U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

Geothermal Technical Working Paper No. 2:

Production Drilling and Well Completion

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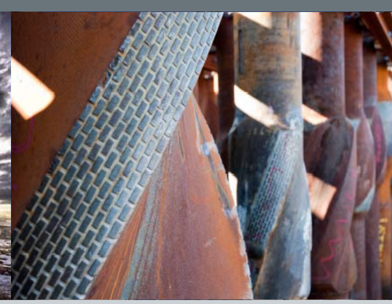


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GLOSSARY

Acronyms and Terms	Definition
BOPE/BOP	Blow Out Prevention Equipment/Blow Out Preventer; A set of redundant valves that close in different ways to seal in the well and that prevents fluid flow out of it. The BOPE consists of rotating heads, annular preventers, pipe rams, blind rams, and shear rams that all shut off the well by different means (see Table 2-8 in TWP #2). This equipment is typically a regulatory requirement so its design, testing, and installation are driven by these regulations
Borehole	See **wellbore.**
Downhole Fluid	A liquid or gas that is introduced below the surface to support generation of geothermal energy.
Drilling Fluid	A fluid that is used to aid in the drilling of any kind of wellbore, including for geothermal energy purposes. The main categories are water-based **drilling muds**, non-water-based (e.g., oil-based) muds, and gaseous (pneumatic). Each category has a variety of subcategories that frequently overlap.
Drilling Mud	A water-based **drilling fluid** that also includes active and inert solids to affect viscosity and density, respectively. An example of a common active solid is bentonite clay, and an example of a common inert solid is barite.
EGS	Enhanced Geothermal Systems; refers to a geothermal resource where the reservoir is man-made; created where there is hot rock but insufficient or little natural permeability or fluid saturation.
Formation Fluid	See **downhole fluid.**
Geothermal Fluid (Geo-fluid)	Any fluid that occurs naturally in rock formations, beds, or strata and refers to the fluid in the subsurface geothermal reservoir.
Greenfield	Previously undrilled land.
Hydrothermal Geothermal System	A naturally occurring geothermal system defined by three key elements: heat, fluid, and permeability at depth.
Injection Well	Well used to inject **geothermal fluid** from the surface power plant back into the geothermal reservoir.
Kick	Refers to the entrance into the **wellbore** of formation fluids. An uncontrolled kick means that the inflow is too large to be controlled by fluid weight or surface **BOPE**.
LCM	Lost circulation material; a type of material that is mixed into the **drilling fluid** as a result of **lost circulation**.
Lost Circulation	Refers to the situation when **drilling fluid**s entering the **wellbore** are lost to the rock formation rather than return to the surface.
Matrix Permeability	A measure of a formation’s ability to allow fluids (liquids or gases) to pass through it.

Acronyms and Terms	Definition
MPa	Mega-Pascal; 1 million **Pascal**
NEPA	*National Environmental Policy Act of 1969*
Pascal (Pa)	International System of Units' unit of pressure equal; 101.25 Pa equals standard sea level atmospheric pressure (corresponding to 1013.25 millibars or 1 atmosphere or 29.92" Hg); the corresponding imperial system unit is the **psi**. The pressures used in geothermal applications such as hydraulic stimulation are often given in megapascals.
Permeability	The capability of a porous rock or sediment to permit the flow of fluids through its pore spaces.
Production Well	The well through which **geothermal fluid** flows to the surface that is then utilized to generate electricity.
psi	Pounds per square inch; 1 psi equals approximately 6,894.757 **Pa.**
Shearing	A mechanical process that occurs when the material yields, resulting in an irreversible continuous (non-fracturing) deformation. Drag bits shear the rock in the same way that a machine tool cuts metal.
Surfactants	Surface-active agents which reduce interfacial tension between contacting surfaces including water/oil, water/solid, water/air, and others.
Trouble	Any unplanned scenario during geothermal operations. Types of trouble can include lost circulation, stuck pipe, loss of well control, wellbore instability, difficulty cementing, diameter reduction, and zone closure. While these are unplanned events, there exist process steps for dealing with them that are described below. If the trouble cannot be resolved, the well may have to be plugged and abandoned.
Wellbore (or "well bore")	The drilled hole, also called a borehole, that includes the open hole or uncased portion of the well. The wellbore may specifically refer to the inside diameter of the rock face that bounds the drilled hole (i.e., the wellbore wall).
Well Pad	Refers to all the equipment and structures necessary to operate a well and include a reserve pit for testing new wells. Equipment may include drilling rig, drilling fluid pits, water storage, pipe racks, mud pumping systems, generators, fuel storage, and other material storage. The size of the well pad varies based on the site-specific conditions but it can typically range from 0.7–5 acres (2,800–20,000 m^2).

EXECUTIVE SUMMARY

The U.S. Department of Energy's (DOE) Geothermal Technologies Office (GTO), in collaboration with the U.S. Department of the Interior's (DOI) Bureau of Land Management (BLM), the U.S. Forest Service (USFS) and the U.S. Department of Defense's (DoD) Navy Geothermal Program, has committed to develop and implement a formalized working agreement that facilitates a technical evaluation of environmental impacts of geothermal technologies. This analysis forms a compendium reference document, which is available as an analytical basis for future agency *National Environmental Policy Act of 1969* (NEPA) documents. The analysis is promulgated in the form of technical working papers (TWPs) that will be integrated into the NEPA processes of participating agencies via internal mechanisms. For example, the BLM would issue an Instruction Bulletin/Memorandum, and DOE could issue guidance documents to program and field offices. USFS and DoD will implement through agency-specific methods as well.

This analysis and reference document focuses on providing a baseline of knowledge to the agencies on specific technology areas associated with geothermal development. These papers assume a general knowledge of geothermal activities and focus on giving a detailed description of the working paper technology. The technology areas include those identified as contentious or potentially containing technologically complicated issues. The goal of this effort is to encourage federal NEPA practitioners to use a technically sound and consistent approach during their environmental review to ensure that their NEPA process is streamlined and efficient. The intention is not for these papers to be regulatory; but the BLM and other federal and state agencies can use them as a reference when completing a regulatory review.

DOE commissioned these technical working papers with input from technical and NEPA experts. While each paper contains a thorough description of its topic technology, it is not possible, nor was it DOE's intention, to define and address all geothermal terminology and regulations. The goal is to marry industry practices with BLM regulations under a common understanding and set of terminology and to give guidance for future NEPA and regulatory reviews.

1. INTRODUCTION

Geothermal power uses the heat of the Earth's interior. Although there is worldwide application of this heat for "direct use"—space heating, industrial processes, recreation—this paper focuses on using the hot water and steam produced by this heat. This resource is accessed through a system of deep wells that bore into subsurface rock formations deep underground and penetrate the geothermal reservoir bringing a mixture of heated water, steam, and small amounts of other compounds to the surface for the purpose of converting the heat into electricity. Most existing geothermal production wells are "hydrothermal," which means that they produce *in situ* fluid, either hot water or steam from permeable subsurface rock formations. The condensed brine from the power plants is reinjected into the reservoir, but this process does not form an explicit circuit of fluid. Wells in reservoirs where there is no native fluid due to a lack of formation permeability are enhanced geothermal systems (EGSs). These wells use a circuit in which water is pumped down one well, where it gains heat by passing through fractures in hot rock, and is then returned to the surface for use in a power plant.

Section 2.2 describes the methods used to drill and complete production and injection wells, which are the focus of this paper.

