIGRAPHY, CO_2 SEQUESTRATION PILOT PROJECT, APS CORPORATION

Stratigraphic Unit	Thickness (feet)	Upper Contact Depth[1] (feet)	Lower Contact Depth (feet)	Altitude of Top[2] (feet)
Chinle Formation	~0	~0	~0	~5,120
Moenkopi Formation	210	0	210	5,120
Coconino Sandstone	400	210	610	4,910
Schnebly Hill Formation	300	610	910	4,510
Supai Formation:				
Corduroy member	825	910	1,735	4,210
Ft. Apache Ls. mem.	20	1,735	1,755	3,385
Big A Butte mem.	640	1,755	2,395	3,365
Amos Wash mem.	550	2,395	2,945	2,725
Naco Formation	500	2,945	3,445	2,175
Martin Formation	200	3,445	3,645	1,675
Precambrian basement	---	3,645	---	1,475

[1] Inferred depth in feet below land surface at proposed test well site.

[2] Inferred altitude in feet above mean sea level at proposed test well site.

TABLE 2. SELECTED WELLS IN THE VICINITY OF THE PROPOSED TEST WELL SITE, CO_2 SEQUESTRATION PILOT PROJECT, APS CORPORATION

WELL INVENTORY NUMBER	CADASTRAL LOCATION	RECORD SOURCE	ADWR 55-WELL REGISTRY NUMBER	ADWR 35-WELL REGISTRY NUMBER	GWSI SITE NUMBER	O&C PERMIT NUMBER	UTM COORDINATES (Zone 12, NAD 27) Easting (meters)	Northing (meters)	DATE COMPLETED	WELL DEPTH (feet, bls)	CASING DEPTH (feet, bls)	DIAMETER (inches)	LAND SURFACE ALTITUDE[1] (feet, msl)	WELL DEPTH ALTITUDE (feet, msl)	ESTIMATED ALTITUDE OF TOP OF COCONINO[2] (feet, msl)	INFERRED FORMATION AT TOTAL DEPTH[3]	WELL / WATER USE[4]	OWNER
1	A(17-20) 05ABA	Wells 55	600251				569,460	3,862,899	2/21/1974	350	20	8	5,115	4,765	4,970	Coconino	Irrigation	SHUMWAY, DREW,
2	A(17-20) 05ABA	Wells 35		7113			569,460	3,862,899	2/10/1974	175	45	8	5,115	4,940	4,970	Coconino	Stock	WHITING BROS OIL CO
3	A(17-20) 06BAA	Wells 55	580185				567,417	3,862,874	8/15/2000	173	38	6	5,045	4,872	4,967	Coconino	Stock	WESTOVER, BOYD,L
4	A(18-19) 24BBD	Wells 55	506366				565,361	3,867,500	10/21/1983	118	65	5	5,050	4,932	4,809	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
5	A(18-19) 24DCD	Wells 55	613205				566,182	3,866,291	4/8/1979	57	35	1	5,167	5,110	4,869	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
6	A(18-19) 25	Wells 55	547254				565,885	3,865,380	6/14/1995	50			5,019	4,969	4,836	Moenkopi	Exploration / Monitoring	ARIZONA PUBLIC SERVICE
7	A(18-19) 25AAC	Wells 55	613203				566,386	3,865,888	4/7/1979	50	28	1	5,108	5,058	4,892	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
8	A(18-19) 25AAD	Wells 55	613200				566,587	3,865,890		132	32	1	5,119	4,987	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
9	A(18-19) 25ABA	Wells 55	613204				566,183	3,866,088	4/8/1979	50	28	1	5,046	4,996	4,877	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
10	A(18-19) 25ACC[5]	Wells 55	201626				565,985	3,865,482		650	650	6	5,020	4,370	4,856	Coconino	Domestic	HANCOCK, GERALD
11	A(18-19) 25ADA	Wells 55	613199				566,588	3,865,688		112	32	1	5,097	4,985	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
12	A(18-19) 25ADA	Wells 55	613223				566,588	3,865,688	5/8/1979	80	58	1	5,097	5,017	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
13	A(18-19) 25ADD	Wells 55	613220				566,589	3,865,487	4/4/1979	60	38	1	5,048	4,988	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
14	A(18-19) 25ADD	Wells 55	613221				566,589	3,865,487	4/4/1979	50	28	1	5,048	4,998	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
15	A(18-19) 25ADD	Wells 55	613222				566,589	3,865,487	4/3/1979	50	28	1	5,048	4,998	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
16	A(18-19) 25CDC	Wells 55	613152				565,587	3,864,671	8/30/1973	56	49	6	5,034	4,978	4,876	Moenkopi	Industrial	AZ PUBLIC SERVICE,
	A(18-19) 25CDD	Wells 35		7358			565,789	3,864,673	9/1/1973	70	70	6	5,036	4,966	4,874	Moenkopi	Exploration	ARIZ PUBLIC SERVICE
17	A(18-19) 25DAA	Wells 55	613193				566,591	3,865,286		26	16	1	5,034	5,008	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
18	A(18-19) 36AAB	Wells 55	553270				566,393	3,864,478					5,022		4,901	N/A	Monitoring	AZ PUBLIC SERVICE,
19	A(18-19) 36BBA	Wells 55	906365				565,385	3,864,467					5,037		4,904	N/A	Industrial	ARIZONA PUBLIC SERVICE
20	A(18-19) 36CCD	GWSI	613090		345434110170501		565,497	3,862,915		350	150	20	5,041	4,691	5,000	Coconino	Power	APS
	A(18-19) 36CCD	Wells 55	613090				565,381	3,863,057	3/8/1962	350	60	24	5,029	4,679	4,998	Coconino	Industrial	AZ PUBLIC SERVICE,
	A(18-19) 36CCD	Wells 35		7383			565,381	3,863,057	3/3/1962	350	150	20	5,029	4,679	4,998	Coconino	Industrial	ARIZ PUBLIC SERVICE
21	A(18-19) 36DDC	Wells 55	906363				566,394	3,863,068					5,036		4,972	N/A	Municipal	ARIZONA PUBLIC SERVICE
22	A(18-19) 36DDD	Wells 55	906812				566,596	3,863,070					5,029		4,964	N/A	Industrial	ARIZONA PUBLIC SERVICE
23	A(18-19) 36DDD	Wells 55	907167				566,596	3,863,070					5,029		4,964	N/A	Industrial	ARIZONA PUBLIC SERVICE
24	A(18-20) 19CCA	Wells 55	613201				566,984	3,866,506	4/6/1979	54	32	1	5,135	5,081	4,851	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
25	A(18-20) 20DC	O&G				356	569,223	3,863,100		1,400			5,100	3,700	4,967	Supai	Exploration	Kalil & Associates 1 S
26	A(18-20) 29ADD	Wells 55	535278				569,812	3,865,540	6/3/1992	420	420	10	5,281	4,861	4,816	Moenkopi	Industrial	BRIMHALL SAND & ROCK,
27	A(18-20) 30	Wells 55	547253				567,504	3,865,403	6/7/1995	37			5,058	5,021	4,900	Moenkopi	Exploration / Monitoring	ARIZONA PUBLIC SERVICE
28	A(18-20) 30BCC	Wells 55	613218				566,792	3,865,490	5/1/1979	100	79	1	5,100	5,000	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
29	A(18-20) 30CAA	Wells 55	533820				567,402	3,865,300	2/15/1992	96	20	5	5,059	4,963	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
30	A(18-20) 30CAC	Wells 55	579540				567,201	3,865,094	3/23/2000	40	30	2	5,092	5,052	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
31	A(18-20) 30CAC	Wells 55	579541				567,201	3,865,094	3/28/2000	60	50	2	5,092	5,032	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
32	A(18-20) 30CBA	Wells 55	533817				566,996	3,865,292	2/15/1992	141	140	5	5,090	4,949	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
33	A(18-20) 30CBA	Wells 55	536055				566,996	3,865,292	7/23/1992	40	18	4	5,090	5,050	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
34	A(18-20) 30CBA	Wells 55	536056				566,996	3,865,292	7/20/1992	21			5,090	5,069	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
35	A(18-20) 30CBA	Wells 55	536057				566,996	3,865,292	7/21/1992	51			5,090	5,039	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
36	A(18-20) 30CBA	Wells 55	536058				566,996	3,865,292	7/22/1992	30			5,090	5,060	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
37	A(18-20) 30CBA	Wells 55	536059				566,996	3,865,292	7/28/1992	40			5,090	5,050	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
38	A(18-20) 30CBA	Wells 55	613213				566,996	3,865,292	5/19/1979	120	88	1	5,090	4,970	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
39	A(18-20) 30CBA	Wells 55	613214				566,996	3,865,292	5/16/1979	120	88	2	5,090	4,970	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
40	A(18-20) 30CBA	Wells 55	613215				566,996	3,865,292	5/7/1979	116	88	1	5,090	4,974	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
41	A(18-20) 30CBB	Wells 55	613216				566,793	3,865,289	3/26/1979	70	43	1	5,050	4,980	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
42	A(18-20) 30CBB	Wells 55	613217				566,793	3,865,289	4/3/1979	37	19	1	5,050	5,013	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
43	A(18-20) 30CBD	Wells 55	539103				566,998	3,865,090	6/1/1993	40	20	5	5,049	5,009	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,

TABLE 2. SELECTED WELLS IN THE VICINITY OF THE PROPOSED TEST WELL SITE, CO_2 SEQUESTRATION PILOT PROJECT, APS CORPORATION

							UTM COORDINATES (Zone 12, NAD 27)				CASING							
WELL INVENTORY NUMBER	CADASTRAL LOCATION	RECORD SOURCE	ADWR 55-WELL REGISTRY NUMBER	ADWR 35-WELL REGISTRY NUMBER	GWSI SITE NUMBER	O&C PERMIT NUMBER	Easting (meters)	Northing (meters)	DATE COMPLETED	WELL DEPTH (feet, bls)	DEPTH (feet, bls)	DIAMETER (inches)	LAND SURFACE ALTITUDE[1] (feet, msl)	WELL DEPTH ALTITUDE (feet, msl)	ESTIMATED ALTITUDE OF TOP OF COCONINO[2] (feet, msl)	INFERRED FORMATION AT TOTAL DEPTH[3]	WELL / WATER USE[4]	OWNER
44	A(18-20) 30CBD	Wells 55	539104				566,998	3,865,090	6/2/1993	40	20	5	5,049	5,009	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
45	A(18-20) 30CBD	Wells 55	553267				566,998	3,865,090	12/21/1995	49	49	5	5,049	5,000	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
46	A(18-20) 30CBD	Wells 55	579542				566,998	3,865,090	3/22/2000	62	52	2	5,049	4,987	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
47	A(18-20) 30CBD	Wells 55	579543				566,998	3,865,090	3/27/2000	85	75	2	5,049	4,964	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
48	A(18-20) 30CBD	Wells 55	579544				566,998	3,865,090	3/23/2000	85	75	2	5,049	4,964	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
49	A(18-20) 30CBD	Wells 55	579545				566,998	3,865,090	3/20/2000	104	90	2	5,049	4,945	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
50	A(18-20) 30CBD	Wells 55	579546				566,998	3,865,090	3/21/2000	83	73	2	5,049	4,966	4,900	Moenkopi	Test	ARIZONA PUBLIC SERVICE
51	A(18-20) 30CBD	Wells 55	613194				566,998	3,865,090		56	41	1	5,049	4,993	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
52	A(18-20) 30CBD	Wells 55	613195				566,998	3,865,090		77	57	1	5,049	4,972	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
53	A(18-20) 30CBD	Wells 55	613196				566,998	3,865,090		146	133	2	5,049	4,903	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
54	A(18-20) 30CBD	Wells 55	613211				566,998	3,865,090	4/6/1979	70	43	1	5,049	4,979	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
55	A(18-20) 30CBD	Wells 55	613212				566,998	3,865,090	4/5/1979	51	29	1	5,049	4,998	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
56	A(18-20) 30CCA	Wells 55	553268				566,999	3,864,888					5,037		4,900	N/A	Monitoring	AZ PUBLIC SERVICE,
57	A(18-20) 30CCC	Wells 55	560489				566,797	3,864,684	2/11/1997	30		4	5,029	4,999	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
58	A(18-20) 30CCC	Wells 55	553269				566,797	3,864,684	12/19/1995	45	45	4	5,029	4,984	4,900	Moenkopi	Monitoring	AZ PUBLIC SERVICE,
59	A(18-20) 30CCD	GWSI			342526110155501		567,109	3,864,652		145		10	5,042	4,897	4,900	Coconino	Domestic	
	A(18-20) 30CCD	Wells 35		7385			567,001	3,864,687	1/1/1939	145	10	10	5,038	4,893	4,900	Coconino	Domestic	
60	A(18-20) 30CDA	Wells 55	613197				567,405	3,864,894		92	52	1	5,079	4,987	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
61	A(18-20) 30CDA	Wells 55	613198				567,405	3,864,894		191	175	2	5,079	4,888	4,900	Coconino	Exploration / Monitoring	AZ PUBLIC SERVICE,
62	A(18-20) 30CDA	Wells 55	613208				567,405	3,864,894	3/27/1979	60	38	1	5,079	5,019	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
63	A(18-20) 30CDA	Wells 55	613210				567,405	3,864,894	4/6/1979	50	28	1	5,079	5,029	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
64	A(18-20) 30CDB	Wells 55	613209				567,202	3,864,891	4/5/1979	51	29	1	5,047	4,996	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
65	A(18-20) 30DC	O&G				67	567,716	3,864,790		310			5,107	4,797	4,901	Coconino	Exploration	Tucson O&G Company 1 W
66	A(18-20) 30DC	O&G				89	567,707	3,864,790		1,785			5,106	3,321	4,901	Supai	Exploration	Tucson O&G Company 1X
67	A(18-20) 30DCB	Wells 55	613206				567,608	3,864,897	3/27/1979	60	38	1	5,111	5,051	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
68	A(18-20) 30DCB	Wells 55	613207				567,608	3,864,897	3/26/1979	60	38	1	5,111	5,051	4,900	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
69	A(18-20) 30DDA	Wells 55	613202				568,217	3,864,905	4/7/1979	50	28	1	5,139	5,089	4,902	Moenkopi	Exploration / Monitoring	AZ PUBLIC SERVICE,
70	A(18-20) 31AAC1	GWSI			345515110151701		568,076	3,864,320		120		8	5,125	5,005	4,921	Coconino	Public Supply	
	A(18-20) 31AAC	Wells 35		7386			568,020	3,864,294	1/1/1955	120		8	5,123	5,003	4,921	Coconino	Municipal	
71	A(18-20) 31AAC2	GWSI	541134		345512110151701		568,076	3,864,228		160		6	5,115	4,955	4,924	Coconino	Public Supply	CARL KEMPTON
	A(18-20) 31ACC	Wells 55	541134				567,616	3,863,886	11/8/1993	160	100	6	5,068	4,908	4,930	Coconino	Domestic	KEMPTON, CARL,
72	A(18-20) 31BBB	Wells 55	539986				566,798	3,864,482	9/7/1993	130	30	61	5,029	4,899	4,900	Coconino	Domestic	HUNT, BOYCE,B
73	A(18-20) 31BDC	Wells 55	638034				567,208	3,863,882	10/20/1980	130	40	9	5,045	4,915	4,923	Coconino	Domestic	HUNT,D
	A(18-20) 31BDC	Wells 35		7387			567,208	3,863,882	5/24/1929	130	40	8	5,045	4,915	4,923	Coconino	Domestic	HUNT, D
74	A(18-20) 31CDC	Wells 55	537495				567,212	3,863,076	2/2/1993	125	125	0	5,040	4,915	4,954	Coconino	Domestic	WESTOVER, BOYD,L
75	A(18-20) 31DAB	GWSI			345450110151501		568,132	3,863,550		380			5,073	4,693	4,948	Coconino	Irrigation	
	A(18-20) 31DAB	Wells 35		7388			568,027	3,863,689		380	50	16	5,066	4,686	4,942	Coconino	Irrigation	
76	A(18-20) 31DD	O&G				54	568,134	3,863,250		1,683			5,091	3,408	4,962	Supai	Exploration	Besoil Company 1 Hunt
77	A(18-20) 31DD	O&G				470	568,211	3,863,280		1,615			5,090	3,475	4,962	Supai	Exploration	Cree, G.B. 1 Hunt
78	A(18-20) 31DDD	Wells 35		7389			568,238	3,863,087	6/10/1958	252	84	12	5,106	4,854	4,971	Coconino	Irrigation	HUNT, B.R.
79	A(18-20) 32CD	O&G				9-27	569,134	3,863,100		100			5,098	4,998	4,967	Moenkopi	Exploration	Oil Holdings 01
80	A(18-20) 32DDA	Wells 55	614308				569,859	3,863,309	1/1/1958	100		9	5,084	4,984	4,952	Coconino	Stock	AZ STATE LAND DEPT,
81	A(18-20) 33BBA	Wells 55	552166				570,245	3,864,517					5,157		4,872	N/A	Domestic	TUBBS, ADRIAN Q
82	A(18-20) 33BC	Wells 55	604646				570,151	3,864,015	11/28/1973	250	80	8	5,112	4,862	4,910	Coconino	Irrigation	PARISH,J D
83	A(18-20) 33BCA	Wells 55	637905				570,253	3,864,116	3/19/1980	170	40	6	5,123	4,953	4,903	Coconino	Domestic	HOLYOAK,J

TABLE 2. SELECTED WELLS IN THE VICINITY OF THE PROPOSED TEST WELL SITE, CO_2 SEQUESTRATION PILOT PROJECT, APS CORPORATION

WELL INVENTORY NUMBER	CADASTRAL LOCATION	RECORD SOURCE	ADWR 55-WELL REGISTRY NUMBER	ADWR 35-WELL REGISTRY NUMBER	GWSI SITE NUMBER	O&C PERMIT NUMBER	UTM COORDINATES (Zone 12, NAD 27)		DATE COMPLETED	WELL DEPTH (feet, bls)	CASING		LAND SURFACE ALTITUDE[1] (feet, msl)	WELL DEPTH ALTITUDE (feet, msl)	ESTIMATED ALTITUDE OF TOP OF COCONINO[2] (feet, msl)	INFERRED FORMATION AT TOTAL DEPTH[3]	WELL / WATER USE[4]	OWNER
							Easting (meters)	Northing (meters)			DEPTH (feet, bls)	DIAMETER (inches)						
84	A(18-20) 33BCA	Wells 35		7393			570,253	3,864,116	11/28/1973	250	90	8	5,123	4,873	4,903	Coconino	Domestic	PARISH, J.D.
85	A(18-20) 33CC	O&G				460	570,141	3,863,250		3,585			5,066	1,481	4,951	Precambrian	Exploration	Cree, G.B. 1 Scorse
86	A(18-20) 33CCA	GWSI			345440110135601		570,139	3,863,257				12	5,067		4,951	N/A	Unused	
87	A(18-20) 33CCD	GWSI	645034		345435110134901		570,292	3,863,197		200		8	5,076	4,876	4,952	Coconino	Unused	A W ROGERS
	A(18-20) 33CCD	Wells 55	645034				570,272	3,863,111	12/13/1968	200	85	9	5,084	4,884	4,954	Coconino	Irrigation	ROGERS,A W
	A(18-20) 33CCD	Wells 35		7395			570,272	3,863,112	12/16/1969	200	85	8	5,084	4,884	4,954	Coconino	Domestic	ROGERS, A.W.

Abbreviations:

ADWR = Arizona Department of Water Resources
ft, bls = feet below land surface
ft, mls = feet above mean sea level
GWSI = Groundwater Site Inventory
NAD 27 = North American Datum 1927
NAVD 88 = North American Vertical Datum of 1988
USGS = United States Geological Survey
UTM = Universal Transverse Mercator projection
Wells 35 = Well registry database that preceeded the 1980 Groundwater Code
Wells 55 = Well registry database following enactment of the 1980 Groundwater Code
O&C = Arizona Oil and Gas Conservation Commission

Notes:

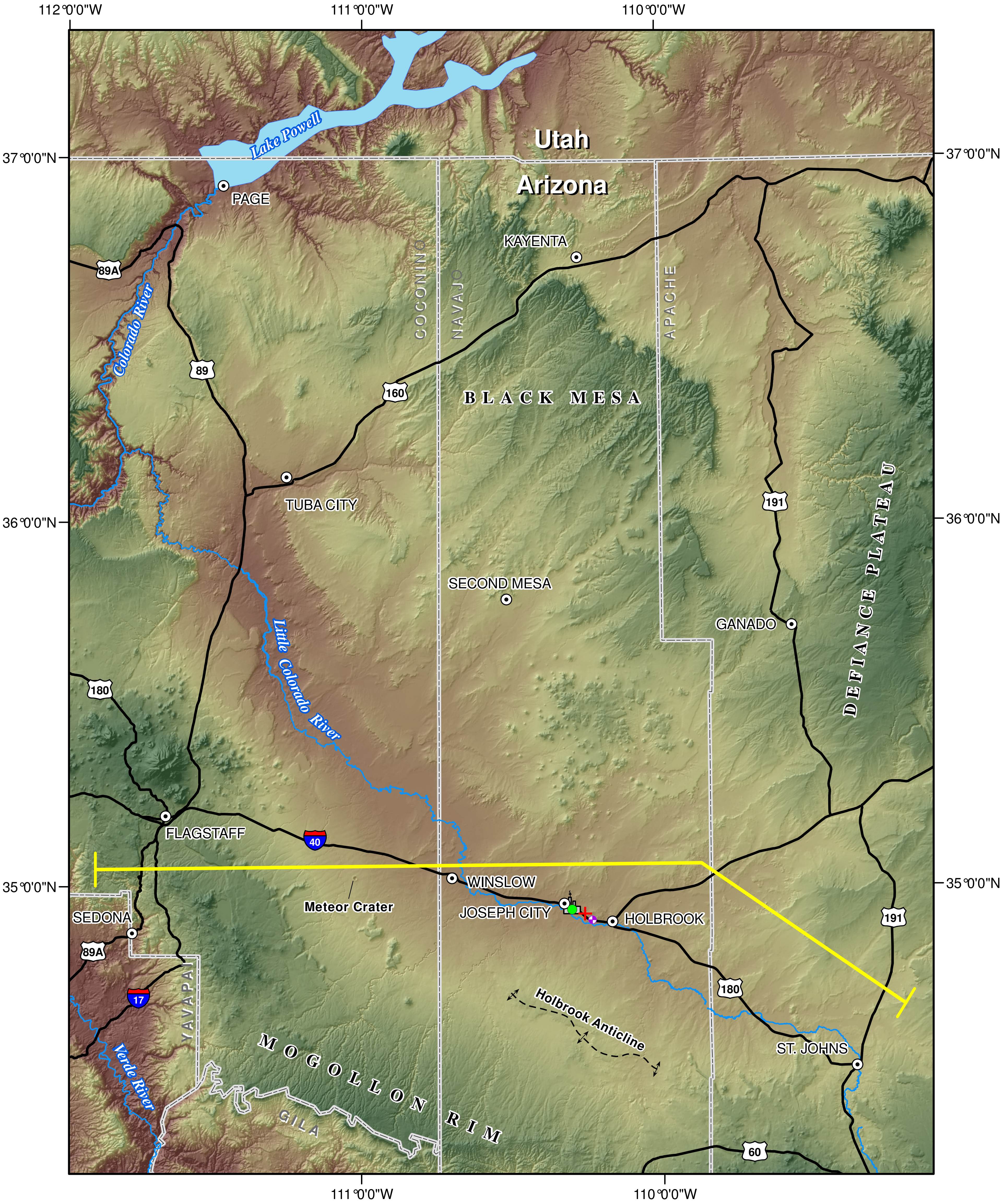
[1] Land Surface Estimates referenced to NAVD88; obtained from USGS National Elevation Data.

[2] Top of Coconino Sandstone estimated from drill log data.

[3] Inferred formation at total depth determined from land surface altitude and total well depth relative to estimated top of Coconino Sandstone, or Oil and Gas data where available. All domestic and other potable supply wells assumed to be completed in the Coconino Sandstone.

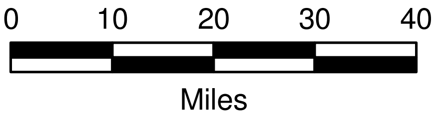
[4] Well / water uses listed are from ADWR databases, except where the registered use of APS-owned wells conflicted with the known actual use.

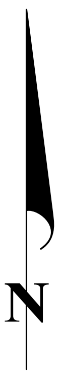
[5] Location of 55-201626: review of well registration records indicate that well is registered in the wrong location; actual location is Section 2 of Township 11 North, Range 14 East.



