RESPONSE TO NOTICE OF DEFICIENCY

PRYOR CHEMICAL COMPANY

PERMIT NO. IW-NH-49022-R1

Item 1: *In Attachment A of the Application, PCC suggests that utilization of a standard Cone of Influence calculation methodology will result in a calculated infinite radius. Page 28135 of the Federal Register (FR), Vol. 53, No. 143 states "But in recognition that is some circumstances an area of review may be greater than 2 miles, the Director has the discretion to require a larger area of review. One such reason may be the cone of influence, which must still be calculated and provided by the owner or operator to the Director for his determination of whether corrective action would be required for abandoned or improperly completed wells." Since it may not be feasible to conduct calculations as stated in the FR, please provide an alternative methodology to include empirical testing and monitoring to satisfy the requirement of the FR and the regulations and demonstrate that there is no environmental harm. Please submit this demonstration to DEQ within ninety (90) days of your receipt of this letter.*

Response: Pursuant to 40 CFR 146.6, which has been incorporated by reference at OAC 252:652-1-3, ODEQ "may solicit input from the owners or operators of injection wells" in the state as to the appropriate methodology for Area of Review (AOR) determination. This includes input from the actual permit applicant. As stated in the preamble to the final rule establishing the federal UIC regulatory program, **permit applicants are to be "given a voice in the decision of how the area of review would be determined for his well or field."** 45 Fed. Reg. 42472, 42481. Though a previous consultant retained by PCC proposed the possibility of empirical methods for AOR determination, "empirical methods" of AOR determination are neither defined in, nor required by, the applicable regulations.

Rather, the AOR for Class I non-hazardous wells is to be determined based on either (a) the zone of endangering influence calculation, or (b) a fixed radius of at least ¼ mile. Natural geologic conditions in the area around the wellbore render the zone of endangering influence calculation an inappropriate method of AOR determination for the PCC well. The Theis equation provided in 40 CFR 146.6, as well as other known zone of endangering influence calculation methods, results in an asymptote that would purport to require an AOR of hundreds or thousands of miles simply because these calculation methods were not developed to consider injection into formations exhibiting artesian characteristics. Thus, the appropriate AOR methodology for the PCC well is a fixed radius distance from the wellbore. The 2-mile AOR proposed by PCC completely encompasses the projected maximum horizontal extent of the injected effluent plume based on the conservative plume model results as described in Section I.A.5 of PCC's permit renewal application. Further, PCC's proposed two-mile AOR is eight times greater than the ¼ mile minimum required by 40 CFR 146.6. The 2-mile Area of Review proposed by PCC here is thus appropriately conservative.

We also note that the federal register language cited in Attachment A of PCC's permit renewal application and cited by ODEQ in the technical NOD (53 Fed. Reg. 28135), relates to the AOR determination for Class I hazardous wells under 40 CFR 146.63, rather that that of Class I non-hazardous wells under 40 CFR 146.6. The federal register language was cited by PCC in its permit application simply as a demonstration of EPA's recognition that it is infeasible to determine the AOR of an injection well via the zone of endangering influence calculation in situations where the injection formation exhibits artesian characteristics. Despite PCC's conservative proposal of a 2-mile AOR, the PCC well has always been classified as a Class I non-hazardous well, and the PCC well is not subject to the standards governing the operation of hazardous waste wells in 40 CFR 146 Subpart G.

An analogous case of a formation exhibiting artesian characteristics that is used for injection is the Minnelusa Formation of North Dakota. Two permitted Class I nonhazardous injection well sites in North Dakota utilize the Minnelusa Formation for disposal of effluent. These two sites are the Dakota Gasification Company, located near Beulah, ND, and the Marathon Mandan Refinery, located near Bismark, ND. In both cases, the Minnelusa Formation maintains artesian wellhead pressures. Therefore, the Pryor Chemical Company site is not unique in this respect and these two cases confirm that existence of artesian conditions alone is not a barrier to permitting Class I well operations. Notably, the Dakota Gasification Company and the Marathon Mandan Refinery Class I nonhazardous injection wells utilize a fixed-radius for their AOR determination.

Factual information with regards to the Minnelusa Formation Injection Zone in North Dakota is detailed below. The cited data are included in the well files with the Environmental Health Section of the North Dakota Department of Health (NDDH).

<u>Dakota Gasification Company, Beulah, ND</u>

The Dakota Gasification Company has two injection wells, both of which inject into the Minnelusa Formation, which were installed in the early 1980s and have been in operation since that time (35 years of injection service). During construction of Injection Well No. 1, drill stem tests were successfully run in the Minnelusa Formation, indicating a formation pressure of 2,852 psi at a depth of 5,735 feet (a pressure gradient of 0.497 psi per foot of depth). Fluid analyses included a determination of specific gravity for the recovered brine, which allows for a calculation of the "environmental head" in the formation. The static environmental head (pre-injection conditions) in the Minnelusa Formations indicate artesian conditions approaching 160 feet above ground level for the injection interval.