There are four major phases in the development of a geothermal power project:

- **Exploration:** Geothermal exploration helps define a geothermal resource in terms of its geometry, boundaries, permeability, temperature distribution, and fluid flow paths.
- **Development:** After determining a site-specific viable reservoir, the next phase is to develop the site for commercial operation, including development of the subsurface reservoir and the surface power plant facilities.
- **Production/Utilization:** Operation, reservoir management, maintenance, and repair of all components of the geothermal system and the generation of electricity can all achieve reservoir production sustainability.
- **Reclamation:** Once a site is no longer viable, all facilities and infrastructure related to the geothermal power project are decommissioned and the project site is reclaimed.

This paper focuses on these processes and provides information about the related activities, equipment, environmental impacts, mitigations, and permitting issues. The geothermal industry considers all drilling activity done prior to a successful full flow test that proves the resource's capability to be pre-production or "exploration" drilling. Thus, drilling the first production-size well occurs in the development phase of the project. This paper focuses on wells drilled after the resource has been proven viable and the site is being developed for commercial operation. Figure

1-1 shows the geothermal power project phases where production drilling and well completion occur.

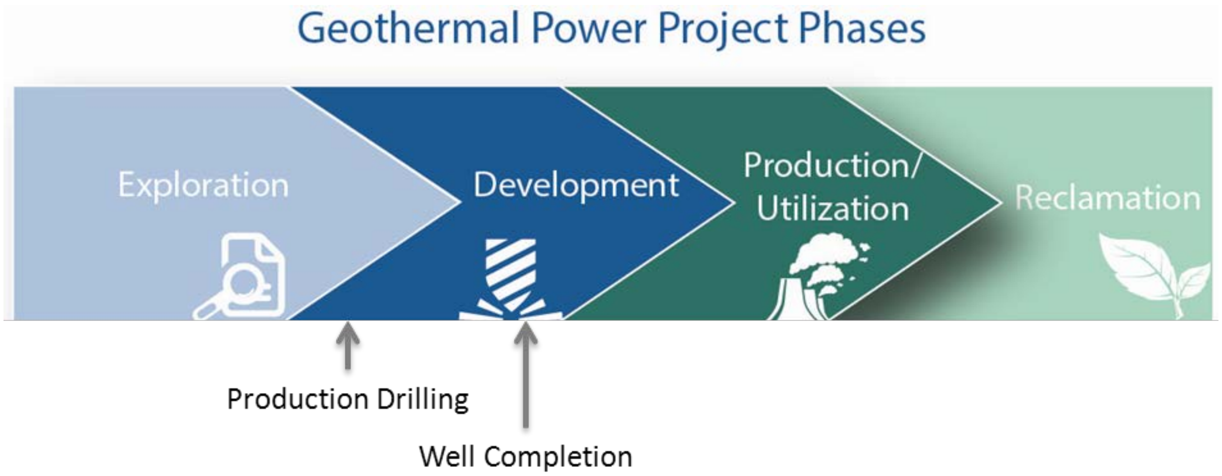


Figure 1-1. Implementation of technology in the geothermal power project

2. TECHNICAL DESCRIPTION

This section provides an overview of the production drilling and well completion process followed by a more technical description of the implementation of these processes in geothermal wells. Production drilling is a process whereby a borehole is made in the ground for extracting subsurface resources such as heat or fossil fuels. This paper will focus on rotary drilling, which is the most common method for drilling geothermal wells, along with specialized techniques within rotary drilling such as air, percussion hammer, and directional that Section 2.1.3 describes. Well completion is an integral part of drilling where each successive interval of the borehole is lined with steel casing cemented in place so that the next interval can be drilled. The purpose of this technical description is to provide detailed information on the processes that will help identify potential environmental impacts resulting from production drilling and well completion, as well as mitigation strategies.

2.1 TECHNOLOGY OVERVIEW

Section 2.1 provides a general definition of production drilling and well completion activities. It also includes background information and describes the current state of the technology as it applies to geothermal power production.

2.1.1 Definition and Purpose

For the purpose of this paper, it is assumed that the geothermal reservoir has been confirmed and that the drilling activity occurs in a greenfield. Methods such as geophysical surveys and exploratory drilling can confirm the site resources; these methods are the subjects of other TWPs in this series.

2.1.1.1 Production Drilling Definition and Purpose

Production drilling is a process that cuts a hole (also referred to as a wellbore) in the ground with a cutting tool known as a drill bit for the purpose of extracting subsurface resources such as oil, gas, water, and steam or to inject materials into the ground such as water or carbon dioxide (CO_2) gas. In the case of geothermal wells, the wellbore conveys the heated fluids in subsurface reservoirs to the surface to generate electricity.

Rotary drilling is the most common method of creating a geothermal well.[1] This type of drilling requires a drill rig, its associated drill string and drill pipe, a drill bit, a drilling fluid system that circulates and cleans the fluid (or an air compressor for air drilling), and a data logging system that provides feedback about how the drilling is progressing. The drilling process occurs continuously until the desired depth is achieved or "trouble" is encountered.[2] The process steps section of the paper describes techniques for addressing trouble. There are two separate but closely related parts of preparing for a drilling project—*planning* the well and *designing* the well. "Planning" means to list, define, schedule, and budget for all the multitude of individual activities required to drill the well, and "designing" means to specify all the physical parameters (depth, diameter, etc.) that define the well itself. The well design and drilling plan will normally be submitted as part of the application for a drilling permit.

Careful planning is critical for any drilling operation. It will not only minimize cost but also reduce the risk of injury or property damage from unexpected events. A drilling plan should list and define all the activities required to complete the well, with their related costs and times, and it should give sufficient descriptions of individual tasks to make clear the sequence in which they must be performed. It is also essential that all contractors and service companies meet, or at least thoroughly communicate, during the planning stage, so that the plan clearly assigns responsibilities for the various activities to specific project participants and there is no confusion as to which person or company performs each step.

2.1.1.2 Well Completion Definition and Purpose

Well completion is an integral part of drilling that seals off the wellbore from surrounding rock formations by lining the well with steel casing cemented in place. This casing serves several functions by protecting groundwater aquifers, isolating troublesome formations that are unstable or have lost circulation, and protecting surface operations from an uncontrolled "kick." When wells are drilled to depths of more than a few hundred feet, conventional practice is to set successive, separate strings of casing as the well gets deeper. Several factors determine the depth of each string; these include rock properties (fracture gradient, sloughing, swelling, and unstable or unconsolidated formation), formation fluids (pore pressure much less or much greater than drilling fluid pressure), well control considerations, or even regulatory requirements. Such regulatory requirements have a driving influence on well completion, covering the drilling rig, casing, cement, pumps, and blow out prevention equipment (BOPE). Geothermal wells require that the casing from the surface to the reservoir or production zone be completely cemented, rather than only cemented at the bottom as in oil and gas wells.

Installation of the BOPE at the top of the casing protects surface operations from a loss of well control. The BOPE is a set of redundant valves that close in different ways to seal in the well and prevent fluid from flowing out of it. As each interval of the well is drilled and cased, its associated BOPE will be removed and replaced with smaller BOPE for the next interval. If the BOPE is not properly activated during a "kick," a blowout is likely.[3] A kick refers to an uncontrolled flow of reservoir fluids into a wellbore, and sometimes catastrophically to the surface, where a blowout is an uncontrolled release of fluids from a well into another subsurface formation or at the surface and may be the result of a BOPE being not properly activated. Thus, the BOPE and its operation are important to safe drilling; Section 2.2.3. describes this further.