EXPLANATION

- ◑ Oil and Gas Well 460 (Cree #1 Score)
- + Proposed Test Well Site
- ⌂ Cholla Generating Station
- ⊢⊣ Line of Schematic Cross-Section





CO$_2$ Sequestration Pilot Project
APS Corporation

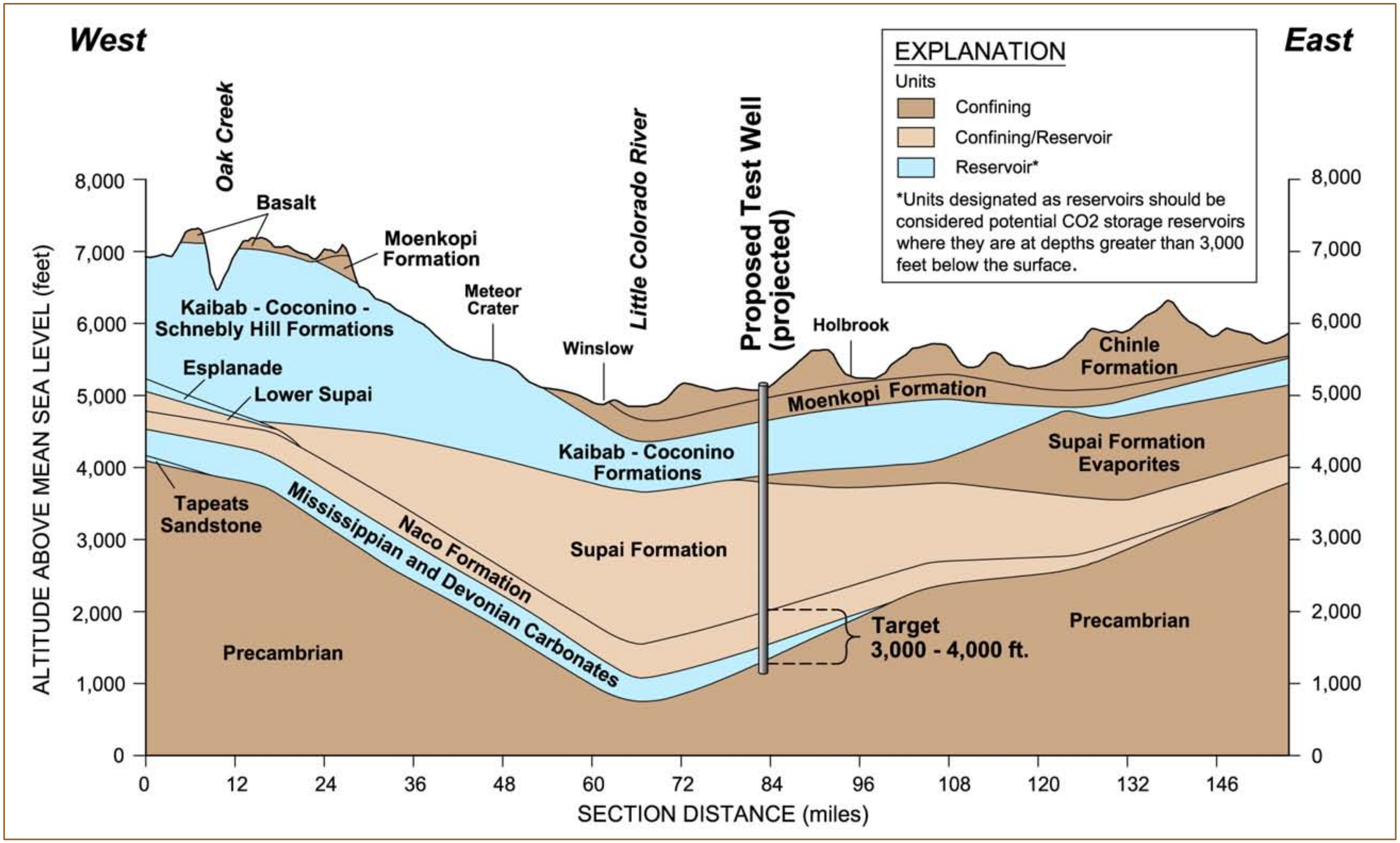
REGIONAL LOCATION MAP

ERROL L. MONTGOMERY & ASSOCIATES, INC.
WATER RESOURCE CONSULTANTS
SCOTTSDALE, ARIZONA

2008

FIGURE 1

PHX\1263.03\Figure1\8Apr08



*Units designated as reservoirs should be considered potential CO2 storage reservoirs where they are at depths greater than 3,000 feet below the surface.

FIGURE 2. EAST-WEST REGIONAL SCHEMATIC GEOLOGIC CROSS-SECTION, CO_2 SEQUESTRATION PILOT PROJECT, APS CORPORATION

ERROL L. MONTGOMERY & ASSOCIATES, INC.

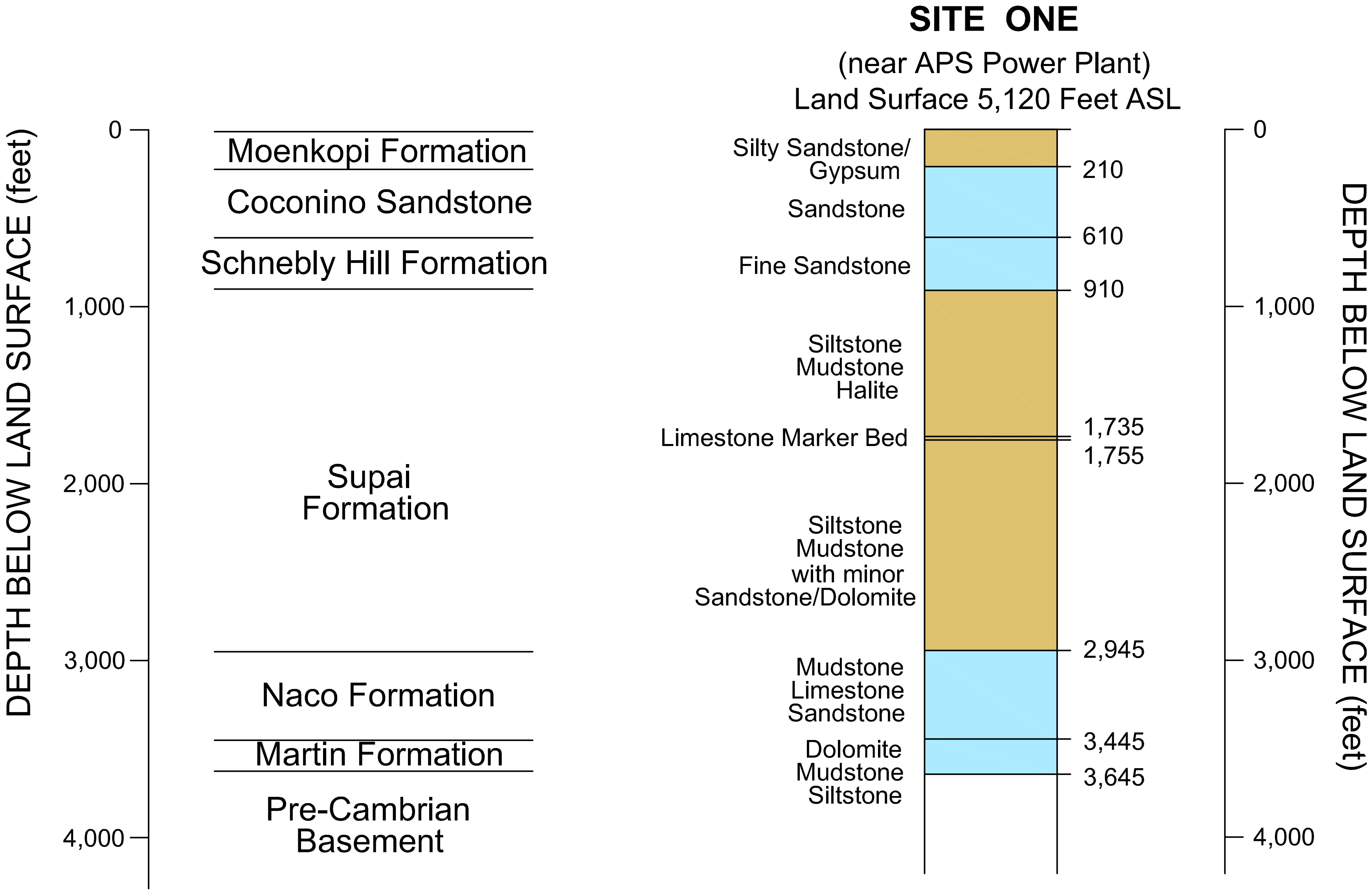
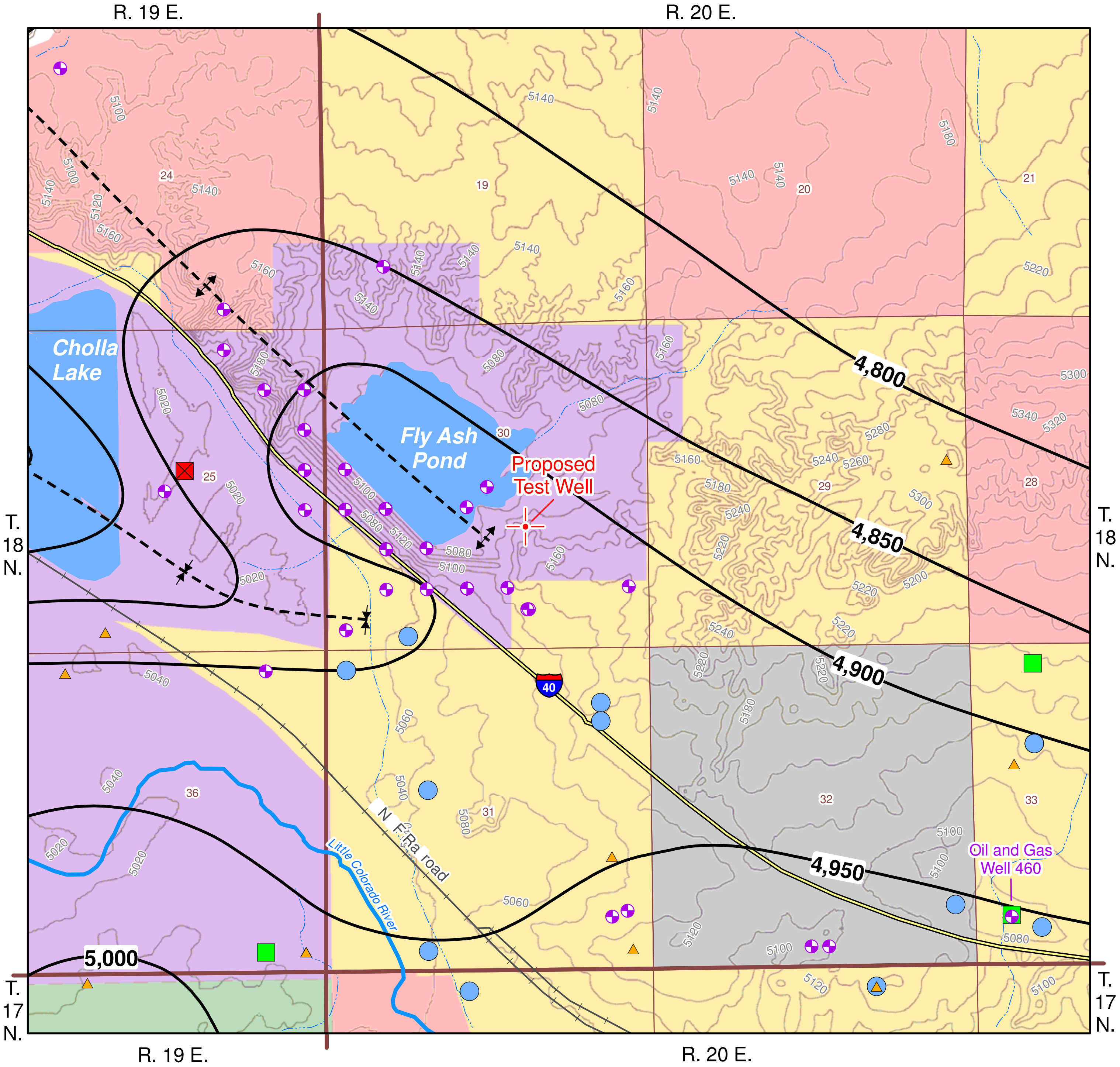


FIGURE 3. INFERRED GEOLOGY IN THE CHOLLA AREA

Drafting\1263.03\InferredGeology_REV\23July2008

ERROL L. MONTGOMERY & ASSOCIATES, INC.



EXPLANATION

Topographic Contour (feet, msl; CI = 20 feet)

Proposed Test Well

Wells of Record

- ▲ Industrial, Irrigation
- ● Exploration, Monitor
- ● Stock, Domestic — *Coconino Sandstone*
- 🟩 Stock, Domestic — *Undetermined Formation*
- 🟥 Domestic, Miss-Located

Land Ownership

- 🟪 APS
- 🟩 Aztec
- 🟥 BLM
- 🟨 Private
- ⬜ State Trust

Coconino Structure

- Structure Contour (feet, msl)
- Syncline
- Anticline

N

0 2,000

Feet

CO$_2$ Sequestration Pilot Project
APS Corporation

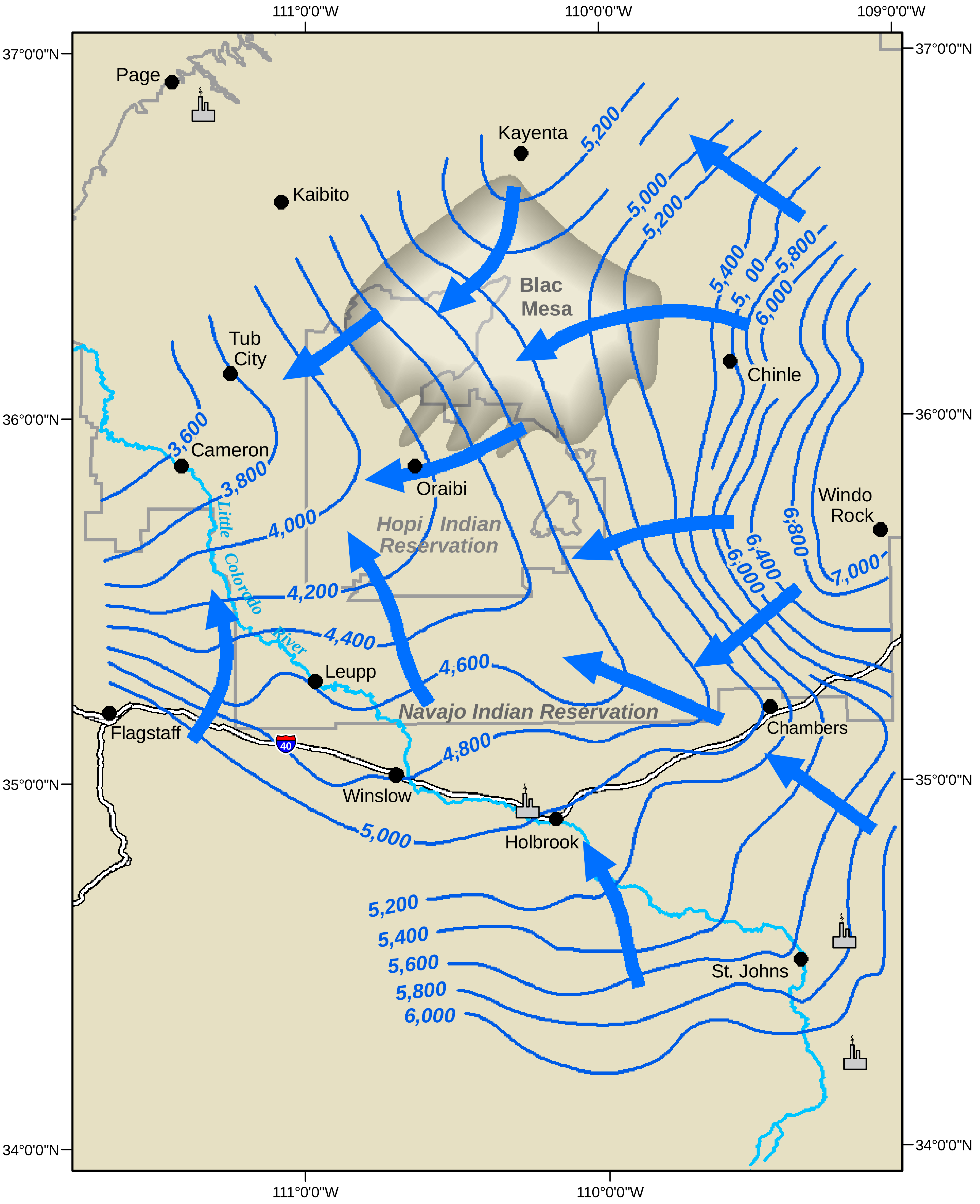
PROPOSED PILOT SITE LOCATION MAP

ERROL L. MONTGOMERY & ASSOCIATES, INC.
WATER RESOURCE CONSULTANTS
SCOTTSDALE, ARIZONA

2008

FIGURE 4

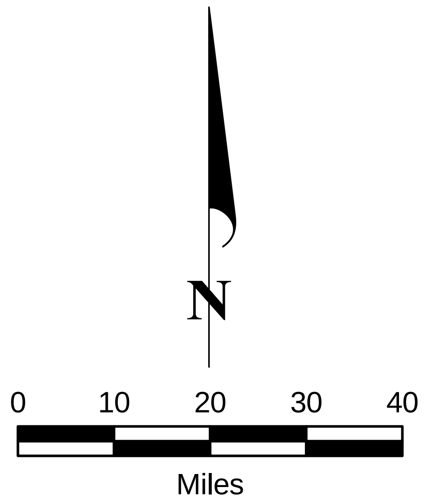
1263/03/Fig4 EPRI Test Site.mxd 21May08



EXPLANATION

Large coal-fired electrical generating station

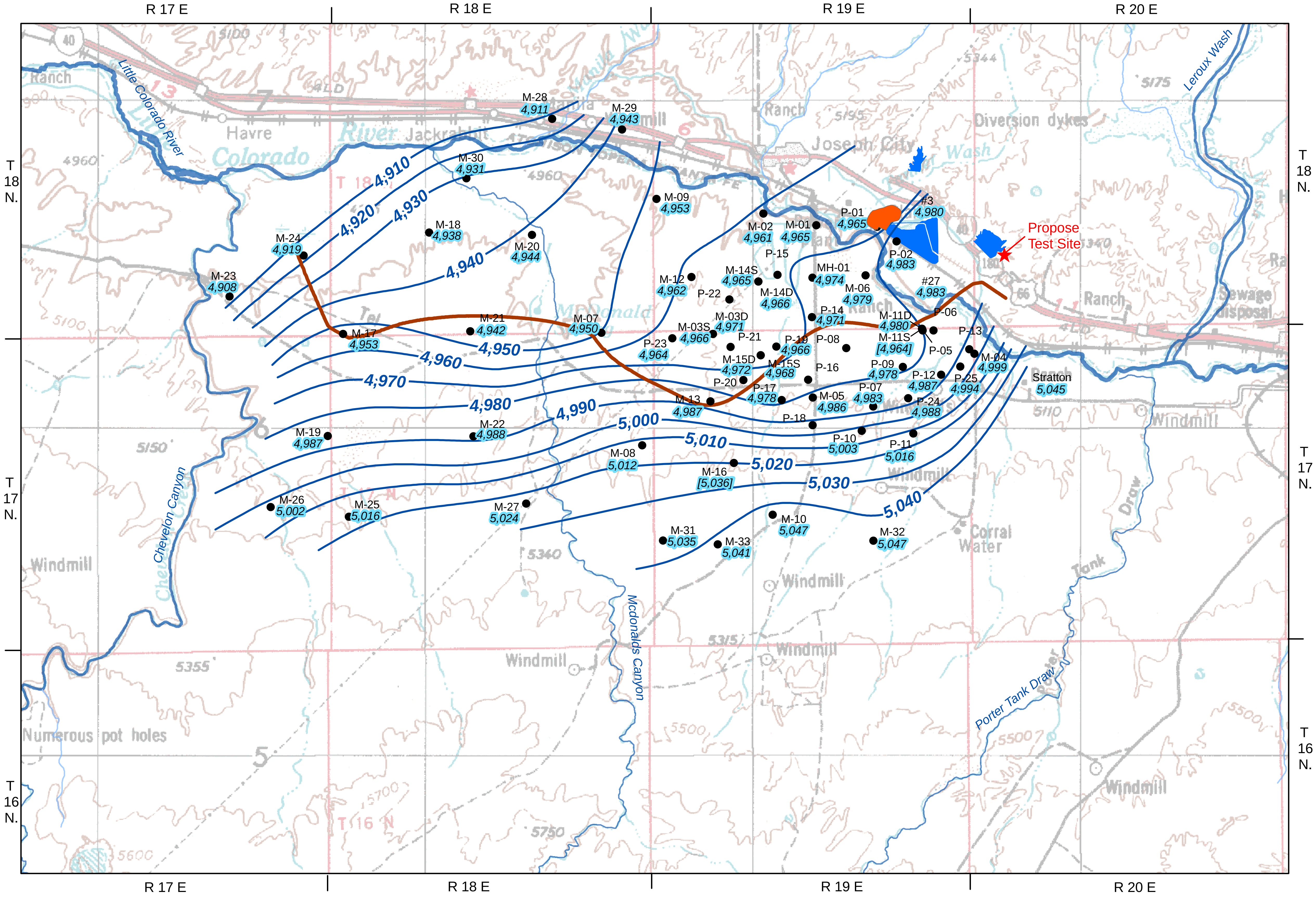
6,000 — Contour of altitude of water level in Coconino / DeChelly Sandstone



REGIONAL ALTITUDE OF C-AQUIFER

ERROL L. MONTGOMERY & ASSOCIATES, INC.
CONSULTANTS IN HYDROGEOLOGY
TUCSON, ARIZONA

FIGURE 5



Explanation

● P-01 4965 Existing APS Well Location and Identifier
Non-Pumping Water Level
[ ] Indicates Anomalous Data

🟦 Lakes

🟧 Power Plant

5,040 — Contour of Groundwater Level Altitude in Coconino, February 2006 (feet)

— Confined Aquifer Boundary for 2006

DRAFT

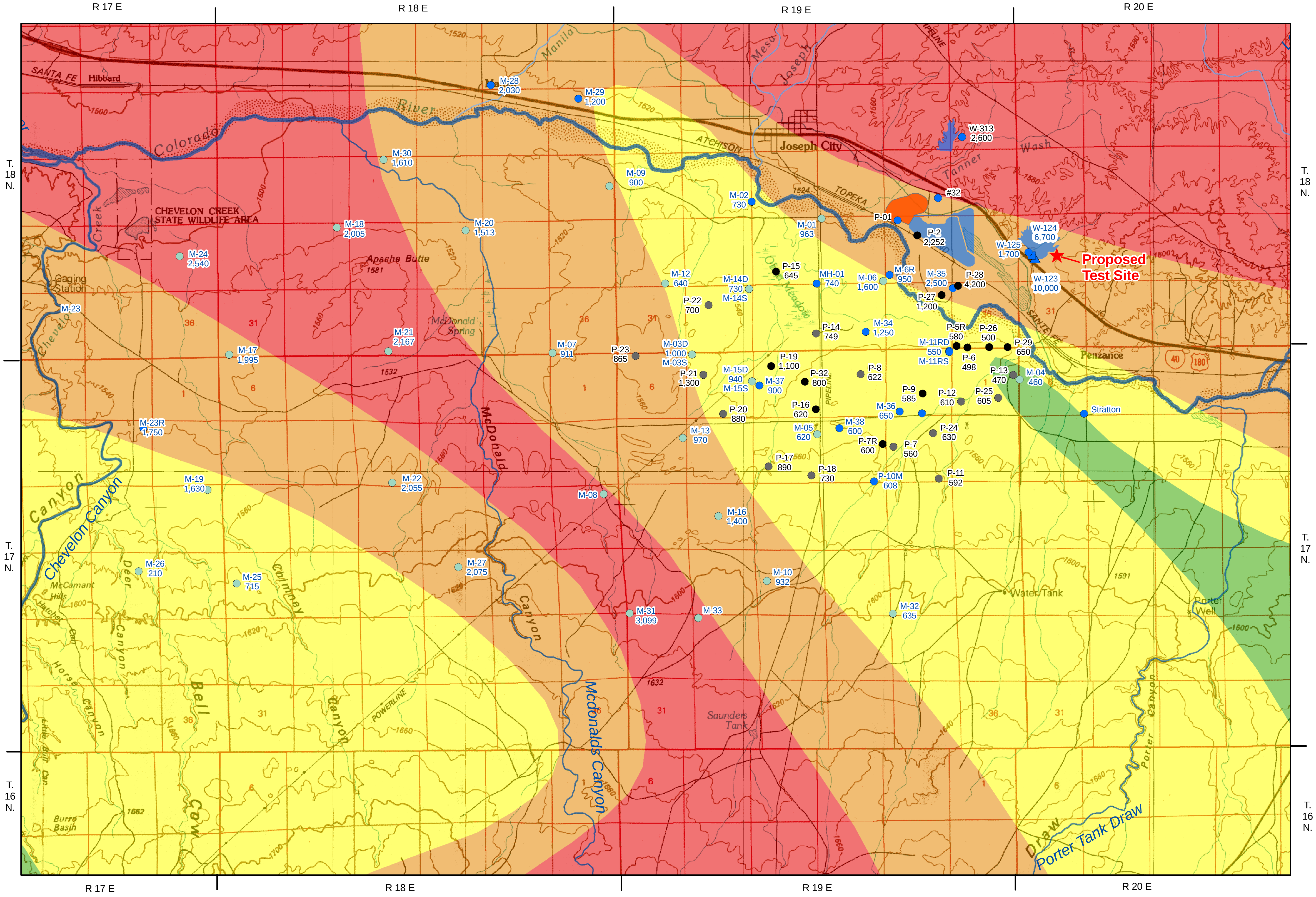
CO$_2$ Sequestration Pilot Project
APS Corporation

CONTOURS OF GROUNDWATE
LEVEL ALTITUDE IN
COCONINO SANDSTON
FEBRUARY 2006

ERROL L. MONTGOMERY & ASSOCIATES, INC.
WATER RESOURCE CONSULTANTS
TUCSON, ARIZONA
2008

FIGURE 6

1263.03\GWL_Coconino2006.mxd\23July UTM NAD 27



EXPLANATION

P-5 ● Existing Production Well and Identifier

P-8 ● Unused Existing Production Well and Identifier

M-34 ● Existing Coconino Monitor Well and Identifier

M-10 ● Unused Existing Coconino Monitor Well and Identifier

W-124 ■ Moenkopi Monitor Well

W-123 ▲ Alluvium Monitor Well

🟦 Lakes

🟧 Power Plant

TOTAL DISSOLVED SOLIDS, in milligrams per liter (Mann, L.J., 1976)

🟩 <500

🟨 500 - 1,000

🟧 1,000 - 2,000

🟥 >2,000

N

0 8,000

Feet

CO_2 Sequestration Pilot Project
APS Corporation

TOTAL DISSOLVED SOLIDS
CONCENTRATIONS IN THE C-AQUIFER
2006/2007

ERROL L. MONTGOMERY & ASSOCIATES, INC. 2008
WATER RESOURCE CONSULTANTS
TUCSON, ARIZONA

FIGURE 7

GIS-Tuc\1263.03\TDS_ChollaValues_CO2project\23July2008UTM NAD 27

H. OPERATING DATA - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

(1) Average and maximum daily rate and volume of the fluids to be injected:

Estimated rate of CO_2 injection: 50-200 tons per day

Total mass of CO_2 to be injected: up to 2,000 metric tons (≈ 2,200 US short tons)

Time interval for CO_2 injection: 14-20 days

Total volume of CO_2: CO_2 will be delivered to the project site and stored in tanks on the well pad as a liquid. Before injection at the wellhead, the CO_2 will be heated so that it is a gas at approximately near-surface ambient temperature. As the CO_2 is pumped down the well in the production tubing, increasing pressure will result in the CO_2 entering the supercritical state before reaching the reservoir formation. Supercritical CO_2 has high density like a liquid, with low viscosity like a gas. It is highly compressible, with its density dependent on pressure and temperature. If CO_2 is injected into the Martin Formation at a depth of 3,500 feet with reservoir conditions of 1,500 psi and 130^0F (based on normal hydrostatic pressure and geothermal temperature gradients), then 2,000 metric tons of CO_2 would occupy a volume of approximately 200,000 cubic feet of pore space.

