PRYOR CHEMICAL COMPANY
PRYOR FACILITY
ODEQ PERMIT RENEWAL APPLICATION
PERMIT NO. IW-NH-49022-R1
RESERVOIR MECHANICS

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I. RESERVOIR MECHANICS

After analysis of the local and regional geology near the Pryor Chemical Company (PCC) facility, injection well flow and pressure models (*DuPont Basic Plume and DuPont Multilayer Pressure*) were run to evaluate the effects of effluent disposal under the conditions requested in this permit application. Detailed descriptions of these models are shown in Attachments 1 and 2 of this document.

The DuPont Deepwell models are structured to focus on the key physical mechanisms influencing the system behavior at a site. These models permit evaluation of the contribution of each mechanism to the system under consideration. The DuPont Deepwell models are understandable, and are accepted by the U.S. Environmental Protection Agency (EPA) and many state regulatory agencies, including the Oklahoma Department of Environmental Quality (ODEQ). Model results are obtained from equations, which provide a relationship between the physical mechanisms governing the system response. The ease of understanding these relationships provides the means for technical interaction by a diverse group of interested people.

The PCC facility has one injection interval, the Arbuckle Dolomite Injection Interval. (See Attachment F, for a discussion of the injection interval.) This interval is the focus of the model simulations. Predicted effects of effluent disposal into the injection interval are modeled for injection time periods of actual historical injection (Year-End 2016) and 10 years (Year-End 2028). A post-closure period of 30 years is also modeled to show the pressure decay once injection ceases.

I.A. Reservoir Mechanics of the Injection Reservoir

An understanding of the regional and local geology is essential to constructing the reservoir model. Based on interpretation of borehole geophysical logs, scout ticket information, and published literature, a comprehensive picture of the subsurface geology was developed for the facility (Attachment F). Input parameters required by the flow and containment model are the following:

- Carbonate, Sandstone, and Shale Layers
  - Average Thickness
  - Permeability
  - Porosity
  - Rock Compressibility
- Original formation fluid salinity, viscosity, density
- Original formation pressure
- Layer Dispersion Characteristics

The following sections describe where and how the model input parameters were obtained. Note that the model inputs are dependent on the specific model used. The models use different parameter subsets; differentiation between the model inputs is identified in each parameter description section.

I.A.1 Injection Zone Stratigraphy and Lithology

The PCC facility is located in northeastern Oklahoma in Section 3, Township 20 North, Range 19 East of Indian Meridian, in Mayes County, Oklahoma. The area is located between two regional geologic structures: Cherokee Platform and Ozark Plateau (Christenson, et al. 1994). The Cherokee Platform is a shallow geologic platform consisting of mostly marine or shallow-marine Paleozoic Age rocks. The Ozark Uplift formed from the late Paleozoic through the Mississippian era. Movement associated with the Ozark Uplift was upward, which tilted and exposed the subsurface rocks of the Cherokee Platform. The Seneca Fault, a regional feature that extends from southwestern Missouri to northeastern Oklahoma, is located approximately 2.5-miles northwest of the injection well. This fault, along with its minor associated faults, is self sealing.

The stratigraphy of northeastern Oklahoma, in descending order, ranges from Quaternary Alluvium at the surface or near surface into Paleozoic Age rocks followed finally by Pre-Cambrian Age Basement rock. The Quaternary Alluvium (Tertiary in age) is generally silt that contains some gravel. The Paleozoic deposits above the Woodford Shale (Upper Confining Zone) are limestones with significant chert content. The Woodford Shale is a black shale. The Arbuckle Group (Injection Zone) is group of thick dolomites with sandstone lenses. Pre-Cambrian granite basement rocks (Lower Confining Zone) underlie the Arbuckle dolomites.

I.A.2 Characteristics of the Injection Reservoir

I.A.2.1 Layer Thickness

The *DuPont Basic Plume Model* and *Multilayer Pressure Model* perform two-dimensional computations for horizontal distribution of effluent front boundaries and pressure. They accept one thickness value for each modeled layer. The PCC No. 1 injection well is completed as an open hole. The gross thickness of the Arbuckle Dolomite in the PCC injection well totals at least 461 feet. The portion of the injection interval accepting flow has been historically estimated at 220 feet. Based on analysis of mechanical integrity test data (differential temperature and flow meter logs), a very conservative estimate of the portion of the open interval accepting flow was made for this permit renewal. This thickness will be referred to as the effective injection reservoir thickness and totals 30 feet. PCC notes that it is planning a well workover with an objective to return the injection interval to its original estimated thickness.

The effective injection reservoir thickness is used in the *DuPont Multilayer Pressure Model* for the Arbuckle Dolomite Injection Interval. This value is approximately 7 percent of the gross open hole interval potentially available for flow. The effective injection reservoir thickness is also used in the *DuPont Basic Plume Model.* The thickness is conservative in that temperature logs show injection into a thicker interval.

Small-scale variations in layer thickness can influence the overall movement of the waste plume, but these variations are implicitly included within the framework of the dispersion parameters (i.e., "multiplying factor" in the *DuPont Basic Plume Model*) of the model.

I.A.2.2 Permeability and Transmissivity

Permeability is the capacity of a porous media to transmit fluids. Permeability values for the injection interval were determined from analysis of injection/falloff tests of the injection well.

PCC acquired the injection well in 2000 and annual injection/falloff tests have been performed on the well since. These tests were all performed with high-resolution surface gauges. The most recent test was performed in March 2018. This test was run after completing the rework of the completion interval. The falloff portion of each of the historic falloff tests (2001 to 2016) was analyzed using Reservoir Description Service, Inc.'s TRANS II transient analysis software package. TRANS II provides both log-log (multi-rate and derivative type curve) and semi-log (superposition) analyses. The injection/falloff tests from 2001 to 2016 were all reanalyzed for this permit renewal application using an effective injection reservoir thickness of 30 feet in TRANS II. Results are summarized in Table 1 and reanalysis of the 2001 to 2016 tests are included in Attachment 5. Although the well ran effectively over this time period, the well efficiency was hampered by the presence of scale along the open hole borehole wall.

