Bittinger Injection Well Permits Technical Review

Subject:
UIC Permits PAS2D215BWAR and PAS2D215BWAR
Bear Lake Properties, LLC
Bittinger #1 and #4 Class IID Injection Wells
Warren County, Pennsylvania

USEPA Environmental Appeals Board
UIC Appeal No. 11-03

Prepared for:
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A review of the publically available documents related to the Bittinger #1 and #4 UIC injection well permits (PAS2D215BWAR and PAS2D215BWAR) was performed at the request of the Environmental Law Clinic of the University of Pittsburgh School of Law. The following technical review and comments are based on that available information. Additional documents may be in the possession of the applicant or the USEPA which are not currently available for review, and which may address some of the issues raised in the following review.

The following technical review is divided into subject areas addressing various parts of the permit applications, issued permits, public comments, USEPA responsiveness summary, petition for review of permit decision, USEPA response to petition for review, and order denying review in part and remanding in part.

1.0 Well Construction

Both Bittinger wells were perforated and the injection zone strata artificially fractured to improve productivity when completed in 1983 and 1987. No analyses are provided of the well #4 injectivity test, although such reservoir testing was performed as per the application document (operating data section). Reservoir injectivity test analyses of the Bittinger #4 pressure data may provide valuable information on the reservoir characteristics. Analysis of the data may indicate the extent of the induced or natural fractures, provide a site-specific permeability value for the area of review (AOR) calculation, and indicate potential reservoir boundaries such as sealing faults, leaking faults, or stratigraphic pinch outs. It is appropriate that the applicant and the USEPA evaluate this data, considering the valuable information that can be gained from such an analysis.

The operating and workover histories of the two Bittinger wells are not provided in the permit applications. During their 25+ years of operation, numerous well workovers are likely to have been performed, providing useful information related to any recurring mechanical integrity failures, general well failures, or other operational issues. A review of these well histories would allow the USEPA to either confirm or reject the current design and conditions of the wells as being appropriate for the proposed operational parameters (pressures, rates, etc), direct any prescribed monitoring efforts in the most effective and efficient manner, and provide the injection well owner with information to allow operation in a safer and more economic manner.

2.0 Fracture Gradient and Maximum Injection Pressure

The methodology used by the applicant to determine the permitted maximum surface injection pressure (MSIP) for the two injection wells appears overly lenient as to both average fracture gradient (0.933 psi/ft; revised downward from 1.027) and resulting maximum allowable surface injection pressure. Fracture gradients are typically 0.7-0.9 psi/ft, whereas the applicant's consultant (Tetra Tech) revised spreadsheet used a simple formula resulting in a fracture gradient of 0.933 psi/ft. The offset Trisket #1 gas well fracturing job report (dated 1984) indicated a fracture gradient of 0.94, but the source for that value as noted by the contractor (Dowell) is not given. The simple formula Tetra Tech used (no published source provided, although may be a derivative of one) to calculate the Bittinger wells' fracture gradients does not utilize the methodology typically employed in the industry (industry sources typically use Eaton (1969), Matthews & Kelly (1967), Hubbert & Willis (1957), or Christman (1973)), and uses data from adjacent wells (the two Trisket wells), not the permitted Bittinger wells. Furthermore, the Bittinger wells have already been artificially fractured at completion (no fracture job records were provided for these wells), so extension of those fractures will require a pressure significantly lower than that calculated to initiate fractures.

The formula the applicant used to determine the maximum injection pressure (MIP) does not employ variables of tubing size and length, injection rate, Poisson's ratio, or relative roughness factor, all of which are integral to a reliable calculation of the maximum allowable surface injection pressure. The fracture pressure in the adjacent Trisket #1 well occurred at 2,500 psi surface pressure; fracture extension pressures may be up to 1/3 lower (1,675 psi). As the maximum allowable surface injection pressure in the Bittinger #1 well is 1,696 psi, if that surface pressure is reached it is quite possible that extension of the previously induced fractures will occur in the injection zone. The results of such fracture extension related to vertical breaching of the confining zone strata or compromising the integrity the wells long string cement sheath is unknown.

3.0 Area of Review Calculation

The calculation (prepared by Tetra Tech) of the pressure increase in the injection zone as a result of injection into the Bittinger wells, used to define the zone of endangerment/area of review, provides no documented source for several critical reservoir input parameters employed. The permeability value used (100 mD) in the Matthews & Russell (1967) equation employed is critical to determining the size of the zone of endangerment and resulting area of review (AOR), but is a default value noted as being an estimate "representative of the average of the upper and lower range of values for this parameter". The permeability values for consolidated rocks which are fractured to increase productivity are often less than 10 mD, so it is unknown as to how the "representative" value of 100 mD was determined. As noted in the Well Construction discussion above, a valid site-specific permeability value could be obtained from an injectivity test, one of which was apparently performed on the Bittinger #4 well.