2.1.2 Background and Uses

The first wells mechanically drilled in the United States were for water in 1808.[4] Through the early 1800s, drilling was associated with creating fresh and saltwater wells, and it was not until 1859 when Edwin L. Drake first used the technology with oil drilling. Drake drilled a hole lined with an iron pipe and struck oil at a depth of 69.5 feet (ft) [21 meters (m)].[5] Today, production drilling is commonly used to access water, energy, and other natural resources in the oil and gas, mining, and geothermal industries. Each of these industries has adapted drilling and well completion technologies to suit its specific needs and applications. In the case of geothermal production, the essential components are heat, fluids, and permeable rock formations. These components make production drilling and well completion in geothermal reservoirs different from other drilling applications. A principal difference between geothermal and other types of drilling is that the product—hot water or steam—is a low-value fluid relative to crude oil or natural gas.[6] Below is a list of other features associated with geothermal activities.

Heat: Geothermal production zone temperatures are typically between 320^{o}F (160^{o}C) and 572^{o}F (300^{o}C). Although drilling fluid circulation means that actual downhole temperatures will be less than this, drill string equipment and instrumentation must be able to operate within these temperature ranges. The constituents of drilling fluids should remain in solution at these temperatures and additional fluid coolers may be required in order to recirculate the fluid in the drilling process. Well completion materials should be able to withstand large thermal gradients along the length of the well.[7] On average, temperatures below the Earth's surface increase at an average rate of 25^{o}C/kilometer (km), but geothermal resources are found where the geothermal gradient is much higher. There are several commercially producing hydrothermal reservoirs in the United States at depths of less than 1000 ft (0.3 km), but many others are at depths of more than 10,000 ft (3.3 km)—so to speak of an "average" depth has little meaning. Most potential EGS wells are expected to be at greater depths, increasing costs associated with drilling.

Fluid: Produced fluids can include CO_2 and hydrogen sulfide (H_2S) gases, which can accelerate material corrosion. Even high-strength steel compounds in contact with H_2S at these temperatures can fail from sulfide stress cracking. Because of these considerations, operators should choose downhole equipment and metal casings that minimize deterioration upon contact with fluids. Additionally, H_2S gas is a safety hazard requiring the installation of additional detection and alarm equipment that require monitoring during the drilling process.[8] Another important difference between geothermal and other types of drilling is the large volume of fluid that is needed for production. The fluid is an under-pressured mixture of hot water and steam necessitating higher flow rates compared to oil or gas. This results in larger hole and casing diameters, higher drill string and casing weight (and thus larger drill rig capacity), substantially larger volumes of drilling fluids, and greater amounts of material required to complete the well.[9]

Geothermal Formations: Common geothermal reservoir rocks are granite, granodiorite, quartzite, greywacke, basalt, rhyolite, and volcanic tuff. Geothermal formations typically do not have as high-matrix permeability as oil and gas formations, so fractures are the dominant geofluid flow mechanism. Those rock formations are also abrasive and hard, with high compressive strengths. These characteristics result in more expensive drill bit materials, shorter drill bit life, and lower drilling rates of penetration. Because pore pressure is often less than the static head of the drilling fluid, these fluids can be lost to the formation resulting in more trouble occurrences and fewer options to limit fluid loss without damaging the productivity of the reservoir. 10

Section 2.2 describes specific material and equipment solutions that are applied to geothermal drilling to address these challenges not found in conventional oil and gas drilling and well completion.

2.1.3 Current State of Technology

As of December 5, 2012, the BLM recorded 92,583 producible oil and gas wellbores on nearly 700 million acres of federal lands.[11] This is a significantly larger data set than the approximately 500 usable geothermal wells currently on federal lands. For this reason, geothermal drilling technology and its advancements continue to draw extensively from the oil and gas industry. This section describes other drilling methods or enhancements to rotary drilling that exist today.

2.1.3.1 Air Drilling Current Technology

Air drilling uses compressed air or nitrogen as drilling fluids to cool the drill bit and lift cuttings. Typically, this drilling method results in higher rates of penetration and usually requires velocities of 3,000 to 5,000 ft/minute (min). Excessive air velocity can erode softer formations, requiring more air to maintain adequate velocities in the enlarged annular space.[12] Air drilling may permit drilling without loss of circulation (a form of trouble) because it reduces the effective density of the fluid column.[13]

The lifting capability of the air is proportional to its density, and there is a direct relation between air volume requirements and the depth of the wellbore. Excessive air pressure can cause air loss to the formation and, in turn, can result in cuttings not being lifted and tools that stick.[14] Additionally, without the hydraulic pressure of the drilling liquids on the wall of the hole, the wellbore may become unstable.[15]

Air-based drilling also includes air-mist and foam drilling. In air-mist drilling, the addition of wetting agents (like Baroid's Con Det or Penetrol or in Schlumberger's Megamul) controls dust and removes mud rings. Only small amounts of water are recommended, typically 15–25 gallons per minute (gpm) [57–95 Liters per minute (L/min)].[16] When using this method, the volume of air used must increase to account for the increased density of the air column.[17] In foam drilling, the addition of water and additives to large amounts of air create the "foam." The liquid volume fraction must be less than 2.5% to be considered foam drilling. The addition of surfactants, such as polymers and clays, allow the foam to lift greater volumes of water, reduce air volume needs, carry a greater volume of solids, and reduce erosion in poorly consolidated formations.[18]

The advantages of air-based drilling are higher penetration rates, especially in hard rock; easy detection of aquifers and estimation of flow rates; reduction in formation damage; longer drill bit life; less water requirements; and typically better formation samples. The major disadvantage lies in the disposal management of the water brought to the surface, which could be significant given the typical duration of a drilling project.[19] It is best to utilize air-based drilling only in certain portions of the geothermal well where rock formations make it more favorable, but it is not typically used for the entire depth of the well.

2.1.3.2 Percussion Drilling Current Technology

Percussion drilling normally uses a downhole air hammer operated by 100 psi [690 kilopascals (kPa)] air similar to a jackhammer. The bit is in constant contact with the bottom hole surface as the piston provides 800–2,000 strokes per minute. Air exhausted during the strokes directs cuttings into the annular space between the drill pipe and hole wall and forces them up to the surface. A conventional rotary rig rotates the drill pipe and impact bit for even penetration and a straight hole.[20, 21] Because geothermal formations are typically hard, fractured rock, air hammer drilling is well suited because there is little or no plastic deformation of the rock. Faster rates of penetration have been demonstrated using air hammer drilling as compared to rotary drilling with air and stable aqueous foam. This method eliminates the large volumes of drilling fluids but requires costly air compressors to provide the large volumes of high-pressure air. Controlling impact weight on the bit and issues with fishing[a] broken equipment have limited the commercial viability of air hammer drilling within geothermal applications.[22, 23]

2.1.3.3 Directional Drilling Current Technology

Directional drilling is the practice of controlling direction and deviation of a wellbore to a predetermined target.[24] In order to accomplish directional drilling, the drill bit needs to point in the desired drilling direction. The most common way to do this is with a bend near the drill bit in a downhole steerable mud motor. When the entire drill string is not rotating, the bend points the drill bit in a direction different from the axis of the wellbore. Pumping mud through the mud

[a] Fishing is a general term for the removal of junk or debris from a wellbore as defined by Schlumberger's Oilfield Glossary.

motor causes the bit to turn while the drill string does not rotate, thus allowing the bit to drill in the direction it points. Once a particular direction is achieved, it can be maintained by rotating the entire drill string including the bent section.[25]

Instruments to measure the path of the wellbore in three-dimensional space and data links to communicate measurements taken downhole to the surface are also required,[26] but high temperature often challenge both this instrumentation and the elastomers of the motor. Figure 2-1 provides an example of a BHA used in directional drilling.

