UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Response to Comments for The Issuance of an Underground Injection Control (UIC) Permit for Sammy-Mar LLC

On December 3, 2014, the U.S. Environmental Protection Agency Region III (EPA or the Region) issued a public notice requesting comment and announcing the opportunity for a public hearing for the proposed issuance of an Underground Injection Control (UIC) permit, PAS2D030BCLE, to Sammy-Mar LLC (Sammy-Mar) for one Class II-D underground injection well. EPA received numerous requests for a hearing which was held on January 7, 2015 at the Penfield Fire Hall in Penfield, Pennsylvania. About 100 people attended the public hearing and EPA received oral comments from people in attendance at the hearing. At the hearing, EPA extended the public comment period until January 21, 2015, and invited the submission of any additional written comments. In total, EPA received approximately 140 comments. During the public comment period, all the information submitted by the applicant was available for review at the Huston Township Municipal Building in Penfield and at the EPA regional office in Philadelphia.

In response to issues raised during the comment period, the Region requested additional information from the applicant, Sammy-Mar, including but not limited to the submission of a new topographic map and for clarifications or corrections to previously submitted application information. The Region also made modifications to the Draft Permit and Statement of Basis. The newly submitted information, the corrected Draft Permit and the revised Statement of Basis were provided to the public through the announcement of a second or subsequent public comment period which began on August 10, 2015, and closed on September 10, 2015. Several comments were received.

The response to comments which follows consolidates and provides responses to questions and issues raised by people who sent timely written public comment during the initial and subsequent public comment periods or who provided comments at the public hearing. EPA wishes to thank the public for their informative and thoughtful comments and to thank the people from the Huston Township Building and the Penfield Fire Hall that assisted EPA in hosting the public hearing.

1) What does EPA's UIC program have jurisdiction and authority to regulate?

Many people raised concerns about matters that the EPA UIC program does not have the jurisdictional or regulatory authority to address in the UIC permitting process. Some of the concerns mentioned were the potential for increased truck traffic, damage to the roads, increased noise, the potential for the diminishment of property values, and the possibility of surface spills and runoff into nearby streams. Additional public comments which related to protection of wetlands, origin of the brine, proximity to watersheds and streams, wildlife protection, emergency response capabilities, impact on hunting in the area, size and experience of the permittee, nearby water treatment facilities, other waste disposal options, and compensation to the local community, while legitimate, are also outside the Federal UIC permitting process and typically addressed by State and local regulations. When making the decision on whether to issue a UIC permit for Sammy-Mar, EPA's UIC jurisdiction is limited to determining whether the proposed injection operation will safely protect underground sources of drinking water (USDWs) from the subsurface emplacement of fluids and the injection operation must be in compliance with the federal underground injection control regulations. An USDW, as defined in the UIC regulations at 40 C.F.R. § 144.3, is an aquifer or its portion with less than 10,000 mg/l Total Dissolved Solids (TDS) and which currently supplies a public water supply or contains sufficient quantity of ground water to supply a public water supply.

Although the concerns described above may be relevant to residents, unless they are related to the protection of USDWs or compliance with the regulations, EPA is not authorized under the SDWA to address them through the UIC permitting process. Other local, county, state or federal ordinances or regulations may address traffic, road noise, zoning concerns, surface spill prevention and other concerns raised by these commenters.

The UIC permit contains several conditions that address compliance with other local, state or federal laws. Part I.A. of the permit provides that "Issuance of this permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, an invasion of other property rights or any infringement of state or local law or regulations." In addition, Part I.D.12 of the permit states, "Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation." The operator must also receive a permit from the Pennsylvania Department of Environmental Protection (PADEP) prior to initiating construction and operation of the injection well. Therefore, EPA's UIC permit is only one of several authorizations that a permittee may be required to obtain before it is allowed to commence construction and/or operation of the injection well.

2) Do the UIC regulations supersede local land use plans?

As mentioned in response number (1), EPA requirements do not supersede local, county or state laws or regulations.

3) EPA should require the operator to find another location for disposal.

EPA does not have the jurisdictional authority to require operators to construct an injection well in any particular geographic location. The location chosen by an operator is based on many factors such as: economics, property ownership and accessibility, and geologic suitability. EPA's statutory and regulatory responsibility is to review each UIC permit application it receives to determine whether USDWs will be protected from the proposed injection well operation and whether the operation will be in compliance with the UIC regulations. Likewise, EPA cannot deny a permit solely because of residents' opposition to the location, if the applicant otherwise meets the requirements of the UIC program.

4) The construction standards specified in the application do not comply with the standards required by the Pennsylvania Department of Environmental Protection (PADEP) for a new well.

In addition to obtaining a permit from EPA authorizing underground injection, Sammy-Mar will need to obtain a drilling permit from PADEP to construct this new well. PADEP is responsible for ensuring that its permit complies with PADEP's permit standards. EPA is without authority to require compliance with any PADEP standards that are different than EPA standards. Nevertheless, permits issued by PADEP for UIC operations are typically consistent with EPA UIC permits. Any construction and operating permit issued by PADEP typically includes the EPA permit requirements, since EPA is the agency with jurisdiction over the implementation of the UIC program in Pennsylvania. The USDWs will also be protected by three layers of casing and cement.

5) Commenters claimed that a topographic map depicting a one mile radius around the proposed property boundary was not provided by the applicant as required by the regulations. Other commenters claimed that the topographic map provided in the application was too small, and that some of the required information was missing from the maps in the applications, including abandoned coal mines and gas production wells. There were also several comments that the Bark Camp Mine restoration project was not depicted on any of the maps.

The UIC regulations at 40 C.F.R. § 144.31(e)(7) require the submission of a topographic map extending one mile beyond the property boundary, showing the location of the injection well or project area for which the permit is sought. According to those regulatory requirements, the map must depict the facility and each of its intake and discharge structures; each of its hazardous waste treatment, storage, or disposal facilities; each well where fluids from the facility are injected underground; and those wells, springs, and other surface water bodies, and drinking water wells listed in public records or are otherwise known to the applicant within a quarter mile of the facility property boundary. In addition, the map must depict active and abandoned mines, quarries and other pertinent surface features including residences and roads, and faults, if known or suspected within one mile of the proposed injection well. The applicant provided several maps, including a topographic map that was approximately 8" x 11" in size.

Some commenters stated that abandoned coal mines in the area were not depicted in the original map set provided. One commenter claimed that several gas production wells were located outside of the 1/4 mile but within the one mile boundary which were not included on the maps. Upon researching this claim, EPA determined that abandoned coal mines in the area of the proposed injection well were not depicted on any of the maps submitted with the original application. EPA also found that three unconventional gas production wells are located between 1/3 and one mile away from the proposed injection location which were drilled after the permit application was submitted.

Since receiving these comments, EPA required Sammy-Mar to submit additional information. Sammy-Mar provided a single topographic map that depicts the information required by the regulations. Included on the topographic map are abandoned coal mines and conventional and unconventional gas production wells within one mile of the proposed injection well. Three additional maps were provided showing certain features on separate maps for the viewers' ease of interpretation. All of these maps were placed for public review at the Huston Township Municipal Building on 11837 Bennetts Valley Highway, Suite 1 in Penfield, Pennsylvania. None of the features missing in the original maps and included in the updated maps are within the 1/4 mile "area of review" (AOR). The closest abandoned mine is over 1/2 mile from the injection well and the closest conventional gas well is about 1/2 mile away. A recently drilled Marcellus gas well (API well number (API#_033-27054) extends horizontally to about 1/3of a mile away. That well is the closest unconventional well to the location of the proposed UIC well. Due to their distance from the proposed injection well, and because the unconventional gas wells do not penetrate the injection zone, they should not impact or be impacted by the proposed injection operation. One commenter was concerned about possible impacts of the proposed injection well on the Bark Camp Mine project where an abandoned surface coal mine had been filled with fly ash and dredge material, and a composite layer was constructed on top of the mine to stabilize leachate and prevent additional acid mine drainage. The Bark Camp mine is located about 3/4 of a mile south of the proposed injection well and does not penetrate the injection zone or the confining layer. The Bark Camp Mine Project is mainly surficial and below ground. It is considered to be a shallow project with a total depth of no more than 400 feet. The mine therefore, would not be impacted by or impact the injection operation.