(2) Average and maximum injection pressure:

The maximum injection pressure will be limited so that neither the reservoir formation nor the seal formation is fractured. The maximum injection pressure, measured both at the surface and at the reservoir formation, will be determined based on the results of a step-rate injection test performed on the injection interval using formation brine recovered during well development operations. Details of the step-rate injection test are described in Attachment I below.

During CO_2 injection, pressure will be continuously monitored and recorded at the surface and injection interval. Multiple injection rates and pressures will be used to assess the permeability and injectivity of the reservoir rock, but the maximum injection pressure will be controlled so that it never exceeds 90% of the fracture pressure of the reservoir rock.

(3) Nature of annulus fluid:

The annulus completion fluid between the production tubing and the well casing will be an inhibited KCl brine or native brine solution with a density of approximately 9.0 pounds per gallon. Corrosion inhibitor, biocide, and oxygen scavenger additives will be mixed with the annular completion fluid prior to pumping into the well.

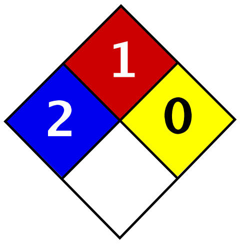
(4) and (5) Source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids:

The injection fluid is commercial grade carbon dioxide (CO_2) purchased from an industrial gas supplier, such as Praxair, Air Products, Air Liquide, or Linde Group. Commercial grade CO_2 is normally 99.97% CO_2 by volume, with trace amounts of oxygen, hydrogen, and water vapor. The gas supplier will provide an assay of the average composition.

As described in **(1)** above, the CO_2 in the reservoir formation will be in a supercritical state. In the Martin Formation, at a depth of 3,500 feet with estimated pressure of 1,500 psi and temperature of 130^0F, the CO_2 will have a density of approximately $0.335 g/cm^3$, or about 1/3 the density of fresh water. Pure CO_2 has low corrosiveness, but when it dissolves in water it forms carbonic acid, which has a pH approaching 3 at reservoir pressure.

During drilling through the Regional C-Aquifer, a small quantity of Optitrak 600 blue dye will be added to the drilling mud so that when water samples are obtained, the amount of mud filtrate in the samples can be determined. Similarly, during drilling through the potential injection interval, Fluorescein fluorescent dye will be added to the drilling mud. Water will be produced from the saline injection interval, filtered, then reinjected for the step-rate injectivity test. Rhodamine dye may be added to the reinjected water. Small quantities of krypton, xenon, and sulfur hexafluoride will be added to the injected CO_2 as tracers. Material Safety Data Sheets for these tracers and dyes are included on the following pages.

MSDSs for
Optitrak 600, Fluorescein, Rhodamine, krypton, xenon, and sulfur hexafluoride.]



Health	2
Fire	1
Reactivity	0
Personal Protection	E

Material Safety Data Sheet

Fluorescein MSDS

Section 1: Chemical Product and Company Identification

Product Name: Fluorescein

Catalog Codes: SLF1135, SLF1645

CAS#: 2321-07-5

RTECS: LM5075000

TSCA: TSCA 8(b) inventory: Fluorescein

CI#: Not available.

Synonym: CI Solvent Yellow 94; Spiro[isobenzofuran-1(3H),9'-[9H]xanthen]-3-one, 3'6'-dihydroxy-; 2-(6-Hydroxy-3-oxo-(3H)-xanthen-9-yl)benzoic acid; D & C Yellow #7; Fluorescein, alcohol soluble.

Chemical Name: Fluorescein

Chemical Formula: $C_{20}H_{12}O_5$

Contact Information:

Sciencelab.com, Inc.
14025 Smith Rd.
Houston, Texas 77396

US Sales: **1-800-901-7247**
International Sales: **1-281-441-4400**

Order Online: ScienceLab.com

CHEMTREC (24HR Emergency Telephone), call:
1-800-424-9300

International CHEMTREC, call: 1-703-527-3887

For non-emergency assistance, call: 1-281-441-4400

Section 2: Composition and Information on Ingredients

Composition:

Name	CAS #	% by Weight
Fluorescein	2321-07-5	100

Toxicological Data on Ingredients: Fluorescein LD50: Not available. LC50: Not available.

Section 3: Hazards Identification

Potential Acute Health Effects: Hazardous in case of skin contact (irritant), of eye contact (irritant), of ingestion, of inhalation.

Potential Chronic Health Effects:
CARCINOGENIC EFFECTS: Not available.
MUTAGENIC EFFECTS: Mutagenic for bacteria and/or yeast.
TERATOGENIC EFFECTS: Not available.
DEVELOPMENTAL TOXICITY: Not available.
Repeated or prolonged exposure is not known to aggravate medical condition.

Section 4: First Aid Measures

Eye Contact:
Check for and remove any contact lenses. In case of contact, immediately flush eyes with plenty of water for at least 15 minutes. Get medical attention.

Skin Contact:
In case of contact, immediately flush skin with plenty of water. Cover the irritated skin with an emollient. Remove contaminated clothing and shoes. Wash clothing before reuse. Thoroughly clean shoes before reuse. Get medical attention.

Serious Skin Contact:
Wash with a disinfectant soap and cover the contaminated skin with an anti-bacterial cream. Seek medical attention.

Inhalation:
If inhaled, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.

Serious Inhalation: Not available.

Ingestion:
Do NOT induce vomiting unless directed to do so by medical personnel. Never give anything by mouth to an unconscious person. If large quantities of this material are swallowed, call a physician immediately. Loosen tight clothing such as a collar, tie, belt or waistband.

Serious Ingestion: Not available.

Section 5: Fire and Explosion Data

Flammability of the Product: May be combustible at high temperature.

Auto-Ignition Temperature: Not available.

Flash Points: CLOSED CUP: Higher than 93.3°C (200°F).

Flammable Limits: Not available.

Products of Combustion: These products are carbon oxides (CO, CO_2).

Fire Hazards in Presence of Various Substances:
Slightly flammable to flammable in presence of open flames and sparks, of heat.
Non-flammable in presence of shocks.

Explosion Hazards in Presence of Various Substances:
Risks of explosion of the product in presence of mechanical impact: Not available.
Risks of explosion of the product in presence of static discharge: Not available.

Fire Fighting Media and Instructions:
SMALL FIRE: Use DRY chemical powder.
LARGE FIRE: Use water spray, fog or foam. Do not use water jet.

Special Remarks on Fire Hazards: Not available.

Special Remarks on Explosion Hazards: Not available.

Section 6: Accidental Release Measures

Small Spill:
Use appropriate tools to put the spilled solid in a convenient waste disposal container. Finish cleaning by spreading water on the contaminated surface and dispose of according to local and regional authority

requirements.

Large Spill:
Use a shovel to put the material into a convenient waste disposal container. Finish cleaning by spreading water on the contaminated surface and allow to evacuate through the sanitary system.

Section 7: Handling and Storage

Precautions:
Keep locked up.. Keep away from heat. Keep away from sources of ignition. Empty containers pose a fire risk, evaporate the residue under a fume hood. Ground all equipment containing material. Do not breathe dust. Wear suitable protective clothing. In case of insufficient ventilation, wear suitable respiratory equipment. If you feel unwell, seek medical attention and show the label when possible. Avoid contact with skin and eyes. Keep away from incompatibles such as oxidizing agents.

Storage: Keep container tightly closed. Keep container in a cool, well-ventilated area. Do not store above 24°C (75.2°F).

Section 8: Exposure Controls/Personal Protection

Engineering Controls:
Use process enclosures, local exhaust ventilation, or other engineering controls to keep airborne levels below recommended exposure limits. If user operations generate dust, fume or mist, use ventilation to keep exposure to airborne contaminants below the exposure limit.

Personal Protection:
Splash goggles. Lab coat. Dust respirator. Be sure to use an approved/certified respirator or equivalent. Gloves.

Personal Protection in Case of a Large Spill:
Splash goggles. Full suit. Dust respirator. Boots. Gloves. A self contained breathing apparatus should be used to avoid inhalation of the product. Suggested protective clothing might not be sufficient; consult a specialist BEFORE handling this product.

Exposure Limits: Not available.

Section 9: Physical and Chemical Properties

Physical state and appearance: Solid. (Solidcrystalline powder.)

Odor: Not available.

Taste: Not available.

Molecular Weight: 332.31 g/mole

Color: Yellow (Yellowish-Red) to Red.

pH (1% soln/water): Not applicable.

Boiling Point: Not available.

Melting Point: 315°C (599°F)

Critical Temperature: Not available.

Specific Gravity: Not available.

Vapor Pressure: Not applicable.

Vapor Density: Not available.

Volatility: Not available.

Odor Threshold: Not available.

Water/Oil Dist. Coeff.: Not available.

Ionicity (in Water): Not available.

Dispersion Properties: See solubility in water, methanol, acetone.

Solubility:
Easily soluble in acetone.
Soluble in methanol, hot alcohol, glacial acetic acid, alkali hydroxides, and carbonates.
Insoluble in cold water, diethyl ether, petroleum ether, benzene.

Section 10: Stability and Reactivity Data

Stability: The product is stable.

Instability Temperature: Not available.

Conditions of Instability: Excess heat, excess dust generation, incompatible materials

Incompatibility with various substances: Reactive with oxidizing agents.

Corrosivity: Non-corrosive in presence of glass.

Special Remarks on Reactivity: Not available.

Special Remarks on Corrosivity: Not available.

Polymerization: Will not occur.

Section 11: Toxicological Information

Routes of Entry: Inhalation. Ingestion.

Toxicity to Animals:
LD50: Not available.
LC50: Not available.

Chronic Effects on Humans: MUTAGENIC EFFECTS: Mutagenic for bacteria and/or yeast.

Other Toxic Effects on Humans: Hazardous in case of skin contact (irritant), of ingestion, of inhalation.

Special Remarks on Toxicity to Animals: Not available.

Special Remarks on Chronic Effects on Humans: Not available.

Special Remarks on other Toxic Effects on Humans:
Acute Potential Health Effects:
Skin: May cause skin irritation.
Eyes: Causes eye irritation.
Ingestion: May cause irritation of the gastrointestinal (digestive) tract.
Inhalation: may cause respiratory tract irritation.
The toxicological properties of this substance have not been fully investigated.

Section 12: Ecological Information

Ecotoxicity: Not available.

BOD5 and COD: Not available.

Products of Biodegradation:
Possibly hazardous short term degradation products are not likely. However, long term degradation products may arise.

Toxicity of the Products of Biodegradation: The product itself and its products of degradation are not toxic.

Special Remarks on the Products of Biodegradation: Not available.

Section 13: Disposal Considerations

Waste Disposal:
Waste must be disposed of in accordance with federal, state and local environmental control regulations.

Section 14: Transport Information

DOT Classification: Not a DOT controlled material (United States).

Identification: Not applicable.

Special Provisions for Transport: Not applicable.

Section 15: Other Regulatory Information

Federal and State Regulations:
TSCA 8(b) inventory: Fluorescein
SARA 313 toxic chemical notification and release reporting: Fluorescein

Other Regulations: EINECS: This product is on the European Inventory of Existing Commercial Chemical Substances.

Other Classifications:

WHMIS (Canada): Not controlled under WHMIS (Canada).

DSCL (EEC):
R36/38- Irritating to eyes and skin.
S24/25- Avoid contact with skin and eyes.
S37- Wear suitable gloves.
S45- In case of accident or if you feel unwell, seek medical advice immediately (show the label where possible).

HMIS (U.S.A.):

Health Hazard: 2

Fire Hazard: 1

Reactivity: 0

Personal Protection: E

National Fire Protection Association (U.S.A.):

Health: 2

Flammability: 1

Reactivity: 0

Specific hazard:

Protective Equipment:
Gloves.
Lab coat.
Dust respirator. Be sure to use an approved/certified respirator or equivalent.
Splash goggles.

Section 16: Other Information

References: Not available.

Other Special Considerations: Not available.

Created: 10/10/2005 08:18 PM

Last Updated: 10/10/2005 08:18 PM

Linde Gas LLC (216) 642-6600
P.O. Box 94737
Cleveland, Ohio 44101
www.us.lindegas.com

MATERIAL
SAFETY
DATA SHEET

No. 39

PRODUCT NAME Krypton	**CAS #**	7439-90-9
TRADE NAME AND SYNONYMS Krypton, compressed	**DOT I.D. No.:**	UN 1056
	DOT Hazard Class:	Division 2.2
CHEMICAL NAME AND SYNONYMS Krypton	**Formula**	Kr
ISSUE DATES AND REVISIONS Revised January 1995	**Chemical Family:**	Inert Gas

HEALTH HAZARD DATA

TIME WEIGHTED AVERAGE EXPOSURE LIMIT

None listed (ACGIH 1994-1995). Should be considered a simple asphyxiant. Oxygen levels should be maintained at greater than 18 molar percent (Continued on Page 4)

SYMPTOMS OF EXPOSURE

Effects of exposure to high concentrations so as to displace the oxygen in the air necessary for life are headache, dizziness, labored breathing and eventual unconsciousness.

TOXICOLOGICAL PROPERTIES

Krypton is nontoxic but the liberation of a large amount in a confined area could displace the amount of oxygen in air necessary to support life.

Krypton is not listed in the IARC, NTP or by OSHA as a carcinogen or potential carcinogen.

Persons in ill health where such illness would be aggravated by exposure to krypton should not be allowed to work with or handle this product.

RECOMMENDED FIRST AID TREATMENT

PROMPT MEDICAL ATTENTION IS MANDATORY IN ALL CASES OF OVEREXPOSURE TO KRYPTON. RESCUE I PERSONNEL SHOULD BE EQUIPPED WITH SELF-CONTAINED BREATHING APPARATUS.

Inhalation: Conscious persons should be assisted to an uncontaminated area and inhale fresh air. Quick removal from the contaminated area is most important. Unconscious persons should be moved to an uncontaminated area, given assisted respiration and supplemental oxygen. Further treatment should be symptomatic and supportive.

HAZARDOUS MIXTURES OF OTHER LIQUIDS, SOLIDS, OR GASES

None

PHYSICAL DATA

BOILING POINT -244°F (-153.3°C)	**LIQUID DENSITY AT BOILING POINT** 150.6 lb/ft^3 (2412 kg/m^3)
VAPOR PRESSURE @ 70°F (21.1°C) Above the critical temp. of -82.8°F (- 63.8°C)	**GAS DENSITY AT 70°F. 1 atm** .2172 lb/ft^3 (3.479 kg/m^3)
SOLUBILITY IN WATER Negligible	**FREEZING POINT** -250.9°F (-157.2°C)
EVAPORATION RATE N/A (Gas)	**SPECIFIC GRAVITY (AIR=1)** @ 70°F (21.1°C) = 2.9

APPEARANCE AND ODOR Colorless, odorless gas

FIRE AND EXPLOSION HAZARD DATA

FLASH POINT (Method used) N/A	**AUTO IGNITION TEMPERATURE** N/A	**FLAMMABLE LIMITS % BY VOLUME (See Page 4)** LEL N/A UEL N/A

EXTINGUISHING MEDIA Nonflammable, inert gas	**ELECTRICAL CLASSIFICATION** Nonhazardous

SPECIAL FIRE FIGHTING PROCEDURES

If cylinders are involved in a fire, safely relocate or keep cool with water spray.

UNUSUAL FIRE AND EXPLOSION HAZARDS

None

REACTIVITY DATA

STABILITY Unstable		**CONDITIONS TO AVOID** None
Stable	X	

INCOMPATIBILITY (Materials to avoid) None

HAZARDOUS DECOMPOSITION PRODUCTS None

HAZARDOUS POLYMERIZATION May Occur		**CONDITIONS TO AVOID** None
Will Not Occur	X	

SPILL OR LEAK PROCEDURES

STEPS TO BE TAKEN IN CASE MATERIAL IS RELEASED OR SPILLED

Evacuate all personnel from affected area. Use appropriate protective equipment. If leak is in container or container vlave, contact your closest supplier location o' call the emergency telephone number listed herein.

WASTE DISPOSAL METHOD

Do not attempt to dispose of waste or unused quantities. Return in the shipping container properly labeled, with any valve outlet plugs or caps secured and valve protection cap in place to your supplier. For emergency disposal assistance, contact your closest supplier location or call the emergency telephone number listed herein.

SPECIAL PROTECTION INFORMATION

RESPIRATORY PROTECTION **(Specify type)**	Positive pressure air line with mask or self-contained breathing apparatus should be available for emergency use.	
VENTILATION See Local Exhaust	**LOCAL EXHAUST** See Last Page	**SPECIAL** N/A
	MECHANICAL (Gen.) N/A	**OTHER** N/A
PROTECTIVE GLOVES Any material		
EYE PROTECTION Safety goggles or glasses		
OTHER PROTECTIVE EQUIPMENT Safety shoes		

SPECIAL PRECAUTIONS*

SPECIAL LABELING INFORMATION

DOT Shipping Name:	Krypton, compressed	DOT Hazard Class:	Division 2.2
DOT Shipping Label:	Nonflammable Gas	I.D. No.:	UN 1956

SPECIAL HANDLING RECOMMENDATIONS

Use only in well-ventilated areaS. Valve protection caps must remain in place unless container is secured With valve outlet piped to use point. Do not drag, slide or roll cylinders. Use a suitable hand truck for cylinder movement. Use a pressure reducing regulator when connecting cylinder to lower preSsure (<3,000 psig) piping or systems. Do not heat cylinder by any meanS to increase the discharge rate of product from the cylinder. Use a check valve or trap in the discharge line to prevent hazardous back flow into the cylinder.

For additional handling recommendations, consult Compressed Gas Association’s Pamphlet P-1, P-9, P-14, and Safety Bulletin SB-2.

SPECIAL STORAGE RECOMMENDATIONS

Protect cylinders from physical damage. Store in cool, dry, well-ventilated area away from heavily trafficked areas and emergency exits. Do not allow the temperature where cylinders are stored to exceed 125F (52C). Cylinders should be stored upright and firmly secured to prevent falling or being knocked over. Full and empty cylinders should be segregated. Use a “first in - first out’. inventory system to prevent full cylinders being stored for excessive periods of time.

For additional storage recommendations, consult Compressed Gas Association’s Pamphlets P-1, P-9, P-14, and Safety Bulletin SB-2.

SPECIAL PACKAGING RECOMMENDATIONS

Krypton is noncorrosive and may be used with any common structural material.

OTHER RECOMMENDATIONS OR PRECAUTIONS

Compressed gas cylinders should not be refilled except by qualified producers of compressed gases. Shipment of a compressed gas cylinder which has not been filled by the owner or with his (written) consent is a violation of Federal Law (49CFR). (Continued on Page 4)

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*Various Government Agencies (i.e. Department of Transportation, Occupational Safety and Health Administration, Food and Drug Administration and others) may have specific regulations concerning the transportation, handling, storage or use of this product which will not be reflected in this data sheet. The customer should review these regulations to ensure that he is in full compliance.

HEALTH HAZARD DATA

TIME WEIGHTED AVERAGE EXPOSURE LIMIT: (Continued)

at normal atmospheric pressure (pO2>135 torr). OSHA 1993 PEL (8 Hr. TWA) None listed.

SPECIAL PROTECTION INFORMATION

LOCAL EXHAUST:

To prevent accumulation of high concentrations so as to reduce the oxygen level in the air to less than 18 molar percent.

SPECIAL PRECAUTIONS

OTHER RECOMMENDATIONS OR PRECAUTIONS: (Continued)

Always secure cylinders in an upright position before transporting them. NEVER transport cylinders in trunks of vehicles, enclosed vans, truck cabs or in passenger compartments. Transport cylinders secured in open flatbed or in open pick-up type vehicles.

Reporting under SARA, Title III, Section 313 not required.

NFPA 704 NO. for krypton = 1 O O None

MATERIAL SAFETY DATA SHEET

MSDS NO. 12335 **Trade Name:** OPTITRAK* 600 **Revision Date:** 07/18/2007

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

Trade Name: OPTITRAK* 600
Chemical Family: Dye
Product Use: Oil well drilling fluid additive.
Emergency Telephone (24 hr.): 281-561-1600

Supplied by:
M-I L.L.C.
P.O. Box 42842
Houston, TX 77242
www.miswaco.com
Telephone Number: 281-561-1512
Prepared by: Product Safety Group

Revision Number: 1

HMIS Rating

Health: 2 **Flammability:** 1 **Physical Hazard:** 0 **PPE:** E

HMIS Key: 4=Severe, 3=Serious, 2=Moderate, 1=Slight, 0=Minimal Hazard. *Chronic effects - See Section 11. See Section 8 for Personal Protective Equipment recommendations.

2. HAZARDS IDENTIFICATION

Emergency Overview: Warning! May cause an allergic reaction. May cause mechanical irritation of eyes, skin and respiratory tract. Long term inhalation of particulates may cause lung damage.

Canadian Classification:
UN PIN No: Not regulated. **WHMIS Class:** D2B

Physical State: Powder, dust. **Odor:** None **Color:** Blue

Potential Health Effects:

Acute Effects

Eye Contact: May cause mechanical irritation
Skin Contact: May cause mechanical irritation. May cause an allergic skin reaction.
Inhalation: May cause mechanical irritation.
Ingestion: May cause gastric distress, nausea and vomiting if ingested. May cause an allergic reaction.

Carcinogenicity & Chronic Effects: See Section 11 - Toxicological Information.
Routes of Exposure: Eyes. Dermal (skin) contact. Inhalation.
Target Organs/Medical Conditions Aggravated by Overexposure: Eyes. Skin. Respiratory System.

3. COMPOSITION/INFORMATION ON INGREDIENTS

Ingredient	CAS No.	Wt. %	Comments:
Blue dye		100	No comments.

4. FIRST AID MEASURES

Eye Contact:	Promptly wash eyes with lots of water while lifting eye lids. Continue to rinse for at least 15 minutes. Get medical attention if any discomfort continues.
Skin Contact:	Wash skin thoroughly with soap and water. Remove contaminated clothing and launder before reuse. Get medical attention if any discomfort continues.
Inhalation:	Move person to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.
Ingestion:	Dilute with 2 - 3 glasses of water or milk, if conscious. Never give anything by mouth to an unconscious person. If signs of irritation or toxicity occur seek medical attention.
General notes:	Persons seeking medical attention should carry a copy of this MSDS with them.

5. FIRE FIGHTING MEASURES

Flammable Properties

Flash Point: F (C): NA
Flammable Limits in Air - Lower (%): ND
Flammable Limits in Air - Upper (%): ND
Autoignition Temperature: F (C): ND
Flammability Class: NA
Other Flammable Properties: Particulate may accumulate static electricity. Dusts at sufficient concentrations can form explosive mixtures with air.
Extinguishing Media: Carbon dioxide. Foam. Water mist.

Protection Of Fire-Fighters:

Special Fire-Fighting Procedures: Do not enter fire area without proper personal protective equipment, including NIOSH/MSHA approved self-contained breathing apparatus. Evacuate area and fight fire from a safe distance. Water spray may be used to keep fire-exposed containers cool. Keep water run off out of sewers and waterways.

Hazardous Combustion Products: Oxides of: Sulfur. Carbon. Nitrogen.

6. ACCIDENTAL RELEASE MEASURES

Personal Precautions:	Use personal protective equipment identified in Section 8.
Spill Procedures:	Evacuate surrounding area, if necessary. Wet product may create a slipping hazard. Contain spilled material. Avoid the generation of dust. Sweep, vacuum, or shovel and place into closable container for disposal.
Environmental Precautions:	Do not allow to enter sewer or surface and subsurface waters. Waste must be disposed of in accordance with federal, state and local laws.

7. HANDLING AND STORAGE

Handling:	Put on appropriate personal protective equipment. Avoid contact with skin and eyes. Avoid generating or breathing dust. Product is slippery if wet. Use only with adequate ventilation. Wash thoroughly after handling.
Storage:	Store in dry, well-ventilated area. Keep container closed. Store away from incompatibles. Follow safe warehousing practices regarding palletizing, banding, shrink-wrapping and/or stacking.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Exposure Limits (TLV & PEL - 8H TWA):

Ingredient	CAS No.	Wt. %	ACGIH TLV	OSHA PEL	Other	Notes
Blue dye		100	NA	NA	NA	(1)

Notes

(1) Control as an ACGIH particulate not otherwise specified (PNOS): 10 mg/m^3 (Inhalable); 3 mg/m^3 (Respirable) and an OSHA particulate not otherwise regulated (PNOR): 15 mg/m^3 (Total); 5 mg/m^3 (Respirable).

Engineering Controls: Use appropriate engineering controls such as, exhaust ventilation and process enclosure, to ensure air contamination and keep workers exposure below the applicable limits.

Personal Protection Equipment

All chemical Personal Protective Equipment (PPE) should be selected based on an assessment of both the chemical hazards present and the risk of exposure to those hazards. The PPE recommendations below are based on our assessment of the chemical hazards associated with this product. The risk of exposure and need for respiratory protection will vary from workplace to workplace and should be assessed by the user.