<u>Marathon Mandan Refinery Mandan, ND</u>

Injection Well No. 2 at the Mandan Refinery is completed into the Minnelusa Formation at a depth of 3,778 feet, which has been used for injection since the early 2000s. During construction of Injection Well No. 1, a formation pressure test was taken in the Minnelusa Formation to characterize the natural hydrologic pressure regime in the interval. Initial pressure was found to be 2,099 psi at a depth of 3,872 feet (a pressure gradient of 0.542 psi per foot of depth). Fluids were recovered from the Minnelusa and the analyses included a determination of specific gravity, which allows for a calculation of the "environmental head" in the formation. The static environmental head (pre-injection conditions) in the Minnelusa Formations indicate artesian conditions greater than 800 feet above ground level for the injection interval. Operating wellhead pressure is approximately 730 psi and shut-in static well pressure averages 350 psig in Injection Well No. 2.

Notably, both ODEQ and NDDH administer their UIC programs via delegated authority from U.S. EPA, and both ODEQ and NDDH regulations applicable to Class I nonhazardous injection wells largely mirror federal regulations pertaining to Class I nonhazardous injection wells found at 40 CFR parts 144 and 146. There are no rules under Oklahoma, North Dakota, or federal Class I non-hazardous regulations that prohibit injection into artesian formations or formations that exhibit artesian characteristics.

Item 2: *In Attachment C, it is stated that there are four (4) injection-related wells located within the 2.0 mile Area of Review. Three (3) of the wells are discussed including Kaiser Injection Well No.1, Kaiser Injection Well No. 2 and Oklahoma Ordnance Work Authority #2. PCC states that the fourth well is discussed in Attachment A; however, Attachment A provides no discussion of the fourth injection-related well. Please provide discussion and information on this well and all artificial penetrations of the upper confining layer. Pursuant to item 1 above, if the Area of Review is expanded, PCC must provide information on all artificial penetrations and wells within the expanded Area of Review.*

Response: PCC has corrected this reference to "..there are three injection related wells..". Information for each of these wells is presented in Table A-1 and records information is included in Attachment C. A revised Attachment C is included with these responses for replacement into the permit application document. Since the AOR has not been expanded, nor is expansion warranted, there are no additional artificial penetrations to consider within an expanded AOR.

Item 8: *In Section I.A.2.8, a pressure gradient of 0.472 psi/ft. is predicted based on historical data with an estimated static reservoir pressure of 212.83 psi and assuming a reservoir depth of 451 feet. If using the flowing pressure at the end of the injection period from the most recent fall-off test (317.6 psig) and assuming negligible friction loss and a reservoir depth of 451 feet, the resulting pressure gradient is 0.704 psi/ft. which is greater than 0.65 psi/ft., thus violating OAC 252:652-9-1(1)(B). Please provide an evaluation/demonstration of the maximum allowable injection pressure (MAIP) to show conformance with OAC 252:652-9-1(1)(A) or (B). Also, please provide a calculation for the MAIP in accordance with 40 CFR 146.13(a)(1).*

Response:

Fracture Gradient in the Arbuckle in the Area Local to the PCC Site

As an initial matter, we note that site-specific information from two stimulation activities on the Pryor Injection Well indicates that very high fracture gradients are present in the Arbuckle within Mayes County. Two acid fracture jobs were performed on the well; the first well stimulation treatment was performed on May 12, 1976; and the second well stimulation treatment was performed on July 10, 1980. The stimulation treatments were performed using 28 percent hydrochloric acid fluid, with a specific gravity of 1.14. The initial stimulation treatment with acid was evaluated by Louis R. Reeder and Associates in 1977. They concluded that breakdown of the Arbuckle occurred at a wellhead pressure of 1,500 psi. At this wellhead pressure, the estimated downhole pressure at the base of the well casing was 1,790 psi. Propagation of the stimulation treatment out into the formation occurred at a treating pressure of 1,200 psi (injection rate at 1,260 gallons per minute). Based on the stimulation, Louis R. Reeder and Associates (1977) calculated that the formation fracture gradient was as high as 4.53 psi/foot of depth at the top of the Arbuckle Group. A safety margin of 59 percent at the midpoint of the Arbuckle Group was determined using a working operating wellhead pressure of 450 psi with a fluid stream specific gravity of 1.026 (assuming a tubing friction loss calculated at an injection rate of 285 gallons per minute).

ALL Consulting (2011) evaluated both the May 12, 1976, and the July 10, 1980, well treatments. In ALL Consulting's analysis of the May 12, 1976, well stimulation treatment, they concluded that breakdown of the Arbuckle occurred at a treating pressure of 1,200 psi on the wellhead during the initial stimulation. Breakdown of the Arbuckle was interpreted to occur at treating pressures ranging from 1,400 psi to 1,100 psi during the final portions of the May 1972 stimulation event (ALL Consulting (2011)).

During the second well treatment (July 10, 1980), injection of 10/20 sand at 20 barrels per minute and 1,200 psi was immediately followed with injection of 28 percent hydrochloric acid containing a friction reducing agent at a rate 25 barrels per minute. Treatment pressure increased during the injection of the acid, with breakdown estimated to occur at a treating pressure of 1,400 psi (ALL Consulting (2011)). Following breakdown of the Arbuckle, gel water containing salt was injected at a rate of 25 barrels per minute until a gasket on the wellhead failed during pumping operations. The well treatment was restarted, and 10/20 sand was injected at 800 psi using an injection rate of 25 barrels per minute. Once the sand had been placed in the well, acid and water were injected at 25 barrels per minute. The acid treatment was followed by a gel water flush at wellhead injection pressures of up to 900 psi. Water mixed with salt was then injected, reducing wellhead pressures back down to 800 psi. A second sequence of sand, salt, acid, and gel water was injected. This second treatment period was followed by injection of water with salt, with an observed formation breakdown at a wellhead treating pressure of 1,050 psi. A third sequence of sand, acid, and gel water was injected as part of the final well treatment. During injection of the water with acid, a breakdown at a wellhead treating pressure of 975 psi was observed (ALL Consulting (2011)). Injection of gel water flush concluded the well treatment.