6) The construction parameters for the injection well are not protective of underground sources of drinking water. There may be freshwater formations below 1,250 feet, the extent of the cemented surface casing.

The UIC regulations at 40 C.F.R. § 147.1955(b)(1) require that an injection well surface casing be placed to a depth of 50 feet below the determined lowermost USDW. Sammy-Mar identified the lowermost USDW where the injection well will be located at a depth of approximately 800 feet, based on historical drilling log records.

As mentioned earlier, an underground source of drinking water, as defined in the UIC regulations is an aquifer or its portion with less than 10,000 mg/l Total Dissolved Solids (TDS) and which currently supplies a public water supply or contains sufficient quantity of ground water to supply a public water supply. Drilling records of nearby production wells within the one mile radius of the proposed injection well, as well as gamma ray logs, submitted in the permit application, confirm that drillers were not finding water that would qualify as a USDW below 800 ft. (See Permit Application Attachment B). In addition, based on EPA experience with the construction of other UIC wells in Pennsylvania, water bearing formations that meet the definition of an USDW are limited generally to within 500 to 800 feet below the land's surface. Generally below 1000 feet deep, Pennsylvania geology does not provide for aquifer systems that would be categorized as USDWs. Geologic formations at these depths are generally tight shale and limestone formations, which do not typically bear water. The tight shale and limestone formations can be followed by deeper oil and gas bearing formations, which may bear water, but due to the high levels of total dissolved solids, would not qualify as USDWs.

A commenter suggested that there may be fresh water as low as 2,635 feet and this water would not be protected from injection fluids. The drilling report provided with the permit application for well API# 033-25765 indicates there is a thin-bedded freshwater bearing formation at 2,635 feet, consisting of between 1/4 inch and 1/2 inch in total thickness. Because of its scant thickness, this formation would not be able to provide a sufficient yield to support a public water supply and therefore would not meet the definition of USDW. In addition, the permit application includes the drilling report for well API #033-25739 located less than 1/4 mile to the west of well API# 033-25765. That report identifies a salt water formation at approximately 2,800 feet deep. The drilling reports for well API# 033-25765 and well API# 033-25739 correlate with respect to the depth to water and distance from the proposed injection well and therefore, support the conclusion that the water bearing zones identified do not satisfy the definition of a USDW.

Furthermore, the construction requirements for the proposed injection well are protective of USDWs. The permit will require the applicant to place surface casing to a depth of 1,250 feet and cement the casing back to the ground surface. This exceeds the requirements of the UIC regulations at 40 C.F.R. Section 147.1955(b)(1). This depth also satisfies PADEP requirements.

The permit will also require the permittee to install two additional water protective casings, one to a depth of 200 feet and the other to a depth of 375 feet. The depths of these additional water protective casings are based on the depth of the only drinking water well located within the 1 mile radius of the propose UIC well. That well is reported to be about 100 feet deep. Both of these protective casings will be cemented back to the surface. One commenter noted that the permit application shows only two water protective casings. EPA has corrected that inadvertent error to state that there will be a total of three water protective casings installed. The corrected draft permit was placed for public review as part of the supplemental comment period in August, at the Huston Township Municipal Building on 11837 Bennetts Valley Highway, Suite 1 in Penfield, Pennsylvania.

Some commenters were concerned that the drilling of the injection well could affect their drinking water. Sometimes well drilling can initially increase water turbidity and affect water pressure. In this case, the injection well design and construction plan minimizes any impacts on USDWs during construction because two additional water protection casings will have been installed and cemented prior to further drilling. This drilling and casing process isolates the USDWs during construction to prevent pressure loss and turbidity. To the extent that any turbidity occurs, the effects are usually temporary and cease once the water protection casings described have been set and cemented.

After the injection well is drilled and the well casings are installed and cemented, but before the injection begins, the permittee is required by the permit to submit to EPA a construction completion report providing details about the drilling, completion and testing of the well. The completion report must include the injection well drilling records, logging information, cementing records and mechanical integrity testing information. EPA will review this information to verify that the geological information submitted in the permit application was accurate, and that the injection well was properly constructed and cemented to prevent leaks during operation and fluid movement out of the injection zone through the injection wellbore.

EPA will review the cementing logs to verify proper cementing without voids between the casing and the well bore that could provide a conduit for fluid movement. Also, the required mechanical integrity test must show that there are no internal failures in the tubing, casing or packer installed within the well before injection operations take place. If new information obtained from the completion report warrants changes to the permit, EPA will modify the permit conditions as appropriate.

7) The long string casing should be cemented back to the surface. The uncemented annular portion, extending from 1250 feet to about 5030 feet, could allow fluid movement between the formations. In addition, during the cementing process, pressurized gases and fluids from the injection formation could channel upward through the 2000 feet of cement and potentially migrate through the uncemented portion of the casing and into a USDW.

The permit includes construction requirements for the injection well that include the installation of long string casing to a depth of 7,030 feet and circulation of cement behind the long string casing to approximately 5,030 feet. The cement placed behind the long string casing is designed to seal and isolate the well to prevent fluid movement from the injection formation. Cement logs will confirm the adequacy of the cement job. Sammy-Mar's proposed well construction meets EPA's regulatory requirements for Class II wells in Pennsylvania, found in the UIC regulations at 40 C.F.R. §147.1955(b)(5), which were adopted to prevent endangerment of the USDWs.

During the cementing process, the pressure exerted by the column of cement behind the annulus at the bottom of the long string casing would be approximately 2200 pounds per square inch (psi) based on the density of class A cement. The reservoir pressure in the injection formation reported in the permit application is 25 psi. Therefore, fluids present in the injection formation would not overcome the pressure exerted by the column of cement in the annulus above and could not create channels upward into the cement.

While the UIC regulations do not require pressure monitoring in the annular space behind the uncemented long string casing, the PADEP does require such monitoring at the well head. This pressure is limited by PADEP not to exceed a specific limit based on the depth of the uncemented portion of the long string casing. Such monitoring is intended to prevent the movement of fluids between and into formations.

8) The proposed injection well is located close to several geologic faults and this could cause fluid migration and seismic activity.

As explained in the Statement of Basis, although EPA must consider appropriate geological data on the injection and confining zones when permitting Class II wells, the SDWA regulations for Class II wells do not require specific consideration of seismicity, unlike the SDWA regulations for Class I wells used for the injection of hazardous waste. See regulations for Class I hazardous waste injection wells at 40 C.F.R. §§ 146.62(b)(1) and 146.68(f). Nevertheless, EPA evaluated factors relevant to seismic activity such as the existence of any known faults and/or fractures and any history of, or potential for, seismic events in the area of the injection well as discussed below and addressed more fully in *"Region 3 framework for evaluating seismic potential associated with UIC Class II permits, updated September, 2013."*

An EPA report that looks at injection-induced seismicity ("Minimizing and Managing Potential Impacts of Induced-Seismicity from Class II Disposal Wells: A Practical Approach," EPA UIC National Technical Workgroup, February 5, 2015[1]) provides a standard operating procedure for assessing regional and local seismicity when reviewing permit applications. This procedure correlates any area seismicity with past injection practices; evaluates geological information to assess the likelihood of activating any faults; evaluates storage capacity of the formation with consideration of porosity and permeability; includes operational parameters to limit injection rate and volume and to limit operation at below fracture pressure; and requires monitoring of injection pressure and rates.