Eye/Face Protection:	Dust resistant safety goggles.
Skin Protection:	Not normally necessary. If needed to minimize irritation: Wear appropriate clothing to prevent repeated or prolonged skin contact. Wear chemical resistant gloves such as: Nitrile. Neoprene.
Respiratory Protection:	All respiratory protection equipment should be used within a comprehensive respiratory protection program that meets the requirements of 29 CFR 1910.134 (U.S. OSHA Respiratory Protection Standard) or local equivalent. If exposed to airborne particles of this product use at least a NIOSH-approved N95 half-mask disposable or re-useable particulate respirator. In work environments containing oil mist/aerosol use at least a NIOSH-approved P95 half-mask disposable or re-useable particulate respirator.
General Hygiene Considerations:	Work clothes should be washed separately at the end of each work day. Disposable clothing should be discarded, if contaminated with product.

9. PHYSICAL AND CHEMICAL PROPERTIES

Color:	Blue
Odor:	None
Physical State:	Powder, dust.
pH:	6.5 - 7.5 (1 g/l water)
Specific Gravity (H2O = 1):	0.8 - 1.0 at 68F (20C)
Solubility (Water):	Soluble
Melting/Freezing Point:	ND
Boiling Point:	ND
Vapor Pressure:	ND
Vapor Density (Air=1):	ND
Evaporation Rate:	ND
Odor Threshold(s):	ND

10. STABILITY AND REACTIVITY

Chemical Stability:	Stable
Conditions to Avoid:	ND

10. STABILITY AND REACTIVITY

Materials to Avoid:	Oxidizers.
Hazardous Decomposition Products:	For thermal decomposition products, see Section 5.
Hazardous Polymerization:	Will not occur

11. TOXICOLOGICAL INFORMATION

Component Toxicological Data: Any adverse component toxicological effects are listed below. If no effects are listed, no such data were found.

Ingredient	CAS No.	Acute Data
Blue dye		Oral LD50: >5000 mg/kg (rat)

Ingredient	Component Toxicological Summary
Blue dye	This blue dye 1 has caused mutagenicity using the Salmonella/microsome preincubation and micronucleus assays. Other mutagenicity tests were negative. This compound has caused allergic reactions when ingested, injected and in skin prick tests. (HSDB)

Product Toxicological Information:
Long term inhalation of particulate can cause irritation, inflammation and/or permanent injury to the lungs. Illnesses such as pneumoconiosis ("dusty lung"), pulmonary fibrosis, chronic bronchitis, emphysema and bronchial asthma may develop.

12. ECOLOGICAL INFORMATION

Ingredient	CAS No.	Data
Blue dye		IC0 >300 (sludge organisms); LC50 96H: 1000 mg/l (trout)

Product Ecotoxicity Data:	Contact M-I Environmental Affairs Department for available product ecotoxicity data.
Biodegration:	ND
Bioaccumulation:	ND
Octanol/Water Partition Coefficient:	ND

13. DISPOSAL CONSIDERATIONS

Waste Classification:	ND
Waste Management:	Under U.S. Environmental Protection Agency (EPA) Resource Conservation and Recovery Act (RCRA), it is the responsibility of the user to determine at the time of disposal, whether the product meets RCRA criteria for the hazardous waste. This is because product uses, transformations, mixtures, processes, etc., may render the resulting materials hazardous. Empty containers retain residues. All labeled precautions must be observed.
Disposal Method:	Recover and reclaim or recycle, if practical. Should this product become a waste, dispose of in a permitted industrial landfill. Ensure that the containers are empty by the RCRA criteria prior to disposal in a permitted industrial landfill.

14. TRANSPORT INFORMATION

U.S. DOT Shipping Description:	Not regulated under TDG, IMDG, ICAO/IATA.

Canada TDG Shipping Description:	Not regulated.
UN PIN No:	Not regulated.
IMDG Shipping Description:	Not regulated.
ICAO/IATA Shipping Description:	Not regulated.

15. REGULATORY INFORMATION

U.S. Federal and State Regulations

SARA 311/312 Hazard Catagories:	Immediate (acute) health hazard.
SARA 302/304, 313; CERCLA RQ, California Proposition 65:	Note: If no components are listed below, this product is not subject to the referenced SARA and CERCLA regulations and is not known to contain a Proposition 65 listed chemical at a level that is expected to pose a significant risk under anticipated use conditions.

International Chemical Inventories

Australia AICS - Components are listed or exempt from listing.
Canada DSL - Components are listed or exempt from listing.
China Inventory - Components are listed or exempt from listing.
European Union EINECS/ELINCS - Components are listed or exempt from listing.
Japan METI ENCS - Components are listed or exempt from listing.
Korea TCCL ECL - Components are listed or exempt from listing.
U.S. TSCA - Components are listed or exempt from listing.
U.S. TSCA - No components are subject to TSCA 12(b) export notification requirements.

Canadian Classification:

Controlled Products Regulations Statement: This product has been classified in accordance with the hazard criteria of the CPR and the MSDS contains all the information required by the CPR.

WHMIS Class: D2B

16. OTHER INFORMATION

The following sections have been revised: 1, 2, 3, 8, 16

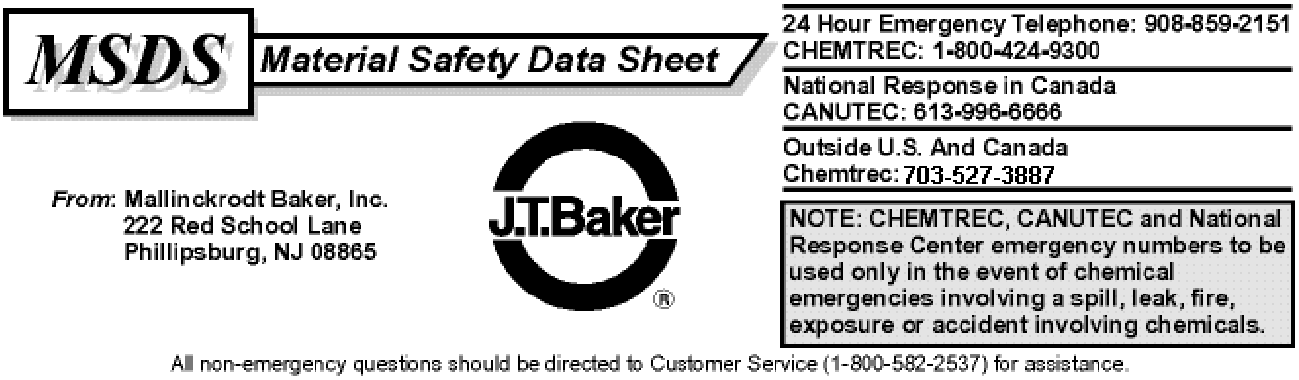
NA - Not Applicable, ND - Not Determined.

*A mark of M-I L.L.C.

Disclaimer:

MSDS furnished independent of product sale. While every effort has been made to accurately describe this product, some of the data are obtained from sources beyond our direct supervision. We can not make any assertions as to its reliability or completeness; therefore, user may rely on it only at user´s risk. We have made no effort to censor or conceal deleterious aspects of this product. Since we cannot anticipate or control the conditions under which this information and product may be used, we make no guartantee that the precautions we have suggested will be adequate for all individuals and/or situations. It is the obligation of each user of this product to comply with the requirements of all applicable laws regarding use and disposal of this product. Additional information will be furnished upon request to assist the user; however, no warranty, either expressed or implied, nor liability of any nature with respect to this product or to the data herein is made or incurred hereunder.

MSDS Number: **R5500** * * * * * *Effective Date:* ***06/20/07*** * * * * * *Supercedes:* ***05/07/07***



MSDS Material Safety Data Sheet

From: Mallinckrodt Baker, Inc.
222 Red School Lane
Phillipsburg, NJ 08865

J.T.Baker®

24 Hour Emergency Telephone: 908-859-2151
CHEMTREC: 1-800-424-9300

National Response in Canada
CANUTEC: 613-996-6666

Outside U.S. And Canada
Chemtrec: 703-527-3887

NOTE: CHEMTREC, CANUTEC and National Response Center emergency numbers to be used only in the event of chemical emergencies involving a spill, leak, fire, exposure or accident involving chemicals.

All non-emergency questions should be directed to Customer Service (1-800-582-2537) for assistance.

Rhodamine 6G

1. Product Identification

Synonyms: C.I. Basic Red 1; C.I. 45160; Basic Rhodamine Yellow
CAS No.: 989-38-8
Molecular Weight: 479.02
Chemical Formula: C28H30N2O3.HCl
Product Codes: U874

2. Composition/Information on Ingredients

Ingredient	CAS No	Percent	Hazardous
Rhodamine 6G	989-38-8	90 - 100%	Yes

3. Hazards Identification

Emergency Overview

WARNING! HARMFUL IF SWALLOWED. CAUSES IRRITATION.

SAF-T-DATA$^{(tm)}$ Ratings (Provided here for your convenience)

Health Rating: 1 - Slight
Flammability Rating: 0 - None
Reactivity Rating: 1 - Slight
Contact Rating: 1 - Slight
Lab Protective Equip: GOGGLES; LAB COAT; PROPER GLOVES
Storage Color Code: Green (General Storage)

Potential Health Effects

Inhalation:
May be harmful.
Ingestion:
None identified.
Skin Contact:
None identified.
Eye Contact:
None identified.
Chronic Exposure:
No information found.
Aggravation of Pre-existing Conditions:
No information found.

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4. First Aid Measures

Inhalation:
If inhaled, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Prompt action is essential.
Ingestion:
Induce vomiting immediately as directed by medical personnel. Never give anything by mouth to an unconscious person. Get medical attention.
Skin Contact:
In case of contact, flush skin with water.
Eye Contact:
In case of eye contact, immediately flush with plenty of water for at least 15 minutes.

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5. Fire Fighting Measures

Fire:
Not expected to be a fire hazard.
Explosion:
None identified.
Fire Extinguishing Media:
Use extinguishing media appropriate for surrounding fire.
Special Information:
In the event of a fire, wear full protective clothing and NIOSH-approved self-contained breathing apparatus with full facepiece operated in the pressure demand or other positive pressure mode.

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6. Accidental Release Measures

Wear self-contained breathing apparatus and full protective clothing. With clean shovel, carefully place material into clean, dry container and cover; remove from area. Flush spill area with water.

---

7. Handling and Storage

Keep container tightly closed. Suitable for any general chemical storage area. Containers of this material may be hazardous when empty since they retain product residues (dust, solids); observe all warnings and precautions listed for the product.

---

8. Exposure Controls/Personal Protection

Airborne Exposure Limits:
None established.
Ventilation System:
A system of local and/or general exhaust is recommended to keep employee exposures as low as possible. Local exhaust ventilation is generally preferred because it can control the emissions of the contaminant at its source, preventing dispersion of it into the general work area. Please refer to the ACGIH document, *Industrial Ventilation, A Manual of Recommended Practices*, most recent edition, for details.
Personal Respirators (NIOSH Approved):
For conditions of use where exposure to the substance is apparent and engineering controls are not feasble, consult an industrial hygienist. For emergencies, or instances where the exposure levels are not known, use a full-facepiece positive-pressure, air-supplied respirator. WARNING: Air purifying respirators do not protect workers in oxygen-deficient atmospheres.
Skin Protection:
Wear impervious protective clothing, including boots, gloves, lab coat, apron or coveralls, as appropriate, to prevent skin contact.
Eye Protection:
Use chemical safety goggles and/or full face shield where dusting or splashing of solutions is possible. Maintain eye wash fountain and quick-drench facilities in work area.

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9. Physical and Chemical Properties

Appearance:
Brown to black crystalline solid.
Odor:
No information found.
Solubility:
Slight (0.1-1%)
Specific Gravity:
No information found.
pH:
No information found.
% Volatiles by volume @ 21C (70F):
0
Boiling Point:
No information found.
Melting Point:
No information found.
Vapor Density (Air=1):
Not applicable.
Vapor Pressure (mm Hg):
Not applicable.
Evaporation Rate (BuAc=1):
No information found.

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10. Stability and Reactivity

Stability:
Stable under ordinary conditions of use and storage.
Hazardous Decomposition Products:
Oxides of nitrogen, ammonia, hydrogen chloride.
Hazardous Polymerization:
Will not occur.
Incompatibilities:
Strong oxidizing agents.

Conditions to Avoid:
No information found.

11. Toxicological Information

--------\Cancer Lists\--

	---NTP Carcinogen---		
Ingredient	Known	Anticipated	IARC Category
Rhodamine 6G (989-38-8)	No	No	3

12. Ecological Information

Environmental Fate:
No information found.
Environmental Toxicity:
No information found.

13. Disposal Considerations

Whatever cannot be saved for recovery or recycling should be managed in an appropriate and approved waste disposal facility. Processing, use or contamination of this product may change the waste management options. State and local disposal regulations may differ from federal disposal regulations. Dispose of container and unused contents in accordance with federal, state and local requirements.

14. Transport Information

Not regulated.

15. Regulatory Information

--------\Chemical Inventory Status - Part 1\---------------------------------

Ingredient	TSCA	EC	Japan	Australia
Rhodamine 6G (989-38-8)	Yes	Yes	Yes	Yes

--------\Chemical Inventory Status - Part 2\---------------------------------

		--Canada--		
Ingredient	Korea	DSL	NDSL	Phil.
Rhodamine 6G (989-38-8)	Yes	Yes	No	Yes

--------\Federal, State & International Regulations - Part 1\----------------

	-SARA 302-		------SARA 313------	
Ingredient	RQ	TPQ	List	Chemical Catg.
Rhodamine 6G (989-38-8)	No	No	Yes	No

--------\Federal, State & International Regulations - Part 2\----------------

		-RCRA-	-TSCA-
Ingredient	CERCLA	261.33	8(d)
Rhodamine 6G (989-38-8)	No	No	No

Chemical Weapons Convention: No   TSCA 12(b): No   CDTA: No

```
SARA 311/312:  Acute: Yes      Chronic: Yes  Fire: No  Pressure: No
Reactivity: No          (Pure / Solid)
```

Australian Hazchem Code: None allocated.
Poison Schedule: None allocated.
WHMIS:
This MSDS has been prepared according to the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all of the information required by the CPR.

16. Other Information

NFPA Ratings: Health: **1** Flammability: **0** Reactivity: **0**
Label Hazard Warning:
WARNING! HARMFUL IF SWALLOWED. CAUSES IRRITATION.
Label Precautions:
Avoid contact with eyes, skin, clothing.
Keep in tightly closed container. Wash thoroughly after handling.
Label First Aid:
If swallowed, induce vomiting immediately as directed by medical personnel. Never give anything by mouth to an unconscious person. In case of contact, immediately flush eyes or skin with plenty of water for at least 15 minutes. Remove contaminated clothing and shoes. Wash clothing before reuse.
Product Use:
Laboratory Reagent.
Revision Information:
MSDS Section(s) changed since last revision of document include: 3, 15.
Disclaimer:
****

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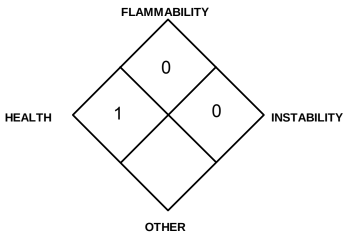
****

Prepared by: Environmental Health & Safety
Phone Number: (314) 654-1600 (U.S.A.)

Airgas

NFPA RATING



MATERIAL SAFETY DATA SHEET

Prepared to U.S. OSHA, CMA, ANSI and Canadian WHMIS Standards

PART I *What is the material and what do I need to know in an emergency?*

1. PRODUCT IDENTIFICATION

CHEMICAL NAME; CLASS:	**SULFUR HEXAFLUORIDE - SF_6** Document Number: 001048
PRODUCT USE:	For General Analytical Chemical Uses
SUPPLIER/MANUFACTURER'S NAME:	AIRGAS INC.
ADDRESS:	259 N. Radnor-Chester Road Suite 100 Radnor, PA 19087-5283
BUSINESS PHONE:	1-610-687-5253
EMERGENCY PHONE:	1-800-949-7937 International: 423-479-0293
DATE OF PREPARATION:	May 20, 1996
DATE OF REVISION:	March 26, 2004

2. COMPOSITION and INFORMATION ON INGREDIENTS

CHEMICAL NAME	CAS #	mole %	EXPOSURE LIMITS IN AIR					
			ACGIH-TLV		OSHA-PEL		NIOSH	OTHER
			TWA ppm	STEL ppm	TWA ppm	STEL ppm	IDLH ppm	ppm
Sulfur Hexafluoride	2551-62-4	> 99.8%	1000	NE	1000	NE	NE	NIOSH REL: TWA = 1000 DFG MAK: TWA = 1000 PEAK = 8•MAK 15 min. average value, 1-hr interval
Maximum Impurities		< 0.2%	None of the trace impurities in this mixture contribute significantly to the hazards associated with the product. All hazard information pertinent to this product has been provided in this Material Safety Data Sheet, per the requirements of the OSHA Hazard Communication Standard (29 CFR 1910.1200) and State equivalent standards.					

NE = Not Established. See Section 16 for Definitions of Terms Used.

NOTE (1): ALL WHMIS required information is included in appropriate sections based on the ANSI Z400.1-1998 format. This gas mixture has been classified in accordance with the hazard criteria of the CPR and the MSDS contains all the information required by the CPR.

3. HAZARD IDENTIFICATION

EMERGENCY OVERVIEW: Sulfur Hexafluoride is a colorless, odorless, non-toxic, non-flammable gas which is shipped as a liquefied gas. The liquefied gas will rapidly boil at standard temperatures and pressures. The main health hazard associated with releases of this gas is asphyxiation, by displacement of oxygen. Sulfur Hexafluoride can decompose at very high temperatures or when subjected to an electric discharge forming highly toxic decomposition products, including sulfur tetrafluoride and hydrogen fluoride. Contact with the liquefied gas can cause frostbite to any contaminated tissue. Sulfur Hexafluoride is not flammable or reactive under typical emergency response situations.

3. HAZARD IDENTIFICATION (Continued)

HAZARDOUS MATERIAL IDENTIFICATION SYSTEM

HEALTH HAZARD	(BLUE)	1
FLAMMABILITY HAZARD	(RED)	0
PHYSICAL HAZARD	(YELLOW)	0

PROTECTIVE EQUIPMENT

EYES	RESPIRATORY	HANDS	BODY
🥽	See Section 8	🧤	See Section 8

For Routine Industrial Use and Handling Applications

See Section 16 for Definition of Ratings

SYMPTOMS OF OVEREXPOSURE BY ROUTE OF EXPOSURE: The most significant route of overexposure for this gas is by inhalation. The following paragraphs describe symptoms of exposure by route of exposure.

INHALATION: High concentrations of this gas can cause an oxygen-deficient environment. Individuals breathing such an atmosphere may experience symptoms which include headaches, ringing in ears, dizziness, drowsiness, unconsciousness, nausea, vomiting, and depression of all the senses. The skin of a victim of overexposure may have a blue color. Under some circumstances of overexposure, death may occur. The effects associated with various levels of oxygen are as follows:

CONCENTRATION	**SYMPTOMS OF EXPOSURE**
12-16% Oxygen:	Breathing and pulse rate increased, muscular coordination slightly disturbed.
10-14% Oxygen:	Emotional upset, abnormal fatigue, disturbed respiration.
6-10% Oxygen:	Nausea and vomiting, collapse or loss of consciousness.
Below 6%:	Convulsive movements, possible respiratory collapse, and death.

OTHER POTENTIAL HEALTH EFFECTS: If Sulfur Hexafluoride is subjected to electrical discharge, highly toxic decomposition products are formed which may include sulfur tetrafluoride and other sulfur fluorides, sulfuryl fluoride, thionyl fluorides, sulfur oxides, hydrogen sulfide and/or hydrogen fluoride. Exposure to these decomposition products may result in pulmonary edema, a potentially fatal accumulation of fluid in the lungs. Symptoms of pulmonary edema include shortness of breath, pain in the chest and difficulty breathing. Symptoms may not develop for up to 24 hours after exposure. Contact with liquid or rapidly expanding gases (which are released under high pressure) may cause frostbite. Symptoms of frostbite include change in skin color to white or grayish-yellow. The pain after contact with liquid can quickly subside.

HEALTH EFFECTS OR RISKS FROM EXPOSURE: An Explanation in **Lay Terms**. Overexposure to Sulfur Hexafluoride may cause the following health effects:

ACUTE: The most significant hazard associated with this gas is inhalation of oxygen-deficient atmospheres. Symptoms of oxygen deficiency include respiratory difficulty, ringing in ears, headache, dizziness, indigestion, nausea, and possible death. Contact with liquid or rapidly expanding gases (which are released under high pressure) may cause frostbite.

CHRONIC: There are currently no known adverse health effects associated with chronic exposure to this gas.

TARGET ORGANS: ACUTE: Respiratory system. CHRONIC: None known.

PART II *What should I do if a hazardous situation occurs?*

4. FIRST-AID MEASURES

RESCUERS SHOULD NOT ATTEMPT TO RETRIEVE VICTIMS OF EXPOSURE TO SULFUR HEXAFLUORIDE WITHOUT ADEQUATE PERSONAL PROTECTIVE EQUIPMENT. At a minimum, Self-Contained Breathing Apparatus Personal Protective equipment should be worn.

Remove victim(s) to a safe location. Trained personnel should administer supplemental oxygen and/or cardio-pulmonary resuscitation, if necessary. Only trained personnel should administer supplemental oxygen. Victim(s) must be taken for medical attention. Rescuers should be taken for medical attention, if necessary. Take copy of label and MSDS to physician or other health professional with victim(s).

In case of frostbite, place the frostbitten part in warm water. DO NOT USE HOT WATER. If warm water is not available, or is impractical to use, wrap the affected parts gently in blankets. Alternatively, if the fingers or hands are frostbitten, place the affected area of the body in the armpit. Encourage victim to gently exercise the affected part while being warmed. Seek immediate medical attention.

MEDICAL CONDITIONS AGGRAVATED BY EXPOSURE: Pre-existing respiratory conditions may be aggravated by overexposure to Sulfur Hexafluoride.

RECOMMENDATIONS TO PHYSICIANS: Treat symptoms and reduce overexposure.

5. FIRE-FIGHTING MEASURES

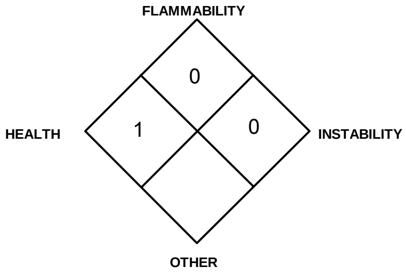
FLASH POINT: Not applicable.
AUTOIGNITION TEMPERATURE: Not applicable.
FLAMMABLE LIMITS (in air by volume, %):
Lower (LEL): Not applicable.
Upper (UEL): Not applicable.

FIRE EXTINGUISHING MATERIALS: Non-flammable, inert gas. Use extinguishing media appropriate for surrounding fire.

UNUSUAL FIRE AND EXPLOSION HAZARDS: Although Sulfur Hexafluoride is a non-flammable gas, it can present minor health hazards to firefighters. Sulfur Hexafluoride does not burn; however, containers, when involved in fire, may rupture or burst in the heat of the fire. Products of thermal decomposition of Sulfur Hexafluoride includes toxic gases (e.g., sulfuryl and thionyl fluorides).

Explosion Sensitivity to Mechanical Impact: Not sensitive.
Explosion Sensitivity to Static Discharge: Not sensitive.

NFPA RATING



See Section 16 for Definition of Ratings

SPECIAL FIRE-FIGHTING PROCEDURES: Structural firefighters must wear Self-Contained Breathing Apparatus and full protective equipment. In the event of fire, cool containers of Sulfur Hexafluoride with water to prevent failure. Use a water spray or fog to reduce or direct vapors. If cylinders are exposed to heat, the cylinder may rupture or burst and release the contents. It may be prudent to remove potentially heat-exposed cylinders from the area surrounding a fire, if it is safe for fire-fighters to do so.

6. ACCIDENTAL RELEASE MEASURES

SPILL AND LEAK RESPONSE: Uncontrolled releases should be responded to by trained personnel using pre-planned procedures. Proper protective equipment should be used. In case of a release, clear the affected area, protect people, and respond with trained personnel. Minimum Personal Protective Equipment should be **Level B: protective clothing, mechanically-resistant gloves and Self-Contained Breathing Apparatus**. Locate and seal the source of the leaking gas. Allow the gas to dissipate. Monitor the surrounding area for Sulfur Hexafluoride and oxygen levels. Sulfur Hexafluoride must be below the levels indicated in Section 2 (Composition and Information on Ingredients). The atmosphere must have at least 19.5 percent oxygen before personnel can be allowed in the area without Self-Contained Breathing Apparatus. Attempt to close the main source valve prior to entering the area. If this does not stop the release (or if it is not possible to reach the valve), allow the gas to release in-place or remove it to a safe area and allow the gas to be released there.

PART III *How can I prevent hazardous situations from occurring?*

7. HANDLING and STORAGE

WORK PRACTICES AND HYGIENE PRACTICES: As with all chemicals, avoid getting Sulfur Hexafluoride IN YOU. Do not eat or drink while handling chemicals. Be aware of any signs of dizziness or fatigue; exposures to fatal concentrations of Sulfur Hexafluoride could occur without any significant warning symptoms.

STORAGE AND HANDLING PRACTICES: Sulfur Hexafluoride should be stored in dry, well-ventilated areas separate from incompatibles, such as strong oxidizing agents, and away from sources of heat. Compressed gases can present significant safety hazards. Store containers away from heavily trafficked areas and emergency exits. Post “No Smoking or Open Flames” signs in storage or use areas. Since Sulfur Hexafluoride is non-corrosive, any of the common structural metals may be used under ordinary conditions.