Calculations by the applicant of the pressure increases in the injection zone employ the Matthews & Russell (M&R) equation, which is a valid methodology, but without providing the source of the input parameters used the results are open to question. The sources of several input parameters are not provided. The initial injection formation pressure (128 psi) is not provided. The viscosity value source of 1.0 cP for formation brine is not provided. The compressibility value used in the calculation (3.0E-06) appears to be incorrect, as it more appropriately should be 6.0E-06 (which includes both the rock and fluid compressibilities). Use of the same input values as the applicant and independently calculating the pressure increases employing the M&R equation results in a pressure increase at the injection well over twice what is presented in the application. This pressure converts to a head level at the injection well after 10 years (with a single well injecting) which is significantly (640 ft) higher than the applicant's calculation. If the applicant's input values for their M&R model are incorrect, the zone of endangerment may be significantly larger, and exceed the ¼ mile radius area of review chosen by the applicant.

In its responsiveness summary to public comment regarding the permit application, the USEPA noted that it conducted its own zone of endangering influence calculation to verify the applicant's calculations, and found the calculations acceptable. None of the USEPA calculations have been provided for public comment or review, which brings into question the independent nature of the USEPA review. The USEPA notes that the only wells in the zone of endangering influence are production wells owned by the applicant, yet the applicant and the USEPA do not address the adequacy of cement of those production wells. Producing, as well as plugged wells, are potential pathways for pressure or fluid movement out of the injection zone and into USDWs, either due to substandard cement sheaths or casing corrosion, but there is no indication that these wells' records have been provided to, or reviewed by, the USEPA staff for adequacy of cement or casing.

4.0 Injection Zone Monitoring

The USEPA notes in the permits that it is requiring the operator to monitor water levels in several offset shut-in and depleted natural gas wells located within the defined areas of review. No discussion is presented as to what method will be employed to monitor fluid levels in these wells, or the sensitivity of such monitoring techniques. There is also no information presented confirming that these wells are currently in communication with the proposed Bittinger wells' injection interval. Semi-annual monitoring of these offset wells' fluid levels may not be at the frequency to provide adequate safeguards relative to pressure increases which might occur in the injection reservoir, potentially endangering USDWs. If fluid levels rise to within 100 ft of the USDW base in these monitor wells, the injection reservoir hydrostatic head fluid levels may have already reached the USDW at geographic locations closer to the injection wells, particularly since the pressure increase curve is not linear but is logarithmic. Any incorrectly plugged undocumented boreholes or natural transmissive conduits (faults, fractures) could endanger shallow USDWs before the proposed monitoring program results would initiate cessation of injection well operations.

In its responsiveness summary to public comments regarding the permit application, the USEPA noted that if endangerment of USDWs does occur, the USEPA can require the operator to remediate any aquifer system affected by the injection operation. Such a remediation would be impracticable to perform to the level of returning the aquifer to drinking water standards, and it is unlikely that the operator would have the financial resources to even attempt such a remediation effort. As such, this USDW safeguard is not a viable alternative to well failure.

5.0 Mechanical Integrity Testing

No mechanical integrity test (MIT) results were included in the original application, or with subsequent permit application modifications or USEPA documents released to the public. The value of these tests are that they demonstrate the current mechanical integrity of the wells, and provide assurance that the current condition of the casing, tubing, and packer are sufficient to prevent failure of the wellbore tubulars and contamination of underground sources of drinking water. No MIT results, in the form of annulus pressure tests, have been provided to show that the annulus has been pressure tested to 10 percent above the permitted maximum injection pressure and held for at least 30 minutes, with no more than a 5 percent loss in pressure (as required in the terms of the permit prior to operation). Passing results of a current MIT are typically required by most states with UIC regulatory primacy prior to issuance of an injection well permit. In the case of the Bittinger wells (commercial injection well permit applications are infrequently submitted in this state), the USEPA through its primacy over UIC applications in Pennsylvania should consider requiring such MITs to be available for public review and comment prior to final permit issuance or initiation of operations.

Additionally, no historical or recent cement bond or variable density logs were provided for either well's long string or surface casing which would document the height and quality of the cement in these wells, as required under the terms of the permit. These wells are nearly 30 years old, and as such significant internal and external corrosion may have occurred to the production casing, packer and injection tubing. Without recently performed casing inspection logs, there is no way to determine if the burst and collapse strengths of the casing strings or the integrity of the cement sheaths are still valid for the proposed operating pressures, or whether significant corrosion has occurred over the lives of these wells. The USEPA has permitted these injection wells without the applicant having provided any publically reviewable documentation that these wells have or can pass the mechanical integrity testing required by the permits. Once permitted, the mechanical integrity testing results will, according to the terms of the permits, only have to be reviewed and approved by the USEPA staff, thus preventing any opportunity for public review and comment prior to the well operator beginning injection operations.