Both well treatments in the PCC Injection Well show that the site-specific fracture gradient in the Arbuckle Group is significantly higher than values that would be determined from average correlations. Even using the minimum observed formation breakdown pressure from the well stimulations results in a calculated fracture gradient of 2.66 psi per foot of depth at the Pryor site.

The "Δpskin" Effect

Additionally, ODEQ's Item No. 8 fails to consider the fact that most of the injection pressure exerted at the wellhead is not transferred into the Arbuckle injection formation. To clarify, ODEQ's comments assume that there is no loss of pressure from the well skin effect, described below, which is a well recognized concept in the relevant literature. This failure to account for pressure loss due to the well skin effect in determining the MAIP for the PCC Injection Well is not reflective of the real-world operating conditions of the well.

Under normal, day-to-day operations, there is not a perfect connection between the well and the porous injection interval. This imperfect connection or formation damage at the completion, known in the literature as **"Δpskin"** (Earlougher, 1977, Gringarten et al., 1979, Lee, 1982, Bourdet et al., 1983), can be defined as the impairment to fluid flow and pressure in the near-well region of the completion. It is essentially a zone of reduced permeability at the completion face in the wellbore that acts as an unintended impedance to the flow of fluids and pressures out of an injection well wellbore. This impedance to fluid flow results in an additional pressure drop (Δpskin) between the wellhead and the Arbuckle Injection Interval. This additional pressure drop must be subtracted from the measured pressure at the wellhead in order to obtain the flowing pressure in the formation.

The "Δpskin" can be calculated from the evaluation of the annual ambient injection/falloff pressure test in an injection well. From the analysis of the test, the well skin factor can be determined from either the log-log analysis plot of the falloff, where the vertical separation between the stabilized derivative function level and the pressure is indicative of the well skin value (i.e., more separation equals higher "Δpskin"). The well skin factor can also be determined from the straight-line extrapolation from the radial flow (reservoir) on the superposition (or Horner plot). These calculations have been performed for each of the annual injection falloff tests conducted in the injection well. Results are tabulated in Table 2 of the Reservoir Mechanics section of the permit renewal (Volume 1). Notably, ODEQ has reviewed each annual falloff test report submitted from 2001 to 2018 and has indicated that the annual reports satisfy all applicable requirements.

The falloff test analyses show that, on average, the injection well operates at an efficiency of no better than 20 percent, with the impedance to fluid flow resulting in an additional pressure drop (Δpskin) between the wellhead and the Arbuckle Injection Interval of 80 percent. The pressure drop due to well skin ranges from 200 psi to 366 psi. This additional pressure drop has to be subtracted from the wellhead pressure in order to obtain the flowing pressure in the formation. Thus, if the incremental injection pressure measured at the wellhead is 380 psi, the actual incremental pressure flowing into the Arbuckle formation is roughly 75 psi (380 psi x 20% efficiency).

As a result of the well skin effect, the actual pressure present in the formation is within federal and state regulatory limits. The federal and state regulations related to maximum injection pressure are designed to prevent the initiation of fractures in the injection formation's confining zone. Further, EPA has recognized that the measured injection pressure relevant to fractures in the injection or confining zone **is the pressure that is actually present in the injection formation during injection**. As EPA stated in the preamble to the final rule establishing the federal UIC regulatory program, "the proposed regulations used the term 'bottom hole pressure' inappropriately. Because of the friction loss across the perforations of the casing, the injection pressure in the formation is not equal to the bottom hole pressure within the casing. **The concern of the Agency is with the pressure in the formation, and the final regulations have been changed to require the calculation of pressure at the well-head so as to produce an**

acceptable pressure in the injection formation as opposed to the casing at the bottom of the hole." 45 Fed Reg 42472, 42483. ODEQ regulations appear to recognize this fact as well, as the regulations allow for an adjustment of the pressure at the surface to account for pressure loss due to friction in piping or tubing of the well. OAC 252:652-9-1(1).

The well skin effect described above has a similar impact on injection pressure as friction loss across the perforations of the casing. In both scenarios, the measured pressure at the well head or at the bottom of the hole is substantially greater than the pressure acting on the injection formation during injection. Thus, the stated friction losses across well perforations recognized by the cited federal register language and ODEQ regulations is completely analogous to the presence of well skin in the injection well, and the well skin effect should be considered in the calculation of the Maximum Allowable Injection Pressure as measured at the wellhead for the PCC Injection Well.

<u>Pressure Calculation</u>

Under Section 252:652-9-1 of the Oklahoma Administrative Code, there are two options available for computing the Maximum Injection Pressure in Oklahoma. Under the first option, in a geographic area where no effective overburden gradient pressure has been established, the maximum injection pressure gradient shall not exceed a value of 0.65 psi/ft of depth from the ground surface to the top of the disposal zone. Under the second option, where an effective overburden gradient pressure can be established, the maximum injection pressure gradient shall not exceed sixty-five percent (65%) of the established overburden pressure gradient, expressed in pounds per square inch per foot of depth (psi/ft) from the ground surface to the top of the disposal zone. As discussed below, the availability of site-specific data for the area around the PCC injection well allows for the establishment of an effective overburden pressure gradient for Arbuckle Injection Interval in Mayes County.