SPECIAL PRECAUTIONS FOR HANDLING GAS CYLINDERS: Protect cylinders against physical damage. Store in cool, dry, well-ventilated fireproof area, away from flammable materials and corrosive atmospheres. Store away from heat and ignition sources and out of direct sunlight. Do not store near elevators, corridors or loading docks. Do not allow area where cylinders are stored to exceed 52°C (125°F). Use only storage containers and equipment (pipes, valves, fittings to relieve pressure, etc.) designed for the storage of Liquid Sulfur Hexafluoride. Do not store containers where they can come into contact with moisture. Cylinders should be stored upright and be firmly secured to prevent falling or being knocked over. Cylinders can be stored in the open, but in such cases, should be protected against extremes of weather and from the dampness of the ground to prevent rusting. Never tamper with pressure relief devices. The following rules are applicable to situations in which cylinders are being used:

Before Use: Move cylinders with a suitable hand-truck. Do not drag, slide or roll cylinders. Do not drop cylinders or permit them to strike each other. Secure cylinders firmly. Leave the valve protection cap, if provided, in-place until cylinder is ready for use.

During Use: Use designated CGA fittings and other support equipment. Do not use adapters. Do not heat cylinder by any means to increase the discharge rate of the product from the cylinder. Use check valve or trap in discharge line to prevent hazardous backflow into the cylinder. Do not use oils or grease on gas-handling fittings or equipment.

After Use: Close main cylinder valve. Replace valve protection cap, if provided. Mark empty cylinders “EMPTY”.

7. HANDLING and STORAGE (Continued)

NOTE: Use only DOT or ASME code containers. Close valve after each use and when empty. Cylinders must not be recharged except by or with the consent of owner. For additional information refer to the Compressed Gas Association Pamphlet P-1, *Safe Handling of Compressed Gases in Containers*. Additionally, refer to CGA Bulletin SB-*2 "Oxygen Deficient Atmospheres*".

PROTECTIVE PRACTICES DURING MAINTENANCE OF CONTAMINATED EQUIPMENT: Follow practices indicated in Section 6 (Accidental Release Measures). Make certain application equipment is locked and tagged-out safely. Purge gas handling equipment with inert gas (e.g., Nitrogen) before attempting repairs.

8. EXPOSURE CONTROLS - PERSONAL PROTECTION

VENTILATION AND ENGINEERING CONTROLS: Use with adequate ventilation. Local exhaust ventilation is preferred, because it prevents Sulfur Hexafluoride dispersion into the work place by eliminating it at its source. If appropriate, install automatic monitoring equipment to detect the level of Sulfur Hexafluoride and oxygen.

RESPIRATORY PROTECTION: Maintain Sulfur Hexafluoride levels below those indicated in Section 2 (Composition and Information on Ingredients) and oxygen levels above 19.5% in the workplace. If respiratory protection is needed, use only protection authorized in the U.S. Federal OSHA Standard (29 CFR 1910.134), applicable U.S. State regulations, or the Canadian CSA Standard Z94.4-93 and applicable standards of Canadian Provinces. Oxygen levels below 19.5% are considered IDLH by OSHA. In such atmospheres, use of a full-facepiece pressure/demand SCBA or a full facepiece, supplied air respirator with auxiliary self-contained air supply is required under OSHA's Respiratory Protection Standard (1910.134-1998).

EYE PROTECTION: Splash goggles, face-shields or safety glasses. If necessary, refer to U.S. OSHA 29 CFR 1910.133, or Canadian Standards.

HAND PROTECTION: Wear mechanically-resistant gloves when handling cylinders of Sulfur Hexafluoride. If necessary, refer to U.S. OSHA 29 CFR 1910.138 or appropriate Standards of Canada.

BODY PROTECTION: Use body protection appropriate for task. Transfer of large quantities under pressure may require protective equipment appropriate to protect employees from splashes of liquefied product, as well provide sufficient insulation from cold. If a hazard of injury to the feet exists due to falling objects, rolling objects, where objects may pierce the soles of the feet or where employee's feet may be exposed to electrical hazards, use foot protection, as described in U.S. OSHA 29 CFR.

9. PHYSICAL and CHEMICAL PROPERTIES

VAPOR DENSITY: 6.162 kg/m^3 (0.38 lb/ft^3)
SPECIFIC GRAVITY (air = 1): 5.114
SOLUBILITY IN WATER, v/v @ 20 °C: 0.001%
VAPOR PRESSURE (psig): 320
EXPANSION RATIO: Not applicable.
EVAPORATION RATE (nBuAc = 1): Not applicable.
MELTING POINT: -50.8°C (-59.4°F)
BOILING POINT: (Sublimation Point) -63.7°C (-82.7°F)
pH: Not applicable.
ODOR THRESHOLD: Not applicable. Odorless.
COEFFICIENT WATER/OIL DISTRIBUTION: Not applicable. SPECIFIC VOLUME (ft^3/lb): 2.5
APPEARANCE AND COLOR: Sulfur Hexafluoride is a colorless, odorless gas.

HOW TO DETECT THIS SUBSTANCE (warning properties): There are no unusual warning properties associated with a release of Sulfur Hexafluoride. In terms of leak detection, fittings and joints can be painted with a soap solution to detect leaks, which will be indicated by a bubble formation.

10. STABILITY and REACTIVITY

STABILITY: Normally stable, inert gas.

DECOMPOSITION PRODUCTS: Sulfur fluorides and hydrogen fluoride. Sulfur Hexafluoride may be partially decomposed if subjected to static discharge. Sulfur Hexafluoride is not corrosive to most metals under normal conditions. Some of the breakdown products are corrosive and will be enhanced by the presence of moisture or at high temperatures. Sulfur Hexafluoride also decomposes slightly in the presence of certain metals at temperatures in excess of 204°C (400°F), this effect being most pronounced with silicon and carbon steels. Sulfur Hexafluoride is non-reactive with most chemicals. Sulfur Hexafluoride, however, can react violently with disilane. Sulfur Hexafluoride is only stable at elevated temperatures [e.g., 204°C (> 400°F)] when contained in aluminum, stainless steel, copper, brass, or silver. Other metals can cause slow decomposition to sulfur-fluoride compounds. If this decomposition occurs in the presence of oxygen, thionyl fluoride compounds can be generated.

HAZARDOUS POLYMERIZATION: Will not occur.

CONDITIONS TO AVOID: Contact with incompatible materials. Cylinders exposed to high temperatures or direct flame can rupture or burst.

PART IV *Is there any other useful information about this material?*

11. TOXICOLOGICAL INFORMATION

TOXICITY DATA: The following data are for Sulfur Hexafluoride:

LD_{50} (Intravenous-Rabbit) 5790 mg/kg

LCLo (Inhalation-Mammal-Species Unspecified) 300 gm/m3: Peripheral Nerve and Sensation: flaccid paralysis with appropriate anesthesia; Behavioral: muscle weakness, rigidity (including catalepsy)

Male rats were exposed for periods of 16-24 hours to 20% oxygen and 80% Sulfur Hexafluoride at 1 atmosphere ambient pressure showed no changes.

SUSPECTED CANCER AGENT: Sulfur Hexafluoride is not found on the following lists: FEDERAL OSHA Z LIST, NTP, CAL/OSHA, IARC; therefore it is not considered to be, nor suspected to be a cancer-causing agent by these agencies.

IRRITANCY OF PRODUCT: Contact with rapidly expanding gases can cause frostbite and damage to exposed skin and eyes.

SENSITIZATION OF PRODUCT: Sulfur Hexafluoride is not known to be a human skin or respiratory sensitizer.

REPRODUCTIVE TOXICITY INFORMATION: Listed below is information concerning the effects of Sulfur Hexafluoride on the human reproductive system.

Mutagenicity: Sulfur Hexafluoride is not reported to cause mutagenic effects in humans.

Embryotoxicity: Sulfur Hexafluoride is not reported to cause embryotoxic effects in humans.

Teratogenicity: Sulfur Hexafluoride is not reported to cause teratogenic effects in humans.

Reproductive Toxicity: Sulfur Hexafluoride is not reported to cause adverse reproductive effects in humans.

A mutagen is a chemical which causes permanent changes to genetic material (DNA) such that the changes will propagate through generation lines. An embryotoxin is a chemical which causes damage to a developing embryo (i.e. within the first eight weeks of pregnancy in humans), but the damage does not propagate across generational lines. A teratogen is a chemical which causes damage to a developing fetus, but the damage does not propagate across generational lines. A reproductive toxin is any substance which interferes in any way with the reproductive process.

BIOLOGICAL EXPOSURE INDICES (BEIs): Currently, Biological Exposure Indices (BEIs) are not applicable for Sulfur Hexafluoride.

12. ECOLOGICAL INFORMATION

ENVIRONMENTAL STABILITY: The gas will be dissipated rapidly in well-ventilated areas.

EFFECT OF MATERIAL ON PLANTS or ANIMALS: Any adverse effect on animals would be related to oxygen deficient environments. No adverse effect is anticipated to occur to plant-life, except for frost produced in the presence of rapidly expanding gases.

EFFECT OF CHEMICAL ON AQUATIC LIFE: No data are currently available on the effects of Sulfur Hexafluoride on aquatic life.

13. DISPOSAL CONSIDERATIONS

PREPARING WASTES FOR DISPOSAL: Product removed from the cylinder must be disposed of in accordance with appropriate U.S. Federal, State, and local regulations or with regulations of Canada and its Provinces. Return cylinders with residual product to Airgas, Inc. Do not dispose of locally.

14. TRANSPORTATION INFORMATION

THIS GAS IS HAZARDOUS AS DEFINED BY 49 CFR 172.101 BY THE U.S. DEPARTMENT OF TRANSPORTATION.

PROPER SHIPPING NAME:	Sulfur hexafluoride
HAZARD CLASS NUMBER and DESCRIPTION:	2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER:	UN 1080
PACKING GROUP:	Not Applicable
DOT LABEL(S) REQUIRED:	Class 2.2 (Non-Flammable Gas)

NORTH AMERICAN EMERGENCY RESPONSE GUIDEBOOK NUMBER (1996): 126

MARINE POLLUTANT: Sulfur Hexafluoride is not classified by the DOT as a Marine Pollutant (as defined by 49 CFR 172.101, Appendix B).

14. TRANSPORTATION INFORMATION (Continued)

TRANSPORT CANADA TRANSPORTATION OF DANGEROUS GOODS REGULATIONS: This gas is considered as Dangerous Goods, per regulations of Transport Canada. The use of the above U.S. DOT information from the U.S. 49 CFR regulations is allowed for shipments that originate in the U.S. For shipments via ground vehicle or rail that originate in Canada, the following information is applicable.

PROPER SHIPPING NAME: Sulfur hexafluoride
HAZARD CLASS NUMBER and DESCRIPTION: Class 2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER: UN 1080
PACKING GROUP: Not Applicable
HAZARD LABEL(S) REQUIRED: Class 2.2 (Non-Flammable Gas)
SPECIAL PROVISIONS: None
EXPLOSIVE LIMIT & LIMITED QUANTITY INDEX: 42
ERAP INDEX: 0.12
PASSENGER CARRYING SHIP INDEX: None
PASSENGER CARRYING ROAD OR RAIL VEHICLE INDEX: 75
MARINE POLLUTANT: Air is not a Marine Pollutant.

15. REGULATORY INFORMATION

ADDITIONAL U.S. REGULATIONS:

U.S. SARA REPORTING REQUIREMENTS: Sulfur Hexafluoride is not subject to the reporting requirements of Sections 302, 304 and 313 of Title III of the Superfund Amendments and Reauthorization Act.

U.S. SARA THRESHOLD PLANNING QUANTITY: There are no specific Threshold Planning Quantities for this gas. The default Federal MSDS submission and inventory requirement filing threshold of 10,000 lb (4,540 kg) may apply, per 40 CFR 370.20.

U.S. CERCLA REPORTABLE QUANTITIES (RQ): Not applicable.

U.S. TSCA INVENTORY STATUS: Sulfur Hexafluoride is listed on the TSCA Inventory.

OTHER U.S. FEDERAL REGULATIONS: Not applicable.

CALIFORNIA SAFE DRINKING WATER AND TOXIC ENFORCEMENT ACT (PROPOSITION 65): Sulfur Hexafluoride is not on the California Proposition 65 lists.

CGA LABELING (For Compressed Gas):

CAUTION: LIQUID AND GAS UNDER PRESSURE.
CAN CAUSE RAPID SUFFOCATION.
MAY CAUSE FROSTBITE.
Store and use with adequate ventilation.
Do not get liquid in eyes, on skin or clothing.
Cylinder temperature should not exceed 52°C (125°F).
Close valve after each use and when empty.
Use in accordance with the Material Safety Data Sheet.

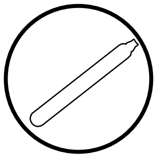
FIRST-AID: **IF INHALED**, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Call a physician.
IN CASE OF FROSTBITE, obtain immediate medial attention.
DO NOT REMOVE THIS PRODUCT LABEL.

ADDITIONAL CANADIAN REGULATIONS:

CANADIAN DSL/NDSL INVENTORY STATUS: Sulfur Hexafluoride is on the DSL Inventory.

CANADIAN ENVIRONMENTAL PROTECTION ACT (CEPA) PRIORITIES SUBSTANCES LISTS: Sulfur Hexafluoride is not on the CEPA Priorities Substances Lists.

CANADIAN WHMIS CLASSIFICATION AND SYMBOLS: **Class A:** Compressed Gases



16. OTHER INFORMATION

PREPARED BY:
CHEMICAL SAFETY ASSOCIATES, Inc.
PO Box 3519, La Mesa, CA 91944-3519
619/670-0609

DEFINITIONS OF TERMS

A large number of abbreviations and acronyms appear on a MSDS. Some of these which are commonly used include the following:

CAS #: This is the Chemical Abstract Service Number that uniquely identifies each constituent. **EXPOSURE LIMITS IN AIR:**

CEILING LEVEL: The concentration that shall not be exceeded during any part of the working exposure.

LOQ: Limit of Quantitation.

MAK: Federal Republic of Germany Maximum Concentration Values in the workplace.

NE: Not Established. When no exposure guidelines are established, an entry of NE is made for reference.

NIC: Notice of Intended Change.

NIOSH CEILING: The exposure that shall not be exceeded during any part of the workday. If instantaneous monitoring is not feasible, the ceiling shall be assumed as a 15-minute TWA exposure (unless otherwise specified) that shall not be exceeded at any time during a workday.

NIOSH RELs: NIOSH's Recommended Exposure Limits.

PEL-Permissible Exposure Limit: OSHA's Permissible Exposure Limits. This exposure value means exactly the same as a TLV, except that it is enforceable by OSHA. The OSHA Permissible Exposure Limits are based in the 1989 PELs and the June, 1993 Air Contaminants Rule (Federal Register: 58: 35338-35351 and 58: 40191). Both the current PELs and the vacated PELs are indicated. The phrase, "Vacated 1989 PEL," is placed next to the PEL that was vacated by Court Order.

SKIN: Used when a there is a danger of cutaneous absorption.

STEL-Short Term Exposure Limit: Short Term Exposure Limit, usually a 15-minute time-weighted average (TWA) exposure that should not be exceeded at any time during a workday, even if the 8-hr TWA is within the TLV-TWA, PEL-TWA or REL-TWA.

TLV-Threshold Limit Value: An airborne concentration of a substance that represents conditions under which it is generally believed that nearly all workers may be repeatedly exposed without adverse effect. The duration must be considered, including the 8-hour.

TWA-Time Weighted Average: Time Weighted Average exposure concentration for a conventional 8-hr (TLV, PEL) or up to a 10-hr (REL) workday and a 40-hr workweek.

IDLH-Immediately Dangerous to Life and Health: This level represents a concentration from which one can escape within 30-minutes without suffering escape-preventing or permanent injury.

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS: This rating system was developed by the National Paint and Coating Association and has been adopted by industry to identify the degree of chemical hazards.

HEALTH HAZARD:

0 (Minimal Hazard: No significant health risk, irritation of skin or eyes not anticipated. *Skin Irritation*: Essentially non-irritating. PII or Draize = "0". *Eye Irritation*: Essentially non-irritating, or minimal effects which clear in < 24 hours [e.g. mechanical irritation]. Draize = "0". *Oral Toxicity LD_{50} Rat*: < 5000 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: < 2000 mg/kg. *Inhalation Toxicity 4-hrs LC_{50} Rat*: < 20 mg/L.); **1** (Slight Hazard: Minor reversible Injury may occur; slightly or mildly irritating. *Skin Irritation*: Slightly or mildly irritating. *Eye Irritation*: Slightly or mildly irritating. *Oral Toxicity LD_{50} Rat*: > 500-5000 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 1000-2000 mg/kg. *Inhalation Toxicity LC_{50}* 4-hrs *Rat*: > 2-20 mg/L); **2** (Moderate Hazard: Temporary or transitory injury may occur. *Skin Irritation*: Moderately irritating; primary irritant; sensitizer. PII or Draize > 0, < 5. *Eye Irritation*: Moderately to severely irritating and/or corrosive; reversible corneal opacity; corneal involvement or irritation clearing in 8-21 days. Draize > 0, ≤ 25. *Oral Toxicity LD_{50} Rat*: > 50-500 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 200-1000 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.5-2 mg/L.); **2** (Moderate Hazard: Temporary or transitory injury may occur. *Skin Irritation*: Moderately irritating; primary irritant; sensitizer. PII or Draize > 0, < 5. ; *Eye Irritation*: Moderately to severely irritating and/or corrosive; reversible corneal opacity; corneal involvement or irritation clearing in 8-21 days. Draize > 0, ≤ 25. *Oral Toxicity LD_{50} Rat*: > 50-500 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 200-1000 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.5-2 mg/L. **3** (Serious Hazard): Major injury likely unless prompt action is taken and medical treatment is given; high level of toxicity; corrosive. *Skin Irritation*: Severely irritating and/or corrosive; may destroy dermal tissue, cause skin burns, dermal necrosis.

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS (continued):

HEALTH HAZARD (continued):

3 (continued): PII or Draize > 5-8 with destruction of tissue. *Eye Irritation*: Corrosive, irreversible destruction of ocular tissue; corneal involvement or irritation persisting for more than 21 days. Draize > 80 with effects irreversible in 21 days. *Oral Toxicity LD_{50} Rat*: > 1-50 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: > 20-200 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: > 0.05-0.5 mg/L.); **4** (Severe Hazard: Life-threatening; major or permanent damage may result from single or repeated exposure. *Skin Irritation*: Not appropriate. Do not rate as a "4", based on skin irritation alone. *Eye Irritation*: Not appropriate. Do not rate as a "4", based on eye irritation alone. *Oral Toxicity LD_{50} Rat*: ≤ 1 mg/kg. *Dermal Toxicity LD_{50}Rat or Rabbit*: ≤ 20 mg/kg. *Inhalation Toxicity LC_{50} 4-hrs Rat*: ≤ 0.05 mg/L).

FLAMMABILITY HAZARD:

0 (Minimal Hazard-Materials that will not burn in air when exposure to a temperature of 815.5°C [1500°F] for a period of 5 minutes.); **1** (Slight Hazard-Materials that must be pre-heated before ignition can occur. Material require considerable pre-heating, under all ambient temperature conditions before ignition and combustion can occur, Including: Materials that will burn in air when exposed to a temperature of 815.5°C (1500°F) for a period of 5 minutes or less; Liquids, solids and semisolids having a flash point at or above 93.3°C [200°F] (e.g. OSHA Class IIIB, or; Most ordinary combustible materials [e.g. wood, paper, etc.]; **2** (Moderate Hazard-Materials that must be moderately heated or exposed to relatively high ambient temperatures before ignition can occur. Materials in this degree would not, under normal conditions, form hazardous atmospheres in air, but under high ambient temperatures or moderate heating may release vapor in sufficient quantities to produce hazardous atmospheres in air, Including: Liquids having a flash-point at or above 37.8°C [100°F] Solid materials in the form of course dusts that may burn rapidly but that generally do not form explosive atmospheres; Solid materials in a fibrous or shredded form that may burn rapidly and create flash fire hazards (e.g. cotton, sisal, hemp; Solids and semisolids that readily give off flammable vapors.); **3** (Serious Hazard- Liquids and solids that can be ignited under almost all ambient temperature conditions. Materials in this degree produce hazardous atmospheres with air under almost all ambient temperatures, or, unaffected by ambient temperature, are readily ignited under almost all conditions, including: Liquids having a flash point below 22.8°C [73°F] and having a boiling point at or above 38°C [100°F] and below 37.8°C [100°F] [e.g. OSHA Class IB and IC]; Materials that on account of their physical form or environmental conditions can form explosive mixtures with air and are readily dispersed in air [e.g., dusts of combustible solids, mists or droplets of flammable liquids]; Materials that burn extremely rapidly, usually by reason of self-contained oxygen [e.g. dry nitrocellulose and many organic peroxides]); **4** (Severe Hazard-Materials that will rapidly or completely vaporize at atmospheric pressure and normal ambient temperature or that are readily dispersed in air, and which will burn readily, including: Flammable gases; Flammable cryogenic materials; Any liquid or gaseous material that is liquid while under pressure and has a flash point below 22.8°C [73°F] and a boiling point below 37.8°C [100°F] [e.g. OSHA Class IA; Material that ignite spontaneously when exposed to air at a temperature of 54.4°C [130°F] or below [e.g. pyrophoric]).

PHYSICAL HAZARD:

0 (*Water Reactivity*: Materials that do not react with water. *Organic Peroxides*: Materials that are normally stable, even under fire conditions and will not react with water. *Explosives*: Substances that are Non-Explosive. Unstable *Compressed Gases*: No Rating. *Pyrophorics*: No Rating. *Oxidizers*: No "0" rating allowed. *Unstable Reactives*: Substances that will not polymerize, decompose, condense or self-react.); **1** (*Water Reactivity*: Materials that change or decompose upon exposure to moisture. *Organic Peroxides*: Materials that are normally stable, but can become unstable at high temperatures and pressures. These materials may react with water, but will not release energy. *Explosives*: Division 1.5 & 1.6 substances that are very insensitive explosives or that do not have a mass explosion hazard. *Compressed Gases*: Pressure below OSHA definition.

DEFINITIONS OF TERMS (Continued)

HAZARDOUS MATERIALS IDENTIFICATION SYSTEM HAZARD RATINGS (continued):

PHYSICAL HAZARD (continued):

Pyrophorics: No Rating. *Oxidizers*: Packaging Group III; Solids: any material that in either concentration tested, exhibits a mean burning time less than or equal to the mean burning time of a 3:7 potassium bromate/cellulose mixture and the criteria for Packing Group I and II are not met. Liquids: any material that exhibits a mean pressure rise time less than or equal to the pressure rise time of a 1:1 nitric acid (65%)/cellulose mixture and the criteria for Packing Group I and II are not met. *Unstable Reactives*: Substances that may decompose, condense or self-react, but only under conditions of high temperature and/or pressure and have little or no potential to cause significant heat generation or explosive hazard. Substances that readily undergo hazardous polymerization in the absence of inhibitors.); **2** (*Water Reactivity*: Materials that may react violently with water. *Organic Peroxides*: Materials that, in themselves, are normally unstable and will readily undergo violent chemical change, but will not detonate. These materials may also react violently with water. *Explosives*: Division 1.4 – Explosive substances where the explosive effect are largely confined to the package and no projection of fragments of appreciable size or range are expected. An external fire must not cause virtually instantaneous explosion of almost the entire contents of the package. *Compressed Gases*: Pressurized and meet OSHA definition but < 514.7 psi absolute at 21.1°C (70°F) [500 psig]. *Pyrophorics*: No Rating. *Oxidizers*: Packing Group II Solids: any material that, either in concentration tested, exhibits a mean burning time of less than or equal to the mean burning time of a 2:3 potassium bromate/cellulose mixture and the criteria for Packing Group I are not met. Liquids: any material that exhibits a mean pressure rise time less than or equal to the pressure rise of a 1:1 aqueous sodium chlorate solution (40%)/cellulose mixture and the criteria for Packing Group I are not met. *Unstable Reactives*: Substances that may polymerize, decompose, condense, or self-react at ambient temperature and/or pressure, but have a low potential for significant heat generation or explosion. Substances that readily form peroxides upon exposure to air or oxygen at room temperature); **3** (*Water Reactivity*: Materials that may form explosive reactions with water. *Organic Peroxides*: Materials that are capable of detonation or explosive reaction, but require a strong initiating source, or must be heated under confinement before initiation; or materials that react explosively with water. *Explosives*: Division 1.2 – Explosive substances that have a fire hazard and either a minor blast hazard or a minor projection hazard or both, but do not have a mass explosion hazard. *Compressed Gases*: Pressure ≥ 514.7 psi absolute at 21.1°C (70°F) [500 psig]. *Pyrophorics*: No Rating. *Oxidizers*: Packing Group I Solids: any material that, in either concentration tested, exhibits a mean burning time less than the mean burning time of a 3.:2 potassium bromate/cellulose mixture. Liquids: Any material that spontaneously ignites when mixed with cellulose in a 1:1 ratio, or which exhibits a mean pressure rise time less than the pressure rise time of a 1:1 perchloric acid (50%)/cellulose mixture. *Unstable Reactives*: Substances that may polymerize, decompose, condense or self-react at ambient temperature and/or pressure and have a moderate potential to cause significant heat generation or explosion.); **4** (*Water Reactivity*: Materials that react explosively with water without requiring heat or confinement. *Organic Peroxides*: Materials that are readily capable of detonation or explosive decomposition at normal temperature and pressures. *Explosives*: Division 1.1 & 1.2-explosive substances that have a mass explosion hazard or have a projection hazard. A mass explosion is one that affects almost the entire load instantaneously. *Compressed Gases*: No Rating. *Pyrophorics*: Add to the definition of Flammability "4". *Oxidizers*: No "4" rating. *Unstable Reactives*: Substances that may polymerize, decompose, condense or self-react at ambient temperature and/or pressure and have a high potential to cause significant heat generation or explosion.). **2** (materials that on intense or continued exposure under fire conditions could cause temporary incapacitation or possible residual injury);

NATIONAL FIRE PROTECTION ASSOCIATION HAZARD RATINGS (continued):

HEALTH HAZARD (continued): **3** (materials that can on short exposure could cause serious temporary or residual injury); **4** (materials that under very short exposure could cause death or major residual injury).