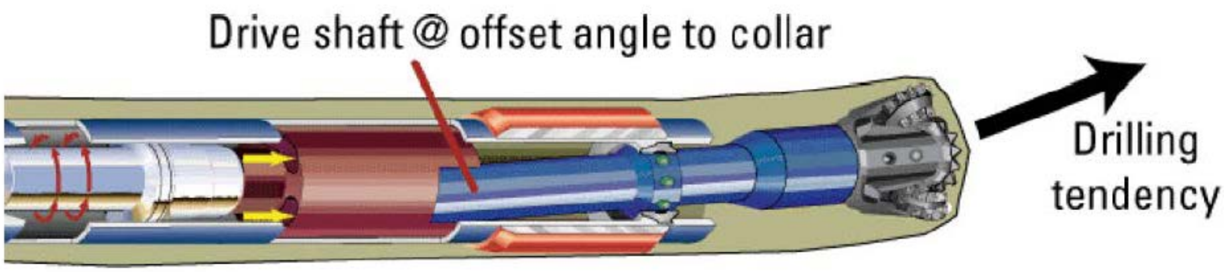


Figure 2-1. Typical BHA for directional drilling[27]

Directional drilling is necessary for several reasons. First, directional drilling provides access to resources even when the surface directly above the target cannot be disturbed for historical structures, ecosystems, delicate terrain, or other reasons. Secondly, directional drilling allows for using the same platform to drill wells 30–50 feet (10–15 m) apart at the surface but at a much larger distance apart at the reservoir depth as shown in Figure 2-2.[28] This is an important advantage for geothermal reservoirs where wells are typically drilled in pairs (injection and production). Finally, geothermal reservoirs often have high-angle fractures that carry most of the geofluids, so directional drilling allows the wellbore to intersect more of these fractures.

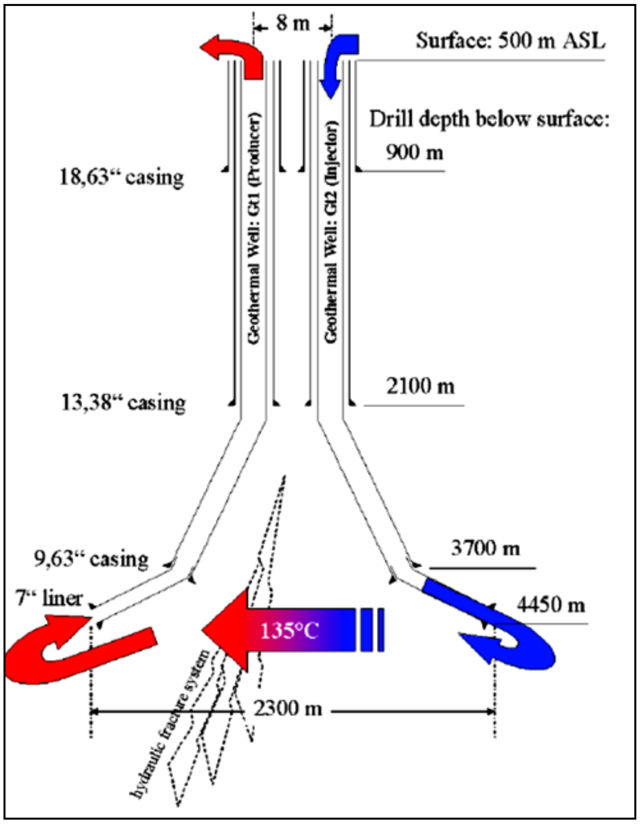


Figure 2-2. Well pair in South German Malm Carst formation[29]

Horizontal Drilling: Horizontal drilling is a subset of directional drilling in the oil and gas industry where the drilling in a nonvertical direction exceeds about 80 degrees resulting in a horizontal well. Because the horizontal portion of the well typically penetrates a greater length of the reservoir at the same depth, it can offer significant production improvement over a vertical well. Horizontal drilling is common in shale reservoirs because it puts the well in contact with the most productive reservoir rock.[30] This also allows access to greater parts of a reservoir without having to drill another wellbore at the surface. Horizontal drilling equipment is generally similar to directional drilling. There are no horizontally drilled wells in existing geothermal power plants, but the potential is being examined for future test sites.

Other Directional Drilling Methods: Multilateral wells are a variation on directional drilling in which several wellbore branches spread out from the main wellbore. The technology has advanced significantly in recent years within the oil and gas industry to recover hydrocarbons in heavy-oil applications,[31] but it is also commonly used in geothermal fields such as The Geysers.

2.1.3.4 Casing Current Technology

Casing for geothermal wells is generally similar to that for oil and gas wells in that there are various grades (alloy compositions), wall thicknesses, and diameters. Typical geothermal production diameters are 13-3/8 in, 10-3/4 in, and 9-5/8 in, where the first two are considered “big-hole” completions and the latter is considered a “standard-hole” completion.[32] Table 2-1 is representative of geothermal well casing descriptions.

Table 2-1. Representative Casing Sizes for a Geothermal Well[33]

Casing Name	Purpose[a]	Geothermal Well	
		Diameter	Depth
Conductor	Prevents cave-ins at the surface.	30 in (0.8 m)	40 ft (12.2 m)
Surface	Protects freshwater zones near the top.	20 in (0.5 m)	1500 ft (460 m)
Intermediate	Seals off trouble zones longest part of the well and may require multiple casing strings.	13-3/8 in (0.3 m)	3000 ft (900 m)
Production	Final section; casings and liners may not be necessary, depending on well type, because holes in permeable rock can convey steam and water to the surface.	9-5/8 in (0.2 m)	6000 ft (1800 m)

2.1.3.5 Cement Current Technology

As noted in Section 2.1.1 Definition and Purpose, geothermal wells typically have a complete cement sheath from the reservoir to the surface. The types of cements used in conventional oil wells have limited use in geothermal wells because of their high density and susceptibility to acids and CO_2, which are present in geothermal formations. Brookhaven National Laboratory developed two cements for geothermal wells in the late 1990s. The first is calcium aluminate phosphate (CaP) and was designed as CO_2-resistant for mildly acidic (pH~5.0) environments, and has since been commercialized. The second is sodium silicate-activated slag, which was made to resist high temperatures (200°C), strong acidic conditions, and low CO_2 levels.[34]

2.1.3.6 Coiled Tubing Current Technology

Coiled tubing is a continuous length of small-diameter flexible or jointed steel pipe and related surface equipment and techniques, primarily used to deploy tools and materials through production tubing or casing; to drill; or to perform completion, workover, or remediation. Coiled tubing has been used to produce geothermal wells because it can minimize non-productive drilling time, avoid lost circulation, limit damage to the formation, and prevent drill equipment from getting stuck in the hole.[35] Additionally, it can allow for more rapid mobilization and rig-up, requires fewer personnel, and has a smaller environmental footprint than traditional drilling technologies. This technology has the potential for significant cost savings over conventional drilling or workover techniques.[36]

2.2 TECHNICAL FEATURES

Section 2.2 provides a description of the process steps, materials, and equipment associated with production drilling and well completion. It also discusses the drill plan and well design, which are precursors to these processes.

