Appendix C
Fluid Minerals Activity Descriptions
Reasonably Foreseeable Development Scenario

**Fluid Minerals Activity Descriptions**

Oil & Gas

An oil & gas lease conveys the right to explore and develop oil & gas resources on federal lands for a ten year period. Oil and gas exploration and development activities progress through four separate phases: 1) preliminary exploration; 2) exploratory drilling; 3) field development and production; and 4) field abandonment. Each phase is implemented sequentially but may overlap in time, and probable implementation of each phase and degree of environmental impact would be contingent upon the success or failure of each preceding phase.

*Preliminary Exploration.*

Geological and geophysical exploration occurs during the preliminary exploration phase of an area. Where bedrock geology of an area is well exposed, it is often possible to predict where oil might concentrate. Once potential target areas are identified, one or more geologists may examine and sample rock outcrops in the area and map the surface geology. Geological exploration can be performed with little surface disturbance. Four-wheel drive pickups, motorcycles or all terrain vehicles are commonly used to access the area.

Geophysical prospecting is used in cases where geology may not be accurately identified from surface outcroppings. Three subsurface characteristics are measured by geophysical methods: gravitational field; magnetic field; and seismic characteristics. Seismic surveys are the most popular of the geophysical methods and seem to give the most reliable results.

Seismic exploration involves sending sound waves into the ground by one of three methods, i.e., vibration, thumping, or explosive, and recording how they reflect back. The results are then interpreted to provide an image of subsurface geology and determine whether fluid mineral resources may exist. Where possible, existing roads are used to conduct seismic operations, but some lines may require clearing of vegetation and loose rock to improve vehicle access. Each mile of line, cleared to a width of eight to 14 feet, represents disturbance of about one acre; however, completely clearing a seismic line is unusual. The majority of lines in remote and roadless areas are not bladed, except as required to cross drainages or washes. Support and operating vehicles primarily travel overland. In extreme cases, a bulldozer may be used to tow the vehicles through rough spots or in sandy areas.

The vibrator (or vibration) method is widely used in accessible areas. A typical operation would use three or more large trucks or tractors, each equipped with a vibrator mounted between the front and back wheels, four or five support vehicles, and a crew of ten to 15 people. Travel along the line usually consists of one pass by the vibrators. The vibrator trucks stop at regular intervals to lower a vibratory plate (typically the size of a full 4- by 8-foot sheet of plywood) which vibrates through a range of frequencies (sound waves) in a matter of seconds. The pad is then lifted, the trucks move forward several feet and repeat the sequence.

The sound waves from the vibrator trucks are reflected back from subsurface layers or structures and received by sensors (geophones or “jugs”) on the surface. The geophones are connected to a common cable which is connected to a recording truck (or “dog house”). As the vibrator trucks move down the line, cable trucks and line personnel (or “juggies”) pick up cable and geophones from the back of the line and lay them down at the front. Seismic lines can range up to several miles in length depending on the depth of reflection that is desired. The actual duration for on-the-ground activities along a seismic line are short. In most cases, a seismic line is completed at the rate of one or more miles per day.

*Exploratory Drilling.*
After the surface geological and subsurface geological studies and geophysical studies are completed, the prospect is evaluated. Only by drilling a wildcat well (a well drilled in unproved territory) will the oil company know if the prospective rocks contain oil or gas. Nationally, about one in sixteen wildcat wells produce commercial amounts of oil or gas. As a general rule, the deeper the well, the larger the drilling rig and facilities required. Deeper wells may require several months or more to complete; shallow wells up to a few thousand feet deep may be competed in a few weeks of drilling.

The position of a particular well is determined by the lessee and/or operator followed by a proposal to drill submitted to the BLM by either a Notice of Staking (NOS) or an Application for Permit to Drill (APD). In all cases, an on-site inspection of the proposed drilling location is made by representatives of the BLM, the lessee/operator, and other interested parties. During this on-site inspection, the site location and access route most advantageous from and environmental standpoint is selected. In addition, surface use and reclamation requirements are developed for inclusion in the APD.