Induced seismicity background

Under certain conditions, disposal of fluids through injection wells has the potential to trigger seismicity. However, induced seismicity associated with brine injection is uncommon, as conditions necessary to trigger seismicity often are not present. Seismic activity induced by Class II wells is likely to occur only where all of the following conditions are present: (1) there is a fault in a near-failure state of stress; (2) the fluid injected has a path of communication to the fault; and (3) the pressure exerted by the fluid is high enough and lasts long enough to allow movement along the fault line. Induced Seismicity Potential in Energy Technologies, National Academy Press, 2013, at p. 10-11. Although there are approximately 30,000 Class II-D wastewater disposal wells operating in the United States, only a few of these wells have been documented to have triggered earthquakes of significance and none of these earthquakes, which the Region is aware of, has caused injected fluids to flow into or contaminate a USDW.

The presence of a fault in a receiving formation potentially creates a more vulnerable condition for a future seismic event. A fault is a fracture or a crack in the rocks that make up the Earth's crust, along which displacement has occurred. Where a fault is present near an injection site, scientists believe that injection can trigger seismicity when the pore pressure (pressure of fluid in the pores of the subsurface rocks) in the formation increases to such levels as to overcome the frictional force that keeps the fault stable. Pore pressure increases with increases in the volume and rate of injected fluid. Thus, the probability of triggering a significant seismic event due to injection, where the injection fluid reaches an active fault, increases with the volume and the rate of fluid injected. In addition, the larger the volume injected over time, the more likely a fault could be intersected, because the fluid will travel farther within a formation. When injected fluid reaches a fault, frictional forces that have been maintained within that fault can be reduced by the fluid. At high enough pore pressure, the reduction in frictional forces can result in the formation shifting along the fault line, resulting in a seismic event.

Because increases in pore pressure due to the rate and the volume of injected fluid can act on existing faults and provide a mechanism for induced seismicity, most examples of injection-induced seismicity are in cases where the receiving formation has low permeability and/or the pressure or volume of fluid injected over time is quite large. Formations such as crystalline

[1] The EPA UIC Technical Workgroup finalized this report on February 5, 2015 at EPA Headquarters.

basement rock (deeper geological formations of igneous or metamorphic rock that underlie layers of sedimentary rock) have very low permeability. Permeability is the ease with which a fluid can flow through the pores in a rock layer. Where permeability is low, injected fluid cannot flow easily through the pores in this rock and therefore flow is oriented mainly through existing fractures or faults in the rock (secondary permeability). These kinds of rock formations have high transmissivity and low storativity. This means that the formation cannot store a lot of fluid; rather fluid moves farther and faster in these formations than in more porous formations. Because of the high transmissivity and low storativity of these kinds of rocks, the potential exists to induce pore pressure increases at considerable distances away from the injection well.

Faults near the proposed well

The UIC regulations at 40 C.F.R. § 146.22 require that all new Class II injection wells be sited in such a fashion that they inject into a formation which is separated from any USDW by a confining zone that is free of known open faults or fractures within the AOR. Open faults, or transmissive faults, allow fluid to move along the fault and between formations. Non-transmissive faults, on the other hand, act as a barrier which would prevent movement of fluid along the fault and into another formation across the fault. Because not all faults act as a channel to conduct fluids, but rather as barriers, the UIC Class II requirements focus on ensuring that open faults are not present within the area an injection operation could influence.

The applicant submitted, and EPA reviewed , geological information indicating the probable presence of two faults which appear to be located about one-quarter mile from the injection well site, in the Oriskany/Huntersville Chert receiving formation. Drilling records and geologic cross sections provided in the permit application show displacement of the bedrock. The presence of the fault to the south of the proposed well in the Oriskany/Huntersville Chert receiving formation is confirmed by drilling records included in the permit application. In addition, a seismic survey was submitted by Sammy-Mar which appears to indicate that both faults are localized and non-transmissive. These non-transmissive faults provide the structural confinement which enabled natural gas to be fully contained within, and later produced from this area from the 1950s through the present. Other gas production wells drilled outside the fault zone in which the Sammy-Mar well is located were plugged for lack of production. For example gas production well API# 033-20047 was documented as a dry hole and was actually plugged and abandoned in 1959 shortly after completion. This gas well production history helps to illustrate that the displacement of the Huntersville Chert/Oriskany formation created by the faults established confinement of natural gas and formation fluids within the immediate fault block structure and that fluid flow (natural gas and produced water) along or across the faults is not evident. Because of the non-transmissive nature of the faults, fluid that is injected into the Huntersville Chert/Oriskany formation at the proposed injection well location should be confined within the fault block.

No geologic evidence indicates that these faults extend to the deep Precambrian crystalline basement rock. In this location, Precambrian basement rock is approximately 9,500 feet below the proposed injection zone.

These non-transmissive faults discussed above in the Oriskany/Huntersville Chert formation do not extend to the surface. This can be seen by reviewing the results of a seismic survey submitted with the permit application which does not show displacement caused by these faults extending upward.

The United States Geologic Survey (USGS) tracks, records and maps faults and earthquake epicenters in certain areas throughout the United States. The USGS monitors several active seismometers located in Clearfield County in the vicinity of the proposed well. The USGS as well as the Pennsylvania Department of Conservation and Natural Resources (PA DCNR) which includes the Bureau of Topographic and Geologic Survey, the principal organization that conducts geologic research in Pennsylvania, have not recorded any seismic activity that has originated in Clearfield County.

Although the USGS has recorded seismic events in Clearfield County, such events are extremely rare. Earthquakes that have been recorded, as well as felt in the area, were the result of seismic events that had their origins in other parts of the state or outside of the state's borders. Clearfield County is not located in a seismically active area and although there are a couple sub-surface geologic faults located within one-quarter mile of the injection well site, their presence in the area will not be impacted by the injection operation because they do not penetrate the injection formation. The PA DCNR website http://www.dcnr.state.pa.us/topogeo/hazards/earthquakes/index.htm has an interactive seismicity map and catalog of all recorded seismic events in or near Pennsylvania from 1724 to present.

During an earthquake, energy is radiated away from the hypocenter of the fault in the form of seismic waves. This energy causes the ground to move as the seismic waves travel away from the fault. Seismic events that have been felt in Clearfield County are seismic waves that were transmitted through the bedrock from the hypocenter of a seismic event that originated elsewhere. Seismic events which originate elsewhere do not provide information about the geology of Clearfield County, even if these events were felt there. The distance that the seismic waves travel is not indicative of the extent of the fault where displacement occurred due to the earthquake. Although seismic waves can cause the ground to shake a large distance away from the hypocenter of the earthquake, the fault where displacement occurred does not extend everywhere where the earthquake was felt. For this reason, history of seismicity that originates in areas other than the location of the injection well does not provide information about potential faults or formation pressures at the location of the well. For example, in the case of the Northstar 1 injection well in Youngstown, Ohio, the earthquake is believed to have been generated by injection into Precambrian crystalline bedrock, a deeper receiving formation, with different geology, than what is proposed for the Sammy-Mar well. The seismic waves radiating away from this area were felt in locations at significant distances away from Youngstown, including western Pennsylvania, but they have no relevancy to the geologic setting in Clearfield County or at the Sammy-Mar location.