The March 2018 test was run shortly after completion of well rework operations. This test was analyzed using Reservoir Description Service, Inc.'s TRANS II transient analysis software package, following the methodology used for the historic tests. The analysis of the post-rework test is included in the *2017 Ambient Pressure Falloff Test Report* (GKS, 2018). Analysis results from the falloff portion of the March 2018 test shows that the well rework was very effective in increasing injection capability to the well. Test derived transmissibility following the well rework is approximately twice the transmissibility values determined from the 2014 through 2016 tests. The March 2018 test falls within the upper range of all of the tests previously run in the well (only exceeded by the 2007 test value). This is a vast improvement in well performance and sets a new baseline for well operating conditions.

Based on the collective falloff test results in the injection well, an effective permeability of 3,150 millidarcies is assigned to the Arbuckle Dolomite Injection Interval in the modeling. This value is reasonable based on average well test results. The use of this average value results in a conservative prediction of pressure by the model. The modeled permeability value of 3,150 millidarcies is almost one-half of the permeability determined from the March 2018 test (5,770 millidarcies) that followed the well rework. Using the post-rework permeability value in the modeling would result in one-half of the pressure increase presented in this section. Therefore, actual pressurization in the Arbuckle is expected to be lower than model results reported herein, producing a very conservative overprediction of expected behaviors.

I.A.2.3 Porosity

Porosity is the ratio of void space in a given volume of rock to the total bulk volume of rock expressed as a percentage. The more porous a rock, the more fluid can be stored in a given rock volume. Porosity for Arbuckle Dolomite is estimated at 10 percent based on information reported in historical reports for the site, and the value will be used for both the pressure and plume models. Minor variations in porosity are handled in the *DuPont Basic Plume Model* using a "Multiplying Factor" (see Section 1.A.2.5).

I.A.2.4 Temperature

The PCC facility is in Mayes County which has an average surface temperature of 60 °F (Oklahoma Climatological Survey, 2017). Based on geothermal gradient maps and previous work, the original formation temperature for the Arbuckle Dolomite at a depth of 451 feet is estimated at 70 °F. This yields a temperature gradient of 2.0 °F per 100 feet of depth.

I.A.2.5 Layer Dispersion Characteristics

Dispersivity is a measure of the mechanical dispersion property of a porous material and is defined as a length to describe the ability of media to disperse solutes (Walton, 1985). Dispersivity is a function of both the vertical and lateral permeability variations, and increases with formation heterogeneity. In general, increasing travel distance equates to greater dispersion, and, therefore, higher dispersivities.

To be conservative, a multiplying factor, M, of 2.0 is used in the PCC model to more conservatively represent the waste plume areal extent. The multiplying factor was estimated from work performed by Xu and Eckstein (1995) for dispersivity as a function of field-scale movement. The multiplying factor used in the model is equivalent to an upper-end dispersivity value of approximately 76 feet. This is a reasonable value for the scale of the plume within a 30 foot effective injection reservoir thickness.

I.A.2.6 Wellbore Characteristics

The *DuPont Multilayer Pressure Model* uses a default wellbore radius of 0.5 feet and a wellbore skin factor of zero (i.e., no enhancement or pressure drop at the completion). These defaults are used in the PCC model. Therefore, the model is predicting the incremental flowing pressure increase in the formation, which provides a stable point of comparison for future monitoring, since actual wellbore skin conditions vary year to year (Table 1).

I.A.2.7 Reservoir Fluid Dissolved Solids Content, Viscosity, and Specific Gravity

Arbuckle Dolomite formation's sodium chloride content and total dissolved solids levels were determined in the Kaiser Aluminum injection wells when they were drilled. The Kaiser wells are located approximately 1.2 miles north northwest of the PCC No. 1 injection well. The chloride content was 21,620 mg/l, and the total dissolved solids were 35,195 mg/l.

Using the estimated formation temperature of 70 ºF (Section I.A.2.4), the equivalent specific gravity for the formation fluid is 1.014.

A viscosity of the formation fluid as described here is 1.0 centipoise.

I.A.2.8 Static Reservoir Pressure

The *DuPont Multilayer Pressure Model* predicts the incremental pressure increase with time, above the background initial formation pressure. From historical data, the estimated static reservoir pressure is 212.83 psi. (see Table 2). Assuming a reservoir depth of 451 feet below ground surface, this yields a pressure gradient of 0.472 psi/ft.

I.A.2.9 Compressibility

Compressibility is the change in volume per unit increase in pressure. In a zone that is 100 percent saturated with water the total compressibility is defined as the formation compressibility plus the compressibility of water corrected for water saturation:

$$c_t = c_f + c_w S_w$$

Fluid (water) compressibility (c_w) is built into the program code of the *DuPont Multilayer Pressure Model* as a fixed value of $3.034E^{-06}$ psi^{-1} after Table 2-5 in Freeze and Cherry (1979).

Compressibility of the rock can be estimated from correlations in Hall (1953), which indicate compressibility in the range of $5x10^{-6}$ psi^{-1} for consolidated rocks with porosities near 10 percent. The *DuPont Multilayer Pressure Model* uses the classic "hydrology" definition (Freeze and Cherry, 1979; Lohman, 1979) for compressibility of "alpha", which is related to the rock compressibility as shown below.

$$c_f = \alpha / \phi$$

Since porosity is approximately 10 percent, a value for alpha of $5.0E^{-07}$ psi^{-1} is assigned in the model input file for the value of rock compressibility.

I.A.3 Prediction of Reservoir Pressure Increase

I.A.3.1 The DuPont Multilayer Pressure Model

When effluent is injected into a subsurface geological formation, the pressure within the receiving reservoir will increase. This pressure increase will be greatest at the well, and will decrease with distance away from the injection site. After injection ceases, the pressure will diminish, and approach its value before injection.

The *DuPont Multilayer Pressure Model* is used to determine the pressure distribution within the injection reservoir. Documentation of this model is presented in Attachment 1. The model is an extension of an earlier treatment presented by Miller, et al., (1986) that is based on the Theis (1935) equation. The model discounts the ability of the aquiclude layers to compressively store fluids, which provides a conservative upper bound to the pressures modeled within the injection reservoir. The pressure model is set up as a single-layer simulation of injection into the Arbuckle Dolomite. The *DuPont Multilayer Pressure Model* requires four layers as a minimum, consisting of an alternating sequence of impermeable (odd numbered layers) and permeable (even numbered layers) units. The base of the bottom layer is a “no flow” boundary, which does not allow pressure or fluid leak-off from the system. The Arbuckle Dolomite Sand is set up as the bottom layer (Layer 4) in the four-layer *DuPont Multilayer Pressure Model*; therefore, it is confined from below.