The drilling program provided in the APD is reviewed by the BLM for technical adequacy and protection of subsurface resources. The review ensures the adequacy of all downhole operations associated with the drilling of the well. The APD is also reviewed for surface resource concerns, and an EA is completed. Approval of the APD incorporates all requirements for surface use and drilling, which were identified at the on-site and during the technical review.

After completing the necessary permitting procedures, construction of the access road and well site can begin. Initially, construction will involve the development of an access route to the well site, which usually requires a road with a 12- to 14-foot wide travel surface with two to three-foot borrow ditch, for a total road surface disturbance of 18 feet. Bulldozers, graders, and other types of heavy equipment are used to construct and maintain the temporary roads and the well site.

A drill pad (well site) is generally from one (200 by 200 feet) to three (400 by 425 feet) acres in size. The pad is cleared of all vegetation, and leveled for the drill rig, mud pumps, mud (or reserve) pits, generators, pipe rack, and tool house. Topsoil is usually removed and stockpiled for use in reclamation of the well pad area. The mud pit may be lined with plastic or bentonite to prevent fluid loss or prevent contamination of water resources. Other facilities, such as storage tanks for water and fuel, are located on the pad or are positioned nearby on a separate, cleared area. If the well site is not large enough for the equipment required to rig-up (prepare the drilling rig for operation), a separate staging area may be constructed. Staging areas are usually no larger than 200 by 200 feet (approximately one acre) and may simply be a wide flat spot along the access road on which vehicles and equipment are stored.

*Field Development and Production.*
If a wildcat well becomes a discovery well (a well that yields commercial quantities of oil or gas), additional (development) wells will be drilled to confirm the discovery, establish the extent of the field, and to efficiently drain the reservoir. The procedures for drilling development wells are about the same as for wildcat wells. Oil well spacing for production from federal leases in Nevada is a minimum of 40 acres for wells with depths 5,000 feet or less and 160 acres with wells greater than 5,000 feet. Gas wells for production above and below 5,000 feet deep are spaced at 160 and 640 acres, respectively. If a field is producing from more than one formation, the surface location of the wells would be closer.

During the development stage, the road system of the area is greatly expanded. Once it is known which wells produce and their potential productive life, a permanent road system can be designed and built. In addition to roads, other surface uses for development drilling may include pipelines, storage tank batteries, and facilities to separate oil, gas and water, and injection wells for water disposal.

Production in an oil field begins just after the discovery well is completed and is usually concurrent with development operations. Temporary facilities may be used at first but as development proceeds and reservoir limits are determined, permanent facilities are installed. The primary means of producing oil from a well is by pump jacks. The pump jacks may be powered by electric motors requiring construction of powerlines. If there is sufficient casing head gas (natural gas produced with the pumped oil) or another gas source available, internal combustion engines may be employed.

Any production activities resulting in new or additional surface disturbance and/or not approved under the APD require approval of the BLM. Activities requiring prior approval include but are not limited to re-drilling, deepening, performing casing repairs, plugging back, altering casing, performing non-routine fracturing jobs, recompleting in a different interval, performing water shutoff, and converting to injection or disposal.

*Field Abandonment.*
The life-span of an oil field from discovery to abandonment would depend on a variety of circumstances. An estimate of 15 to 25 years may be considered the average life of a typical field. Abandonment is likely to occur concurrently with production as a reservoir becomes depleted. Wells that formerly produced may be plugged as they are depleted, or allowed to stand idle for possible later use in a secondary recovery program. Truck mounted equipment is used to abandon depleted or dry (never produced) wells.

During well abandonment, a cement plug is installed at the bottom of the casing and across any perforated sections over the producing zones, the casing is filled with heavy mud, and a cement cap is installed on the top of the casing. A pipe monument giving the location, lease number, operator, and name of the well is then erected at the surface. The cement pump jack foundations are removed or buried below ground level. Surface flow and injection pipelines are removed but buried pipelines are usually left in place and plugged at intervals as a safety measure.

After the well is plugged, the disturbed areas (access roads, drill pads and reserve mud pits) are recontoured using bulldozers and graders to restore the landform to its approximate original contour, minimize erosion, and allow revegetation to take place. Prior to recontouring, reserve mud pits are evaporated or pumped dry and filled with the top soil material that was stockpiled when the site was prepared. After recontouring and topsoiling, well sites will be seeded with an appropriate seed mix. A fence may be erected to protect the site until revegetation is complete. Any water wells developed are commonly turned over to the land managing agency to use for resource enhancement; i.e., wildlife, livestock, recreation.