Factors affecting fluid transmission and pore pressure

Research indicates that continuous very high rates of injection or over-pressurization of a geologic formation can contribute to the possibility of seismic activity. Conditions included in the Sammy-Mar permit were developed to prevent over-pressurization of the injection formation.

The permit limits the surface injection pressure during the injection operations to 2598 psi and the bottom-hole injection pressure to 6194 psi. The surface injection pressure and the bottom-hole injection pressure limits were calculated to ensure that, during operation, the injection will not propagate existing fractures or create new fractures in the formation. Limiting the pressure not only prevents the propagation of fractures that could become potential channels for fluid movement into USDWs but that could also serve as conduits for fluids to travel from the injection zone to known or unknown faults.

The Sammy-Mar permit will also require a yearly pressure fall-off test. During the test, the rate of fluid and volume injected is increased over a predetermined time period, and then the injection is stopped. The top-hole pressure is monitored during active injection and after injection is stopped. The fall-off testing will assist EPA in determining injection reservoir bottom-hole conditions as well as the flow conditions that the injection formation will exhibit during the injection operation. Analyzing flow conditions can help determine whether a preferential flow pattern exists and assist in determining whether that flow could be moving toward or coming into contact with the nearby faults.

A significant volume of gas and brine has already been removed from the proposed injection reservoir during previous gas production operations making the Huntersville Chert/Oriskany formation receptive for the disposal of fluid. The Huntersville Chert/Oriskany formation, the intended injection zone, has been a prolific producer of natural gas in this area since the late 1950s/early 1960s. Literature, as discussed below, documents that the accumulation of gas there is related to the fault system in the Oriskany, because gas migration has not been observed between fault zones. Evidence from gas production records from the PADEP Office of Oil and Gas Management, Oil and Gas Reporting Website[2] indicates that gas production wells located within the Oriskany fault structure, where the injection well is proposed, have produced significantly greater volumes of natural gas and produced water than gas production wells located outside of this fault structure. The removal of both natural gas and brine from the natural pore spaces that exist in a formation lowers the formation's pore pressure (reservoir pressure) and creates available storage capacity making reservoirs with a history of gas and oil production good candidates for the disposal of fluids. The National Academy of Sciences Report entitled Induced Seismicity Potential in Energy Technologies (2013) indicates that where fluids are injected into sites such as depleted oil, gas or geothermal reservoirs, these reservoirs can make excellent disposal zones, because in those cases, pore pressures may not reach their original levels, or in some cases, may not increase at all due to the relatively small volume of fluid injected compared to the volume of fluid extracted.

One commenter states that little brine has been removed from the receiving formation during gas production and that therefore there is not much pore space for the injected fluid. Ultimately, the storage capacity of a receiving formation will be determined by the injection well's operating pressure. This particular injection well is limited by the maximum injection pressure established in the permit for the well. See Part III.B.4 of the permit. Therefore, if pressure buildup occurs quickly during operation, an indication of limited storage capacity, the operation of the injection well will be limited by the established maximum injection pressure.

[2] The PA DEP Office of Oil and Gas Management, Oil and Gas Reporting Website is a public website located at www.paoilandgasreporting.state.pa.us.

As pore space capacity to assimilate injected fluids decreases, the pressure needed to inject fluids will need to increase. Under the operating parameters of the permit, if such pressure reaches the maximum injection pressure, injection cannot proceed regardless of how long the well has been operating. Therefore, if the storage capacity of the receiving formation is limited, the result will be a reduced operating life of the injection well under the terms of the proposed UIC permit.

The public brought to EPA's attention recent seismic events that have occurred in Ohio, Texas, Oklahoma, West Virginia and Arkansas that were attributed to the underground injection of fluids produced from oil and gas extraction activities. EPA recognizes that there is strong evidence that supports the underground injection of fluids as being the trigger that led to these seismic events. In some cases, these earthquakes occurred in locations where there were no known faults. However, the likely relevant factors behind these seismic events, specifically the geologic setting or the operational history of the injection wells, differ significantly from the proposed Sammy-Mar injection operation as discussed above. Scientific evidence indicates that seismic activity is most likely associated with the depth of a well, the volume and rate of injection, and the injection pressure. In these aspects the Sammy-Mar well contrasts greatly with the wells in the known cases of induced-seismicity.

The "Preliminary Report on the Northstar1 Class II Injection Well and the Seismic Events in Youngstown, Ohio Area, Ohio Department of Natural Resources, March 2012", has indicated that the seismic activity associated with the injection of fluid in the Northstar 1 was likely due to the injected fluid coming into contact with a fault system located in deep Precambrian basement crystalline bedrock. This bedrock is located beneath the sedimentary bedrock structure and has very low permeability. Fluid injected in crystalline basement rocks is essentially transmitted by a network of inter-connected fractures and joints. Because of the high transmissivity (the ability of fluids to move through rock) and minimal ability to store fluids in these kinds of rocks, the potential exists to create flow at considerable distances from the injection well. Once flow reaches a fault, it allows the frictional forces that exist to be reduced thereby allowing the rocks to slip, leading to seismic activity.

In contrast, the injection zone for the Sammy-Mar injection well is the Huntersville Chert/Oriskany formation, a sedimentary rock formation of Lower Devonian age, which has a higher natural porosity and greater interconnection of that pore space throughout the formation than the crystalline bedrock. The Huntersville Chert/Oriskany formation is located at a depth of approximately 7030 feet below land surface at the proposed injection well site. The Precambrian crystalline basement rock in the area of the proposed injection well is located approximately 9,500 feet below the proposed injection formation (Pennsylvania Geologic Survey – General Geology Open File Report 05-01.0). In the Huntersville Chert/Oriskany formation the rock will more readily store injected fluid and the permeability (the available interconnected space between the grains and natural fractures in the rock) within the rock structure will allow a more uniform flow to occur throughout the formation. For these reasons, the geologic setting and reservoir characteristics of the proposed injection well are very different than the circumstances encountered in Ohio. For the proposed Sammy-May well, injection will not occur within, or flow into, the deeper Precambrian crystalline rocks.

Regarding the seismic event in Texas, a study conducted at the University of Texas at

Austin's Institute for Geophysics (Proceedings from National Academy of Sciences, August, 2012), indicates that the seismic activity was likely triggered by the significant volume of fluid that was injected in a relatively short period of time. Approximately 150,000 barrels of fluid per month had been injected down a disposal well since 2006. This equals approximately 75,600,000 gallons of fluid injected yearly for about a five year period. The proposed Sammy-Mar injection well will be limited to a maximum of 30,000 barrels per month, one-fifth the monthly limit of the Texas well. Researchers studying the circumstances that led to the seismic events in both Oklahoma and Arkansas believe that over-pressurization of a nearby fault after years of injection may have led to the seismicity. Similar to what happened in Ohio, injected fluid migrated into Precambrian rocks, which in the case of those wells were found just below the injection zone, and came into contact with a fault ("Science", Volume 335, March 23, 2012). It is believed that the reduction of the frictional stress in the faults led to slippage along the faults (From the journal "Geology", co-authored by researchers with USGS and Oklahoma Geologic Survey, March 3, 2013).

In Braxton, West Virginia, there is no definitive evidence, unlike the evidence produced for Youngstown, Ohio, that concludes injection was responsible for the seismicity in the area. However, information obtained from the West Virginia Department of Environmental Protection seems to indicate that when the injection rate, and later the injection volume, were reduced in the injection well, seismic activity in the area ceased. The geology where this injection well was completed is also different from the geology of the proposed Sammy-Mar injection well. The injection well in West Virginia is drilled into the Marcellus Shale, which has low permeability. The last recorded seismic event in the Braxton, West Virginia area was recorded in January, 2012; the injection well that was suspected of causing the seismicity continues to operate.