The Arbuckle Dolomite is assigned a thickness of 30 feet, a permeability of 3,150 millidarcies (md), and a fluid viscosity of 1.0 centipoise (cp). Therefore, the model transmissibility (permeability-thickness/ viscosity) is conservative compared to the average calculated transmissibility of 107,245 md-ft/cp, determined from the historical ambient falloff tests (Table 1). An average porosity of 10 percent is also used in the model. An “alpha” value of $5.00E^{-7}$ psi^{-1} is assigned to the Arbuckle Dolomite so that the total system compressibility [formation compressibility plus water compressibility ($3.034E^{-6}$ psi^{-1})] value of $3.53E^{-6}$ psi^{-1} is also matched. The overlying shale layer is assigned a vertical permeability of $1.0E^{-15}$ darcies. Studies of the Woodford Shale throughout Oklahoma report porosities ranging from 4 percent to 20 percent; therefore, a minimum porosity of 13.5 percent is not unreasonable and is used in the models. Since the Woodford Shale is modeled as an impermeable layer, the exact assignment of porosity is not critical. The Arbuckle Dolomite is essentially a “confined” unit in the model, allowing no leak-off or exchange of pressure or fluid above or below the modeled unit. The single-layer model set-up for the Arbuckle Dolomite used in the simulation is shown in Table 3.

I.A.3.2 Modeled Injection Rate

For this Permit Application, modeling of injection at the PCC facility modeled future injection at the Maximum Injection Rate (175 gpm) for 10 years (Year-End 2028) and a post-closure period (no injection) of 30 years. Projected injection is modeled on an annual time step. Historical injection rates have been well below the permitted maximum injection rate, and it is anticipated that future injection rates will also be less than the maximum rate. The use of the maximum requested rate for modeling, therefore, is conservative.

I.A.3.3 Modeled Injection Interval Transmissibilities

Model predicted formation pressure increase due to injection is directly proportional to the assigned transmissibility (kh/μ) value used for that interval. Calculated injection reservoir transmissibility from the model inputs (thickness x permeability/viscosity) is shown in Table 4.

I.A.3.4 Pressure Model Results

Model runs for the Arbuckle Dolomite injection interval are made to predict lateral pressure distributions for the historical injection period and 10 years (2017 through Year-End 2028) at the Maximum Injection Rate of 175 gpm. Using the input parameters discussed above, the model set up is tested to ensure that the resulting pressures match or overmatch the measured flowing bottomhole pressures from the annual injection/falloff tests (Figure 1).

The DuPont Multilayer Pressure Model run files for the Arbuckle Dolomite consist of

Injection Rate (gpm)	Filename	Comment
175	pryor_flow_2028.rcv	Master job input deck and run file
	pryor_flow_2028.prm	Model parameter dimension file

These model input files for the pressure simulations are contained in Attachment 3.

The DuPont Multilayer Pressure Model output files for the Arbuckle consist of:

Injection Rate (gpm)	Filename	Comment
175	pryor_flow_2028.sum	Master job run summary output file
	pryor_flow_2028.pinj	Pressure increase at injection well output file
	pryor_flow_2028.pmon	Pressure increase at artificial penetrations
	pryor_flow_2028.pcnt	Areal pressure distribution plot file – End of Historical, 10 Years

These output files for the pressure simulations are contained in Attachment 3.

Results of the pressure simulation are based on the *DuPont Multilayer Pressure Model* runs. For current case conditions over the modeling term, a summary of the pressure increases at both the injection well and at the 2.0-mile radius Area of Review Boundary are shown in Table 5. Note that the pressure predictions are conservative relative to the post-rework permeability value. Comparative modeling with the higher permeability value determined following the well rework would result in one-half of the pressure increase presented on Table 5. Therefore, actual pressurization in the Arbuckle is expected to be lower than model results reported herein, producing a conservative overprediction of expected behaviors.

Figure 2 graphically shows the modeled incremental predicted pressure increase with time in the Arbuckle Dolomite at the injection well. Note that the incremental model pressure increase has been translated to a downhole wellbore pressure at the reference depth of 451 feet using the reference zero pressure of 213 psi (right graph axis). The areal extent of pressure from the injection well at Year-End 2016 is shown in Figure 4. The pressure profile away from the injection well at Year-End 2028 (projected injection period) is shown in Figures 3 and 5 at the maximum injection rate of 175 gpm. Note that the pressure predictions are also conservative relative to the recent waste minimization efforts conducted at the plant. Average injection rates are now expected to be approximately *one-third* (60 gpm) of the value used in the modeling. Comparative modeling with the new lower injection rate following waste minimizations efforts would result in one-third of the pressure increase presented in Figures 3 and 5. Therefore, actual pressurization in the Arbuckle is expected to be much lower than model results reported herein, producing a conservative overprediction of expected behaviors.

I.A.3.5 Pressure Recovery

The *DuPont Multilayer Pressure Model* simulation run also is used to predict the post-injection pressure recovery toward initial formation pressure for a period of 30 years after injection is modeled to cease. The results of the modeling for the maximum injection rate (175 gpm) indicate that pressure recovery in the injection reservoir will begin immediately and continue at a rapid pace through the first-year post-injection. Pressure recovery is projected to continue asymptotically, with formation pressure returning to approximate background pressure after 30 years (see Figure 2). Results indicate that pressure in the injection reservoir will equilibrate rapidly within the Area of Review.

I.A.4 Justification of Plume Geometry

In a purely homogeneous geological formation, the interface between the effluent and formation fluid will advance laterally as a sharp vertical front, and, in the case of a single isolated well, the front will take the shape of a right circular cylinder. The diameter of the circle will be determined strictly by geometric considerations, involving the total volume of the injected effluent, and the height and porosity of the formation. Such a plume is referred to as an ideal circular plume.