2.2.1 Process Steps

The following section details the process steps associated with production drilling and well completion.

2.2.1.1 Drill Plan and Well Design

Production drilling and well completion require a large number of resources and equipment. Many of the tools and equipment are site-specific and of custom design requiring long lead times for fabrication. The drill rigs, pumps, compressors, and other heavy equipment are rented and must be scheduled for use, so understanding what is needed before any equipment is sent to the site is important. For all these reasons, it is necessary to develop a drill plan as a precursor to production drilling activities.

The drill plan provides all the details about how the hole will be drilled. It describes the well design; the equipment needed to make (drill) the hole; the need for directional drilling, if any; the types and quantities of drilling fluids anticipated; the data collection requirements; and an estimated schedule to complete the work.[37] These details must be provided to obtain a geothermal drill permit (GDP) prior to commencing drilling activities.[38]

The well design, which is part of the drill plan, provides further details on the hole such as well depth, casing diameters, grades, thickness, and lengths.[39] Geothermal reservoirs are located on average 1.3 miles (mi) (2.1 km) below the surface. The estimated flow rates based on reservoir properties will determine the size of the bottom of the well, known as the production hole. While flow rates dictate hole diameter in the production zone, reservoir depth and rock formations drive the geometry above the production zone. The well design defines the details of the hole depth and diameter at different depths along the well. Typically, the hole diameter gets successively larger as the hole reaches the surface due to drilling and/or geological considerations. Figure 2-3 shows the telescoping cross-section of a typical geothermal wellbore and Table 2-1 provides the distinct casing names, typical sizes, and purposes. The next section describes the process for creating the telescoping well cross-section.

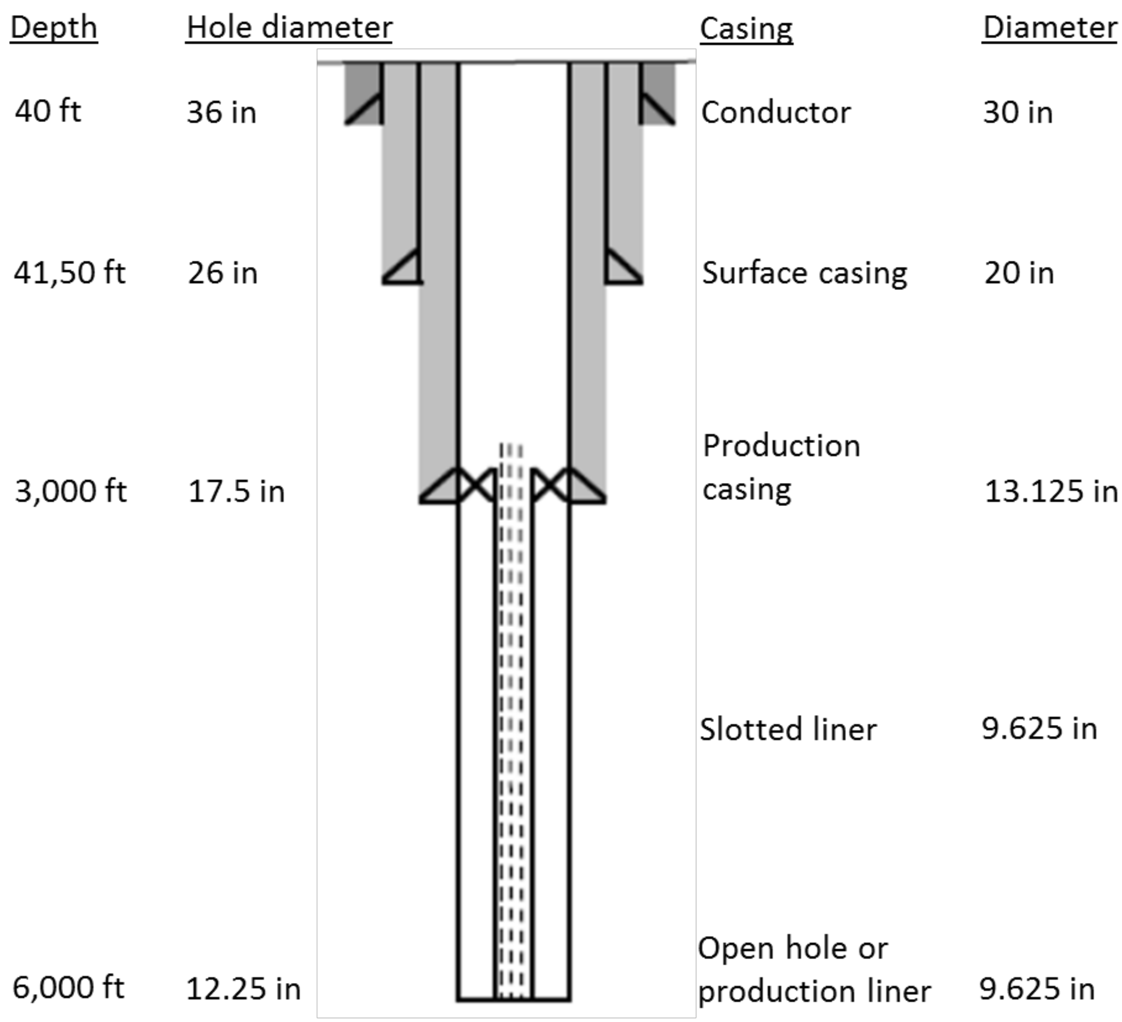


Figure 2-3. Typical geothermal well cross-section[40]
Acronyms: feet (ft), inches (in).

2.2.1.2 Creating a Telescoping Well

To achieve the telescoping hole geometry shown in Figure 2-4, production drilling and well completion processes repeat several times until the reservoir depth is reached and the final production hole is drilled and completed. Figure 2-4: Process Steps Associated with Production Drilling and Well Completion shows the high-level steps associated with production drilling and well completion. The steps associated with production drilling are in green boxes. The first two production drilling steps on the left are planning steps needed prior to breaking ground with any drilling activities. The blue boxes represent the well completion steps. The well completion process is done incrementally as the wellbore is drilled, and hence the timelines of the two processes are interwoven, as illustrated by gray arrows that flow from one process to the other. Both processes have steps that occur above the surface and below the surface. The activities occurring above the surface are above the black horizontal line in the figure. The next series of sections describe in detail the process steps for production drilling and well completion.