Several commenters also mentioned synclinal and anticlinal features in the geology of the area of the proposed well. Synclines and anticlines refer to folds in geological layers similar to surface hills and valleys. These synclines and anticlines also occur in the subsurface but they have no bearing on the faults located in the area of the proposed injection well. The specific syncline in question, the Caledonia Syncline, travels through Indiana County, located directly adjacent to Clearfield County. The synclines and anticlines in the area should not impact injection fluid movement because they are shallow and the injection well will be drilled to a depth of over 7,000 feet, and not in communication with these surface features.

9) Endangerment of USDWs due to earthquakes

Of the hundreds of thousands of injection wells operating in the United States, EPA is not aware of any case where a seismic event caused an injection well to contaminate a USDW. An inquiry through EPA regional offices did not reveal any reports of earthquakes having affected the integrity of injection wells in the cases of induced-seismicity in Ohio, Texas, Oklahoma, West Virginia or Arkansas. A number of factors help to prevent injection wells from failing in a seismic event and contributing to the contamination of a USDW. Most deep injection wells, that are classified as Class I or Class II injection wells are constructed to withstand significant amounts of pressure. They are typically constructed with multiple strings of steel casing that are cemented in place. The casing in these wells is designed to withstand both significant internal and external pressure. The American Petroleum Institute (API) (see www.api.org) and oil and gas service companies such as Halliburton Services (see Halliburton Cementing Tables, 1980), have developed industry standards for casing and cementing wells. Drillers are required to follow these standards.

Similarly, the proposed Sammy-Mar injection well, under the terms of the permit will be constructed with multiple strings of steel casing cemented in place. Furthermore, the proposed Sammy-Mar injection well will be required under the permit to be mechanically tested to ensure integrity before it is operated and will be continuously monitored during operation to ensure that mechanical integrity is maintained. This mechanical integrity testing is required by the UIC regulations for all brine injection wells. If a seismic event were to occur that affected the operation and mechanical integrity of the Sammy-Mar injection well, the well will be designed to automatically detect a failure due to pressure changes in the well annulus between the long string casing and the injection tubing, and this would cause the well to automatically stop injection. See Part II.C.2 of the Permit.

10) Comments questioned where the confining zone(s) were located and the adequacy of the confining zone above the injection zone.

The confining zone is defined as a geologic formation, group of formations or part of a formation that is capable of limiting fluid movement above an injection zone. 40 C.F.R. § 146.3. Formations with low porosity and permeability, limit fluid from passing through it. A series of low permeability shale and limestone formations are located above the receiving formation and separate that formation from the lowermost USDW. The Sammy-Mar application indicates a confining layer immediately above the injection zone, the Onondaga Limestone formation that will serve as an initial confining formation. The Onondaga Limestone formation is approximately 12 feet thick in the area of the injection well according to specific info in the permit application. This thickness, is sufficient to prevent the movement of injected fluid into shallower geologic formations since fracturing is not permitted in the injection formation during injection. In addition, the Hamilton Group and Tully limestone, geologic formation above the Onondaga, will serve as additional confining formations preventing fluid movement upward toward the USDWs. The Hamilton group consisting of medium gray shale directly overlays the Onondaga limestone and has a thickness of approximately 500 feet. Directly above the Hamilton group is the Tully Limestone Formation, a hard, dark limestone approximately 100 feet thick. Cumulatively these formations provide confinement for all injected fluids, as they did for previous natural gas within the Huntersville Chert formation.

The proposed Sammy-Mar injection well 4 ½ inch long string casing will be cemented from the interval beginning above the Tully limestone through the Tully, Hamilton, and Onondaga limestone to the injection formation, preventing fluid movement above those formations.

Several commenters expressed concern that fracturing of the Marcellus gas production wells in the area could have introduced fractures in the confining zone within the area of review. While there are several Marcellus gas production wells completed within a one mile radius of the proposed Sammy-Mar injection well. The closest Marcellus well (API # 033-27054) extends to about 1/3 mile from the proposed injection well and is separated from the injection formation by the confining formations previously described.

The UIC regulations for Class II injection wells limit injection pressure to prevent the fracturing of the confining zone **adjacent to the** USDW however, the Region has developed a more protective approach when it issues permits, by establishing injection pressure limits to prevent the fracturing of the injection formation itself. Establishing a maximum injection pressure that prevents fracturing of the injection formation also protects the adjacent confining zones. Therefore the injection pressure limit of 2598 psi will protect the Onondaga Limestone Formation, the confining zone adjacent to the injection zone, from fracturing and prevent any communication with the Marcellus Shale. The Marcellus wells are outside of the area of review, but even if within the area of review, they do not penetrate the injection formation therefore they can continue operations.

11) A commenter raises the issue that the UIC Permit has no provision regarding the siting of future Marcellus gas wells in the vicinity of the proposed Sammy-Mar injection well.

At the present time there do not appear to be any Marcellus gas wells permitted within the AOR. Marcellus wells could be permitted in the vicinity of the proposed injection well in the future. The wells could only be drilled as deep as the Marcellus formation which is separated from the injection formation by the Onondaga Lime formation, a confining zone. The PADEP is responsible for the regulation of any such wells. Any fracturing of a formation outside the Marcellus Shale would constitute a violation of PADEP regulations.

12) Commenters raised concerns that the injected brine wastewater may be incompatible with salt water already existing in the injection formation and that the chemicals proposed to be added to the injection fluid for maintenance of the well are not Class II fluids by definition.

The produced fluid proposed for injection is very similar to and compatible with the brine fluid that is already present in the Huntersville Chert/Oriskany formation and others produced in Pennsylvania. The corrosion inhibiting and oxygen scavenging additives proposed for maintaining the well, are products that will be mixed with the produced fluid and are designed to preserve the integrity of the injection well. These products are used in very low quantities; about one part per 4,000. In these minute concentrations, their toxicity is estimated to be very low. In addition similar additives are used for both production wells and drinking water wells. Further information can be obtained from both the American Petroleum Institute (API) and the American Water Works Association (AWWA) regarding industry practices associated with well maintenance additives. Based on the comments received, the permit has been modified in Part III B. 2 to identify that produced fluids and additives necessary for maintaining the integrity of the well are permitted.

13) Abandoned or improperly plugged gas wells may pose a risk to drinking water supplies. The 1/4 mile Area of Review (AOR) may not be adequate. Injection fluids could migrate beyond the AOR.

Without certain precautions, abandoned wells can pose a risk to USDWs by providing a conduit for the migration of fluid out of an injection zone. Therefore, the UIC regulations and the permit impose certain requirements on an injection well operator to protect USDWs from that risk. Specifically, the operator is required to determine whether any abandoned wells exist within a specified area, calculated and defined as the AOR around the proposed well, which could pose a threat to USDWs. If abandoned wells are found to exist within a one-quarter mile AOR, then the permittee must either perform corrective action, which requires plugging those wells, or use the abandoned wells for monitoring the injection formation during operation. When abandoned wells found within the AOR have been plugged as verified by a certificate of plugging which is submitted to the PADEP, EPA accepts this information as confirmation that a well has been plugged properly in accordance with PADEP plugging requirements which were in effect at the time the well was plugged. The permit application identifies only one abandoned well within the proposed 1/4 mile AOR that has been plugged. The abandoned well, according to the plugging record provided, is located approximately 1/4 mile from the proposed UIC well and was only 370 feet deep and did not penetrate the injection formation which is over 7,000 feet deep. Two additional deep gas wells which do penetrate the injection zone, are located on the perimeter of the 1/4 mile AOR, and will be used by the permittee as fluid monitoring wells.