The overburden (or lithostatic) pressure gradient at the top of the Arbuckle Injection Interval is a result of the cumulative weight of the fluid saturated rocks above the zone that are pressing down upon the disposal interval. The overburden pressure gradient, as a function of depth, can be determined from integration of the bulk density log curve from an open hole geophysical well log following the method outlined in Zoback (2009). The average overburden gradient at any depth point in the subsurface is simply equal to the overburden pressure at that depth divided by the depth.

A Compensated Density Sidewall Neutron Log for the nearby Red Fork (USA) Investments, Inc. RDFK No. 1-3 well is used in the determination of the overburden gradient in the Pryor area. A quality control review of open hole log shows that the density tool pad maintained reasonable contact in all portions of the well. Therefore, the data is reflective of actual densities in the encountered formations and it is valid to use this log for the calculation of the effective overburden pressure gradient for the Arbuckle Injection Interval. The bulk density curve and the density correction curve from this well was digitized from a depth of 20 feet to a depth of 600 feet below ground level. The density correction curve was combined with the bulk density curve to produce the "environmentally corrected" bulk density value. Summing the overburden from the bulk density log from surface to the top of the Arbuckle Formation and dividing that cumulative value by the depth to the top of the Arbuckle Formation results in an effective overburden gradient value of 1.157 psi/foot of depth in Mayes County.

Therefore, the allowable injection pressure at PCC can be computed by subtracting the injectate fluid column pressure from sixty-five percent of the effective overburden gradient and adding the pressure due to the sum of friction losses in the well (assuming a well completion efficiency of no more that 42 percent):

> 65% * Overburden Pressure Gradient * depth = Injectate Fluid Colum Pressure + Sum of Pressure Losses due to Tubing Friction and Δpskin
>
> Or
>
> 0.65 * 1.157 * 451 feet depth = (0.433 * 1.05 SG * 451 feet depth) + (11.2 psi + 0.42* WHP)
>
> Solving for Wellhead Pressure = 346 psi

The calculation assumes a maximum injectate specific gravity of 1.05 gm/cm^3, a tubing friction loss calculated at 175 gallons per minute in smooth 3-1/2-inch tubing (inner tubing diameter of 2.992 inches), and a completion efficiency (well skin) no greater than 42% (best recorded well completion efficiency from ambient well testing). Thus, due to the well skin effect described above, a maximum wellhead pressure of 346 psi yields a pressure <u>in the formation</u> that is within federal and state regulatory limits.

<u>References</u>

Bourdet, D., Whittle, T. M., Douglas, A. A., and Pirard, Y. M., 1983, A new set of type curves simplifies well test analysis: World Oil, Gulf Publishing Co., Houston, Texas.

Earlougher, R.C., 1977, Advances in Well Test Analysis: SPE Monograph Series Vol. 5, Society of Petroleum Engineers, Richardson, Texas, 264 p.

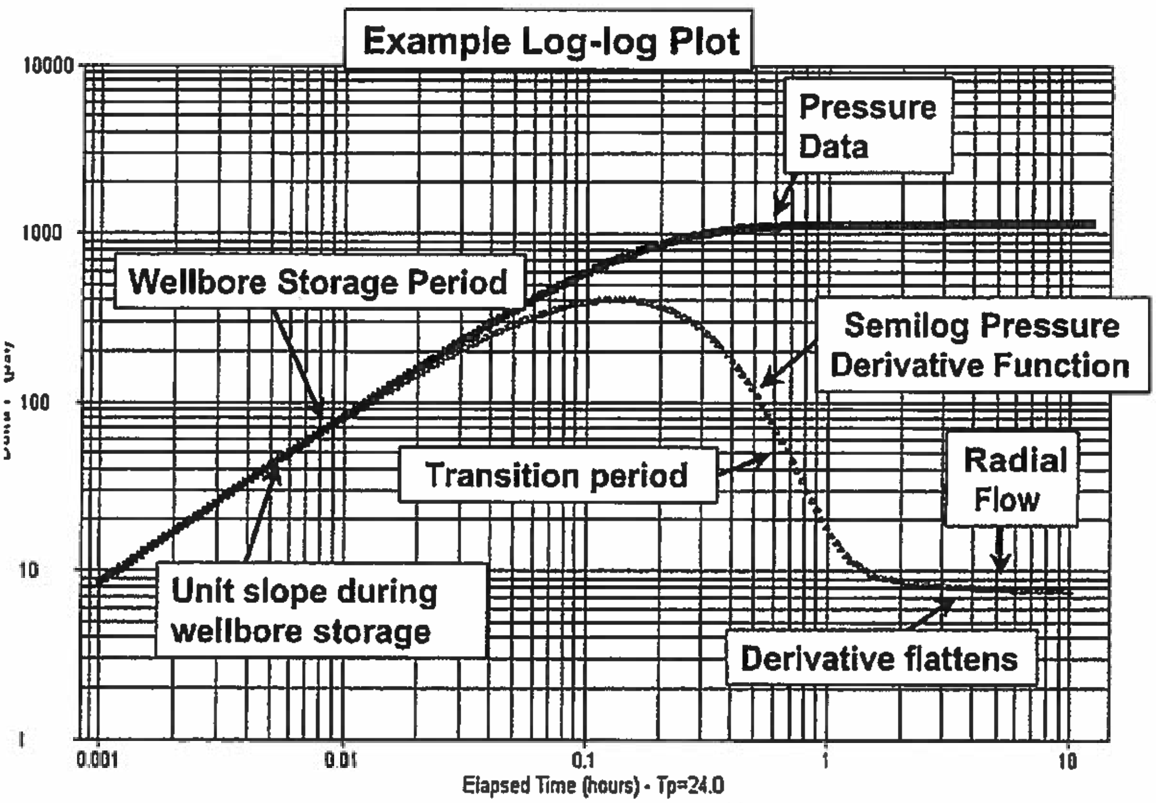
Gringarten, A. C., Bourdet, D., Landel, P-A, and Kniazeff, V., 1979, A comparison between different skin and wellbore storage type-curves for early-time transient analysis: SPE 8205, Society of Petroleum Engineers, 53rd Annual Fall Meeting Technical Conference and Exhibition of SPE of AIME, Las Vegas.