<u>Geothermal</u>
Four separate and sequential phases of geothermal development could occur. The probable sequence and degree of environmental impact would be contingent upon the success or failure of each preceding phase. The four phases are exploration, development, production, and close-out.

*Exploration.*
This stage includes all activities to explore for geothermal resources. The discrete actions or identifiable actions, which in the aggregate comprise this stage, include geologic, geochemical, and geophysical surveys. Cross-country vehicle travel could occur in order to complete the surveys. After the surveys have been completed, road building and drill pad construction could occur in order to drill temperature gradient and exploration wells. Activities common to geothermal exploration are detailed below:

- Geologic, Geochemical, and Geophysical Surveys. These surveys consist of analyzing the surface geology and collecting water samples from hot springs. Based on the geologic and geochemical analysis, inference could be made as to where higher temperature gradients could occur. This work usually covers a broad surface area. Typically, geologic and geochemical surveys cause minimal surface disturbance.

- Drilling Temperature Gradient Wells. The next step in exploration is to confirm where higher temperature gradients occur—this is done by drilling temperature gradient wells. These wells are narrow in diameter and are drilled to depths of several hundred to several thousand feet and include road building and drill pad construction. When completed, the operator lowers a thermistor down the well to measure how much the temperature gradient increases with depth. An operator may not produce any fluids out of, or inject any fluids into a temperature gradient well.

- Drilling Exploration Wells. After the exploration data has been evaluated, one or more exploration wells could be drilled to a depth of several hundred to several thousand feet, in order to test the prospect. These wells could be flow tested. Each well could disturb approximately one acre. A new road could be constructed into the site. An operator could drill several gradient wells on a lease to determine the extent of the temperature anomaly and where the highest temperature gradient occurs. Well pads are about .07 acres (55 feet by 55 feet) in size. Typically these wells are located adjacent to existing roads; however, new road construction could be necessary.

*Development.*
This could include the development of a geothermal electric generating plant, direct use facilities, such as green houses or dehydration plants, or a combination of the two. At this stage is where most of the intense activities occur. The producing limits of the field(s) are determined by developmental drilling. Because of the intense drilling at this time, more surface disturbance to construct roads and drill pads would occur. Drilling of production wells would be initiated. Geothermal fluid production and associated waste production is likely to occur for short periods as wells are tested to determine reservoir characteristics.

If geothermal fluids are discovered in commercial quantities, development of the geothermal field is likely. The rate of fluid production from a geothermal reservoir is unknown until the development-testing phase is completed. During the initial stages of testing, one well is likely to be tested at a time. If testing is successful and the well and reservoir are sufficient for development, wellheads, valves, and control equipment would be built on top of the well casing. Other facilities that would be constructed include pipelines, power plants, electric transmission line construction, greenhouses, dehydration plants, cooling ponds, and warehouse and maintenance facilities. Generally, prior to initiating development scenarios, geothermal developers secure contracts with power companies that allow connection to local electrical grids. Activities common to geothermal development are detailed below:

- <u>Road Construction</u>. Often new access roads to well pad sites must be built. These roads are usually a half-mile to three miles in length.

- <u>Drill Site Construction</u>. Compared to exploration drilling, a well pad for a production well is usually much larger, approximately two acres (300 feet by 300 feet) in size. The number of wells drilled depends on the geothermal resource available. In general, one or two production wells would be drilled.

- <u>Geothermal Pipelines</u>. Geothermal pipelines are usually 24-36 inches in diameter and covered with insulation, and would parallel the access road when possible and could be one to four miles in length.

- <u>Power Plant and/or Direct-Use Facility Construction</u>. Electrical generation plants would range in generating capacity from 3–25 megawatts. The plant and other required facilities would occupy up to 30 acres. Direct use facilities could include construction of greenhouses or vegetable dehydration plants and other facilities such as cooling ponds. These facilities could occupy up to 5–30 acres.