Sammy-Mar proposed a fixed radius of one-quarter mile (1320 feet) for the AOR and a maximum injection volume of 30,000 barrels per month. To review the proposed fixed radius, EPA considered past practices at the proposed injection well site and the chemistry of the fluids to be injected. The injection well will be used to inject brine and related fluids into a depleted formation from which large quantities of gas have been extracted, as well as brine similar to that which will be injected. The application also provides information on other wells in the area and on the residents and landowners surrounding the site.

Although not required when applying a fixed radius for AOR, the permit requires Sammy-Mar to submit certain geologic information to EPA that will be collected after the proposed injection well is drilled and during well development. Specifically, Part III.A.7 of the permit requires Sammy-Mar to provide the porosity and permeability values within the injection formation prior to conducting injection operations. EPA does not specify a method for determining porosity and permeability because there is more than one accepted method for determining such values. Based on this information and other existing parameters, EPA will calculate the zone of endangering influence (ZEI), in accordance with 40 C.F.R. § 146.6(a)(2) using the modified Theis equation, and if warranted, may modify the 1/4 mile fixed radius AOR.

For ongoing confirmation of the adequacy of the AOR, the permit requires an annual pressure fall-off test, even though fall-off tests are not typically required of Class II wells. (fall-off testing is a regulatory requirement for Class I hazardous waste disposal wells.) A fall-off test will help to determine flow characteristics within the injection zone and can establish whether there is any preferential flow or flow changes over time. The pressure fall-off test will also help to determine whether reservoir pressures in the injection formation become greater than anticipated. If a buildup of reservoir pressure occurs sooner than anticipated, the permittee may need to change its operational parameters or cease operation to avoid violating the maximum injection pressure permit condition, or the Region may require a modification of the AOR.

Two existing wells located at about the one-quarter mile perimeter of the AOR penetrate the injection zone and potentially could allow injected fluids to move upwards out of the injection zone. Well API# 033-20263 is located to the northwest, and well API# 033-20228 is located to the east of the proposed injection well. Rather than plug these wells, the permit requires Sammy-Mar to utilize the wells for monitoring the fluid level on a quarterly basis.

In addition, according to information submitted by the permittee and the public, there are two shallow wells: one is a private drinking water well, and the other is an operating gas well, located within the one-quarter mile AOR. Both the drinking water well and the operating gas well are much shallower than the injection zone. The UIC regulations do not prohibit locating Class II injection wells near drinking water wells. Instead the regulations and the permit establish requirements to protect USDWs from endangerment by the injection operation. In the case of this injection well, there will be three separate cemented steel surface casings protecting shallow drinking water wells and the lowermost USDW. In addition, approximately six thousand feet of rock containing numerous confining zones exist between the injection zone and the formations that supply drinking water to shallow wells. Finally, aside from the two fluid level monitoring wells located at the quarter mile radius, there were no conduits (e.g., abandoned wells that penetrate the injection formation) identified within the AOR that would allow upward fluid migration into USDWs.

14) Injecting fluids under pressure may migrate back to the surface? What assurances are there that the injection fluids will remain in the injection zone?

Many commenters expressed concern that once the fluid is injected under pressure it will come back to the surface. As discussed in response #10 above, there is a confining zone, or group of geologic formations, immediately above the injection zone, the Onondaga Limestone formation. This is a limestone geologic formation which typically has a very low permeability, giving it the ability to confine and trap fluids from migrating upwards. In addition, other confining zones exist above the Onondaga Limestone and beneath the lowermost USDW. As noted in this document, the Huntersville Chert/Oriskany formation, the intended injection zone, has produced natural gas in this area for many decades. It is the confinement of this natural gas that enabled successful production. The natural gas and fluids in the formation were also under pressure prior to and during production. The confining zoneabove the Huntersville Chert/Oriskany formation, as well as other geologic factors such as the faulting discussed in response #8,that kept this natural gas in place. Natural gas did not migrate to the surface on its own from the Huntersville Chert/Oriskany formation. It required gas production wells to be drilled into the formation before natural gas could be recovered. Therefore, the confining zone will similarly prevent fluid movement out of the injection formation.

Several other factors will keep the injected fluid in place and not allow it to migrate out of the injection zone. One factor is that the permit does not allow the injection pressure to exceed the injection formation's fracture pressure and thereby prevents fracturing that could allow fluid to migrate out of the injection zone. In addition, no other artificial penetrations (e.g., abandoned wells) of the injection zone were identified within the AOR. The absence of any other artificial penetration into the injection zone within the AOR will prevent injection fluid from migrating out of the injection zone and into USDWs.

To confirm that the injected fluid remains in the receiving formation, the permit requires continuous monitoring of pressure conditions within the injection well. In addition, the annual pressure fall-off testing will establish reservoir pressure conditions and help analyze fluid movement within the reservoir. The permit also requires fluid level monitoring wells which will provide real-time pressure measurements at two locations at the outer edge of the AOR.

15) Injection fluids may migrate into abandoned coal mines in the area and could eventually find their way into shallow ground water or surface water.

The coal mines mentioned by commenters are over 1/2 mile away from the proposed injection well as depicted in some of the maps provided by the applicant. In addition, these mines are not deep relative to the depth of the injection zone and are, in fact, located at a depth of about 400 feet or less from the surface. EPA is requiring that the Sammy-Mar proposed injection well have surface casing placed to a depth of 1,250 feet below land surface and cemented back to the surface. The depth of the lowermost USDW has been located at a depth of approximately 800 feet. The coal mines therefore are both too distant from the injection well and are too shallow to influence or be influenced by the injection operation.

16) Are the fluids being injected into the well toxic, hazardous and/or radioactive? Why can't you just treat the brine water and dispose of it another way?

Individual constituents contained within fluid produced from an oil or gas production reservoir could be determined to be toxic, hazardous or radioactive. However, these fluids, when generated in association with oil and gas production, are exempt from hazardous waste regulation under the UIC program because they are not classified as hazardous under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. § 6901 et seq. In December 1978, EPA proposed hazardous waste management standards that included reduced requirements for several types of large volume wastes. Generally, EPA believed these large volume "special wastes" were lower in toxicity than other RCRA regulated hazardous wastes. Subsequently, Congress exempted the wastes from RCRA Subtitle C pending a study and regulatory determination by EPA. In 1988, EPA issued a regulatory determination that the control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted, in part because other State and Federal programs, such as the UIC program, effectively manage the disposal of such wastes. Therefore, the UIC program regulates fluids produced in association with oil and gas production activities, but not as hazardous waste. Disposal of these fluids is permissible down Class II brine disposal injection wells.

Commenters advocated that well construction requirements that apply to Class I hazardous waste wells be applied to Class II wells. Due to the nature of those fluids, Class I hazardous waste wells are the wells subject to the strictest requirements. Some of those requirements include: long string casing cemented to the surface; two-mile area of review; post closure monitoring; mapping of the vertical and lateral limits of the USDWs; periodic external as well as internal mechanical integrity testing. These requirements do not apply to Class II wells under the UIC regulations. As explained above, the Agency made a regulatory determination that brine and associated fluids need not be disposed of, or injected as, hazardous waste.