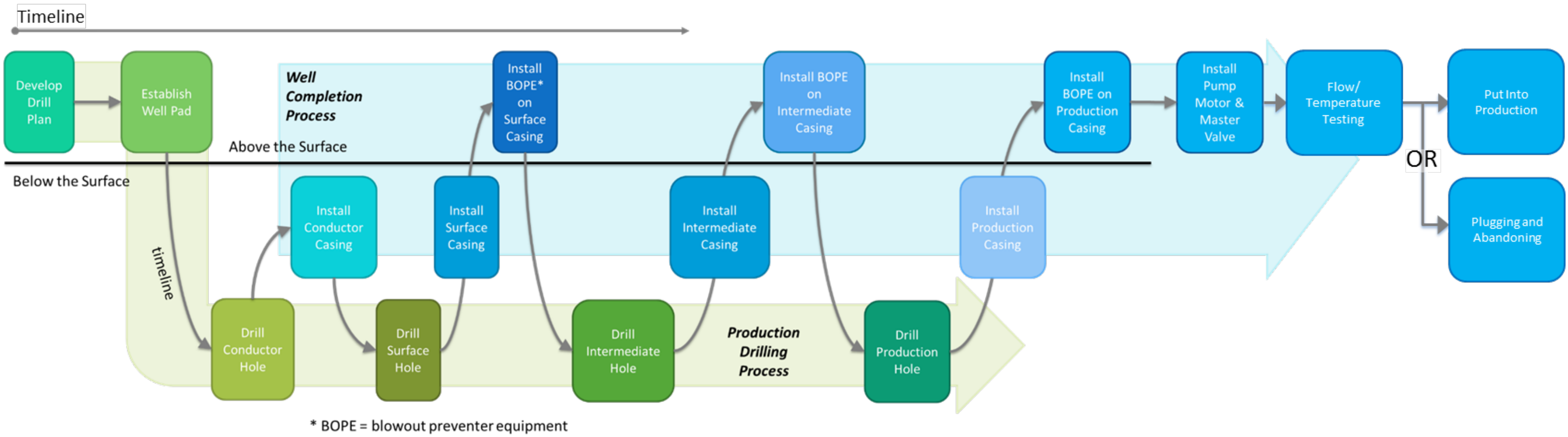


Figure 2-4. Process steps associated with production drilling and well completion

Adapted from Salt Wells Energy Project EIS[41]

2.2.1.3 Production Drilling Process Steps

Production drilling is the cutting process that removes rock to create a wellbore at the site of a geothermal reservoir. Rotary drilling, where a drill bit rotates to cut the hole, is the most common method of creating a geothermal well.[42] The drill bit is typically a roller cone or drag bit like the ones shown in Figure 2-5. The roller cone crushes and gouges rock as the cone's teeth contact the rock. The drag bit shears the rock similar to machining metal.

Figure 2-5. Geothermal drill bits[43]

A bottom hole assembly (BHA) like the one shown in Figure 2-6 includes the aforementioned drill bit, bit sub, a mud motor (only in certain cases), stabilizers, drill collar, heavyweight drill pipe, jarring devices ("jars"), and crossovers for various threadforms. The BHA, drill pipe, and any other tools needed to make the drill bit turn are collectively called the drill string.[44] The drill pipe provides a means of circulating drilling fluids down the drill pipe, through holes (called jets) in the bit, and back to the surface though the annulus between the drill pipe and the wellbore. The fluid's most important function is to carry away the cuttings, but it also cools and lubricates the bit and contributes to wellbore stability.[45]

The drill rig that supports and turns the drill string is generally selected based on its power and mast capacity, and these criteria are driven by the hole diameter, depth, and casing design.[46] The rotary drill rig can impart torque through a rotary table and kelly, or through what is known as a top drive system. The top drive system consists of an electric or hydraulic motor that hangs beneath a block and travels up and down the mast providing torque directly on the drill pipe.[47]

2.2.1.4 Well Completion Process Steps

Overview: Well completion is the process of sealing off the wellbore. When drilling has achieved a desired depth, such as the total depth of the conductor casing, the drill string is brought to the surface. Drilling muds are then circulated, and the drill string is left in the hole while circulating and conditioning the hole, without further drilling to make sure the hole is clear of cuttings and debris.[48] Next, a casing with a diameter that is slightly smaller than the hole diameter is lowered into the hole. Several sections of casing are installed sequentially until the pipe covers the entire depth of the hole. Cement is then pumped through the center of the casing until it flows up the annulus between the rock wall and the casing all the way to the surface. A necessary waiting period of generally 12–24 hours then follows to allow the cement to set. Once the cement has set, it anchors the casing within the hole and seals the hole from the rock, thereby completing the subsurface portion of the well.[49]

Casing Placement: The first casing joint that is lowered into the well has a guide shoe on the bottom and a float collar on the top. The guide shoe guides the casing into the well bore. The float collar contains a valve that allows the casing to float into the well to lessen the load on the hoisting system. The float collar also acts as a check valve that keeps drilling fluids (and later cement) from entering through the bottom of the casing. On the exterior of the casing, there are centralizers and scratchers. Centralizers keep the casing off the borehole wall to ensure a good cement job. The scratchers remove wall cake to ensure a good cement bond with the borehole.[50, 51]

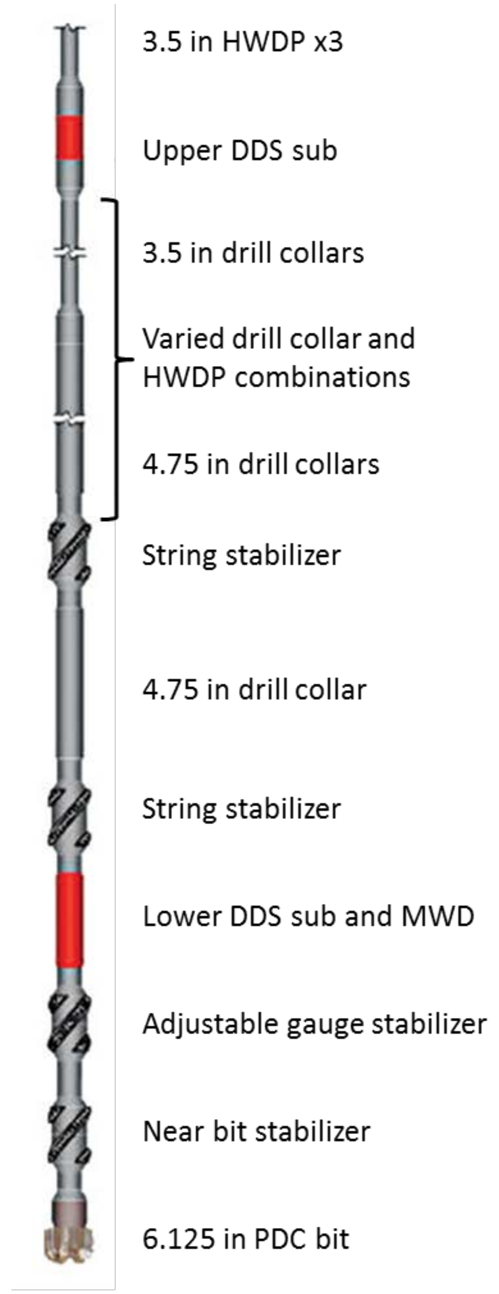


Figure 2-6. A typical bottom hole assembly (BHA)[52]

Acronyms: heavy weight drill pipe (HWDP), directional drilling system (DDS), measurement while drilling (MWD), polycrystalline diamond compact (PDC)

Cementing: Cementing is one of the most difficult and important parts of the well completion process. Cementing seals the casing into the well, protecting it and sealing it off from the surrounding formation. Cementing during drilling helps prevent loss of drilling fluid. It is also used for setting kick-off plugs and for well plugging and abandonment. Cement slurry is mixed on-site by a cementing unit that rapidly mixes water, dry cement, and additives to create liquid slurry. Cement quantities are estimated based on the annulus width and hole depth. A cementing head (also known as a plug retainer) is created on-site and installed on the top casing joint suspended from the rig elevator. The cementing head has a slurry inlet, slurry valves, a plug storage area, and a fluid inlet. The slurry inlet is where the cement enters the system. The slurry valves control the flow of cement into the wellbore. The plug storage area contains two wiper plugs, top and bottom, which are dropped into the well before and after cementing to isolate the cement from the drilling fluids. The fluid inlet is for pumping muds, water, or displacement fluid into the wellbore. Displacement fluids push cement into the annulus between the wellbore wall and casing.[53, 54]