- Electric Transmission Line Construction. Electric transmission lines could range in length from 5-50 miles. They would most likely be supported by wooden poles. Typically a substation also is required to be constructed in conjunction with electrical transmission lines.
- Miscellaneous Support Facilities. These facilities could include communications, septic systems, fresh water distribution, cooling towers, etc.

*Production.*
The production stage involves the continued operation and maintenance of the field(s) and includes: new drill sites, maintenance of existing facilities, waste disposal, and geothermal energy production. Assuming 5 million gallons per day, per well as an average production figure, a lease with two producing wells would produce 10 million gallons of fluid per day. Using data from other areas of geothermal development, it appears that production of geothermal fluids could be expected to vary from 1-6 million gallons per day, per well. Most geothermal fluids produced are re-injected back into the geothermal reservoir, via re-injection wells. In flash steam facilities about 15-20 percent of the fluid would be lost due to flashing to steam and evaporation through cooling towers and ponds. Binary power plants[1] are non-consumptive and utilize a closed loop system. Fluids could also be lost due to pipeline failures or surface discharge for monitoring/testing the geothermal reservoir.

[1] In binary power plants, the hot geothermal fluid is used to heat a separate, binary fluid in a heat transfer process. The binary fluid flashes at a lower temperature and is used to turn the power generating turbines

**Reasonably Foreseeable Development Scenario**

Assumptions supporting an oil & gas and geothermal leasing RFD scenario over a 10 year planning period are presented below.

Oil & Gas
The average disturbance created by oil & gas exploration wells drilled near Gabbs, Nevada was used as a basis for the hypothetical exploration disturbance in this RFD. Wells drilled near Gabbs, Nevada have not gone to production; therefore, the production disturbance estimates for the RFD are based on oil field production data from Railroad Valley, Nevada. The time frame for oil & gas exploration and production is the 10-year lease period. The hypothetical oil & gas exploration and production disturbance that may be expected within the six lease areas comprising the Proposed Action over the 10-year lease period are detailed below:

*Preliminary Exploration*
Up to eight miles of seismic line at a width of 10-feet would be surveyed per year for an overall anticipated total of 10-acres of disturbance over the life of the EA. Each year 100 percent of the disturbance would be reclaimed (earthwork and reseeding would be completed). Other geophysical surveys may also be conducted with little or no surface disturbance.

*Exploratory Drilling*
Past activity in the area near Gabbs, Nevada, supports that one wildcat well per year could be drilled, which equates to a total of ten wells drilled over the RFD period. It is estimated that out of the 10 wells drilled, one would be potentially viable for production, while nine would be reclaimed the year following drilling. Drilling time would average eight weeks per well and the pad size for each well would be 300 feet by 300 feet, or two acres. Therefore, the disturbance from drill pad construction could result in a maximum of 20 acres over a 10-year period.

The average access road per drill site would be 18 feet wide by one mile long and would be surfaced with six inches of gravel. Therefore, the disturbance from road construction would be approximately 2.2 acres per year (5,280 feet x 18 feet ÷ 43,560 ft2/acre =2.2 acres) for an expected maximum of 22 acres over the 10 year period. All but 2.2 acres of access

road would remain after reclamation of 9 out of the 10 exploration drill sites and their associated access routes are reclaimed. Gravel for roads and pads would be obtained locally from existing gravel pits. Expansion of gravel pits associated with oil and gas exploration would be one acre.

*Well Stimulation and Hydraulic Fracturing (HF)*

Well Stimulation may be used to enhance oil and gas recovery. Several methods of well stimulation could be used. Hydraulic Fracturing (HF) is one of these methods that is reasonably foreseeable for the lease areas considered in this EA. The HF process was developed experimentally in 1947 and has been used routinely since 1950. The Society of Petroleum Engineers (SPE) estimates that over one million hydraulic fracturing procedures have been conducted in the United States and tens of thousands of horizontal wells have been drilled and hydraulically fractured (Cole 2013: 17-20; Society of Petroleum Engineers 2012).