FLAMMABILITY HAZARD: **0** Materials that will not burn under typical fire conditions, including intrinsically noncombustible materials such as concrete, stone, and sand. **1** Materials that must be preheated before ignition can occur. Materials in this degree require considerable preheating, under all ambient temperature conditions, before ignition and combustion can occur **2** Materials that must be moderately heated or exposed to relatively high ambient temperatures before ignition can occur. Materials in this degree would not under normal conditions form hazardous atmospheres with air, but under high ambient temperatures or under moderate heating could release vapor in sufficient quantities to produce hazardous atmospheres with air. **3** Liquids and solids that can be ignited under almost all ambient temperature conditions. Materials in this degree produce hazardous atmospheres with air under almost all ambient temperatures or, though unaffected by ambient temperatures, are readily ignited under almost all conditions. **4** Materials that will rapidly or completely vaporize at atmospheric pressure and normal ambient temperature or that are readily dispersed in air and will burn readily.

INSTABILITY HAZARD: **0** Materials that in themselves are normally stable, even under fire conditions. **1** Materials that in themselves are normally stable, but that can become unstable at elevated temperatures and pressures. **2** Materials that readily undergo violent chemical change at elevated temperatures and pressures. **3** Materials that in themselves are capable of detonation or explosive decomposition or explosive reaction, but that require a strong initiating source or that must be heated under confinement before initiation. **4** Materials that in themselves are readily capable of detonation or explosive decomposition or explosive reaction at normal temperatures and pressures.

FLAMMABILITY LIMITS IN AIR: Much of the information related to fire and explosion is derived from the **N**ational **F**ire **P**rotection **A**ssociation (**NFPA**). Flash Point - Minimum temperature at which a liquid gives off sufficient vapors to form an ignitable mixture with air. Autoignition Temperature: The minimum temperature required to initiate combustion in air with no other source of ignition. LEL - the lowest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source. UEL - the highest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source.

TOXICOLOGICAL INFORMATION:

Human and Animal Toxicology: Possible health hazards as derived from human data, animal studies, or from the results of studies with similar compounds are presented. Definitions of some terms used in this section are: **LD_{50}** - Lethal Dose (solids & liquids) which kills 50% of the exposed animals; **LC_{50}** - Lethal Concentration (gases) which kills 50% of the exposed animals; **ppm** concentration expressed in parts of material per million parts of air or water; **mg/m^3** concentration expressed in weight of substance per volume of air; **mg/kg** quantity of material, by weight, administered to a test subject, based on their body weight in kg. Other measures of toxicity include **TDLo**, the lowest dose to cause a symptom and **TCLo** the lowest concentration to cause a symptom; **TDo**, **LDLo**, and **LDo**, or **TC**, **TCo**, **LCLo**, and **LCo**, the lowest dose (or concentration) to cause lethal or toxic effects. **Cancer Information:** The sources are: **IARC** - the International Agency for Research on Cancer; **NTP** - the National Toxicology Program, **RTECS** - the Registry of Toxic Effects of Chemical Substances, **OSHA** and **CAL/OSHA**. IARC and NTP rate chemicals on a scale of decreasing potential to cause human cancer with rankings from 1 to 4. Subrankings (2A, 2B, etc.) are also used. **Other Information: BEI** - ACGIH Biological Exposure Indices, represent the levels of determinants which are most likely to be observed in specimens collected from a healthy worker who has been exposed to chemicals to the same extent as a worker with inhalation exposure to the TLV.

DEFINITIONS OF TERMS (Continued)

ECOLOGICAL INFORMATION:
EC is the effect concentration in water. **BCF** = Bioconcentration Factor, which is used to determine if a substance will concentrate in lifeforms which consume contaminated plant or animal matter. **TL_m** = median threshold limit; Coefficient of Oil/Water Distribution is represented by **log K_{ow}** or **log K_{oc}** and is used to assess a substance's behavior in the environment.

REGULATORY INFORMATION:

U.S. and CANADA:

This section explains the impact of various laws and regulations on the material. **ACGIH:** American Conference of Governmental Industrial Hygienists, a professional association which establishes exposure limits. **EPA** is the U.S. Environmental Protection Agency. **NIOSH** is the National Institute of Occupational Safety and Health, which is the research arm of the U.S. **O**ccupational **S**afety and **H**ealth **A**dministration (**OSHA**). **WHMIS** is the Canadian Workplace Hazardous Materials Information System. **DOT** and **TC** are the U.S. Department of Transportation and the Transport Canada, respectively. Superfund Amendments and Reauthorization Act **(SARA)**; the Canadian Domestic/Non-Domestic Substances List **(DSL/NDSL)**; the U.S. Toxic Substance Control Act **(TSCA)**; Marine Pollutant status according to the **DOT**; the Comprehensive Environmental Response, Compensation, and Liability Act **(CERCLA or Superfund)**; and various state regulations. This section also includes information on the precautionary warnings which appear on the material's package label. **OSHA** - U.S. Occupational Safety and Health Administration.

Material Safety Data Sheet

Version 2.2
Revision Date 07/20/2004

MSDS Number 300000000137
Print Date 07/24/2005

1. PRODUCT AND COMPANY IDENTIFICATION

Product name : Xenon

Chemical formula : Xe

Synonyms : Xenon

Product Use Description : General Industrial

Company
Air Products and Chemicals,Inc
7201 Hamilton Blvd.
Allentown, PA 18195-1501

Telephone : 800-345-3148

Emergency telephone number
800-523-9374 USA
01-610-481-7711 International

2. COMPOSITION/INFORMATION ON INGREDIENTS

Components	CAS Number	Concentration Volume)
Xenon	7440-63-3	100 %

Concentration is nominal. For the exact product composition, please refer to Air Products technical specifications.

3. HAZARDS IDENTIFICATION

Emergency Overview

Can cause rapid suffocation.
Compressed liquefied gas.
Avoid breathing gas.
Direct contact with liquid can cause frostbite.
Self contained breathing apparatus (SCBA) may be required.

Potential Health Effects

Inhalation : In high concentrations may cause asphyxiation. Symptoms may include loss of mobility/consciousness.Victim may not be aware of asphyxiation. Asphyxiation may bring about unconsciousness without warning and so rapidly that victim may be unable to protect themselves.

Eye contact : Contact with liquid may cause cold burns/frost bite.

Skin contact : Contact with liquid may cause cold burns/frost bite.

Ingestion : Ingestion is not considered a potential route of exposure.

Chronic Health Hazard	:	Not applicable.

Exposure Guidelines

Primary Routes of Entry	:	Inhalation
Target Organs	:	None.
Symptoms	:	Exposure to oxygen deficient atmosphere may cause the following symptoms: Dizziness. Salivation. Nausea. Vomiting. Loss of mobility/consciousness.

Aggravated Medical Condition

None known.

4. FIRST AID MEASURES

General advice	:	Remove victim to uncontaminated area wearing self contained breathing apparatus. Keep victim warm and rested. Call a doctor. Apply artificial respiration if breathing stopped.
Eye contact	:	In the case of contact with eyes, rinse immediately with plenty of water and seek medical advice. Keep eye wide open while rinsing. Seek medical advice.
Skin contact	:	Wash frost-bitten areas with plenty of water. Do not remove clothing. Cover wound with sterile dressing.
Ingestion		Ingestion is not considered a potential route of exposure.
Inhalation		Move to fresh air. If breathing has stopped or is labored, give assisted respirations. Supplemental oxygen may be indicated. If the heart has stopped, trained personnel should begin cardiopulmonary resuscitation immediately. In case of shortness of breath, give oxygen.

5. FIRE-FIGHTING MEASURES

Suitable extinguishing media		All known extinguishing media can be used.
Specific hazards		Upon exposure to intense heat or flame, cylinder will vent rapidly and or rupture violently. Product is nonflammable and does not support combustion. Move away from container and cool with water from a protected position. If possible, stop flow of product. Keep adjacent cylinders cool by spraying with large amounts of water until the fire burns itself out. Most cylinders are designed to vent contents when exposed to elevated temperatures.
Special protective equipment for fire-fighters	:	Wear self contained breathing apparatus for fire fighting if necessary.

6. ACCIDENTAL RELEASE MEASURES

Personal precautions		Gas/vapor heavier than air. May accumulate in confined spaces, particularly at

	or below ground level. Evacuate personnel to safe areas. Wear self-contained breathing apparatus when entering area unless atmosphere is proved to be safe. Ventilate the area. Monitor oxygen level.
Environmental precautions	Should not be released into the environment. Do not discharge into any place where its accumulation could be dangerous. Prevent further leakage or spillage. Prevent from entering sewers, basements and workpits, or any place where its accumulation can be dangerous.
Methods for cleaning up	Ventilate the area.
Additional advice	If possible, stop flow of product. Increase ventilation to the release area and monitor oxygen level. If leak is from cylinder or cylinder valve, call the Air Products emergency telephone number. If the leak is in the user's system, close the cylinder valve, safely vent the pressure, and purge with an inert gas before attempting repairs.

7. HANDLING AND STORAGE

Handling

Only experienced and properly instructed persons should handle compressed gases. Protect cylinders from physical damage; do not drag, roll, slide or drop. Do not allow storage area temperature to exceed 50°C (122°F). Before using the product, determine its identity by reading the label. Know and understand the properties and hazards of the product before use. When doubt exists as to the correct handling procedure for a particular gas, contact the supplier. Do not remove or deface labels provided by the supplier for the identification of the cylinder contents. When moving cylinders, even for short distances, use a cart (trolley, hand truck, etc.) designed to transport cylinders. Leave valve protection caps in place until the container has been secured against either a wall or bench or placed in a container stand and is ready for use. Use an adjustable strap wrench to remove over-tight or rusted caps. Before connecting the container, check the complete gas system for suitability, particularly for pressure rating and materials. Before connecting the container for use, ensure that back feed from the system into the container is prevented. Ensure the complete gas system is compatible for pressure rating and materials of construction. Ensure the complete gas system has been checked for leaks before use. Employ suitable pressure regulating devices on all containers when the gas is being emitted to systems with lower pressure rating than that of the container. Never insert an object (e.g. wrench, screwdriver, pry bar, etc.) into valve cap openings. Doing so may damage valve, causing a leak to occur. Open valve slowly. If user experiences any difficulty operating cylinder valve discontinue use and contact supplier. Close container valve after each use and when empty, even if still connected to equipment. Never attempt to repair or modify container valves or safety relief devices. Damaged valves should be reported immediately to the supplier. Close valve after each use and when empty. Replace outlet caps or plugs and container caps as soon as container is disconnected from equipment. Do not subject containers to abnormal mechanical shocks which may cause damage to their valve or safety devices. Never attempt to lift a cylinder by its valve protection cap or guard. Always use backflow protective device in piping. When returning cylinder install valve outlet cap or plug leak tight. Never use direct flame or electrical heating devices to raise the pressure of a container. Containers should not be subjected to temperatures above 50°C (122°F). Prolonged periods of cold temperature below -30°C (-20°F) should be avoided. Never attempt to increase liquid withdrawal rate by pressurizing the container without first checking with the supplier. Never permit liquefied gas to become trapped in parts of the system as this may result in hydraulic rupture.

Storage

Full containers should be stored so that oldest stock is used first. Containers should be stored in the vertical position and properly secured to prevent toppling. The container valves should be tightly closed and where appropriate valve outlets should be capped or plugged. Container valve guards or caps should be in place.

Observe all regulations and local requirements regarding storage of containers. Stored containers should be periodically checked for general condition and leakage. Protect containers stored in the open against rusting and extremes of weather. Containers should not be stored in conditions likely to encourage corrosion. Containers should be stored in a purpose build compound which should be well ventilated, preferably in the open air. Keep containers tightly closed in a cool, well-ventilated place. Store containers in location free from fire risk and away from sources of heat and ignition. Full and empty cylinders should be segregated. Do not allow storage temperature to exceed 50°C (122°F). Return empty containers in a timely manner.

Technical measures/Precautions

Containers should be segregated in the storage area according to the various categories (e.g. flammable, toxic, etc.) and in accordance with local regulations. Keep away from combustible material.

8. EXPOSURE CONTROLS / PERSONAL PROTECTION

Engineering measures

Provide natural or mechanical ventilation to prevent oxygen deficient atmospheres below 19.5% oxygen.

Personal protective equipment

Respiratory protection		Self contained breathing apparatus (SCBA) or positive pressure airline with mask are to be used in oxygen-deficient atmosphere. Air purifying respirators will not provide protection. Users of breathing apparatus must be trained.
Hand protection	:	Sturdy work gloves are recommended for handling cylinders. The breakthrough time of the selected glove(s) must be greater than the intended use period.
Eye protection		Safety glasses recommended when handling cylinders.
Skin and body protection		Safety shoes are recommended when handling cylinders.
Special instructions for protection and hygiene	:	Ensure adequate ventilation, especially in confined areas.

9. PHYSICAL AND CHEMICAL PROPERTIES

Form	:	Compressed gas.
Color		Colorless gas
Odor	:	No odor warning properties.
Molecular Weight	:	131 g/mol
Relative vapor density	:	4.5 (air = 1)
Relative density	:	1.5 (water = 1)
Density	:	0.343 lb/ft3 (0.0055 g/cm3) at 70 °F (21 °C) Note: (as vapor)

Specific Volume	:	2.93 ft3/lb (0.1829 m3/kg) at 70 °F (21 °C)
Boiling point/range	:	-162 °F (-108 °C)
Critical temperature		62 °F (16.6 °C)
Melting point/range		-170 °F (-112 °C)
Water solubility	:	0.644 g/l

10. STABILITY AND REACTIVITY

Stability	:	Stable under normal conditions.

11. TOXICOLOGICAL INFORMATION

Acute Health Hazard

Ingestion	:	No data is available on the product itself.
Inhalation	:	No data is available on the product itself.
Skin.	:	No data is available on the product itself.

12. ECOLOGICAL INFORMATION

Ecotoxicity effects

Aquatic toxicity	:	No data is available on the product itself.
Toxicity to other organisms	:	No data available.

Persistence and degradability

Mobility	:	No data available.
Bioaccumulation	:	No data is available on the product itself.

Further information

This product has no known eco-toxicological effects.

13. DISPOSAL CONSIDERATIONS

Waste from residues / unused products	:	Return unused product in orginal cylinder to supplier. Contact supplier if guidance is required.
Contaminated packaging		Return cylinder to supplier.

14. TRANSPORT INFORMATION

CFR

Proper shipping name	: Xenon
Class	2.2
UN/ID No.	UN2036

IATA

Proper shipping name	Xenon
Class	2.2
UN/ID No.	UN2036

IMDG

Proper shipping name	XENON
Class	2.2
UN/ID No.	UN2036

CTC

Proper shipping name	XENON
Class	2.2
UN/ID No.	UN2036

Further Information

Avoid transport on vehicles where the load space is not separated from the driver’s compartment. Ensure vehicle driver is aware of the potential hazards of the load and knows what to do in the event of an accident or an emergency.

15. REGULATORY INFORMATION

OSHA Hazard Communication Standard (29 CFR 1910.1200) Hazard Class(es)

Compressed Gas.

Country	Regulatory list	Notification
USA	TSCA	Included on Inventory.
EU	EINECS	Included on Inventory.
Canada	DSL	Included on Inventory.
Australia	AICS	Included on Inventory.
South Korea	ECL	Included on Inventory.
China	SEPA	Included on Inventory.
Philippines	PICCS	Included on Inventory.
Japan	ENCS	Included on Inventory.

EPA SARA Title III Section 312 (40 CFR 370) Hazard Classification:

Sudden Release of Pressure Hazard.

US. California Safe Drinking Water & Toxic Enforcement Act (Proposition 65)

This product does not contain any chemicals known to State of California to cause cancer, birth defects or any other harm.

16. OTHER INFORMATION

NFPA Rating

Health : 0
Fire 0
Instability : 0
Special SA

HMIS Rating

Health : 0
Flammability : 0
Physical hazard : 3

REVISION NOTES : 14. TRANSPORT INFORMATION

Prepared by : Air Products and Chemicals, Inc. Global EH&S Product Safety Department

For additional information, please visit our Product Stewardship web site at
http//www.airproducts.com/productstewardship/

I. FORMATION TESTING PROGRAM - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

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

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

WELL LOGGING, CORING, AND TESTING PROGRAM

Proposed Well Logging Program

The following geophysical well logs will be run in the open-hole section of the surface casing hole of the CO_2 Injection Well:

- Platform Express (AITH Induction/Spontaneous Potential/Gamma Ray/ Compensated Neutron/Triple Litho Density/Borehole Caliper)
- Modular Formation Dynamics Tester (MDT)

The following geophysical well logs will be run in the open-hole section of the protection casing (long string) hole of the CO_2 Injection Well:

- Platform Express (AITH Induction (or laterolog)/Spontaneous Potential/Gamma Ray/Compensated Neutron/Triple Litho Density/Borehole Caliper)
- Combinable Magnetic Resonance (Naco and Martin Formations from 2,960 to 3,660 feet or minimum run)
- Formation Micro-Imager survey (lower Supai to base of Martin Formations from 1,800 to 3,660 feet)
- Dipole Shear Imager

Additional diagnostic logs and/or formation cores (whole core or sidewall cores) may be run at the discretion of the Arizona Utilities Project Team.

The following cased hole geophysical well logs will be run after cementing the protection casing in place:

- Cement evaluation and casing inspection log
- Gyroscopic survey

- Differential temperature survey

  Additional diagnostic logs (such as a video log) may be run at the discretion of the Arizona Utilities Project Team.

INJECTION ZONE AND CONFINING ZONE TESTING

A whole core is proposed for the CO_2 Injection Well in the Martin Formation, based on anticipated funding. The core depth will be picked based on correlation from the offset wells and the mud log. The proposed conventional core may be supplemented or replaced with sidewall cores or horizontal rotary cores.

Conventional Coring

Core Size	Depth	Formation/Lithology
7-7/8” x 4” x 30 feet	+/-3,600 feet	Martin Formation

Supplemental conventional coring in the injection zone may be conducted to obtain additional reservoir data. The Arizona Utilities Project Team will select the actual core point during the drilling of the CO_2 Injection Well, in consultation with the mud logger’s correlation to offset wells. If insufficient formation core is recovered in any core run, the core run may be repeated at the discretion of the team, or sidewall coring may be conducted in the interval. The core depth will be adjusted relative to actual drilling depths encountered.

Sidewall Coring/Horizontal Rotary Coring

Sidewall coring or horizontal rotary coring may be taken in the injection zone or the confining zone during the open-hole logging of the protection hole to supplement the conventional core data. The Arizona Utilities Project Team, based on the evaluation and percent recovery of the conventional core, will determine if sidewall coring is necessary and select actual core depths. If sufficient whole core is recovered, sidewall cores may not be taken in the CO_2 Injection Well.

Formation Fluid Sampling

The CO_2 Injection Well will be back flowed (pumping or via nitrogen) to obtain background native formation fluids from the Martin Formation. The decision to collect fluid samples in other intervals, via either wireline or drillstem testing, will be made based on open-hole logging and the condition of the borehole at the time of logging operations. Any fluid samples collected will be transported to a selected laboratory for detailed analysis.

Step Rate Injection Test

A step rate injection test using formation brine (recovered during well development operations) will be performed on the injection interval. An initial low rate, low injection pressure injectivity test will be performed to assess receptivity of the injection interval.

From these data, a detailed step rate test will be designed and performed, so that test injection pressures span the range from the measured initial shut-in pressure to a maximum pressure determined by multiplying the top of the completed injection interval depth by a value of 0.622 psi/foot of depth. It is expected that the 0.622 psi/foot of depth pressure gradient is below the parting pressure of the injection interval. For example, assuming a native background initial pressure equal to a freshwater gradient (0.433 psi/foot of depth) and a below ground depth of 3,445 feet to the top of the Martin Formation, the step rate test would be planned to span the pressure range of 1,492 psi (initial pressure) to 2,143 psi (maximum test pressure) at 3,445 feet below ground surface, or 651 psi above the native background pressure.

The step rate test will be initiated following pressure recovery from the low rate, low pressure initial injectivity test. Injection will be initiated and stepped up in equal rate increments using equal time intervals (one or two hours). The equal time increments should be sufficient to allow for proper rate stabilization of the injection pump(s) and allow sufficient time to overcome wellbore storage effects between each rate change (especially at the low rates when the well may be on a vacuum). General test procedure is as follows:

STEP-RATE TEST PROCEDURE:

1. The well will be shut in long enough prior to testing such that the bottom hole pressures approximate the initial shut-in formation pressure. Pressure gauges will be installed on the wellhead and downhole near the top of the perforated completion. The downhole gauge will include surface read-out, so that the test may be monitored.
2. A series of successively higher injection rates will be used. Both surface and downhole pressures will be read and recorded at the end of each rate and time step. Each rate step will last as long as the preceding rate (i.e., equal duration steps).
3. Injection rates will be controlled with a constant flow regulator that has been tested prior to use. Flow rates will be measured with a calibrated turbine flowmeter. Injection rates and surface and downhole pressures will be digitally recorded. Injection pressures will be measured and recorded for immediate evaluation and interpretation by recording and plotting each time step and corresponding pressure.
4. A plot of injection rates and the corresponding stabilized pressure values at the end of each step are expected to follow a constant slope straight line. If the slope reaches a point at which the formation fractures (i.e., “breakdown” pressure is exceeded), the slope of this plotted line will be observed to decrease. The injection pump(s) will be immediately stopped and the flow line valve will be quickly closed. Pressure will be allowed to bleed off into the injection interval.

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

Constant Rate Injection Test

After the step rate injection test, a constant rate hydraulic test may be performed to further define aquifer properties. This may directly follow the last step of the step rate test. Pressure will be adjusted to maintain a steady injection rate for 8-12 hours, or until the remaining stored formation water is injected. Then the well will be shut in. Bottom hole pressure will be measured throughout the injection and recovery periods.

WELL TESTING PROGRAM

Mechanical integrity tests will be performed during completion of the CO_2 Injection Well. The following tests will be performed:

- Pressure testing of the surface and protection casing to 70 percent of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, which ever is less, for at least 30 minutes. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Test data will be digitally recorded and a copy of the test results will be maintained on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report.
- Pressure testing of the 5-1/2-inch protection casing by tubing annulus to confirm the mechanical integrity of the completion. The pressure test will be run at equal to the lesser of the maximum authorized injection pressure or 1,000 psi, provided that no testing pressure will be less than 300 psi. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Test data will be digitally recorded and a copy of the test results will be maintained on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report.
- Casing inspection and cement bond evaluation of the 5-1/2-inch protection casing from total depth to surface. Interpretation report to be prepared by the vendor.
- Radioactive tracer survey of the completed CO_2 Injection Well following perforation to show the absence of fluid movement in vertical channels adjacent to the well.
- Baseline and repeat reservoir saturation logging (RST log) to show the distribution of CO_2 adjacent to the well.

J. STIMULATION PROGRAM - Outline any proposed stimulation program.

To obtain formation water for the step-rate injectivity test, well flow may be stimulated by scraper/swab, backlift, nitrogen lift, and/or bottom hole pump. Formation fluid properties will be monitored until parameters stabilize indicating that formation fluids are being recovered. Once clean and stable formation brine is established, divert returns to a “fresh” frac tank(s). The stored formation fluids will be filtered to remove particulates, then used for injection testing of the injection interval. All other fluids not reinjected will be disposed of at an appropriate disposal site in accordance with state regulations.

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

The CO_2 Injection Well surface facilities will provide CO_2 from temporary surface storage tanks to the CO_2 Injection Well wellhead. As shown in Figure K1, the Injection Well surface facilities will consist of:

- CO_2 storage tanks
- Injection pump (truck or skid)
- Inline temperature monitor
- Inline pressure monitor
- Inline flow meter
- Inline heater
- Annulus pressurization and monitoring system
- Surge protection system.

Carbon Dioxide Storage Tanks

Liquid CO_2 will be hauled to the location by commercial haulers and transferred to CO_2 storage tanks. The temporary storage tank facility will be designed for onsite storage of approximately 120 to 240 tons of liquid CO_2, in two to four storage vessels (60-ton portable storage tanks). Horizontal 60-ton vessels, with a maximum working pressure of 350 pounds per square inch gauge (psig) will be used. The vessels will be fitted with safety valves and a pressure vent system. This volume will provide approximately 24 to 48 hours of onsite storage under average flow conditions anticipated for the experiment (50 to 200 tons per day). If required, soil under the storage vessels will be stabilized to support the load, or the vessels will be braced to distribute the load over a larger area.

Injection Pump(s)

One or more injection pumps will be used during the CO_2 injection program. The pump(s) will be temporary and will be either truck mounted or skid mounted. It is anticipated that the pump(s) will only be on location during the active injection phase of the experiment, plus set up and demobilization time. The injection pump(s) will have a maximum liquid capacity of 42 gallons per minute (gpm) and a maximum operating pressure of 3,500 psig, or better. Actual wellhead injection pressure (and bottomhole injection pressure) will be maintained so as not to initiate fractures in either the test injection interval or the overlying and underlying containment intervals. The injection pump(s) will be designed for pumping cool liquid CO_2 under the conditions for the injection tests scheduled during the project. The CO_2 provider or a third-party pumping vendor will supply the injection pumps.

Additionally, one or more injection pumps will be used during the hydrologic testing program that will be performed using formation brine water. The pump(s) will be temporary and will be either truck mounted or skid mounted. It is anticipated that the pump(s) will only be on location during the active hydrologic test injection phase of the experiment (one to two days), plus set up and demobilization time. The injection pump(s) will have a maximum liquid capacity of 350 gallons per minute (gpm) and a maximum operating pressure of 1,000 psig, or better.

Inline Temperature/Pressure/Flow Monitors

Temperature, pressure, and flow will be monitored and recorded continuously immediately upstream of the CO_2 Injection Well wellhead. Additional temperature, flow, and/or pressure probes may be located upstream or downstream of the injection pump(s) and immediately downstream of the carbon dioxide heater to facilitate pump operation efficiency. The inline temperature and pressure probes will be used to control the surface injection pressure and the temperature of the carbon dioxide injected during the project.