6.0 Operating Requirements

The permit applications note that a pressure differential between the annulus and injection tubing will be kept, but that differential pressure value is not defined. A differential pressure of sufficient size (annulus pressure typically 100 psi above tubing pressure) can provide ample indication of mechanical integrity failure of the well, however no defined differential is noted in the permit. As such, the operator could potentially keep only a 5 psi differential on the annulus, which would not provide an adequate indicator of a loss of mechanical integrity, yet would fulfill the current terms of the permit. In addition, notification of the USEPA of an annulus pressure increase is required in the permit, but not a pressure loss, which is of equal importance in indicating a potential loss of mechanical integrity of the well. Also not defined in the permits is what value (either percentage or psi) of pressure change in annulus pressure would constitute a well failure, initiating shutdown of the well.

7.0 Plugging and Abandonment

The permit application notes that plugging costs are anticipated to be approximately $30,000 per well. Assuming that all 40 CFR §146 regulations are followed, this plugging cost estimate appears to be significantly under-represented. The plugging plan also calls for removing the upper section of the 4 ½-inch long string casing and filling that part of the borehole with a bentonite spacer, plus filling the surface casing with pea gravel. Removal of a section of the 4 ½-inch casing enhances the likelihood of upward migration or brine fluids into underground sources of drinking water (USDWs). Using pea gravel as plugging material in the surface casing provides insufficient protection to prevent movement between or into USDWs in case of surface casing failure due to long-term corrosion. The potential result is surface water contamination or spills from the facility and subsequent seepage into shallow USDWs through the conduit of an inadequately plugged borehole could occur.

8.0 Subsurface Geology

The permit applications provide limited geologic information on the site-specific subsurface geology underlying the two Bittinger wells, other than an open hole gamma ray wireline log on well #1 and a crude stratigraphic column. There is very limited discussion of the reservoir rock lithology, and no discussion of the local structure, faulting, stratigraphy, hydrogeology, reservoir history, rock to waste compatibility, or confining zone characteristics. The confining zone is critical to both the containment of fluids injected and limiting upward pressure increases, and yet no discussion as to the suitability of the overlying strata to provide this confinement is presented. The applicant appears to assume that if dolomite, evaporates, and shale are present in this overlying interval, then these strata provide confinement. There are many geologic examples of such strata being vertically transmissive due to inherent fracturing, faulting, diagenesis, and secondary solution. None of these issues are addressed by the applicant to any extent.

9.0 Earthquake Hazards

In its responsiveness summary to public comments regarding the permit application, the USEPA noted that earthquakes can occur as the result of under-pressurization of reservoirs as well as over-pressurization. That is likely only to occur in the shallow subsurface if shallow withdrawal of liquids or gas has occurred, not at the depths (4,200+ feet) of the proposed injection zone. Thus it is disingenuous to suggest that the lack of earthquakes due to depressurization of the local Medina gas reservoir is proof that the proposed injection wells location is not in an earthquake prone area. The USEPA also notes that with the withdrawal of natural gas, additional pore space has been created to accept the injection of fluids. This is not accurate, as the pore space in these consolidated rock strata does not grow with gas withdrawal, but is either replaced by formation brine or is still filled with natural gas present at a much lower reservoir pressure. It is probable that the Medina gas reservoir is pressure-depleted due to gas withdrawal, but still primarily a dry gas reservoir. Further, in the USEPA's response to petition for review, the author notes that the Medina Formation's currently reduced reservoir pressure results in an increased porosity for the formation, which is patently incorrect based on known geologic and reservoir principles. Together, the USEPA reasoning that the decreased reservoir pressures have increased pore space to accept injection fluids and also indicates that the area is not prone to earthquakes is flawed.

The underlying basement rock structure and faulting has been mapped regionally, but the applicant has not presented maps or other evidence demonstrating the lack of basement faulting in the area, nor whether any basement faults (if present) extend upward into the proposed Medina injection zone. There is also the possibility that faults are present locally within the Silurian and Devonian strata of the injection and confining zones, distinct from the basement rock structure. No published map data or other evidence has been presented by either the applicant or the USEPA demonstrating the presence or lack of fault features in the local area. The discussion of earthquake potential has been only lightly addressed in the permit applications and subsequent USEPA documents, whereas a more in depth appraisal of this potential hazard due to injection activities is warranted considering the heightened sensitivity of this subject due to regional earthquake activity associated with commercial Class II injection wells.

10.0 Summary

The discussion and documentation included in the permit applications, public comments, responses to public comment, permits issuance, petition for review of permit decision, and subsequent responses and orders do not appear to adequately address the issues raised in the sections presented above. These issues may at some point all be addressed adequately to the satisfaction of the petitioners, USEPA, and applicant, and well operations begin at the Bittinger wells in a safe and environmentally protective manner. However, until these issues are addressed in a satisfactory and complete manner, it would be prudent for the USEPA to reconsider the permit applications and proposed permits.

References

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