The public also raised the issue that the disposal of these fluids underground is not safe. All waste produced must be managed in a safe manner and best management practices are typically used by an industry or regulatory agency in determining how and where a waste can be disposed in an environmentally safe manner. If managed and operated properly, EPA believes the risk to the environment by injecting fluids deep underground can be considered safer than other methods of disposal, such as allowing them to be discharged into a stream, disposed in a landfill or treated and stored in containment pits or storage tanks. EPA also believes that the reuse or recycling of produced fluid is a sound environmental management practice. Although produced brine can be treated, recycled and reused in the hydraulic fracturing process or for the enhanced recovery of oil, the byproduct of this continued reuse of the produced fluid eventually becomes very concentrated and therefore must still be disposed of in some manner. Public and privately owned wastewater treatment facilities are unable to adequately remove many constituents found in brine, for example, chlorides and bromides. When these constituents are discharged to streams or rivers they can pose serious risk to fish and other aquatic organisms living in the stream as well as contribute to serious health effects for people who obtain their drinking water from these streams and rivers. The UIC permitting program is designed to ensure that injection covered by the UIC permits can occur in an environmentally protective manner.

Commenters also questioned whether the proposed addition of a corrosion inhibitor and a biocide by the permittee meant that injection would not be limited to fluids produced in connection with oil and gas operations. The additives are not added to the fluid for the purpose of disposal but rather to prevent corrosion and biofilm buildup within the well, and are often also used in production wells. According to the Material Safety Data Sheets supplied by the applicant, the toxicity of these additives is reported to be moderately low, especially since they are proposed to be used in very low concentrations in the injection fluid (less than 1%). The proper operation and maintenance of a Class II well can require the use of such additives as discussed in #12 above.

17) Wastewater injected in the well should be more fully characterized or should be monitored for other parameters.

EPA believes that the conditions found in Parts II, C.3 and C.4 of the permit, are sufficient to adequately characterize and monitor the wastewater for injection purposes. The purpose of this monitoring is to verify that the fluids injected in the well are the type of fluids authorized in the permit. Shallow ground water and drinking water wells, when monitored, are typically tested for many of the same parameters required by the permit. Therefore, if there is evidence of shallow ground water contamination, those results can be compared against the injection fluid analysis to determine whether the injection well is the cause of that contamination. For example, chloride, one of the parameters for which the permit requires monitoring, can be found in drinking water and it can be found in the fluid proposed for injection. In shallow ground water used for drinking water, chloride values are fairly low, and can typically be found at less than 500 mg/l. Injection fluid typically contains chlorides in excess of 10,000 mg/l and sometimes as high as 300,000 mg/l. If shallow drinking water were to become contaminated by the injection fluid, there would be a significant change that could be observed relatively quickly through the monitoring of chloride. In addition, the permit will require monitoring parameters, such as Total Organic Carbon (TOC), that are aggregate surrogates for multiple compounds that are not individually listed in the permit monitoring requirements. In the case of TOC, monitoring for this parameter identifies the presence of various organic compounds found in produced fluid from oil and gas operations. Produced fluid will typically exhibit a much lower TOC value than a RCRA hazardous waste. Therefore if there was a High TOC result that would cause EPA to require further investigation.

A more extensive characterization might be appropriate if this wastewater were disposed in a different manner such as directly into a stream. However, this wastewater will be injected far below land surface into an existing gas bearing formation similar in nature to where the wastewater was generated. Moreover, EPA will periodically sample the injection fluid from Sammy-Mar's injection operation. If EPA found that Sammy-Mar injected fluids other than produced fluids associated with oil and gas production, it would be in violation of the permit and subject to enforcement action.

18) Well casing does not last forever. What is the lifetime maintenance plan for this well?

Once the injection well is constructed, EPA will review the completion report including well construction information, an evaluation of the well logging, casing and cementing, and mechanical integrity testing. EPA reviews the cement bond logs to evaluate whether the well has been properly cemented to prevent injected fluid from flowing through the wellbore outside the casing. The mechanical integrity test involves increasing the pressure in the annulus (the space between the injection tubing and long string casing) ten percent above the maximum injection pressure authorized in the permit. The pressure must be maintained over a period of 30 minutes for the well to have mechanical integrity. This tests the mechanical integrity of the long string casing, tubing and packer to determine whether there are any leaks. The permit requires mechanical integrity testing be performed every five years and after any repair, modification, and rework of the injection well. If possible leaks are indicated, the test may also include an evaluation of whether fluid movement is occurring outside the casing. Under the terms of the permit, EPA can request the permittee to demonstrate mechanical integrity at any time.

Furthermore, Part II.B.2 of the final permit requires continuous monitoring of the injection well for injection pressure, annular pressure and injected volumes. This will enable the operator as well as EPA to determine whether the integrity of the well's long string casing, tubing and packer are compromised over the course of the well's operation. The monitoring will be designed to detect pressure changes. Annular pressure monitoring requires that the well's annulus pressure be set at a positive pressure lower than the injection pressure. If a leak were to develop in the tubing or packer, the annular pressure would increase significantly. If the well experiences a leak in the long string casing, the pressure in the annulus would decrease significantly. Either situation would automatically trigger the well to shut down and cease operating. This would constitute a mechanical integrity failure of the well, and in accordance with Part II.C.2 of the final permit, the operator would be required to cease injection immediately.

Finally, when the operator no longer wants to operate the injection well, it must be permanently plugged and abandoned in accordance with Part II.D.9 and Part III.C of the final permit, which requires that the permittee plug the well in such a manner that plugging does not allow movement of fluids into or between underground sources of drinking water. Since the mid-1980s, several thousand Class II wells in Region 3 have been successfully plugged in accordance with the regulatory requirements. Sammy-Mar has submitted a plugging and abandonment plan on EPA Form 7520-14 which has been approved by EPA and is incorporated into the permit. Sammy-Mar's plugging plan is to be accomplished by one of the methods mandated by the UIC regulations at 40 C.F.R. § 146.10. This plan is provided in Attachment 1 of the final permit.

19) Sammy-Mar must provide financial resources should a well failure occur.

Under the UIC regulations, owners and operators of injection wells are required to demonstrate financial responsibility for the purpose of properly plugging and abandoning the injection well when the operation ceases and the well is no longer used for injection. The cost of plugging a well depends, among others things, upon the depth of the well and how the well was constructed. Sammy-Mar submitted an estimate of $25,912 from an independent plugging contractor on the cost of plugging the well, as well as a $26,000 letter of credit with a standby trust agreement for the plugging and abandonment of the injection well. EPA Region III reviewed and approved this submission. The estimated plugging cost for the Sammy-Mar injection well falls within the range of estimated costs for plugging other Class II-D disposal wells in Pennsylvania. Those plugging estimates range from $10,000 to $75,000, with an average of approximately $32,000. The permit incorporates the requirement that Sammy-Mar maintain financial assurance in the amount of the estimate through a letter of credit. (See Part III.D). EPA can require the permittee to adjust the cost estimate and the financial assurance instrument as necessary. See 40 C.F.R. § 144.52. Although a separate issue from the financial responsibility required for plugging and abandonment, the public also asked whether the operator is required to set money aside to remediate any contamination of their drinking water if the injection operation fails and allows fluids to migrate into a USDW. The operator is not required to set money aside for ground water remediation. However, EPA does have emergency authorities under the Safe Drinking Water Act (SDWA) if endangerment to USDWs should result from injection activities. Section 1431 of the SDWA authorizes EPA to take an action against anyone who causes or contributes to the contamination of a drinking water supply which may present an endangerment to the health of persons using such water supply. Any action brought under Section 1431 of the SDWA can include a requirement that the responsible party provide alternative drinking water to citizens affected by the endangerment.

20) What is EPA's role in inspecting this well during construction and during operation?