Horizontal variations in formation thickness and permeability can affect the lateral extent of effluent transport. Large sudden changes in these parameters can be included explicitly in model calculations, using image well techniques, or using the multiplying factor (see Section 1.A.2.5).

For multiple-well injection sites, methods of analyzing injected effluent transport in purely homogeneous geological formations have been available for many decades, based on work in the petroleum field. The standard approach involves a two-part process. First, determine the lateral velocity distribution within the injection formation at any time using solutions provided by potential flow theory. Second, integrate the time-dependent kinematic equations relating the calculated velocity distribution to the motion of the interfacial front between the injected effluent and formation fluid.

The first step takes advantage of the mathematical analogy between fluid flow in porous media and ideal potential flow of inviscid fluids. This mathematical analogy permits the determination of the velocity distribution in an injection formation directly from the previously established solution to the same problem in potential flow theory.

The second part of the modeling process involves the use of the velocities determined by the mathematical equations to calculate the time-dependent motion of the front between the injected effluent and formation fluid. This is accomplished mathematically by introducing a set of fictitious tracer particles around the circumference of each plume in the *DuPont Basic Plume Model*, and calculating the trajectory of these particles as time progresses. A separate set of tracer particles is employed for each well. Because the model automatically conserves mass, these tracer particles remain situated on the outer perimeter of the individual plumes for all times.

A variety of different forms of horizontal variation can occur, but two of the most common are (a) gradual changes in permeability, and (b) sudden changes, such as a flow barrier. If a sudden change is known to exist, its effects can be modeled directly, using image well methods, as discussed previously. Gradual trends have less of an influence on effluent transport, but are more difficult to model precisely. However, one can obtain a worst-case estimate of their effects simply by approximating these variations as equivalent sudden changes. Other types of horizontal variations that may be present can be handled by using the multiplying factor to provide a margin of safety in predicting an upper bound to the maximum lateral extent of the injected effluent.

At the PCC facility, plume geometry is only influenced by dispersion. Dispersion is handled in the model through the "multiplying factor" described in Section 1.A.2.5, which results in a modeled plume size greater than that which would be predicted using pure plug flow.

I.A.5 Extent of the Waste Plume

I.A.5.1 The DuPont Basic Plume Model

During injection, the movement of effluent within injection reservoirs is dominated by the volumetric growth of the individual plume and related displacement of the formation fluid away from the well. Effluent plume growth during injection is modeled in this Permit Application using the *DuPont Basic Plume Model*.

This model was introduced in Miller, et al., (1986). Model documentation is presented in Attachment 2. The *DuPont Basic Plume Model* calculates the time-dependent lateral movement of the plume emanating from the well at an injection site. The model can handle the effects of multiple well interactions, but that feature is not required in the case of this site. The model is set up as a single layer calculation, which discounts the vertical exchange of fluids between geologic strata.

For this Permit Application, the plume model is set up as a single-layer simulation of injection into the Arbuckle Dolomite. The model does not allow pressure or fluid leak-off from the system. The Arbuckle Dolomite is assigned a very conservative thickness of 30 feet (the Injection Well has 461 feet of open hole) and an average porosity of 10 percent in the plume model.

The Multiplying Factor is set at a value of 2.0. The Multiplying Factor simulates a dispersivity of approximately 76 feet and results in a conservatively large plume because it essentially doubles the volume injected. The singe-layer model set-up used in the simulation is in Table 6.

I.A.5.2 Modeled Injection Rate

For this Permit Application, modeling of injection at the PCC facility considered two time frames: historical injection (Year-End 2016) and 10 years of projected injection (Year-End 2028). It is conservatively assumed that the rate for the site for the full projected period will be at the Maximum Injection Rate of 175 gpm. The injection rate used in the model simulation runs for the PCC facility are shown in Table 7.

The Multiplying Factor enhances the injection rate as a multiplier; therefore, the effective modeled injection rates in the Arbuckle Dolomite is 350 gpm for the maximum injection. The rate was modeled for the full 10 years of the projected modeling period through Year-End 2028.

I.A.5.3 Plume Model Results

The model simulation for the Arbuckle Dolomite Injection Interval was made to predict the plume perimeter at the end of the historical injection period and projected injection through Year-End 2028. The simulation was run using the Maximum Injection Rate of 175 gpm.

The *DuPont Basic Plume Model* run files (Attachment 4) for the Arbuckle Dolomite consist of:

Injection Rate (gpm)	Filename	Comment
175	pryorplume2028.rcv	Master job input deck and run file
	pryorplume2028.prm	Model parameter dimension file
	pryorplume2028.inj	Layer properties and injection rate file

The *DuPont Basic Plume Model* output file (Attachment 4) for the Arbuckle Dolomite consists of:

Injection Rate (gpm)	Filename	Comment
175	pryorplume2028.plt	Areal plume perimeter plot file – Historical, Year-End 2028

The time dependent horizontal distribution of injected effluent (plume geometry) is presented in the following section. The results are obtained from the prediction of the *DuPont Basic Plume Model*.

I.A.5.3.1 Horizontal Extent

The projected maximum horizontal extent of the injected effluent plume in the Arbuckle Dolomite Injection Interval at Year-End 2028 will not exceed a radius of two miles (10,560 feet), using the Maximum Injection Rate of 175 gpm and a Multiplying Factor of 2.00. The model-predicted time-dependent horizontal extent of the plume at Year-End 2028 is shown in Figure 7. The modeling results of the plume perimeter can be found in Attachment 4 .plt File. Note that the plume geometry predictions are conservative relative to the recent waste minimization efforts conducted at the plant. Average injection rates are now expected to be approximately one-third (60 gpm) of the 175 gpm value used in the modeling. Comparative modeling with the new lower injection rate following waste minimizations efforts would result in a much smaller plume than is presented in

Figure 7. Therefore, actual plume dimensions in the Arbuckle are expected to be much smaller than model results reported herein, producing a conservative overprediction of expected behaviors.