Inline Heater

An inline heater will be installed between the injection pump(s) and the CO_2 Injection Well. The heater will be adjusted to regulate the discharge temperature of the CO_2 to the desired temperature. This heater may be an integrated component to the truck or skid mounted injection pumps, or may be independent of the injection pump system. The CO_2 heater will be used to regulate the temperature of the CO_2 to approximately 40 to 70°F, and sized accordingly (minimum 500 MBtu/hr, or better). Propane will be used as the preferred energy source for the heater. Alternative is to use either diesel or electrical energy for the heater.

Annulus Pressurization and Monitoring System

The Injection Well annulus pressurization and monitoring system will maintain a positive pressure versus the tubing pressure at all times. Pressurization of the annulus will be through use of high-pressure nitrogen bottles (nitrogen blanket on a pressurized annulus fluid reserve tank). The alternative is to use a high-pressure, small volume pump connected to a low pressure annulus fluid reserve tank. The annulus pressure will be monitored and recorded continuously.

Well Cellar Box

The CO_2 Injection Well wellhead will be located within a cellar box with dimensions of approximately 8-by-8-by-6 feet, with the top of the box installed at location grade. Materials will be applied surrounding the cellar box to support the sub base of the drill rig. This will be followed by the installation of rat and mouse holes (15-feet in depth), one located inside of the cellar and the second located approximately 2 feet outside of cellar. The rat and mouse holes will be backfilled at the completion of drilling operations.

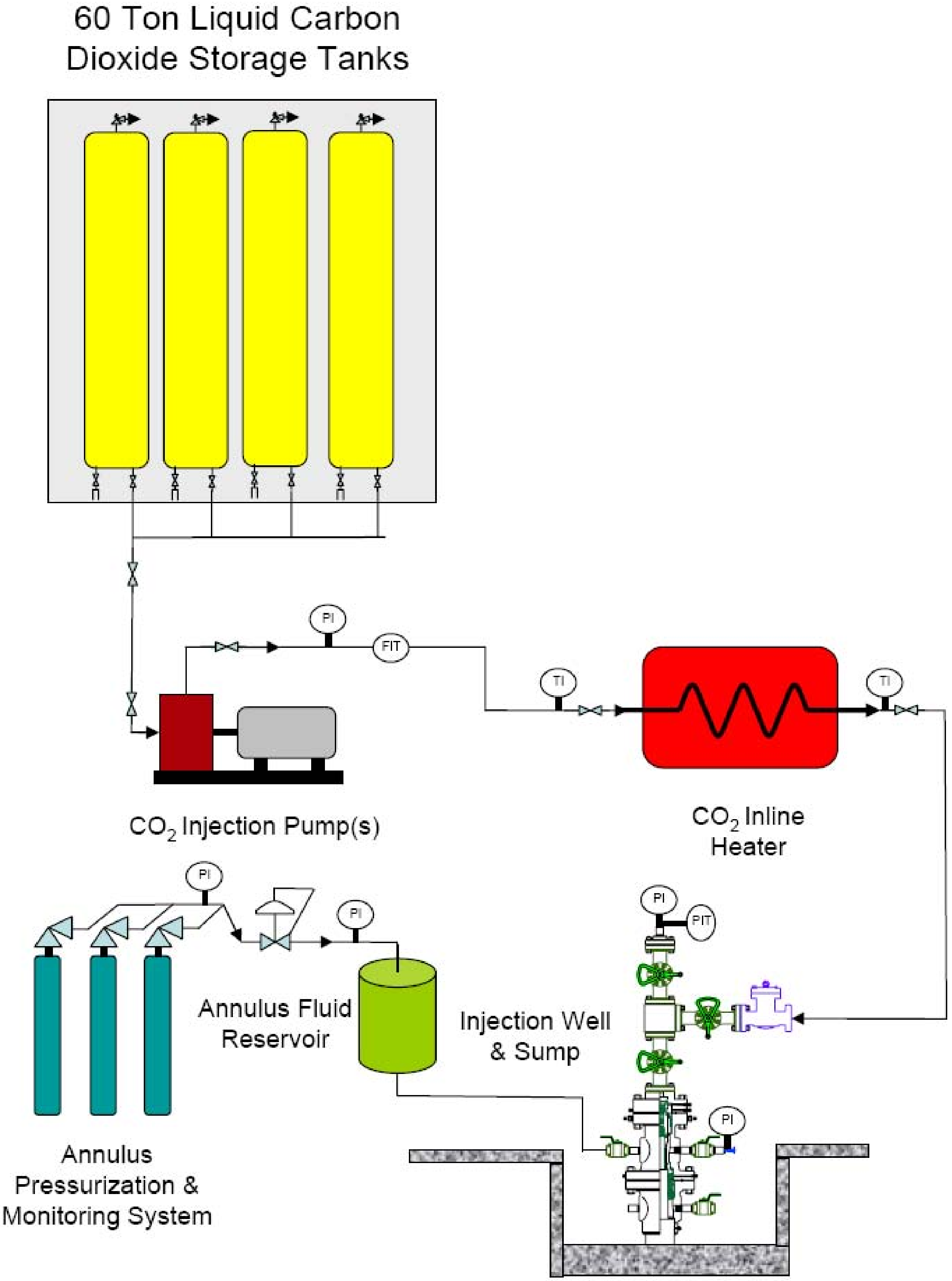


Figure K1: CO_2 Surface Facilities

L. CONSTRUCTION PROCEDURES - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

WELL CORING, LOGGING AND TESTING PROGRAM

Please see Attachment I above.

WELL CONSTRUCTION PLAN

The Arizona Utilities Project Team is requesting a permit to drill one CO_2 Injection Well for the Pilot Test. The injection interval is anticipated to be a sedimentary formation containing highly saline waters. The primary target interval is the Martin Formation, with a backup interval being the shallower Naco Formation, should the Martin Formation be found to be unsuitable.

Well Construction Information

The following sections describe the procedures that will be followed to drill and complete the CO_2 Injection Well prior to initiating the Pilot Test experiment. Note that the expected surface elevation at the Test Site is approximately 5,120 feet above mean sea level and all depths in this attachment are referenced to the drilling rig kelly bushing (standard drilling reference location), which is anticipated to be located at 15 feet above ground elevation.

Total Well Depth

Proposed total drilling depth for the CO_2 Injection Well will be +/-4,000 feet below kelly bushing. At total depth, the CO_2 Injection Well is expected to be in the Pre-Cambrian basement. Protection casing will likely be set into the Pre-Cambrian basement to allow for sufficient rat hole below the Martin Formation for logging and testing (baseline and post-injection) purposes.

Well Casing Specifications

Following rig up of the drilling rig, a 17-1/2-inch conductor hole will be drilled to approximately 40 feet, and 13-3/8-inch conductor casing will be set and cemented from drilled depth to surface. A surface hole will be drilled using a 12-1/4-inch bit to +/-965 feet (just below the base of the Schnebly Hill Formation), and 9-5/8-inch surface casing will be cemented from total depth to surface. A 8-1/2-inch protection hole will drilled to +/-4,000 feet, where 5-1/2-inch protection casing will be set. The 5-1/2-inch protection casing will be cemented back to surface. Casing specifications for the proposed CO_2 Injection Well are shown in Table L1. The casing strings are more than adequately designed for the short life of the Arizona Utilities CO_2 Storage Pilot experiment.

Table L1. Proposed CO_2 Injection Well – Casing Specifications

TUBULAR	Depth (ft)	Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/ Burst (psi)	Tensile Body/Joint (X 1000 lbs.)
Conductor	0 - 40	13-3/8	48	H-40	ST&C	770/1,730	541/322
Surface Casing	0 – 965	9-5/8	36	J-55	ST&C	2,020/3,520	564/394
Protection Casing	0 – 4,000	5-1/2	15.5	J-55	LT&C	4,040/4,810	248/217

Well Drilling Program

The following sections contain the proposed step-by-step program for drilling and completing the proposed CO_2 Injection Well. The CO_2 Injection Well will be used for baseline monitoring and characterization, injection of the CO_2 fluid during the active experiment, and post-injection monitoring of the intervals of interest.

DRILLING PROCEDURE

CONDUCTOR HOLE

1. Prepare surface pad location and install well cellar.
2. Mobilize drilling rig. Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.
3. Notify Arizona Oil and Gas Conservation Commission at least 48 hours prior to spudding the well.
4. Drill mouse and rat holes.
5. Drill 17-1/2” conductor hole to +/-40 feet. Install 13-3/8” casing and grout annular space from set depth to surface with concrete.
6. Wait on concrete to cure for 12 hours.

SURFACE HOLE

7. Rig up mud logging unit and test equipment. Collect and save 10-foot samples from 40 feet to total depth. A set of samples is required to be submitted to the Oil and Gas Administrator, Arizona Geological Survey, within 30 days of completion of the well. Samples should be: 1) washed and dried, 2) place approximately 3 tablespoons of sample in an envelope identifying the well, the well location, the Arizona Oil and Gas Conservation Commission’s Permit Number, and the depth of the sample. Samples to be shipped to:

   Oil and Gas Administrator
   Arizona Geological Survey
   416 West Congress, Suite 100
   Tucson, AZ 85701

8. Pick up 12-1/4 inch bit and the bottomhole assembly (BHA). Drill a 12-1/4 inch surface hole to +/-965 feet (below base of Schnebly Hill) using freshwater spud mud, as detailed in the Drilling Fluids Program section below. Take deviation surveys every 500 feet and at total depth. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary. After reaching surface casing setting depth, the drilling fluid will be circulated and conditioned to ensure correct fluid properties for the open hole logging and testing.

9. Run open-hole formation evaluation logs per the requirements of the Well Logging, Coring, and Testing Program (See Attachment I above).

   If the logging procedure is extended and/or hole becomes sticky or unstable during logging, a conditioning/cleanup trip will be made with the drill string to circulate and condition the drilling fluid. The drilling string will be removed from the well and the logging program will be completed as planned.

10. Notify Arizona Oil and Gas Conservation Commission at least 48 hours prior to setting and cementing the surface casing.

11. Lower the 12-1/4” drilling assembly in the well to the total depth. The drilling fluid will be circulated and conditioned to ensure correct fluid properties for the casing installation and cementing. Remove the drilling assembly from the well.

12. Run 9-5/8 inch surface casing to +/-965 feet. See the Well Casing Specifications section above for a detailed description of the casing and casing equipment.

    Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

    Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical information in the event that circulation is lost.

13. Rig up circulating equipment and perform a pressure test on the lines. Circulate and condition the drilling fluid to ensure correct fluid properties for the cementing procedure. Reciprocate the casing continuously during the circulation of the drilling fluid.

14. Cement the casing in place. Details of the cement blends proposed are located in the Well Construction Cementing Program section below.

    Be prepared to divert cement and cement-contaminated drilling fluid returns away from circulating system and into appropriate containment. Use sugar to retard the premature setting of the cement, if necessary.

15. If no cement returns are observed at surface, contact wireline service provider and schedule a temperature survey to determine the top of the cement.

16. Center the casing in the rotary table of the drilling rig after completing the cementing procedure and before the cement hardens.

17. Cement the annular space that does not contain cement, if required. Fill the annulus space by pumping cement through small tubing that has been run into the annulus to the top of cement.
18. After waiting on cement to harden for a minimum of 12 hours, cut off the surface and conductor pipe and install a 9-5/8 inch SOW (slip-on for welding) x 11-inch 3,000-psi casing head flange. Perform a pressure test on the casing head after installation. Digitally record the test and maintain a copy of the test results on location. Transfer the original test data to the Sandia Office for inclusion in the CO_2 Injection Well Report.

PROTECTION HOLE

19. Install 11-inch 3,000 psi double ram blow out preventer, 11-inch 3,000 psi annular preventer, and auxiliary well control equipment on the 11-inch, 3,000 psi casing head flange. Perform a pressure test on the equipment to the lesser of the manufacturer’s full working pressure rating of the system, 70 percent of the minimum internal yield pressure of any casing subject to test, or one psi per foot of the last casing string depth. Annular or bag-type preventers shall be tested to the lesser of 1,000 psi or 50 percent of the full working pressure on installation. The blowout preventer and related equipment will be tested, as follows: a) after each string of casing is set in the well, b) not less than once every 14 days, and c) following any repairs that required the disconnection of any pressure seal assembly (note, only the repaired or replaced component need be tested unless alteration or repair occurs at a normal full blowout preventer test period).
20. Pick up an 8-1/2 inch bit, BHA, and trip in the hole to the top of cement with the drill pipe. Include drilling stabilizers above the second and third drill collars. Close pipe rams and perform a pressure test on the surface casing for at least 30 minutes. The surface casing will be pressure tested for at least 30 minutes to 70 percent of the internal yield pressure of the casing or one pound per square inch (psi) per foot of setting depth (whichever is less). A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. Transfer the original test data to the Sandia Office for inclusion in the CO_2 Injection Well Report.
21. Convert the drilling fluid in the well to a salt-based drilling fluid. Details of the drilling fluid characteristics are located in the Drilling Fluids Program section below.
22. Drill out casing float equipment and 10 feet of new hole.
23. Perform a pressure test on the casing seat and formation to pressure leak-off point or to an 11.0 pounds per gallon equivalent drilling fluid density.
24. Drill an 8-1/2 inch hole from surface casing point to the core point in the Martin Formation. Alternatively, sidewall coring may be done as part of the wireline activities in Item #26. Take deviation surveys every 500 feet and at core point. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to

minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary. Details of the coring program are described above in Appendix I. Monitor the well path as drilling proceeds.

25. Drill and retrieve the core (Martin proposed injection interval), unless sidewall coring is done instead.
26. Pick up the drilling assembly and lower into the well. Drill the cored interval (if taken) and continue drilling to the proposed total depth (+/-4,000 feet true vertical depth) into the Pre-Cambrian basement. Take deviation surveys every 500 feet and at total depth. The recommended maximum allowable deviation from vertical is 3 degrees with a maximum recommended deviation of no more that 2 degrees per 100 feet (to minimize dogleg severity) at any point in the borehole. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.
27. After reaching total depth, circulate and condition the drilling fluid to ensure correct fluid properties for the wireline logging procedure. Make a short trip by pulling up into the 9-5/8-inch surface casing with the drill bit and BHA. Lower the drilling assembly back to bottom and check for solids fill. Resume circulating and conditioning drilling fluid and wellbore for open hole logging. Remove drilling assembly from well for open hole logging.

    Measure the drill string on the trip out to confirm well depth.

28. Rig up wireline equipment and run the open-hole logging and sampling suite. See Appendix I for Well Logging, Coring and Testing details.

    If the logging procedure is extended and/or hole becomes sticky or unstable during logging, a conditioning/cleanup trip will be made with the drill string to circulate and condition the drilling fluid. The drilling string will be removed from the well and the logging program will be completed as planned.

29. After completing all wireline logging and sampling, go into the hole with bit, drill collars, and drill pipe to bottom. Check and note presence of any fill at the bottom of the hole. Circulate hole clean, condition the drilling fluid for running of the protection casing. Note, a high viscosity pill may be required to keep the bottom portion of the hole open.
30. Pull out of the hole with the drilling assembly. Lay down drill pipe and drilling assembly.

    Notify Arizona Oil and Gas Conservation Commission and USEPA of upcoming cement job at least 48 hours ahead of anticipated activities.

31. Rig up casing handling and make-up equipment. Run the 5-1/2 inch protection casing. Details of the casing program are described in the Well Casing Specifications section above. Set a differential shoe and a differential collar between the second and third joint.

    Ensure that all dimensions of cementing equipment and casing are visually inspected, measured, and drifted before running in the hole.

API Modified thread lubricant or equivalent will be used unless premium threads and/or corrosion resistant casing are used.

Have a casing swedge available, on the rig floor, with circulating hoses ready, in the event the casing must be washed to bottom or in the event that well control procedures are required.

32. Once the casing is on bottom, rig up and circulate the hole for a minimum of 150% of the open hole volume to clear the floats and cool the formation sufficiently for cementing. Add water and chemicals to the drilling fluid to adjust the characteristics of the fluid to improve drilling mud removal from the annulus during the cementing procedure.

    Reciprocate the pipe slowly, but continuously, in ±20-foot strokes during the circulating and cementing operations. If the movement of the pipe begins to indicate that sticking is occurring, lower the pipe to planned setting depth and discontinue pipe movement.

    Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

    Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical information in the event that circulation is lost.

33. Mix and pump the cement. Details of the cementing program are described in the Well Construction Cementing Program section below. Displace the cement with drilling mud, 2% KCl, or fresh water.

34. Lift the BOP stack and hang off the 5-1/2" casing in tension (same hook load as when originally cemented in place). Nipple up the 7-1/16-inch 3,000 psi x 11-inch 3,000 psi tubing spool and perform a pressure test on the seals to the manufacturer's specifications. Isolate the well by installing a 7-1/16-inch 3,000 psi tapped flange with valve on the tubing spool.

35. Rig down the drilling rig and release rig from location. Remove and clean location of all drilling equipment.

COMPLETION PROCEDURE

PROTECTION CASING AND CEMENT EVALUATION

1. Mobilize a workover rig to location and rig up the equipment (note that the drilling rig may be used for completion operations, depending on availability and scheduling). Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.

2. Install 7-1/16" 3,000 psi dual blow out preventer on well and pressure test.

3. Pick up a 4-3/4-inch cement bit and two casing scrapers, trip into the hole with a workstring to tag the top of cement in the casing.

4. Verify tagged depth and dress off cement as needed. Circulate the fluid in the wellbore to remove any solids. Displace the wellbore with filtered 2% KCl or other suitable completion fluid. Pull the workstring, scrapers, and bit.
5. Rig up wireline equipment and lubricator to the top of the annular BOP. Perform a 2,000-psig pressure test on the lubricator. Run cement evaluation/casing inspection/caliper logs, differential temperature survey, and gyroscopic survey as detailed in Attachment I, Well Logging, Coring and Testing. Run cement bond log initially under zero pressure. A repeat run at elevated pressure may be necessary to remove effects from potential micro-annulus. Run cement evaluation/casing inspection logs to surface or approximately 500 feet above the top of calculated annular cement. Rig down wireline equipment.
6. Perform a pressure test on the casing to 70 percent of the manufacturer's rated internal yield pressure or one psi per foot of casing depth, which ever is less, for at least 30 minutes. Note: Arizona Oil and Gas Conservation Commission and/or USEPA may witness casing pressure test. A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the CO_2 Injection Well report. Keep a copy of the pressure test record at the CO_2 Injection Well site with other important records.

WELL COMPLETION – CO_2 INJECTION PILOT

7. Run any pre-experiment baseline testing that requires the well to be clear of completion equipment (such as the baseline VSP).
8. Rig up wireline unit and set up perforating charges. Run in hole and correlate perforation gun(s) on depth. Perforate the Martin Formation (or alternate Naco Formation) injection interval as determined from the open-hole logs. It is recommended that the well be perforated **underbalanced**, to aid in perforation tunnel clean up.
9. Produce formation fluid from the Martin Formation by swabbing or backlift. This will also aid in developing the well. Monitor formation fluid properties at surface (chlorides, pH, temperature, specific gravity, etc.). Continue flowing the well until parameters stabilize, indicating that formation fluids are being recovered. Collect samples periodically for laboratory analysis. Once clean and stable formation brine is established, divert returns to a "fresh" frac tank(s). The stored formation fluids will be used for injection testing of the injection interval.
10. Pick up completion packer and tubing. Attach any downhole monitoring equipment and control lines. Run the completion assembly into the well. Once on bottom, circulate the well with clean formation brine.
11. Space out tubing string and set the packer +/-10 feet above the uppermost perforation in the Martin Formation injection interval.
12. Land the tubing into the wellhead.
13. Install wellhead equipment and control lines.

14. Allow well to equilibrate and perform annulus pressure test. The pressure test will be run at equal to the lesser of the maximum authorized injection pressure or 1,000 psi (no testing pressure will be less than 300 psi). A successful test is a drop of no more than 10 percent of the test pressure over the 30-minute time period. Digitally record the test and maintain a copy of the test results on location. *Note: Arizona Oil and Gas Conservation Commission & USEPA may witness annulus pressure test.* The original copy of the pressure test record **MUST** be sent in to the Sandia Office and made part of the well report. Keep a copy of the pressure test record at the well site with other important records.
15. Rig down the workover rig and move out associated equipment.

GENERAL NOTES

All depths referenced are approximate and are based on the expected log depth from rig Kelly bushing of 15 feet above ground level.

Actual depths may vary based on lithology and evaluation of local formations.

DRILLING FLUIDS PROGRAM

Surface Hole

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
40-300	Freshwater Gel	8.4 – 9.0	40 - 60	control
300-965	Freshwater Gel	8.4 – 9.0	50 - 60	<10

Notes:

1. Should lost circulation and excessive drilling mud losses occur, materials designed for that problem will be used to remedy the problem on an “as needed” basis.
2. High-viscosity sweeps will be used as needed to assist in hole cleaning.

Protection Hole

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
965-2,300	Saltwater Gel	9.5 - 10.5	35-42	<10
2,300-4,000	Saltwater Gel	9.5 - 10.5	35-42	≤5

Notes:

1. Should lost circulation and/or excessive drilling mud losses occur, materials designed for that problem will be used to remedy the problem on an “as needed” basis.
2. High-viscosity sweeps will be used as needed to assist in hole cleaning.

Completion Fluid

Potassium Chloride (KCl) brine is planned for use as the completion fluid. The fluid weight will be maintained to contain reservoir pressures at balance without inducing flow to the wellbore. Only during perforating will the well be in an underbalanced condition. This underbalance will aid in perforation tunnel clean up.

Annular Completion Fluid

The annular completion fluid for the well will be an inhibited KCl brine or native brine solution oxygen scavenger additives will be mixed with the annular completion fluid prior to pumping into the well.

WASTE FLUID AND SOLIDS MANAGEMENT PLANNING

Prior to mobilizing equipment to the CO_2 Injection Well location, the area beneath the drill rig footprint and surrounding area will be cleared and graded. The area will be constructed in a manner to divert any collected liquids to the well cellar or to a sump. The liquids collected in the cellar or sump will be periodically removed and recycled within the active fluid system or disposed of in an approved facility according to their classification.

Drilling mud that is circulated out of the hole will flow through solids control equipment consisting at a minimum of a shale shaker, desander, and/or desilter to remove drill cuttings and other solids from the circulating mud system. The surface system will be “closed loop” and contained at all times. Components of the closed-loop system will be bermed to allow for containment and collection. All drill cuttings and removed solids will be contained and characterized for proper disposal according to applicable state regulations.

Upon completion of the proposed CO_2 Injection Well, the drilling mud will be dewatered to separate the solids from the liquids. The solids will be characterized and disposed of according to all applicable state regulations. The liquids will be characterized and disposed of according to all applicable state regulations at another approved facility appropriate to receive the properly classified wastes.

WELL CONSTRUCTION CEMENTING PROGRAM

Conductor Casing

The following cementing program is proposed for installation of the conductor casing:

- 13-3/8” in 17-1/2” hole at +/-40 feet
- grouted to surface

Conductor casing will be grouted to the surface with approximately 2 cubic yards of concrete slurry. Wait on concrete a minimum of 12 hours before drilling out with the 12-1/4” surface hole bit.

Surface Casing

The following cementing program is proposed for installation of the surface casing string:

- 9-5/8” in 12-1/4” hole at +/-965 feet
- cement to surface
- actual volume to be calculated from open hole borehole caliper log plus 20% excess

Surface casing will be cemented to the surface with Lead Slurry of lightweight cement mixed at ~12.3 lb/gal with Class “G” cement and Tail Slurry of Class “G” cement mixed at ~15.6 lb/gal. Wait on cement a minimum of 12 hours before releasing and cutting casing.

> Note: Final surface hole cement slurries will be designed for the actual wellbore conditions and the cementing company’s recommendations.

Protection Casing

The following cementing program is proposed for installation of the protection casing (longstring) string:

- 5-1/2” in 8-1/2” hole at +/- 4,000 feet
- cement to surface
- actual volume to be calculated from open hole borehole caliper log plus 20% excess

Cement protection casing from total depth to surface with Lead Slurry of lightweight cement mixed at ~11.50 lb/gal with Class “G” cement and Tail Slurry of 50-50 pozmix cement mixed at ~13.5 lb/gal. Displace the cement with clean 2 percent KCl water (or fresh water).

> Note: Final protection hole cement slurries will be designed for the actual wellbore conditions and the cementing company’s recommendations. The final design may incorporate a two-stage cementing program with a cementing stage tool in the 5-1/2” casing string.

CEMENTING ACCESSORIES

Conductor Casing

13-3/8” Float Equipment and Casing Equipment

1. Guide Shoe - 8rd STC
2. Hinged Bow Spring Centralizers
    - Centralizer 10 feet above the guide shoe, straddling a stop collar
    - Centralizer 10 feet below the first casing collar, straddling a stop collar

Surface Casing
9-5/8” Float Equipment and Casing Equipment

1. Float Shoe - 8rd STC
2. Float Collar, installed 2 joints above the float shoe
3. Bottom Wiper Plug
4. Top Wiper Plug
5. Hinged Bow Spring Centralizers
    - 1 Centralizer 10 feet above the float shoe, straddling a stop collar
    - 1 Centralizer straddling the first casing collar above the float shoe
    - 1 Centralizer 10 feet above the float collar, straddling a stop collar
    - 1 Centralizer every other collar, up to the surface

Protection Casing (“Longstring”)
5-1/2” Float Equipment and Casing Equipment

1. Float Shoe
2. Float Collar, 2 joints above the float shoe
3. Bottom Wiper Plug
4. Top Wiper Plug
5. Hinged Bow Spring Centralizers
    - Centralizer 10 feet above the float shoe, straddling a stop collar
    - Centralizer straddling the first casing collar above the float shoe
    - Centralizer 10 feet above the float collar, straddling a stop collar
    - 1 Centralizer every other collar, up to the surface

Well Tubing Specifications
The proposed injection well will be completed with 2-7/8-inch tubing set within a 5-1/2-inch protection casing string. The protection casing string will be set through the Martin Formation to approximately 4,000 feet. This will allow sufficient rat hole below the completion to run anticipated experiment monitoring and testing equipment. Injection tubing specifications for the proposed injection well are shown in Table L2. The tubing string is designed for the anticipated short duration of the CO_2 injection experiment.