Lee, J., 1982, Well Testing: SPE Textbook Series Vo. 1, Society of Petroleum Engineers, Richardson, Texas,

Zoback, M., D., 2009, Reservoir Geomechanics: Cambridge University Press.

Item 10: *In reviewing the log-log plots in Attachment 5, the region where radial flow should occur appears irregular and does not conform to a typical/standard graphical representation of radial flow character. Please provide an explanation for these irregularities.*

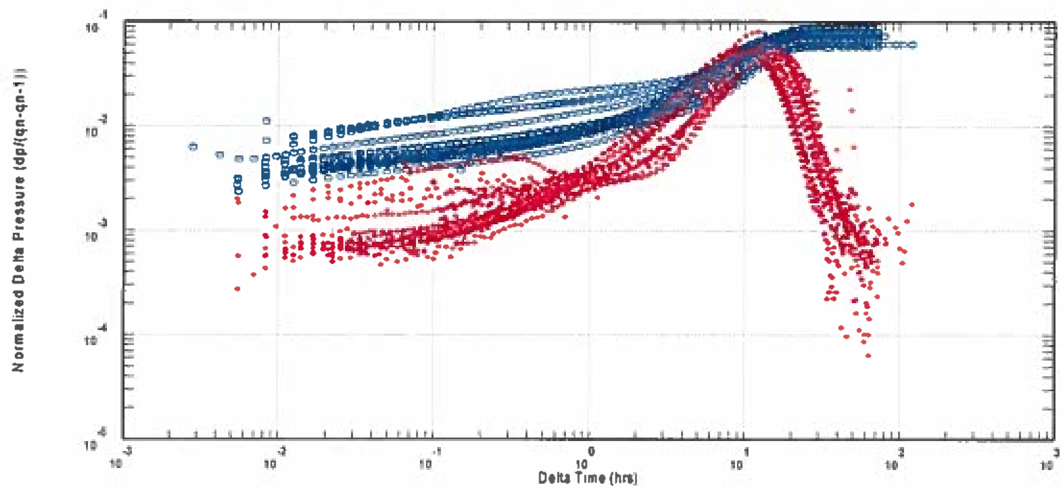
Response: The diagnostic plot is a log-log plot of the pressure change and pressure derivative (vertical axis) from a pressure transient test versus elapsed time (horizontal axis). Idealized (text book) test behavior exhibited during a falloff test is shown below:



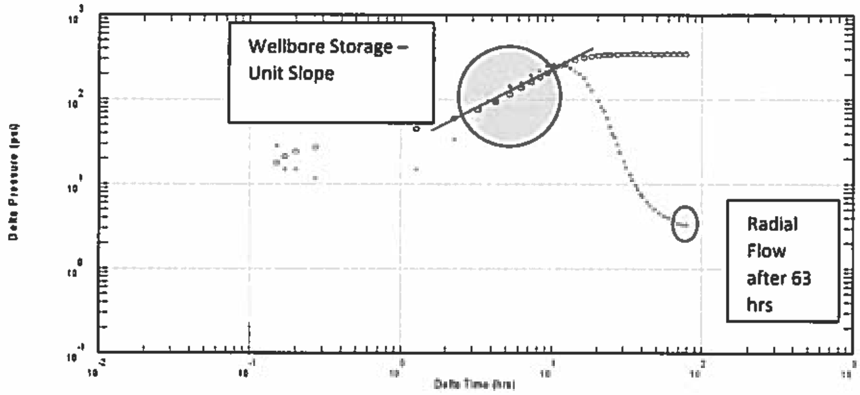
From EPA Region 6 UIC Pressure Falloff Testing Guideline (2002)

In the above idealized figure of a falloff test, the graph can be divided into three differing time regions: early; middle; and late. Sequentially, each successive time region is reflective of conditions further away from the well. At the earliest times on a plot (the "early-time" region), wellbore and near-wellbore effects dominate the test response. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior. In the idealized falloff test case, wellbore storage effects are dominate in early time, immediately following shut in of the well (typified by unit-slope response behavior on the analysis plot). Other potential early time effects include responses due to changing wellbore storage, formation damage, partial penetration, phase redistribution in the wellbore, and stimulation effects. At intermediate times (the "middle-time region"), the behavior in a reservoir will ordinarily be infinite acting. During this radial flow period, the pressure responses recorded are representative of the reservoir, not the wellbore. In an ideal homogeneous reservoir, the pressure derivative function will be horizontal during this middle time region, where data lead to the most accurate estimates of formation permeability and well completion efficiency. Therefore, the critical flow regime is this radial flow period. At the latest times during a test (the "late-time" region), potential boundary effects may dominate response behavior (note that no late time behaviors are illustrated on this figure). The types of boundaries that may affect the pressure response include: sealing faults; closed reservoirs; and phase-change contacts.