The HF process can greatly increase the yield of a well, and development of hydraulic fracturing methods and the drilling technology in which it is applied (in particular, long wells drill horizontally within zones of interest) have enabled production of oil, natural gas and geothermal energy from tight formations formerly not economically feasible to develop. With directional and horizontal drilling technology, several wells can be drilled in a radial pattern from one drill pad/borehole, resulting in up to 50-85% less surface disturbance as compared to traditional vertical drilling practices using multiple individual drill pads (Kreckel).

Drilling and completion techniques may vary in different basins depending on the local geologic strata and depth of the producing zone. Generally, HF can be described as follows:

- Water, proppant, and chemical additives are pumped at extremely high pressures down the wellbore.
- The fracturing fluid is pumped through perforated sections of the wellbore and into the surrounding formation, creating fractures in the rock. The proppant holds the fractures open during production of the well.
- Operator personnel continuously monitor and gauge pressures, fluids and proppants, studying how the propping agent reacts when it hits the bottom of the wellbore, slowly increasing the density of proppant to water as the HF progresses.
- This process may be repeated multiple times, in “stages” to reach maximum areas of the formation(s). The wellbore is temporarily plugged between each stage to maintain the highest water pressure possible and get maximum fracturing results in the rock.
- The plugs are drilled or removed from the wellbore and the well is tested for results.
- The pressure is reduced and the fracturing fluids are returned up the wellbore for disposal or treatment and re-use, leaving the sand in place to prop open the fractures and allow the oil/gas to flow.

The BLM currently does not have any regulations in place regarding HF, but is working on drafting new regulations. However, the State of Nevada’s Division of Minerals (NDOM) does have regulations that require the reporting of the amount and type of chemicals used in a HF operation in “FracFocus” within 60 days of HF completion for public disclosure as part of the Conditions of Approval for all oil and gas drilling permits and sundry notices that include the HF process. For more information concerning FracFocus and hydraulic fracturing see the FracFocus website at www.fracfocus.org and the Division of Minerals website at minerals.state.nv.us.

To ensure that O&G exploration and development is conducted in a safe and environmentally sound manner the BLM approves and regulates all drilling and completion operations and related surface disturbance on Federal publics lands. Prior to approving an NOE or an APD the BLM identifies all potential subsurface formations that will be penetrated by the wellbore. This includes all groundwater aquifers and any zones that would present

potential safety of health risks that may need special protection measures during drilling, or that may require specific protective well construction measures.

Once the geologic analysis is completed the BLM reviews the proposed casing and cementing programs to ensure the well construction design is adequate to protect the surface and subsurface enviromnet, including the potential risks identified by the geologist and all known or anticipated zones with potential risks.

Before HR takes place all surface casing and deeper intermediate zones are required to be cemented from the bottom of the cased hole to the surface. The cemented will is pressure tested to ensure there are no leaks and a cement bond log is run to ensure the cement has bonded to the casing and the formation. If the fracturing of the well is considered to be a "non-routine" fracture for the area the BLM would be onsite during those operations as well as when abnormal conditions develop during the drilling or completion of a well.

Wells that undergo HF may be drilled vertically, horizontally, or directionally and the resultant fracture induced by HF can be vertical, or horizontal, or both. Wells may extend to depths greater than 20,000 feet or less than 1,000 feet and horizontal sections of a well may extend several thousand feet from the production pad on the surface.

Drilling muds, drilling fluids, water, and HF fluids are stored in onsite tanks or lined pits during the drilling and/or completion process. Equipment transport and setup can take several days, and the actual HF and flowback process can occur in a few days up to a few weeks. For oil wells, the flowback fluid from the HF operations is treated in an oil-water separator before it is stored in a lined pit or tank located on the surface. Where gas wells are flowed back using a "green completion process", fluids are run through a multi-phase separator, which are then piped directly to enclosed tanks or to a production unit.

Hydraulic Fracturing Methods

A general description of the HF technology follows:

- All exploratory, testing, and production wells are multiply cased and sealed with cement between the wellbore and the formation. Well integrity is tested throughout the process.
- Drilling and HF fluids can be contained in a pitless system (aboveground tanks) or a lined pit. Cuttings could be contained in roll-off boxes for hauling to disposal or surface casing interval cuttings could be spread over the site during reclamation.
- HF fluids are recovered to a large degree in "flowback" or produced water when the well is tested or produced.
- All recovered fluids are generally handled by one of four methods:
    - Underground injection
    - Captured in steel tanks and disposed of at an approved disposal facility
    - Treatment and reuse
    - Surface disposal pits
- Drilling cuttings could be land farmed and buried on site three feet below root zones. Any cuttings that do not fit the waste profile would be disposed of at an approved disposal facility.