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TABLE 1
SUMMARY OF HISTORICAL INJECTION/FALLOFF TESTS

TEST	TRANSMISSIBILITY (MD-FT/CP)	FORMATION THICKNESS (FEET)	VISCOSITY (CENTIPOISE)	CALCULATED PERMEABILITY (MILLIDARCIES)	SKIN
04/2001*	146,117.26	30	1.0	4,870.57	53.8
04/2002*	151,680.25	30	1.0	5,056.00	55.29
04/2003*	81,050.46	30	1.0	2,701.68	23.38
05/2004*	90,491.11	30	1.0	3,016.37	33.83
05/2005*	67,427.85	30	1.0	2,247.59	23.04
05/2006*	117,550.27	30	1.0	3,918.34	55.69
05/2007*	197,042.73	30	1.0	6,568.09	97.28
05/2008*	134,839.95	30	1.0	4,494.66	59.24
05/2009*	71,068.58	30	1.0	2,368.95	27.18
05/2010*	40,528.22	30	1.0	1,350.94	13.10
05/2011*	148,101.73	30	1.0	4,936.72	74.47
05/2012*	62,560.61	30	1.0	2,085.353	29.15
08/2013*	158,262.03	30	1.0	5,275.40	91.45
07/2014*	85,476.20	30	1.0	2,849.21	39.15
09/2015*	89,331.23	30	1.0	2,977.70	47.31
08/2016*	74,392.46	30	1.0	2,479.74	37.62
03/2018**	173,105.03	30	1.0	5,770.17	163.67

* Denotes test reanalyzed in April 2017
** 2017 testing performed following well workover in early 2018

Table 2
Historical Static Pressures in Pryor Chemical Company No. 1 Injection Well

Test Date	Test Injection Rate (gpm)	Test Type	Gauge Depth (ft GL)	Wellbore Fluid Gradient (psi/ft)	Static Pressure at Gauge Depth (psig)	Static Pressure at Datum Depth (psig)	Incremental Static Pressure (psi)	Flowing Pressure at Gauge Depth (psig)	Flowing BHP at Datum Depth (psig)	Delta Pressure due to Skin (psi)	Skin Adjusted FBHP at Datum Depth (psig)	Incremental Flowing Pressure (psi)	Well Test kh/u (md-ft/cp)	Net Thickness (feet)	Viscosity (cp)	Calculated Permeability (md)
PCC No. 1 Injection Well				***Orig. Static Press=**		**212.83**	**psi***			**Datum= 451' BGL**						
Apr-01	175	Falloff	0	0.432	24	218.6	5.8	383	578	304	275	61.9	146,117	30	1.00	4,871
Apr-02	173	Falloff	0	0.432	21	216.3	3.4	378	572	301	272	59.0	151,680	30	1.00	5,056
Apr-03	173	Falloff	0	0.432	20	214.8	2.0	365	559	243	316	103.4	81,050	30	1.00	2,702
May-04	159	Falloff	0	0.432	21	216.0	3.2	369	564	270	294	81.4	90,491	30	1.00	3,016
May-05	147	Falloff	0	0.432	21	215.9	3.1	365	560	242	318	104.7	67,428	30	1.00	2,248
May-06	128	Falloff	0	0.432	20	214.5	1.7	365	560	293	267	53.7	117,550	30	1.00	3,918
May-07	130	Falloff	0	0.432	20	215.2	2.3	363	558	311	247	34.3	197,043	30	1.00	6,568
May-08	139	Falloff	0	0.432	21	215.7	2.9	365	559	294	265	52.5	134,840	30	1.00	4,495
May-09	137	Falloff	0	0.432	18	212.8	0.0	364	559	255	304	91.2	71,069	30	1.00	2,369
May-10	113	Falloff	0	0.432	22	216.8	3.9	356	550	196	354	141.4	40,528	30	1.00	1,351
May-11	150	Falloff	0	0.432	22	217.3	4.4	439	634	366	268	55.4	148,102	30	1.00	4,937
May-12	140	Falloff	0	0.432	24	218.6	5.7	390	585	271	313	100.5	62,561	30	1.00	2,085
May-13	164	Falloff	0	0.432	23	218.3	5.4	397	592	333	259	45.9	158,262	30	1.00	5,275
Jul-14 **	125	Static Survey	-705	0.432	347	222.6	9.8	--	--	--	--	--	--	--	--	--
July-14	125	Falloff	0	0.432	22	217.3	4.4	372	567	278	289	76.3	85,476	30	1.00	2,849
Sep-15	115	Falloff	6.5	0.432	23	220.3	7.5	381	578	292	286	73.4	89,331	30	1.00	2,978
Aug-16	115	Falloff	6.5	0.432	23	220.9	8.1	383	581	282	299	85.8	74,392	30	1.00	2,480
Mar-18	60	Falloff	6.5	0.432	28	225.4	12.6	320	518	276	242	29.2	173,105	30	1.00	5,770

** Lowest static pressure is from 2009. Used this as original*

*** 2014 ran static gradient survey only*

**** Note: Since surface gauge used, skin includes both completion efficiency and tubing friction loss.*

***** Static pressure measured at end of falloff period, pressure still decreasing.*

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Operating Data

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Operating Data

The PCC injection well system operates as needed to dispose of contaminated storm water runoff, boiler blowdown, cooling tower blowdown, scrubbing system blowdown, and process flush water. The injection rate is adjusted as necessary to meet the demands of plant production. The average and maximum flow rates requested for the injection well and the maximum injection pressure are discussed in the following sections.

Maximum Injection Rate

PCC's existing permit (IW-NH-49022-R1) notes a maximum injection rate of 175 gallons per minute (gpm). PCC has initiated significant source reduction efforts over the past three years resulting in a recent average daily injection rate of approximately 60 gpm. Assuming the 60 gpm rate, the average well in flow will be 86,400 gallons per day (gpd) and at the current maximum permitted injection rate of 175 gpm the maximum flow to the well will be 252,000 gpd. PCC modeled future injection at the maximum injection rate of 175 gpm (see Reservoir Mechanics, Volume I). PCC is requesting that the instantaneous injection rate be calculated and limited as follows:

TABLE H-1
Requested Injection Rate Limitations

Injection Interval	Instantaneous Injection Rate (gpm)	Cumulative Monthly Volume (Gallons)	Cumulative Annual Volume (Gallons)
Arbuckle Interval Maximum	175	7,670,250	92,043,000

* Note cumulative monthly volume based on a 30.4375-day month and cumulative annual volume based on a 365.25-day year; these values are consistent with the time-steps used in the DuPont Deepwell Models

Average and Maximum Injection Pressure

PCC anticipates that maximum daily flow to the injection well will be no more than 252,000 gpd (175 gpm) at full facility operation. The current permitted injection pressure is 450 psi. PCC has supplied the Oklahoma Department of Environmental Quality (ODEQ) with operating data demonstrating compliance with these limits. PCC performed a well workover and stimulation during February 2018. Following completion of this workover, the injection pressure for the well has ranged from 314 to 325 psig on the wellhead at the average injection rate of +/-60 gpm.