EPA has direct implementation authority for the UIC program in the Commonwealth of Pennsylvania. Therefore, in addition to permitting, EPA also will be responsible for inspecting the Sammy-Mar injection well and enforcement of the permit requirements for the operation of the well. EPA has a team of inspectors, including one full time inspector responsible for inspecting Class II underground injection wells. At least one EPA inspector will be present at the Sammy-Mar Injection Well during construction, witness the well mechanical integrity test after construction, and EPA will at a minimum, inspect the well during operation on an annual basis. EPA also reviews the operator's annual report including continuous monitoring reports of pressure and volumes injected.

21) The company is responsible for self-reporting to EPA. This does not seem like an acceptable way for EPA to be able to ensure that the well operates properly.

The UIC regulations are similar to most other federal regulations in that they require self-monitoring and reporting to a state or federal agency. EPA expects all operators to comply with the regulatory requirements as well as their permit requirements. An operator's failure to comply with the permit, including accurately monitoring and reporting to EPA would subject the operator to possible civil or criminal penalties or both. EPA inspects every Class II disposal well in Pennsylvania at least annually. EPA's inspection of injection well facilities and review of annual reports helps determine operator compliance and supplements self-reporting.

Some commenters expressed concern about evidence of noncompliance in the industry and EPA's lack of vigilance. Particular cases in Pennsylvania cited by the public included Hammermill Paper in Erie County, and an EXCO injection well in Clearfield County. Each of these cases demonstrate EPA's responses to particular environmental concern and UIC regulatory violations.

Hammermill Paper is a case that developed in the 1960's. prior to the promulgation of the UIC regulations and is one of the cases typically cited as to why the UIC regulations were necessary. Hammermill was found to have injected under extremely high pressure, production wastewater. The injection pressure fractured the injection zone, confinement was lost and the waste traveled approximately five miles before it moved upwards through an abandoned well on Presque Isle.

The violations at the EXCO well in Clearfield County were also identified through inspections and record reviews. EPA discovered that the operator was injecting fluids into a disposal well that lacked mechanical integrity. EPA identified and addressed the violations before any USDWs were endangered. EPA issued a penalty against the company and required the well to be repaired before it was tested for mechanical integrity and placed back into operation.

Also, as required by the Safe Drinking Water Act, EPA notifies the public of any proposed penalty order and offers the opportunity to comment on such orders. Each of these cases is an example of the need for the UIC regulations and EPA's enforcement of the SDWA UIC program compliance requirements.

22) EPA should conduct an environmental impact assessment and address potential impacts on wildlife prior to issuing the permit.

Section 124.9(b)(6) of Title 40 of the C.F.R. establishes that UIC permits are not subject to environmental impact statement requirements of the National Environmental Policy Act ("NEPA"). NEPA requires environmental impact statements (EIS) when undertaking certain major federal actions. However, under the judicial doctrine of functional equivalent, where a federal agency is engaged primarily in examining environmental questions and there are procedural and substantive standards for adequate consideration on environmental issues, the NEPA EIS requirement does not apply. *See In re American Soda. LLP*, 9 E.A.D. 280, 290-291 (2000). The EPA Environmental Appeals Board has concluded that under the functional equivalent doctrine and Section 124.9(b)(6), EPA is not required to prepare an EIS in support of UIC permits.

As part of the public notice process, EPA provides copies of the Statement of Basis and the draft permit to the U.S. Fish & Wildlife, the Nature Conservancy, the PA Fish & Boat Commission, the Pennsylvania Game Commission, and the Allegheny National Forest for their review and comment. No comments were received by any of these organizations. In addition, EPA conducted a search for possible endangered species in the project area and it appears that there were none in Clearfield County.

23) Commenters questioned whether there is a corporate relationship between Sammy-Mar and Dannic Energy Corporation. They also questioned whether there is a corporate relationship between Sammy-Mar and EQT Production Company.

Based on a statement from the applicant Sammy-Mar, Dannic Energy Corporation and Sammy-Mar are separate entities that are both owned by W. Daniel Sinclair. In addition, Sammy-May has no corporate relationship with EQT Production Company.

24) A commenter was concerned that the injection fluid may migrate beyond the established AOR.

The purpose of the AOR is to establish a specific area for possible corrective action. It is based on potential pressure build-up in the injection formation over the life of the permit. It is not an established boundary for the movement of injection fluid.

25) What happens when the permit expires?

The UIC Class II regulations allow permit issuance for a ten year period. See 40 C.F.R. § 144.36(a). Before the end of that ten year period, Sammy-Mar may request EPA to reissue the permit by submitting a new application. In that event, EPA will review the history of Sammy-Mar's operation, as well any information on the well obtained during the drilling and the pressure fall-off testing, and determine whether to reissue the permit. EPA's tentative decision of whether to reissue or deny the permit for an additional term is subject to the same public notification and public comment process as an initial permit.

If Sammy-Mar decides not to continue its injection operations at the end of the permit term, it must plug and abandon the well in accordance with the permit requirements, prior to the expiration of the permit.

Federal Underground Injection Control Program
Permit Appeals Procedures

The provisions governing procedures for the appeal of an EPA permitting decision are specified at 40 C.F.R. Part 124.19. (Please note that the changes to this regulation became effective on March 26, 2013. See 78 Federal Register 5281, Friday, January 25, 2013.) Any person who commented on the draft permit, either in writing during the comment period or orally at the public hearing, can appeal the final permit by filing a written petition for review with the Clerk of the EPA Environmental Appeals Board (EAB). Persons who have not previously provided comments are limited in their appeal rights to those points which have been changed between the draft and final permits. Appeals may be made by citizens, groups, organizations, governments and the permittee within this procedural framework.

A petition for review must be filed within thirty (30) days of the date of the notice announcing EPA's permit decision. This means that the EAB must receive the petition within 30 days. (Petitioners receiving notice of the final permit by mail have 3 additional days in accordance with 40 C.F.R. § 124.20(d).) The petition for review can be filed by regular mail sent to the address listed below with a copy sent to EPA Region III at the address listed below.

Environmental Appeals Board
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue N.W.
Mail Code 1103M
Washington, DC 20460-0001

U.S. Environmental Protection Agency
Region III Ground Water & Enforcement Branch (3WP22)
Water Protection Branch
1650 Arch Street
Philadelphia, PA 19103

See the Federal Register notice cited above or the EAB website: http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/) for how to file with the EAB electronically or by hand delivery.

The petition must clearly set forth the petitioner's contentions for why the permit should be reviewed. It must identify the contested permit conditions or the specific challenge to the permit decision. The petitioner must demonstrate the issues raised in the petition had been raised previously during the comment period or at the hearing. If the appeal is based on a change between the draft and final permit conditions, the petition should state so explicitly. The petitioner must also state whether, in his or her opinion, the permit decision or the permit's conditions appealed are objectionable because of:

1. Factual or legal error, or

2. The incorporation of a policy consideration which the EAB should, at its discretion, review.

If a petition for review of this permit is filed, the permit conditions appealed would be deemed not to be in effect pending a final agency action.

Within a reasonable time of receipt of the Appeals Petition, the EAB will either grant or deny the appeal. The EAB will decide the appeal on the basis of the written briefs and the total administrative record of the permit action. If the EAB denies the petition, EPA will notify the petitioner of the final permit decision. The petitioner may, thereafter, challenge the permit decision in Federal Court. If the EAB grants the appeal, it may direct the Region III office to implement its decision by permit issuance, modification or denial. The EAB may order all or part of the permit decision back to the EPA Region III office for reconsideration. In either case, a final agency decision has occurred when the permit is issued, modified or denied and an Agency decision is announced. After this time, all administrative appeals have been exhausted, and any further challenges to the permit decision must be made to Federal Court.