**In-field drilling** of additional exploration wells typically occurs when initial drilling has located O&G, to define the limits of the O&G reservoir. The process of in-field drilling is the same as that employed for initial exploratory drilling, although new roads and pads may not be required in every instance.

**Production** begins only if O&G can be transported to a market and sold at a profit. In the WD, because of limited infrastructure, produced oil would likely be piped a short distance for temporary storage, then trucked to a refinery for processing. Production facilities may include one or more of the following: a well head, pumping equipment, a separation system, pipelines, a metering system, storage facilities, water treatment and injection facilities, cathodic protection systems, electrical distribution lines, compressor stations, communication sites, roads, salt water disposal systems, dehydration sites, and fresh/salt water plant sites.

**Well abandonment** may be temporary or permanent. Wells are sometimes shut-in because pipelines or roads needed for production and marketing do not exist and the cost for construction is not justified by the quantity of oil discovered. These wells may later be reentered when their production can be marketed. The permanent abandonment of a well occurs when the well is determined to no longer have a potential for economic production, or when the well cannot be used for other purposes.

**Reclamation**. Abandonment includes removal of facilities and reclamation of surface disturbance. In the case of exploration wells which do not find economically recoverable amounts of oil, initial reclamation (recontouring) is usually completed the following year which provides for sufficient time for the reserve pit to dry out. After revegetation of the site is completed, usually within two to three years, reclamation is complete. If an exploration well finds economically recoverable quantities of oil, all disturbed surface except the small amount needed for a pump and access is reclaimed immediately.

**Induced Seismicity**. Potential geologic hazards caused by HF include induced seismic activity. Earthquakes occur when energy is released due to blocks of the earth's crust moving along areas of weakness or faults. Earthquakes attributable to human activities are called "induced seismic events" or "induced earthquakes." In the past several years induced seismic events related to energy development projects have drawn heightened public attention. Although only a very small fraction of injection and extraction activities at hundreds of thousands of energy development sites in the United States have induced seismicity at levels that are noticeable to the public, seismic events caused by or likely related to energy development have been measured and felt in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas.

A study conducted by the National Research Council (National Research Council 2013) studied the issue of induced seismic activity from energy development. The study found that:

- The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events.
- Injection for disposal of waste water derived from energy technologies into the subsurface does pose some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

The potential for induced seismicity cannot be made at the leasing stage; as such, it will be evaluated at the APD stage should the parcel be sold/issued, and a development proposal submitted.

**Water Consumption.** Public concern over the amount of water used in HF has increased over the last couple of years. There are numerous groundwater protection regulations already in place, and new increases in protection are in the works at state and federal levels, while the debate over HF continues at all levels of government. Because of the increased interest in Nevada's potential for oil discovery, this issue has come under scrutiny. Prior to the advancements in HF and directional drilling, 20,000 to 80,000 gallons of water were typically consumed per well, but with today's advanced fracturing techniques, water consumption during fracturing can be in excess of 8,000,000 gallons of water per well (Kharaka et al. 2013; Swackhamer 2013:64-65). Water use in the Barnett, Fayetteville, and Marcellus Shales is under 4,000,000 gallons per well though (Jenner and Lamadrid 2013).

Water rights (i.e., permission to apply water to beneficial use) are controlled by the Nevada Division of Water Resources (NDWR), not the BLM. Additional discussion regarding water rights is located in Section 3.8.1.

**Water Contamination Potential**. There is a broad array of chemicals that can be used as additives in a fracture treatment including, but not limited to, hydrochloric acid, anti-bacterial agents, corrosion inhibitors, gelling agents (polymers), surfactants, and scale inhibitors (Kharaka et al. 2013). These chemical additives constitute up to 1-5% of the HF fluid (Swackhamer 2013:67). This translates to a minimum of 5,000 gallons of chemicals for every 1.5 million gallons of water used to fracture a well (Paschke 2011), or at least 26,000 gallons of additive for an O&G well requiring 8,000,000 gallons of water for HF activities.