Figure 2-7 shows the cementing process. The first step in cementing is to drop the bottom wiper plug into the casing. Then, a high-pressure pumping unit pumps the cement through the cementing head slurry inlet and into the casing. The cement pump pressure forces the bottom plug down the casing. The plug wipes the mud off the inside of the casing and pushes the drilling fluids out of the casing. When it reaches the bottom of the casing, the cement pump pressure will break a diaphragm in the plug, opening a passage for the cement to exit the casing and enter the annulus. Cement is pumped until the calculated cement volume is displaced. Then the top wiper plug is dropped from the cementing head into the casing on top of the cement. This is followed by displacement fluids, which are pumped through the fluid inlet. The displacement fluids push the wiper plug down the casing. The plug wipes the cement off the inside of the casing and pushes the cement slurry into the annulus. When the top wiper plug reaches the bottom of the casing, it will seat on the bottom wiper plug. This plug is solid, so when there is a sharp rise in displacement fluid pressure the pumps are stopped. When the cementing process is complete, a waiting period (typically 12-24 hours) is necessary to allow the cement to set.[55, 56] If additional drilling is necessary, such as for the next lower hole, the drill bit is capable of drilling through the wiper plugs and any cement at the bottom of the casing.

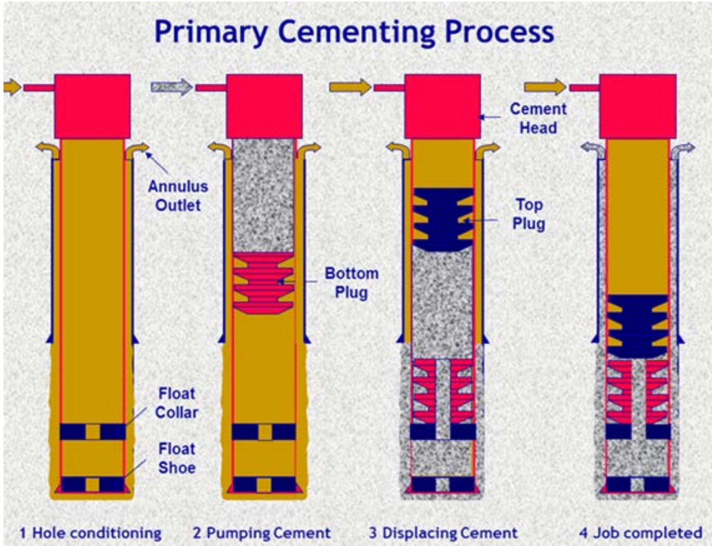


Figure 2-7. Cementing process steps[57]

BOPE Installation: While the cement sets, the well is sealed. A flange is welded to the top of the casing that has just been cemented, and the BOPE assembly is bolted to that flange. Prior to installing the BOPE, there should be two valve lines known as choke and kill lines installed below the BOPE on the casing as an outlet for fluids within the well or as an inlet for pumping fluids into the wellbore. Once the BOPE is installed, the drill string for the next phase of drilling is lowered through the BOPE.

Testing and Production or Plugging and Abandonment: In addition to the testing that is performed during drilling, the well is tested for temperature and flow after completion. This is to verify the value of the reservoir and to support further decision making about the well. At this point the well will either be put into production or plugged and abandoned.

2.2.1.5 Trouble Scenarios

With this type of work, there is always the possibility that one will encounter an unexpected situation. These unplanned scenarios are collectively referred to as trouble. There are several types of trouble that one can encounter such as lost circulation, a stuck pipe, loss of well control, wellbore instability, difficulty cementing, and diameter reduction. While these are unplanned events, there exist process steps for dealing with them as described below. If the trouble cannot be resolved, one may have to plug the well and abandon it.

Lost Circulation: Lost circulation is when drilling fluids entering the wellbore are lost to the rock formation rather than return to the surface. This can occur in any section of the well and poses several issues. Lost drilling fluids do not bring cuttings to the surface, so the hole may not be properly cleaned, which could result in a stuck pipe. Additionally, the absence of fluids could decrease the static head pressure of the drilling fluids resulting in loss of well control. Sealing is necessary if the lost circulation occurs above the production zone, which may require difficult cementing procedures, lost circulation materials, packers, an additional casing string, and other costly equipment. If the lost circulation occurs in the production zone, curing the lost circulation while preserving the production potential may pose difficulties. Access to additional fluids to replace those lost may be costly.[58] Addressing all of these issues will also result in schedule delays and increased costs associated with any needed extensions of equipment rentals.

There are several ways to mitigate lost circulation. One is to accept the loss of fluids and drill without returns. Another is to change to a lightweight drilling fluid that will reduce the pressure of the fluid column. A third is to attempt to plug the zone by mixing solid or fibrous material known as lost circulation materials (LCMs) with drilling fluids. (The section on drilling fluids discusses LCMs.) The last resort, although very common, is to use an open-ended drill pipe (i.e., no bit) to pump cement into the wellbore to seal the loss zone.[59]

Stuck Pipe: The stuck pipe can neither rotate nor move vertically, but the fluids may still circulate. It can occur from cuttings collecting on top of the BHA. It can also occur from a differential in drilling fluid and pore pressure. The process to combat stuck pipe is to eliminate the differential pressure by using lubricant or reducing the density of the fluid column.[60]

Loss of Well Control: Loss of well control can result from a "kick," which occurs when fluids from the rock formation enter the wellbore. This can happen if the static head pressure of the drilling fluid drops below the pore pressure of the rock formation. Flow must be controlled before it results in loss of well control or a blowout. Activating the BOPE and increasing the drilling fluid density are both ways to counter this type of trouble.[61]

Wellbore Instability: Wellbore instability is when the hole walls are mechanically unstable. Wellbore instability can cause problems with clearing cuttings, casing placement, and cementing. The best way to address this is to understand the stress regimes and perform directional drilling to avoid regional stresses.[62]

Difficulty Cementing: A full-length cement sheath is needed for geothermal wells. Achieving this is sometimes difficult because of the density difference between cement and drilling fluids, which can cause water to become trapped causing a collapse in the casing during temperature cycles. Lost circulation also may prevent cement from reaching the surface. Approaches to combat difficulty cementing are to use lightweight cements or to repair cementing process by pumping cement down the annulus in what is known as a top job.[63] However, lightweight cements may not meet federal regulations if they have the potential to compromise the cement job.

Wellbore Diameter Reduction: If trouble requires an unplanned casing string to be used, the production hole diameter will be smaller than planned, meaning lower flow rates than anticipated. If the well is expected to be troublesome, the contingency of an extra casing string can be addressed by using casing one size larger than a standard design for the expected flow rates. This is very expensive, however, and possibly increases well cost by as much as 20+%, so the decision is one of risk assessment, balancing the possibility of reduced flow rates against the increased cost of a contingency casing string.[64]

2.2.2 Resource Requirements

There are several resources needed for production drilling and well completion. In this section, we discuss the primary resources, their material composition, and the volumes needed. Table 2-2 aligns the resources with the different processes.