In general, the PCC Well shows both early and middle time behavior during falloff testing. A consolidated log-log plot of the falloff tests from 2001 through 2017 run in the PCC Well is presented below. The falloff portion of the tests have nominally been between 60 and 80 hours in length, with the longest duration shut-in of the well approaching 125 hours (2002 test)



Note that by and large, the shut-in response in the well has been very consistent since the initial falloff test conducted in 2001. There are no historical falloff tests run before 2001 that would allow for comparison to the more recent testing results. The early time unit slope behavior (wellbore storage) appears from 1 to 10 hours into the falloff. The transition from wellbore storage to radial flow is very delayed in the PCC well. This is likely due to the poor completion efficiency of the well. The 2009 falloff shows the best correspondence to an "ideal" test, as shown below:

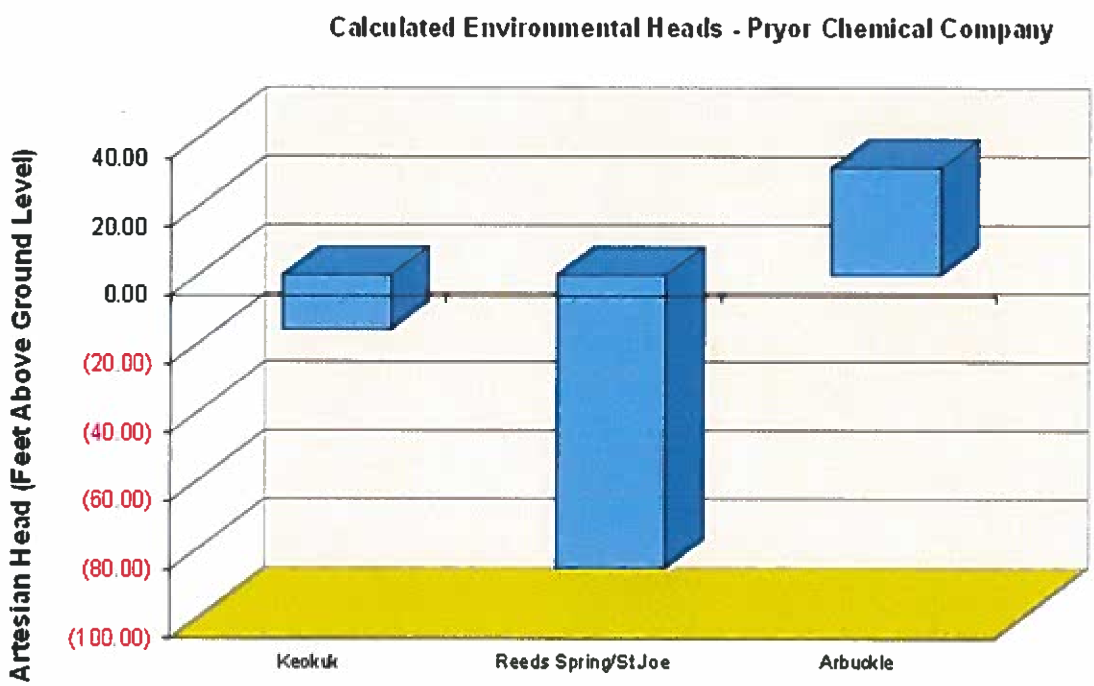


During the 2009 test, wellbore storage (unit slope behavior) is observed from about 2 hours to a little more than 10 hours following shut-in of the well. The transition from wellbore storage to radial flow appears delayed, occurring from 10 hours to about 66 hours following shut-in of the well. Radial flow, as determined from the flattening in the derivative function, occurs from 66 hours through the end of the test (80 hours). Continuation of the duration of shut-in of the well would extend the radial flow portion of the testing.

Falloff testing performed from 2001 through 2017 displays consistent, repeatable response in the well (i.e., no indication of changing conditions). The early time well response is consistent on a year-over-year basis, as is the extended transition from wellbore storage to radial flow. Note that the testing timeframe includes periods when the well was largely inactive (2001 to 2009) and periods when the well was continuously active (2010 to present). There is no apparent difference in the falloff response between either period. The radial flow portion of the falloff could be enhanced by increasing duration of the shut-in period.