Produced water, a byproduct of O&G production, may be considered another potential contributor of groundwater contamination. This water has generally been confined to O&G bearing rock formations for a long period of time and can obtain high levels of dissolved solids, and dissolved gasses such as methane and radon (Kharaka et al. 2013; Farag and Harper in press; Vengosh et al. 2013). The majority of produced water in Nevada is reintroduced into deep brine formations by way of Underground Injection Control wells. A permit to inject produced water must be obtained from the NDWR and a Sundry Notice must be approved by the BLM. The BLM receives its guidelines and directions for disposal of produced water from Onshore Order #7. Certain O&G exploration and production wastes occurring at or near wellheads are exempt from the Clean Water Act (CWA), such as: drilling fluids, produced water, drill cuttings, well completion, and treatment and stimulations fluids to name a few. In general, the exempt status of exploration and production waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. For example, some exempt exploration and production wastes might be harmful to human health and the environment, and many non-exempt wastes might not be as harmful (EPA 2002).

**Air Quality**. There is a potential for impacts to air quality associated with lease development activities, such as fugitive dust produced from well pad and access road construction, pipeline construction, hauling freshwater and produced water to and from well sites. All of these activities can be considered temporary or short-term. Air quality for Nevada is regulated and monitored by the Nevada Division of Environmental Protection (NDEP). Development of unconventional O&G resources has also been identified as a source of GHGs, particularly methane, and volatile organic compounds (VOCs) (Robinson 2013). The level of production is a subject of debate in the literature (Howarth et al. 2011, 2012).

*Field Development and Production*

It is anticipated that one small producing field may be discovered within one of the six lease areas comprising the Proposed Action during the ten year lease period. No more than one drill rig would be in operation in the field at a given time. Only interim reclamation work would occur until the producing field is abandoned. The production life of the field would last from 18 months to 35 years. The following field development scenario is modeled after observations from Railroad Valley, Nevada, using the estimated mineral potential and ground conditions found in the area of the Proposed Action.

It is anticipated that one producing oil well would be discovered during the exploration phase. Nine additional wells would be drilled within the field to determine the boundaries of the oil and gas reservoir, for a total of 18 acres of disturbance over the 10-year life of the RFD. No additional oil would be discovered, and one of the wells would be converted to an injection well. The remaining eight wells would be plugged and abandoned. Reclamation of the eight additional drill sites and interim reclamation of the drill site converted to an injection well would bring the total production disturbance to 0.2 acre (18 acres – 17.8 acres = 0.2 acre [size of injection well]). A tank battery would be placed on the existing drill pad of the producing well and no additional surface disturbance would be required.

To define the oil & gas reservoir boundaries, an additional 14 miles of 20-foot wide roads would be constructed for the nine drill pads. These roads would be surfaced with one-foot of gravel (includes gravel needed for road maintenance) for a maximum of 34 acres of disturbance. Approximately 10 miles, or 24 acres, of these roads would be reclaimed. Gravel for roads and pads would be obtained locally from existing gravel pits. Expansion of gravel pits associated with oil & gas production would be one acre. Total surface disturbance associated with the RFD for oil & gas exploration and development activities for the ten year lease period is shown in the Table below.

| **Activity** | **Disturbance (acres)** | **Reclamation (acres)** |
|---|---|---|
| Seismic Line | 9.7 | 9.7 |
| 10 Exploration Wells | 20 | 20 |
| Exploration Access Roads | 22 | 19.8 |
| Gravel Pit Expansion (Exploration) | 1 | 0 |
| Production Wells | 18 | 17.8 |
| Production Access Roads | 34 | 24 |
| Gravel Pit Expansion (Production) | 1 | 0 |
| TOTAL | 105.7 | 89.3 |

<u>Geothermal</u>

The historic average disturbance created by geothermal exploration and development on the BLM Carson City District was used as a basis for hypothetical disturbance estimates used inanalyzing the environmental consequences associated with fluid minerals leasing within the six lease areas comprising the Proposed Action. The RFD scenario includes the drilling of 20 exploration wells per year and development of five, 15-megawatt, power plants over the course of the 10-year lease period. The time frames for a typical geothermal project are estimated as follows: Exploration, 1 to 5 years; Development, 2 to 10 years; Production, 10 to 30 years.