Well Maintenance and Operation

PCC operates the well in compliance with the requirements specified in the current injection permit. The well and surface facilities are maintained in good working order. The well is identified by a posted sign containing the company name, company well number, and ODEQ permit number (see Figure H-1).

Pressure gauges installed at the wellhead, on the injection tubing, and on the annulus between the injection tubing and the long string casing are maintained in good working order at all times. Continuous recording devices record the following data:

- Injection tubing pressures
- Injection flow rates
- Injection fluid temperatures
- Injection volumes
- Tubing by long string casing annulus pressure
- Tank levels
- Injection pump motor amperage

Annulus pressure is maintained above the injection pressure at all times, including those times when the facility is not injecting.

All gauges, pressure sensing devices, and recording devices are tested and calibrated at least quarterly, and the records are maintained at the facility. All instruments are housed in weatherproof enclosures. Monthly average, maximum and minimum values for injection pressure, rate, and annulus pressure are reported quarterly to the ODEQ per 40 CFR §146.13(c)(ii).

Mechanical Integrity Test (MIT) is performed for the injection well at least once every 5 years, and a pressure fall off test is performed at least annually in accordance with 40 CFR §146.13(b)(3) and 40 CFR §146.13(d). Test results are submitted to the ODEQ per the reporting frequencies of 40 CFR §146.13(c)(2).

An automatic interlock system is in place in the event that pressures, flow rates, or other parameters designated by the Executive Director exceed a range or gradient specified in the injection permit.

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Formation Testing Program

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Formation Testing Program

The PCC No. 1 injection well has been operational since 1969. Initial installation of the well yielded information on the injection zone and formation fluids. PCC acquired the injection well in 2000, and has conducted annual ambient pressure falloff tests since then. Test reports detailing the procedure, results, and analysis of the results were submitted to the ODEQ to meet the requirements of 40 CFR 146.13(d). Details of the historical annual testing operations are included in the Reservoir Mechanics section of this permit application. (See Volume 1.)

Table I-1 summarizes the formation tests performed and lists the test date, test injection rate, and duration of the falloff period. The most recent test was performed in March 2018. The results show that the well rework was effective in restoring injection capability to the well. Test derived transmissibility following the well rework is twice the transmissibility determined from the 2014 through 2016 test and falls within the upper range of all of the tests run in the well.

TABLE I-1
Historical Formation Test Dates

Month & Year	Test Injection Rate (gpm)	Duration of Falloff Period (hours)
Jun 1988	189	-unknown-
Apr 1989	174	-unknown-
Mar 1992	162	-unknown-
Apr 2001	170	64.5
Apr 2002	170	119.2
Apr 2003	174	72.0
May 2004	149	72.0
May 2005	146	72.0
May 2006	128	72.1
May 2007	130	73.0
May 2008	138	72.0
May 2009	138	81.3
May 2010	138	48.1
May 2011	138	72.0
May 2012	138	72.0
Aug 2013	138	71.8
Jul 2014	125	70.9
Sep 2015	115	72.3
Aug 2016	115	71.1
March 2018	60	49.5

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Injection Procedures

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Injection Procedures

The Pryor Chemical Company (PCC) generates wastewater streams that are discharged to the OOWA POTW (via Oklahoma Ordnance Works Authority – Industrial User Permit No. 106) or are disposed of in the PCC No. 1 injection well, located on-site.

Several PCC chemical manufacturing units/plants operate on a continuous basis:

- #4 Ammonia Plant
- #2 Urea Plant
- #1 Acid Plant
- #4 Acid Plant
- CO_2 Plant
- #2 Ammonium Nitrate Solutions Plant
- UAN Blending Plant

Wastewater streams generated in these areas include contaminated storm water runoff, boiler blowdown, cooling tower blowdown, scrubbing system blowdown, and process flush water. The wastewaters are collected in a system of interconnecting piping, concrete trenches, sumps, and concrete pits. These are pumped through the collection system to above ground tanks and then pumped into the injection well. Prior to injection, the wastewater undergoes pH neutralization using sulfuric acid, oil removal by a skimming system, and solids removal (i.e., settling at multiple stages).

Prior to the installation of the wastewater particulate filtration system, wastewater gravity flowed from the Million Gallon Tank (MGT) directly to the Surge Tank. The Surge Tank is a reservoir for injectate and provides pressure head for the Deepwell Injection Pumps. Most of the piping between the MGT and Surge Tank runs underground and is isolatable with a block valve located on the outlet of the MGT and a motor operated valve (MOV) located on the inlet of the Surge Tank. The level in the Surge Tank was controlled with the opening and closing of the MOV.

The new filtration system (Figure K-2), was installed in January 2018, during the injection well workover project. The filtration system consists of a filter pump and two filter banks. To direct wastewater flow from the MGT through the filter system, the inlet MOV to the Surge Tank remains closed at all times. The inlet to the filter pump "Tee's" into the MGT transfer line upstream of the surge Tank MOV. The filter pump provides the required pressure for the filters to function as designed.

Downstream of the filter pump is the first filter bank. There are three 5-micron polyester bag filters in parallel. This bank collects most of the debris entering the wastewater system. The second filter bank serves to "polish" the wastewater exiting the first filter bank. The second filter bank has two filters in parallel. The PCC engineering department has been conducting tests to determine what the best filter media is for the second bank. Until a permanent solution is determined, polyester bag filters will be used. For both banks, filters are changed based on the amount of pressure drop across the filters.

There is a level control valve (LCV) located between the new filter system and the Surge Tank. The LCV is used to control the wastewater level in the Surge Tank. This control valve also controls the operation of the filter pump, such that the pump will start or stop depending on the position of the LCV valve and a timer in the logic.