Table L2. Proposed CO_2 Injection Well – Injection Tubing Specifications

TUBULAR	Depth (ft)	Size (in)	Weight (lb./ft)	Grade	Thread	Collapse/ Burst (psi)	Tensile Body/Joint (X 1000 lbs.)
Injection Tubing	0 -3,660	2-7/8	6.5	J-55	EUE 8rd	7,680/7,260	99.66/100

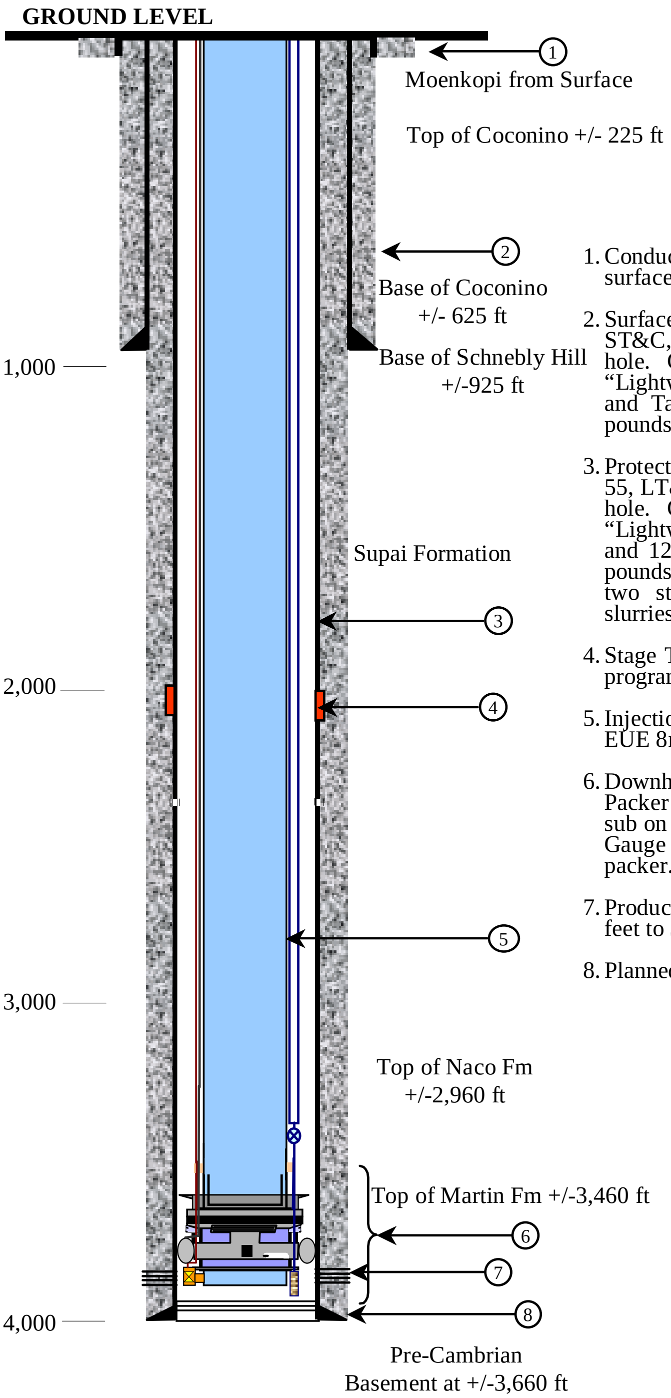
Well Packer Information

The completion packer will be set just above the perforated interval (approximately 10 feet above the top of perforations). Proposed packer is an inflatable 5-1/2-inch by 2-3/8-inch packer, or equivalent. The packer is designed for the life of the CO_2 injection experiment. For design of the CO_2 Injection Well, the packer setting depth is specified as approximately 3,660 feet (top of Martin Formation).

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

Arizona Utilities CO_2 Storage Pilot Injection Well

Proposed Completion Well Schematic



All depths reference Rig Kelly Bushing

Rig Kelly Bushing = 15' above Ground Level

Ground Level ~ 5,120'

COMPLETION DETAILS

1. Conductor Casing: 13-3/8-inch, 48 pounds per foot, surface to +/-40 feet, grouted to surface
2. Surface Casing: 9-5/8-inch, 36-pounds per foot. J-55, ST&C, Set from surface to +/-965 feet in a 12-1/4-inch hole. Cemented with Lead Slurry of 300 sacks of "Lightweight" cement mixed at ~12.3 pounds per gallon and Tail Slurry of Class "G" cement mixed at ~15.6 pounds per gallon.
3. Protection Casing: 5-1/2-inch 15.50 pounds per foot, J-55, LT&C. Set from surface to 4,000 feet in a 8-1/2-inch hole. Cemented with Lead Slurry of 380 sacks of "Lightweight" Cement mixed at ~11.5 pounds per gallon and 120 sacks of 50-50 Pozmix cement mixed at 13.5 pounds per gallon. Note: The final design may include a two stage cementing program and different cement slurries.
4. Stage Tool. Will only be used if a two-stage cementing program is required.
5. Injection Tubing: 2-7/8-inch, 6.5 pounds per foot, J-55, EUE 8rd. Surface to +/- 3,325 feet
6. Downhole completion consisting of: TAM Inflatable Packer (set at 3,460 feet) and inflate line, w/pass through sub on top of packer; Downhole Pressure & Temperature Gauge and LBL Stainless Steel U-Tube Sampler below packer.
7. Production Perforations: Martin Fm Test Interval: 3,460 feet to 3,660 feet w/ 4 shots per foot, 90 degree phasing.
8. Planned Total Depth; +/-4,000 feet

Notes

The Martin Formation is the Primary Target and the Naco is the Secondary Target

The Supai is expected to contain halite beds below +/-1,200 feet below ground

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6731Theall Road, Houston, TX 77066
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Drawn by: djc Date: May 2008 *Drawing not to scale*

Figure M1. Proposed injection well completion schematic.
A schematic figure of surface facilities is provided in Attachment K above.

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

Estimates of the movement of the CO_2 plume after the injection of 2,000 metric tons are presented in the Model Study report in Attachment A. At reservoir conditions, the supercritical CO_2 is approximately one-third the density of fresh water, so the plume will tend to rise and move up-dip (to the southwest) due to buoyancy. However, dip is estimated to be less than one degree, so this effect is expected to be minimal and offset by groundwater flow down-dip to the northeast. As shown by the models, if vertical permeability is high, the plume will rise before stabilizing. If vertical permeability is low and horizontal permeability is high, the plume will extend laterally from the well before stabilizing.

As described in Attachment H, at reservoir conditions the 2,000 metric tons of CO_2 will displace approximately 200,000 cubic feet of native fluid.

The last figure in the Model Study report in Attachment A shows pressure at the rock face of the well bore for different constant rates of CO_2 injection. Low permeabilities of 10 mD horizontally and 1 mD vertically were used to evaluate a “worst case” scenario. The model demonstrates that even under constant injection rate conditions, the pressure falls off rapidly with time. Experience at other pilot-scale CO_2 injection tests has shown that when CO_2 injection stops, reservoir pressure rapidly returns to pre-CO_2 injection levels.

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

CONTINGENCY PLAN

This attachment provides a description of plans that will be developed to remedy specific occurrences of unforeseen events during installation of the CO_2 Injection Well, baseline activities, and injection of CO_2. These plans will then be implemented to solve the specific problem.

WELL CONSTRUCTION ACTIVITIES

Activities performed during installation of the CO_2 Injection Well will be closely monitored. A mud logger will be rigged up prior to drilling the surface casing hole. The mud logger will be responsible for monitoring mud pit volumes for any indication of non-routine loss (lost circulation) or gain (inflow into the wellbore) in mud volume. The mud logger will also monitor drill rate, drill cuttings, and mud gas for indications of potential well control problems. Potential problems that may be encountered during drilling activities are described below.

Lost Circulation - Zones of lost circulation have been identified by review of local offset data. Note, however, that some fluid losses are anticipated during the drilling of the surface and protection hole, as part of normal operations. Normal drilling mud volume losses are a result of the penetration of permeable fresh water and saline water zones. Low mud weights and low solids concentration in the drilling fluid will help minimize losses. The drilling mud system will be monitored for volume losses (including sudden loss of returns). Excessive and sudden losses will be treated as necessary by the addition of sized lost circulation material into the circulating mud system. As necessary, lost circulation pills will be spotted in the event that losses are excessive or returns to surface are lost. Lost circulation material will be stored on location to allow quick response to any observed loss conditions. Advancement of the well will be suspended if all returns to surface are lost, and advancement of the well will not be reinitiated until such time that excessive losses are controlled and returns are observed at surface.

Overpressured Zones - Area review has indicated no overpressured zones in the local subsurface geology down to the total well depths. Offset well data indicates that the normal hydrostatic pressure regime extends down to at least 4,000 feet (basement). These offset well records have been reviewed for expected formation conditions, and the mud system has been designed to overbalance expected conditions, even under static conditions. The mud system will be closely monitored during drilling activities for indications of fluid influx into the wellbore. The drilling fluids program has been designed to provide overbalance to anticipated formation pressures (even under static conditions), based on offset well drill stem test pressure data.

During the drilling of the well, the following measures will be used to control/contain formation pressure:

- Hydrostatic pressure exerted by drilling/completion fluid(s)
- Blowout prevention (BOP) equipment
- Mud logger will monitor drill rate (rate of penetration) and mud volume data.

Stuck Pipe - The possibility of stuck pipe exists due the presence of permeable layers and lost circulation zones in the well path. Drilling jars will be used, if needed, in the drilling of the protection hole to assist in freeing stuck pipe, should the drill string become differentially stuck. Fluid loss control of the drilling fluid will be maintained to reduce the possibility of differential sticking of the work string. The mud system will be closely monitored during drilling activities for indications of volume loss into the subsurface formations. In the event that the work string becomes stuck in the hole, some or all of the following procedures may be utilized to free the pipe.

- Jarring on the work string to free the stuck pipe;
- Circulate a lubricating fluid in the well to assist in removal of the stuck pipe;
- Rig up wireline and run a free point survey to determine the depth of the shallowest stuck point;
- Back off the section of free pipe using wireline detonation charges;
- Engage the stuck portion of the work string with an overshot and fishing jars and attempt to jar the pipe free;
- Wash over the stuck pipe and remove it from the hole;
- Sidetrack the hole above the section of stuck pipe.

Commission notification and consent will be obtained before any sidetrack operations are implemented.

Excessive Wellbore Deviation – The path of the wellbore will be monitored by taking deviation surveys every 500 feet, at surface casing depth, and at total depth. The drilling plan calls for a maximum allowable deviation from vertical of no more than 3 degrees, with a maximum deviation of no more that 2 degrees per 100 feet (to minimize dogleg severity) at any point in the borehole. Should the wellbore deviation start to approach 3 degrees from vertical, the following options may be employed to reduce continued deviation:

- Weight on bit will be reduced to allow the drill string to drop back closer to vertical:
- A pendulum bottomhole assembly (drill collar arrangement that employs a near full diameter stabilizer to center the drill collars in the wellbore at some point (30 feet to 60 feet) above the bit) and reduced drilling weight on bit will be employed;

- A packed bottom hole assembly (large-diameter drill collars and multiple stabilizers to provide added stiffness to the bottomhole assembly and thus reduce deviation tendencies) will be employed;
- Direction drilling equipment will be mobilized to the site and employed if required by well conditions.

Lost Cement Returns – During cementing of the surface casing and the protection casing, fluid returns will be closely monitored. It is proposed in the drilling procedure that both casing strings be cemented to surface (Attachment L). Note that light weight cements are planned, to ensure that circulating pressures on the borehole wall are not excessive. Once casing is on bottom, water and chemicals will be added to the circulating drilling fluid to improve drilling mud removal from the casing borehole annulus. The well will be circulated a minimum of 150% of the calculated open hole volume and the casing will be reciprocated in ±20-foot strokes to ensure efficient removal of the drilling mud during the cementing operation. Should cement returns to surface not be observed, logging equipment will be mobilized to the location and the top of cement will be determined. A remedial cementing plan will be developed based on the observed top of cement. This may involve perforating the casing just above the observed top of cement, re-establishing mud circulation to surface and performance of a second cement job. Alternately, if the observed top of cement is sufficiently close to surface, a small-diameter tremie string will run into the casing-borehole annulus and additional cement pumped through the tremie string until cement is brought to surface.

Perforating and Well Development – The CO_2 Injection Well is not expected to be under artesian conditions. However, during perforating and well development, the well and surface equipment will be closely monitored. Pressure control equipment will be installed on the wellhead and tool lubricators will be used so that positive pressure can be exerted on the wellhead if the need arises. All pressure control equipment and flow lines will be tested to pressures that will exceed expected conditions prior to opening up the wellbore and initiating perforating or well development activities. Supplies and equipment will be maintained on site during perforating and well development so that a frac tank of weighted brine can be mixed and pumped to counteract any fluid influx into the well, effectively killing the well.

CARBON DIOXIDE INJECTION ACTIVITIES

Activities performed during CO_2 injection will be closely monitored. Liquid CO_2 will be hauled to the location by commercial haulers and transferred to carbon dioxide storage tanks. The temporary CO_2 storage tank facility will consist of storage vessels (60-ton portable storage tanks) with maximum working pressures of 350 pounds per square inch gauge (psig). These vessels will be fitted with safety valves and a pressure vent system, which are expected to release small amounts of CO_2. As practical, the temporary storage area will be located downwind of the active CO_2 Injection Well work zone. This will lessen the impact of minor releases of CO_2 on site workers. In general, it is expected that losses of CO_2 will occur as a normal part of transfer operations. Losses will occur during the initial tank fill and will also routinely occur as a result of ambient temperature changes on the storage tanks. One or more surface CO_2 detectors (with sound and visual alarms) will be located near the CO_2 storage area. Local accumulations of CO_2 with concentrations exceeding 2,000 parts per million (ppm) will activate a warning horn and a light beacon. Personnel will be instructed to leave the affected area, and move away from any local low-lying areas, until the source is identified and airborne CO_2 concentrations return to acceptable levels. Releases CO_2 will be allowed to dissipate naturally.

The CO_2 Injection Well will be equipped with a pressurized annulus that will be monitored and recorded digitally. The annulus pressure will be closely monitored for any significant changes in pressure relative to the pressure on the injection tubing. Note that there will be annulus pressure changes that result from conditions of thermal imbalance that occurs at well startup, injection rate changes, and at well shut down. These events are normal, routine, and to be expected. The annulus will be maintained at a higher pressure than the injection tubing, so that in the event of a loss of integrity at the wellhead, along the tubing, or at the completion packer, flow will be directed from the annulus and into the injection interval. An unexplained change in annulus pressure, which is observed to occur during normal operations, will be investigated by site personnel. If, upon conclusion of the investigation, the CO_2 Injection Well appears to lack mechanical integrity, the well will:

1. Immediately cease injection of CO_2 (or brine if the loss occurs during step-rate or hydrologic testing);
2. Take reasonable steps, as necessary, to determine the source and location of the leak;
3. Flush the tubing with a weighted brine or allow the well to vent to release the driving force from injected CO_2, if necessary;
4. Notify the appropriate regulatory authorities within 24 hours after the loss of mechanical integrity is documented;
5. Prepare a remedial action plan for repair of the well or prepare a plan for well closure, for submittal and review by the appropriate regulatory authorities;
6. Notify the appropriate regulatory authorities when the well will be repaired and injection resumed, or when the well will be plugged; and
7. Restore and demonstrate mechanical integrity to the satisfaction of the appropriate regulatory authorities prior to resuming injection of CO_2.

P. MONITORING PROGRAM - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Monitoring of the CO_2 plume will be performed using pre- and post-CO_2 injection geophysical surveys:

1. Vertical seismic profile (VSP) surveys will be used to image the lateral and vertical extent of the CO_2 plume. To perform the VSP surveys, a string of borehole seismic sensors with 25-foot spacing will be lowered into the injection well from the top of the seal formation to below the reservoir formation. A vibrator (Vibroseis) truck will be used at multiple surface locations to generate the signal for a seismic image in the vicinity of the borehole. At other saline formation CO2 pilot-scale injection tests, VSP has been successful at delineating the CO2 plume based upon reduced seismic velocity in CO2-invaded portions of the reservoir.

2. Residual Saturation Tool (RST) borehole logging surveys will be run to monitor the vertical extent of the plume near the well and demonstrate that CO_2 is not leaking above the seal formation through the cemented annular space between the well casing and the formation.

The post-CO_2 injection VSP and RST surveys will be performed 3-5 months after the end of CO_2 injection.

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

WELL PLUGGING AND ABANDONMENT PLANS

General well closure procedures and any post-closure care plans are detailed in the following subsections. These procedures follow Arizona Oil and Gas Conservation Commission requirements for proper well abandonment (*R12-7-127*). An exact plugging and abandonment program will be developed prior to actual well abandonment. This detailed plugging and abandonment plan will be based on final as-built well construction and the specific zones perforated and used for the experiments/monitoring in the well. This well-specific plan will include: 1) information on type, number and placement of the proposed plugs; 2) type, grade, and quality of the cement(s) to be used; and, the method that will be used to place the plugs. The plan will be submitted a minimum 30 days in advance of well plugging for review and approval.

General Well Closure Procedures

The closure procedures for the CO_2 Injection Well are designed to be implemented following completion of monitoring activities for the pilot test. The general procedures for well closure are described below and may be modified prior to performing field operations according to the direction of the Arizona Oil and Gas Conservation Commission and/or
EPA:

A. Notice of intent to plug will be made at least 30 days prior to planned closure. Notification of the start of closure will be made to the Arizona Oil and Gas Conservation Commission at least 48 hours ahead of start of field operations.

B. The following detailed information will be provided with the formal notice of intent to plug:
   1. Type and number of plugs to be set.
   2. Placement of each plug including the approximate elevation of both the top and bottom of the plug.
   3. Type, grade, and quantity of the plugging material and additives to be used.
   4. Method used to place plugs in hole.
   5. Procedure used to plug and abandon the well.
   6. Any information on newly constructed or discovered wells, or additional well data, within the Area of Review.

C. Plugging operations for the CO_2 Injection Well will generally be conducted as follows:

1. Prepare location for workover rig.
2. Move workover rig onto location.
3. Record any shut-in tubing and/or casing pressures. Kill well with brine fluid. Remove wellhead and nipple up blow out preventers.
4. Pull injection tubing, injection packer(s), and downhole instrumentation from the well. Perform any end of experiment monitoring activities
5. Run in the well open-ended and displace the well with mud. Plugging mud, at a minimum, will have 15 pounds per barrel of sodium bentonite and a nonfermenting polymer, have a minimum consistency of 9 pounds per gallon, a minimum viscosity of 50 seconds per quart, and mixed with fresh water.
6. Trip in the well with a 5-1/2" cement retainer and set the retainer approximately 50 feet above the upper perforation in the CO_2 Injection Well. Squeeze approximately 100 feet cement below the retainer. Shear out of the cement retainer and spot approximately 100 feet of cement above the retainer in the 5-1/2" casing.
7. Pressure up on the 5-1/2" casing and plug to 1,000 psi for at least 30 minutes in order to verify integrity of the protection casing and the cement plug. Record the pressure test on a strip chart, circular chart, or digital recording devise. Note Arizona Oil and Gas Conservation Commission and/or EPA may witness the casing/cement pressure test.
8. Place a cement plug opposite the base of the surface casing, located at +/-965 feet. Plug will extend a minimum of 50 feet above and below the surface casing shoe depth (at a minimum top of plug at approximately 915 feet and bottom of plug at 1,015 feet). Displace cement out of tubing and pull up work string. Reverse circulate the hole clean. Allow cement to set and tag top of plug to verify depth. [Note, if the annular cement behind the 5-1/2-inch protection casing by 9-5/8-inch surface casing does not come up to the surface casing shoe, the 5-1/2-inch casing will be perforated at the depth of the surface casing shoe and cement squeezed outside the casing.]
9. A cement surface plug of at least 50 feet will be set from the anticipated casing cut-off point in the protection casing (at a minimum top of plug at surface or cut-off depth and bottom of plug at 50 feet or 50 feet plus cut-off depth). All open annular spaces that extend to surface in any of the other casing strings will also be cemented (minimum 100 feet of cement).
10. Cut off casing three to five feet below ground surface (or depth as designated by the Arizona Public Service Company (surface owner)) and fill any remaining open annular spaces with cement. The well will be marked by a piece of metal pipe, not less than 4 inches in diameter, that is securely set in cement and extends at least 4 feet above general ground level. The well location and identity will be permanently inscribed on the marker.

D. A plugging report will be filed with the Arizona Oil and Gas Conservation Commission and EPA within 15 days after completion of closure operations. The report will include: 1) the method used in plugging the well; 2) casing record details; 3) the size, kind, and depth of plugs used; and 4) the name and depth interval of each formation containing fresh water, oil or gas, or geothermal resources.

POST CLOSURE PLANS

Post-closure monitoring is not anticipated for the CO_2 Injection Well.

S. AQUIFER EXEMPTIONS –If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

No aquifer exemption is requested.

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

No existing EPA permits are associated with the WESTCARB Arizona Utilities CO_2 Storage Pilot Project.

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

WESTCARB Arizona Utilities CO_2 Storage Pilot Test

Capturing carbon dioxide (CO_2) from large industrial point sources and injecting it deep underground in geologic reservoirs is one of several solutions being evaluated to reduce greenhouse gas emissions contributing to global warming.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven regional U.S. Department of Energy (DOE) partnerships formed to assess terrestrial and geologic carbon sequestration opportunities in the western region of the United States and Canada. WESTCARB comprises six states (Alaska, Arizona, California, Nevada, Oregon and Washington), one Canadian province (British Columbia), and nearly 50 organizations representing regulatory agencies; colleges and universities; environmental non-profit groups; oil, gas, power and pipeline companies; trade associations; vendors, service and consulting firms; and national laboratories and research institutions, including Lawrence Berkeley National Laboratory (LBNL). The partnership includes the California Energy Commission (CEC), responsible for executing the DOE-WESTCARB contract; LBNL, responsible for providing technical leadership, developing site models, and conducting monitoring activities in support of geologic pilot projects; and the Electric Power Research Institute (EPRI), responsible for contracting for services related to field operations at the Arizona project site described in this document.

DOE, CEC, EPRI and four Arizona electric utility partners – Arizona Public Service Company (APS), Salt River Project (SRP), Tucson Electric Power (TEP), and Arizona Electric Power Cooperative (AEPCO) – provide financial support and guidance for the project, which has been named the Arizona Utilities CO_2 Storage Pilot. These industry partners are providing funding for twenty percent of the project cost.

The State of Arizona was selected by WESTCARB for a project to test the geologic storage of CO_2 because there are large point sources of CO_2 emissions in the state – the coal-fired power plants – and there is the potential for sequestration of large quantities of CO_2 in deep geologic formations underlying the vast Colorado Plateau. The Colorado Plateau contains extensive sedimentary and carbonate formations containing high-salinity groundwater that could be used for geologic storage of CO_2, with overlying low-permeability confining formations that serve as caps, keeping the CO_2 contained. High-salinity groundwater cannot be used for human or livestock consumption and has very little economic value unless treated using expensive desalination techniques.

For this pilot-scale project, up to 2,000 metric tons[1] of CO_2 will be injected into a deep reservoir. This is the amount of CO_2 generated by a typical 1,000-megawatt (MW) coal-fired power plant in approximately 2.2 hours. The project will test the injectivity of this relatively small amount of CO_2 into the geologic formation, test numerical modeling

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[1] 1 metric ton = 1 tonne = 1,000 kg ≈ 1.1 US short ton ≈ 2,205 pounds

codes that estimate the growth and extent of the CO_2 plume, measure changes in water chemistry within the formation, test methods for monitoring the location of the CO_2 plume to demonstrate that it remains within the predicted point of compliance, and estimate the amount of the injected CO_2 that dissolves in the reservoir water or becomes immobilized in the formation.

Project Objectives

The overall goal of the Arizona Utilities CO_2 Storage Pilot project is to gain practical experience with, and demonstrate the potential for, safe CO_2 storage in deep underground geologic formations in a location with large CO_2 sources and large CO_2 storage potential. In addition, new monitoring approaches will be tested and a two-way exchange of information will be established with governmental agencies and the public. The project has four major objectives:

1) Test the feasibility and safety of CO_2 storage in deep rock formations under the southern portion of the vast Colorado Plateau in northeastern Arizona.
2) Demonstrate and test methods for monitoring CO_2 storage in deep-rock formations.
3) Evaluate numerical modeling codes used to predict the location and movement of CO_2 plumes in reservoirs containing high-salinity groundwater.
4) Gain experience with regulatory permitting and public outreach associated with geologic storage of CO_2 in Arizona.

The primary scientific objectives of the project, and the activities planned to address these objectives, are summarized in the following table.

Summary of the scientific objectives and proposed test plan

Scientific Objective	Measurement Approach
Demonstrate site characterization techniques	• Geologic analysis of existing well data • Baseline characterization data from new well • Numerical modeling of CO_2 plume using existing data • Pre-CO_2 injection vertical seismic (VSP) survey
Determine the injectivity of the reservoir	• Collection of core from the reservoir formation • Step-rate injection test with continuous real-time pressure monitoring
Assess the spatial extent of the CO_2 plume	• Numerical modeling of CO_2 plume • VSP survey to map the lateral extent of the plume
Assess seal integrity	• Collection of core from the seal formation

Assess effects of CO_2 injection on reservoir geochemistry	• Collection of cores from caprock and reservoir • Collection of fluid samples before and after CO_2 injection • Geochemical modeling
Estimate the amount of CO_2 dissolved in the reservoir water	• Dual tracer analysis of CO_2 vented from the well
Evaluate vertical leakage along test well	• Pre- and post-injection residual saturation tool (RST) logs to detect CO_2 migration above the injection interval near the well • Pre- and post-injection Distributed Thermal Perturbation Sensor thermal conductivity measurements to detect CO_2 migration above the reservoir near the well (under consideration)
Evaluate numerical modeling of CO_2 plume location, movement, and stabilization	• CO_2 plume modeling using existing geologic data • Revised modeling using data from the new well • Post-CO_2 injection VSP survey