*Exploration*

During the exploration stage, surface disturbance is minimal with few adverse impacts until the decision is made to drill one or more exploration wells. An exploration-drilling model is shown below which lists the maximum degree of surface disturbance expected during this phase. This and other models, which follow, tend to maximize the degree of surface disturbance that could occur. A total of 20 temperature gradient and/or exploration wells could be drilled within the six lease areas comprising the Proposed Action. This would result in up to approximately 20 acres of new pad disturbance per year. New access roads, each ½ mile in length would disturb an additional 10 acres per year. The total disturbance per site would then total approximately 30 acres per year, or 300 acres over the 10-year leasing period as shown in the Table below.

| Activity | Disturbed Acres/Site | Total Disturbed Acres |
|---|---|---|
| Exploration Roads | 0.5 | 100 |
| Shallow Temperature Gradient or Exploration Wells (several 100 to several 1000 feet deep) | 1 | 200 |
| TOTAL | | 300 |

*Development and Production*

The following model illustrates construction activities required to develop five, 15-megawatt electrical power generating plants, associated wells, pipelines, roads, and electrical transmission lines. The number of wells includes those used for production, standby, and re-injection. Since development is likely to occur in about 5-megawatt increments over a period of several years, the degree of surface disturbance at any given time is less than assumed in the model. Mitigation and enhancement would have occurred in some portions of the lease before additional portions of the lease are developed.

Up to six production or injection wells could be drilled on each lease. Each well pad would disturb approximately 5 acres, and a mainline road would disturb approximately 10 acres. Each of three pipelines would disturb approximately 5 acres and each of three access roads would disturb approximately 7 acres. A power plant would occupy approximately 30 acres, a disposal pond would disturb approximately 5 acres, and a 25-mile transmission line would disturb approximately 10 acres. Total surface disturbance for each plant for this phase of operation would total approximately 121 acres as shown in the table below.

| Feature | Features/Plant | Disturbed Acres/Feature | Total Disturbed Acres |
|---|---|---|---|
| Power Plant | 1 | 30 | 150 |
| Well | 6 | 5 | 150 |
| Cooling Ponds | 1 | 5 | 25 |
| Pipelines | 3 | 5 | 75 |
| Access Road (spurs) | 3 | 7 | 105 |
| Mainline Road | 1 | 10 | 50 |
| Transmission Line | 1 | 10 | 50 |
| TOTAL | | 605 | |

<u>Summary</u>

The total surface disturbance associated with the RFD for oil & gas exploration and development activities would be 105.7 acres, of which 89.3 acres would be reclaimed by the end of the 10-year lease period. No reclamation is expected on the developed oil field by the end of the 10-year lease period. Hence, surface disturbance from oil & gas activities in the RFD scenario would result in 16.4 unreclaimed acres by the end of the 10-year lease period. For planning purposes it is assumed that this surface disturbance could happen in any one of the six lease areas comprising the Proposed Action.

The total surface disturbance associated with the RFD for geothermal exploration and development activities would be 905 acres by the end of the 10-year lease period. No reclamation is expected on the developed geothermal plant and well fields by the end of the 10-year lease period. Hence, surface disturbance from geothermal activities in the RFD scenario would result in 905 unreclaimed acres by the end of the 10-year lease

period. For planning purposes it is assumed that this surface disturbance would be distributed over one or more of the six lease areas comprising the Proposed Action.

Therefore, the total surface disturbance (including reclaimed disturbance) associated with the RFD for fluid minerals exploration, development and production activities would be approximately 1,010-acres, or roughly 0.1 percent of area of the Proposed Action over the course of a 10-year period. These effects would most likely be greatest during the development and abandonment or close-out phases. The disturbance would be spread both spatially and temporally across the six leasing areas. Many of these disturbed areas would be reclaimed shortly after disturbance.