The injection pumps are located inside a building to provide for weather protection. Secondary containment is provided for the pumps, and spills/leaks are collected and processed for appropriate disposal.

Pressure gauges installed at the wellhead on the injection tubing and on the annulus between the injection tubing and the long-string casing are maintained in good working order at all times. Continuous recording devices record the following data:

- Injection tubing pressures
- Injection flow rates
- Injection fluid temperatures
- Injection volumes
- Tubing by longstring casing annulus pressure
- Tank levels
- Injection pump motor amperage

All gauges, pressure sensing devices, and recording devices are tested and calibrated quarterly. Test and calibration records are maintained at the facility. All instruments are housed in weatherproof enclosures.

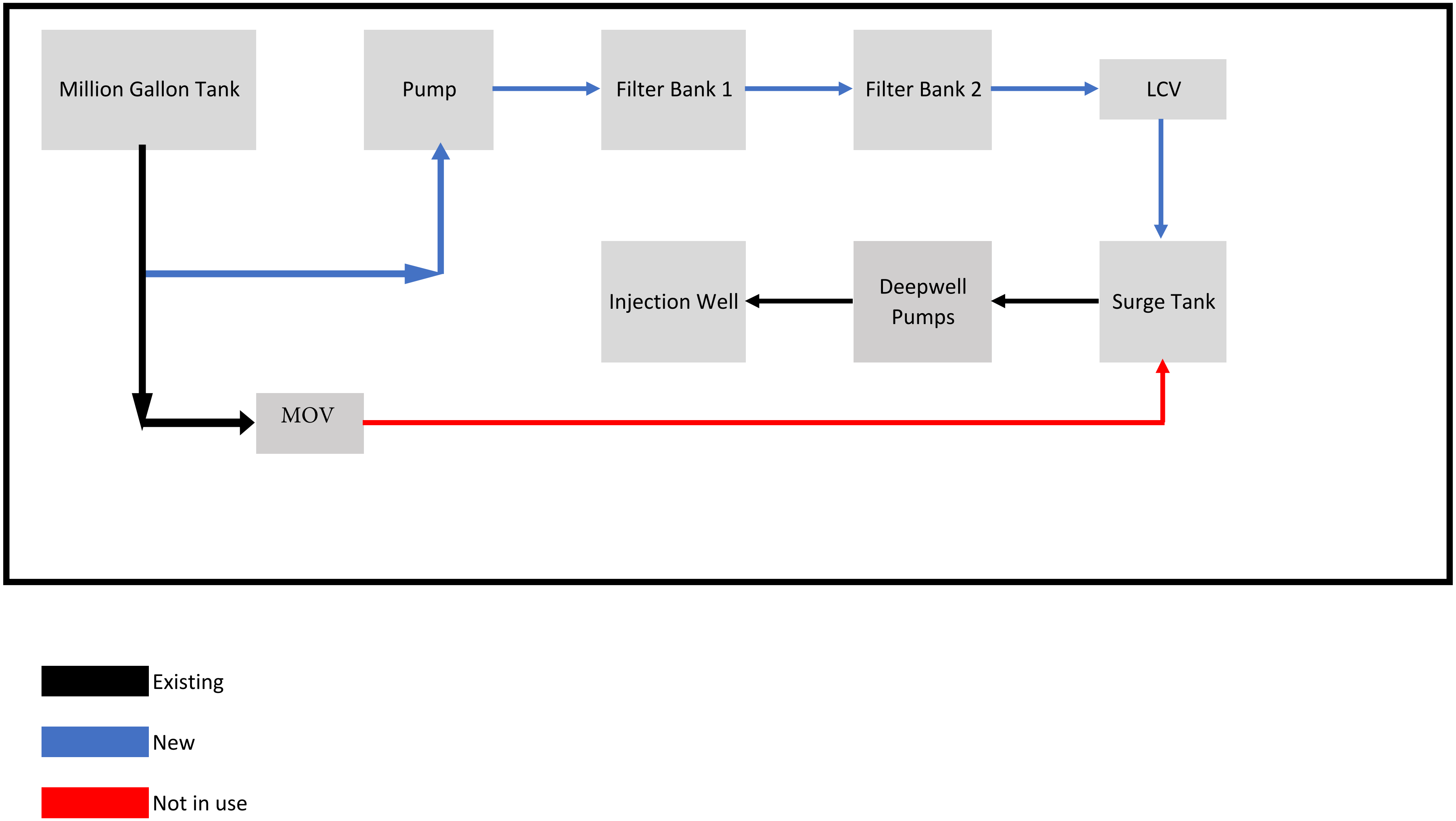

Figure K-2 Wastewater Particulate Filtration System Diagram

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Construction Procedures

ATTACHMENT L

Construction Procedures

Introduction

The PCC No. 1 injection well was originally installed by the Oklahoma Ordnance Works Authority (OOWA) in 1968 and injection began in 1969. The facility was transferred to Wil-Gro Fertilizer in 1989. In December 2000, LSB Industries, the parent company of PCC, acquired the site and injection well. From 2000 and into 2009, the injection well was used for the management of storm water only. Since 2009, when operations were commissioned, PCC has also operated the injection well as required to manage injectate generated from the manufacturing of fertilizer and related products.

Original Installation

The PCC No. 1 injection well was drilled in 1968 by the OOWA to a total depth of 912 feet below ground level (bgl) and completed as an open hole (417 – 912 feet bgl) in the permitted injection zone (Arbuckle Group). The Confining Zone was designated as the Woodford Shale which is located at a depth between 270 to 320 feet bgl.

A 14-inch surface casing string was installed to 20 feet bgl and cemented in place. A 10-inch protection casing string was set at 417 feet bgl and cemented to surface.

Workover History

The injection well underwent a major workover in January 1969, when 7-inch casing was installed to 451 feet. The casing was cemented by circulating cement to the surface. The well was completed with a 4.5-inch injection tubing and Baker Model A-3 Lok-Set Retrievable casing packer set at a depth of 364 feet bgl in the 7-inch casing.