<u>Item 11</u>: *Seeing as the pressure has not increased significantly over time, and given artesian characteristics, please submit a plan on how to identify any seeps within ninety (90) days of your receipt of this letter.*

Response: The absence of significant pressure build up in the Arbuckle Injection Interval is not the result of injected fluids "seeping" out of the injection interval into overlying formations. If the Arbuckle system were unconfined and leaking, it would not exhibit artesian characteristics. Under this leaking scenario, even under natural conditions there would be interformational flow from the higher pressured Arbuckle up into the lower pressured formations above the Woodford Shale. Site-specific information demonstrates the complete opposite, proving containment of the Arbuckle Injection Interval. Monitor well sampling has demonstrated that the fluid columns present in either the DW#1 or the DW#2 well (or their more recent replacements) have always been below ground surface elevation and has never been artesian. In fact, both deep monitor wells have shown the opposite, with each going dry with time. This would not occur if there were higher pressured fluids moving out of the Arbuckle Injection Interval to the shallow monitored depths. Both wells going dry is incompatible with the notion of fluid movement, in fact, it represents the lack of any fluid movement out of the Arbuckle Injection Interval. Witherspoon et al. (1962) demonstrated that confinement between two aquifers can be shown by the presence of significant differences in the hydraulic head values between adjoining aquifers. In their evaluation of sandstone reservoirs in Illinois, they used hydraulic head differences of 25 to 40 feet to be "significant" in identifying hydraulic isolation (Witherspoon et al., 1962). Thus, the confinement of the Keokuk Monitoring Zone, the Reeds Spring/St. Joe Monitoring Zone, and the Arbuckle Injection Interval at the PCC site is demonstrated by the differences in calculated hydraulic heads. The environmental hydraulic head in each interval can be calculated from the undisturbed water levels in the DW#1 and DW#2 wells and the injection well. The heads are corrected for the density of the native formation waters and show the level to which the fluids would rise in a "hypothetical" cased well. Under original conditions, environmental head level differences existed between the Keokuk Monitoring Zone, the Reeds Spring/St. Joe Monitoring Zone, and the Arbuckle Injection Interval.



Historic mechanical integrity testing (five-year temperature surveys) on the injection well confirms the integrity of the upper portion of the Arbuckle Formation, the overlying Simpson Formation, and the confining Woodford Shale. The static shut-in differential temperature profiles show clear containment of injected fluids within the Arbuckle Injection Interval. There is no indication of out-of-zone movement via temperature anomalies in any portion of the shallower geologic column, which would be expected if there was fluid flow out of the Arbuckle Injection Interval. The non-existence of such seeps into overlying formations is also demonstrated by monitoring wells completed in the Reeds Spring/St. Joe formation directly overlying the Arbuckle reservoir, which have gone dry over time. Neither of these monitor wells show elevated pressure characteristics that would be expected if they were in communication with the Arbuckle. Additionally, as explained in PCC's response to ODEQ's Item No. 9, the faults and fractures present in the region are not pathways for vertical fluid migration, but rather are barriers to fluid flow. PCC does and will continue to analyze fluid samples taken from monitoring wells completed in formations overlying the Arbuckle injection formation to ensure that injected fluids are not migrating vertically from the Arbuckle reservoir into the overlying formations.

The lack of pressure buildup is more likely due to the expansive nature of the Arbuckle reservoir. The Arbuckle formation is a porous and permeable reservoir, ranging up to and over 1,500 feet in thickness in Northeast Oklahoma. The Arbuckle extends hundreds of miles to the north into Kansas and Nebraska, and to the west and south across Oklahoma into Texas. Regional extent of the Arbuckle approaches 370,000 square miles in the midcontinent region (Jorgensen, et al., 1993). Therefore, the storage capacity of the Arbuckle is very large, especially in the area around the PCC injection well, where the Arbuckle's thickness is around 1,000 feet (Rottmann, 2018).

Well specific evidence (differential temperature and spinner logging) indicates that injection flow is potentially entering a limited interval immediately below the protection casing shoe in the injection well. The Arbuckle is sealed on top by the Woodford shale and no testing to date has indicated that water may be moving vertically upward and out of the Arbuckle. Therefore, the Arbuckle interval is confined and bounded at the top by the Woodford shale. However, the active near-well injection interval is essentially unbounded at its base, as the Arbuckle formation extends downward to deeper depths. The lower boundary does not occur until the Arbuckle contacts the underlying Pre-Cambrian basement. Logs and well information descriptions from area wells which have drilled through the entire Arbuckle formation into the basal Pre-Cambrian indicate that to both the west and east of the PCC injection well, the Arbuckle thickness is found to exceed a thickness of 1,000 feet (Rottmann, 2018). This indicates that the potential storage capacity of the Arbuckle in the vicinity of Pryor is huge. This large storage capacity within the overall Arbuckle formation, and in the area around the PCC injection well in particular, is the reason that static pressures have remained fairly constant over the years as the small volume of injected fluids quickly diffuses and disperses throughout the expanse of the Arbuckle system.

Notwithstanding the expansive nature of the Arbuckle reservoir, the Arbuckle has been described in the area local to the PCC injection well as having the characteristics of an "artesian" aquifer. An aquifer is termed as being under "artesian conditions" if the water level in an open borehole in the formation rises above the top of the aquifer (Freeze and Cherry, 1979; Vogel, et al., 2018). In cases where the water level rises above the ground surface, the aquifer exists under "flowing artesian conditions" (Freeze and Cherry, 1979; Vogel, et al., 2018). The permitting record for the PCC injection well indicates that the flowing artesian conditions have existed at Pryor since installation of the well in the 1960s. The artesian characteristics exhibited by the Arbuckle formation at the site of the PCC injection well are likely due to the recharging of the Arbuckle in outcrop areas east and southeast of the PCC site.