A second workover was performed in 2011 to install a 5-1/2-inch casing to 413 feet. The casing was cemented to surface. A 3-1/2-inch tubing string was installed to 405 feet and held in place by a D&L Casing Packer set at 369 feet bgl. The tubing delivers injectate to the open hole portion of the well, between depths of 451 to 912 feet bgl.

A rework of the completion was performed between January 29, 2018 to February 5, 2018. With the tubing and packer removed from the well, abrasi-jetting operations were conducted on the open hole completion between select depths from 825 feet to 454 feet, using a total of 72,000 pounds of 100-mesh sand. Following abrasi-jetting operations, fill was removed from the well down to the total well depth at 912 feet. An acid stimulation treatment using 28% HCl-FE acid was pumped at an average rate of 126 gallons per minute (gpm), with treating pressures held below the maximum allowable wellhead injection pressure limit of 450 psi. The well was flushed clean and a new packer and tubing string was installed in the well. Pressure recording equipment was connected to the tubing-casing annulus of the well and an annulus pressure test was successfully run within allowable regulatory requirements set by ODEQ.

Well Casing and Tubing

Specifications

Tubular	Length (feet)	Size (inch)
Surface Casing	20	14
Casing	417	10
Casing	451	7
Casing	413	5-½
Injection Tubing	405	3-½

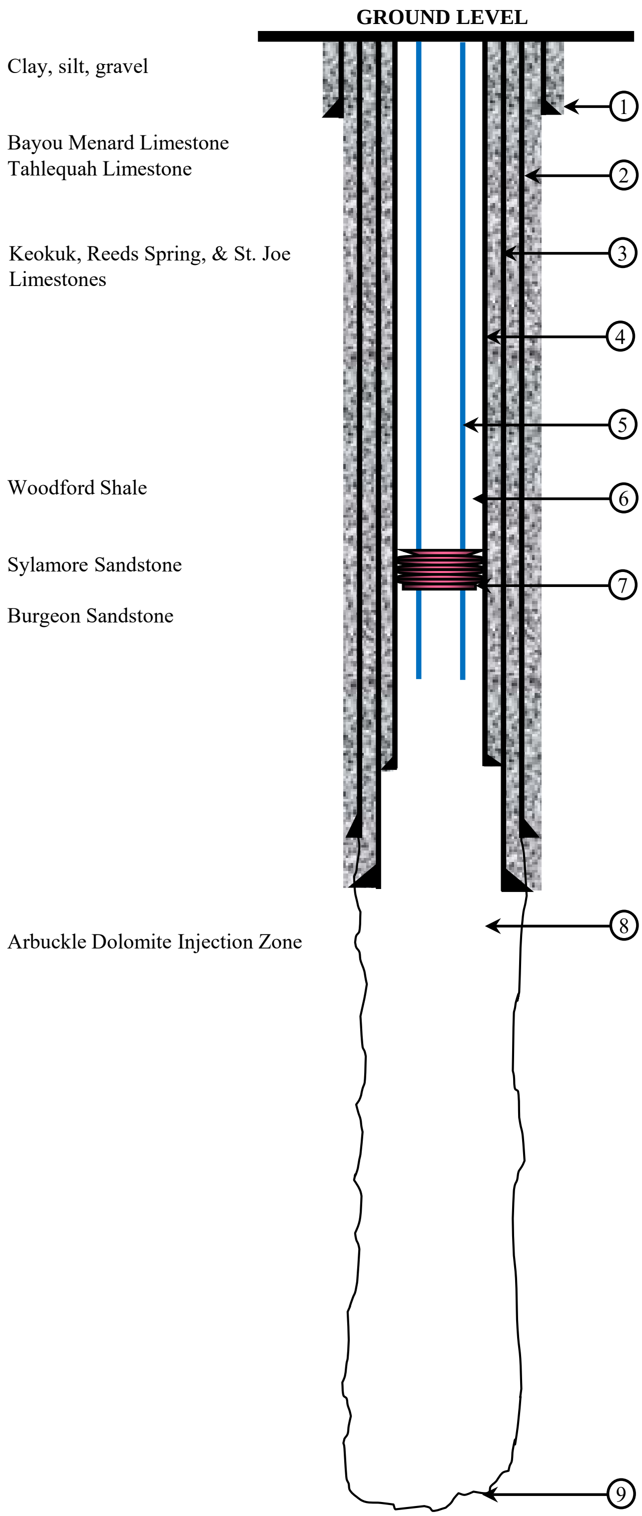
Various operators, including the OOWA, Cherokee Nitrogen Co., Wil-Gro Fertilizer, and Pryor Chemical Company have operated the well for waste disposal injection since 1969. Since the 1960s the facility has manufactured nitrogen fertilizers and associated products. Anhydrous ammonia, urea ammonium nitrate solution, and carbon dioxide are the main products produced by the plant. Currently, the plant runs on a 24-hour schedule. In addition to contaminated storm water, the injection well is used to dispose of select process waste.

Well Construction Engineering Schematic

For an engineering schematic of the current completion in the PCC No. 1 injection well, see Figure M-1. The schematic shows casing measurements and setting depths, cement information, and completion details. The annulus system configuration is shown in Figure M-2.

Pryor Chemical Company

Mayes County Oklahoma
Injection Well No. 1 (IW-NH-49022-R1)



COMPLETION DETAILS

1. **Surface Casing**: 14” set at 20’ cemented to surface.
2. **Protection Casing:** 10” set at 417’ cemented to surface.
3. **Casing:** 7” set at 451’ cemented to surface.
4. **Casing:** 5-1/2” set at 413’ cemented to surface with 60 sx Class A Portland cement (no additives). Casing is flush-joint 17 lb/ft, J-55, Range 3, 8rd.
5. **Tubing:** 3-1/2” set at 402’. Tubing is flush-joint 9.3 lb/ft, N-80, CS Hydril, R-2
6. **Annulus fluid:** Water with inhibitor
7. **Packer:** D&L Casing Packer set from 367’ to 371’ with the packer element at 369’.
8. **Open Hole:** 912’ to 451’ (Avg hole size 11.5”)
9. **Total Depth:** 912’.

Figure M-1: Pryor No. 1 Injection Well Completion Schematic

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Revised by: KDe	Date: 02/05/2018	*Drawing not to scale*

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