The Arbuckle is known to crop out to the east and southeast of the PCC Injection Well, approximately 20-25 miles away, in Delaware and Adair Counties. This is directionally towards the Ozark Plateaus physiographic region of Missouri and Arkansas and is concordant with the eastward shallowing of both the elevation of Pre-Cambrian Basement (Crain and Chang, 2018) and the elevation of the onlapping sedimentary layers onto the Pre-Cambrian basement (Evans et al, 2018) across Mayes and Delaware Counties. Topographically, these outcrop areas are situated at higher elevations than are the western portions of Mayes County, where the PCC injection well is located. In general, groundwater flows from areas of higher elevation to areas of lower elevation. Therefore, the water that enters the Arbuckle aquifer system in the outcrop area is expected to flow in a westerly direction towards the PCC injection well, as the elevations around the PCC well are lower than the elevations of the water tables in the recharge areas. This downgradient flow is observed in the Arbuckle-Simpson Aquifer, located in south central Oklahoma (Christenson, et al., 2011). As the Arbuckle becomes confined beneath the Woodford Shale, it continues to flow both down elevation and downgradient towards under pressured areas in the Arbuckle, both of which are in a westerly direction. The recharging of the Arbuckle in the outcrop areas east and southeast of the PCC injection well likely produces the artesian conditions observed locally at the injection well. The injection activity is then imprinted on this larger expansive flow field.

Finally, though the static pressures have remained fairly constant over the years, annual falloff testing conducted over the last decade shows an increasing pressure trend that corresponds with the increase in injection activity starting in 2009. Historical injection data into the Pryor well shows essentially 3 time periods of activity for the well: 1) active injection period from startup of the well to 2001; 2) relative inactivity from 2001 to 2009 (runoff water injection only); and, 3) active injection since 2009 to present. The long period of relative inactivity from 2001 to 2009 allowed the Arbuckle to return back towards original formation pressures under natural conditions. This time period also coincides with the initiation of annual injection falloff testing in the well. During this time period of relative inactivity, static bottom-hole reservoir pressures recorded at the end of the testing showed a slight decline in values from 2001 to 2009. This is the expected trend of reservoir response during pressure recovery. Since resumption of sustained injection in 2009, slightly increasing static pressure have been observed at the end of the falloff tests.

<u>References</u>

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Item 12: *In the EPA Region 6 January 27, 2016 letter, it is stated that monitoring well #2 (MW #2) before being plugged showed a continuous increase in ammonia, spontaneous potential, conductance, and pH consistent with the facility waste stream. PCC's response to the EPA Region 6 Letter identified that the source of contamination in the plugged MW #2 originated from shallow unconsolidated surficial sediments leaking into the well. The elevated pH in the current MW-2 Deep monitoring well was attributed to high alkalinity native to the monitored zone or cement contamination from the well construction. Please submit a plan, including installation of monitoring wells, to evaluate the nature and extent of contamination in the shallow groundwater. The plan must also include a provision for monitoring continuous pressure in the shallow groundwater over an extended time period to evaluate the injection well as a potential source of contamination. Additionally, please provide a calculation of the time that would be required for injectate potentially released from the injection well to reach monitoring wells equipped with pressure recording devices. Please submit this plan to DEQ within ninety (90) days of our receipt of this letter.*

Response: We are confused by ODEQ's request to evaluate the nature and extent of contamination in the shallow groundwater, as this request appears to be outside the scope of the the UIC program.

In response to ODEQ's comments, the continuous increase in ammonia, spontaneous potential, conductance, and pH in samples taken from the original MW #2 was addressed in PCC's Response to the EPA Region 6 letter. As stated in PCC's Response, a 2001 investigation concluded that the constituents present in the original MW #2 were originating from the shallow unconsolidated surficial sediments and leaking into the wellbore. Evaporation at the bottom of the wellbore then lead to the concentration of the constituents in the fluid column, resulting in the continuous increase referenced by ODEQ, until the original MW #2 eventually went dry because no new formation waters or other fluids were flowing into the well. The elevated pH in the current MW #2 was also investigated and is attributed to the high alkalinity of native formation waters or cement contamination introduced during the construction of the well. Notably, the pH of the samples obtained from MW #2 is consistently around 12 standard units, which is significantly higher than the pH of the waste stream injected into the Arbuckle Injection Interval, which typically ranges from 8-9 standard units.

The 2002 ALL Report demonstrates that there is no hydraulic connection between the injection interval and the overlying formations. High-resolution gauge monitoring of the Keokuk monitor well occurred during the 2002 annual ambient injection/falloff test, with a water level gauge placed in the Keokuk monitoring interval prior to beginning the injection portion of the ambient test. The gauge showed no response to either the injection period (pressure buildup) or the falloff period (pressure recovery) portions of the testing. Therefore, the Keokuk monitoring interval is isolated from the Arbuckle Injection Interval. The Report also concluded that neither of the monitored intervals (the Keokuk and Reeds Spring formations) was receiving water (i.e., groundwater or injectate) from the injection formation. Monitor well sampling conducted from 2002 (the year of the ALL report) to present further demonstrates that injected fluids are not migrating vertically into overlying formations. As explained in PCC's response to ODEQ's Item No. 11, the injected fluids are rather being dispersed over most if not all of the 1,000-foot-thick permeable Arbuckle reservoir that surrounds the wellbore.

The referenced contamination in the shallow groundwater and/or surficial sediments is possibly due to the historic use of the Mid America Industrial Park, including the operation of a government-owned munitions plant in the 1930's and 40's. PCC should not be required to evaluate the nature and extent of such contamination, as PCC has demonstrated time and again that it is not caused by or related to the PCC injection well. Further, PCC's current monitoring program meets all state and federal regulatory requirements for a Class I non-hazardous injection well.