Table 2-2. Resources Associated with Production Drilling and Well Completion

	Production Drilling	Well Completion
Resources Required	Well pad	Cement
	Drilling fluids	Casings
	Diesel for operation equipment	Liners
	Lost circulation materials	

2.2.2.1 Well Pad

The well pad is an area that is graded, compacted, and graveled for staging all the drilling equipment during drilling operations.[65] The well pad layout, as shown in Figure 2-8, includes drilling rig, drilling fluid pits, water storage, pipe racks, mud pumping systems, generators, fuel storage, and other material storage. The size of the well pad varies based on the site-specific conditions, but it can typically range from 0.7–5 acres [2,800– 20,000 square meters (m^2)].[66] Getting the rig and ancillary equipment on the well pad may require 15–20 trips by full-sized tractor-trailers and 10–40 daily trips for commuting and hauling in equipment.[67] Power plants that generate 30–50 megawatts (MW) typically require about 5–10 well pads to support 10–25 production wells and 5–10 injection wells. Multiple wells

may be located on a single well pad.[68] Pads are in place for the duration of the drilling and well completion activities. Once the drilling work is complete, a much smaller well pad footprint remains for the production of the well.

Figure 2-8. Typical geothermal well pad layout[69]

2.2.2.2 Drilling Fluids

Drilling fluids come in three classes: water-based, oil-based, and air-based. Oil-based fluids are not typically used in geothermal applications. Air-based liquids are typically used only for drilling conditions such as a dry steam field. The most commonly used fluids are water-based fluids, also known as drilling muds.[70] Drilling muds are typically a mixture of a base liquid (water), active solids (clay), and inert solids (additives for density and viscosity). The advantages of lightweight drilling fluid in under-pressured reservoirs means that muds are often injected with compressed air or nitrogen to give them lower density—these are known as "aerated muds." Initial drilling mud volume is usually around 42,000 gallons (160,000 liters).[71] Table 2–3 shows the typical property ranges. The drilling fluid is one of the most critical aspects of the drilling operation. Many of the problems encountered in a typical drilling project relate to the drilling fluid, so it is extremely important that the fluid be properly designed and maintained. *TWP No. 3 Downhole Fluids* provides more information about drilling fluids.

Table 2-3. Drilling Mud Material Properties[72]

Property	Value
Density	8.6–9.6 lbs/gal (1.03–1.15 g/cm^3)
Funnel viscosity	35–55 sec/qt
pH	9.5–11.5
Plastic viscosity	10–20 cP (0.01–0.02 Pa·s)
Yield point	5.0–18.1 psi (35–125 kPa)

Acronyms: pounds per gallon (lbs/gal), grams per cubic centimeter (g/cm^3), seconds per quart (sec/qt), centipoise (cP), pascal-second (Pa·s), pounds per square inch (psi), kilopascals (kPa).

2.2.2.3 Diesel Operated Equipment

Electric motors drive most of the major components of the drill rig—mud pumps, drawworks, and rotary table. The power for those motors comes from the diesel motor-generator sets that are a part of the drill rig. Ancillary equipment such as hoists, air compressors, and the like use either their own diesel engines or the rig's electric power. Essentially, then, a diesel engine powers everything on the drill site, either directly or indirectly. Fuel consumption can be more than 600 gallons per day (2,300 liters per day) for a 1,000 horsepower (750 kW) drill rig, which is a relatively small rig.[73]

2.2.2.4 Lost Circulation Materials (LCMs)

The mixing of LCMs into the drilling fluids occurs when fluids are lost into the rock formation. The principle is that the T solid or fibrous LCM will flow into the pores or fractures through which the fluid is being lost and will plug them. Some LCMs used in the past for oil and gas drilling include sawdust, alfalfa pellets, chicken feathers, ground walnut shells, cotton seed hulls, hog hair, and gunk (a combination of bentonite and diesel oil that forms a putty-like mass when mixed with water), but many of these materials are organic and will not withstand the high temperatures of geothermal drilling. There is also the problem that most geothermal production is through fractures, and the fracture aperture is often too large for the LCM particles to bridge.[74] In the Kapoho State 11RD well in Hawaii, micronized cellulose ("MicroCell") was used in 2%–5% by volume of the drilling fluids.[75] *TWP No. 3 Downhole Fluids* provides further information about LCMs.

2.2.2.5 Cement

Cements consist of limestone or other calcium carbonate-rich material, clay or shale, iron, and aluminum oxide that are mixed in different proportions to achieve certain properties, then fired to high temperatures and ground down to different fineness.[76] Geothermal cements should have high-bond strength to the casing and should be impermeable. However, it is also very advantageous for the cement to be lightweight (at least compared to conventional cement, which has a specific gravity of approximately 1.6). Lightweight is important because formations are often underpressured, meaning that the formation's pore pressure is less than a column of water or mud to that depth. If the formation will not even support drilling fluids, then it is impossible to lift a column of normal-weight cement back to the surface when casing is cemented in place. One solution to this problem is foam cement, which has gas injected into it, in the same way as drilling fluid is aerated to make it lighter. Geothermal wells typically use Class G Portland cements with approximately 40% silica flour and retardants to prevent premature setting at high temperature.[77] Gas injection can reduce the density of the cement. This cement type is known as foam cement.

The amount of cement needed depends on the well design and excess cement requirements. A volume of cement is calculated based on the annulus in the casing design, but this is often modified by the results of a caliper log in the wellbore that is about to be cemented. This log will show any washouts, or hole enlargements caused by drilling, so the calculated volume will be increased to allow for that. Even after this is taken into account, many companies or drilling engineers like to specify an additional amount ("excess") of cement to allow for losses due to underpressure, or cavities. As an example, the 6,000 ft. (1800 m) depth well shown in Figure 2-4 where the top of the reservoir is at 3,000 ft (910 m), the annulus cement volume is approximately 4,400 cubic feet (ft^3) [125 cubic meters (m^3)]. However, if there are lost circulation zones or poor cement jobs, more may be necessary.

2.2.2.6 Casings

The casings used in the well completion process are made of seamless steel pipes according to the American Petroleum Institute's Specification 5CT. Casing design is primarily determined by the bottom-hole depth and diameter. Typical geothermal bottom-hole diameters are 13.375 in, 10.75 in, and 9.625 in, where the first two are considered "big hole" completions and the latter is considered a "standard hole" completion.[78] Characteristics of casing designs include the casing's diameter, weight, and grade. Diameter refers to the nominal outside diameter; weight is actually the weight per unit length and refers to the wall thickness; and grade is primarily a measure of the material's tensile strength.[79]

Casing has to withstand different kinds of loading in different situations, and the most common design criteria are for burst pressure, collapse pressure, and axial tension. Burst pressure and axial tensile strength for a given casing size are a function of the casing grade, but collapse relates more to the wall thickness, because the material's elastic properties and geometry, as well as its tensile strength, determine collapse. In a casing design, it may also be important to consider strength degradation at high temperature and corrosion due to brine chemistry.

Many different grades of steel are used for geothermal casing. Two that are common when conditions are not extreme are K-55 and L-80—both of these have the same tensile strength of 95,000 pounds per square inch (psi), but K-55 has a yield strength of 55,000 psi and L-80 is 80,000 psi. The alloy composition of L-80 is also adjusted for H_2S, and it has a hardness requirement of 23 Rockwell C.

Geothermal reservoirs often produce H_2S gas, thus requiring that casing materials meet National Association of Corrosion Engineers 0175 standard. In extremely corrosive environments such as the Imperial Valley of California, a corrosion rate of 0.1 inch [3 millimeter (mm)] of carbon steel per year was observed. For these conditions, the installation of titanium casings help to extend the life of the well.[80]

2.2.2.7 Liners

Liners are just strings of casing that do not go up to the surface. They are often used in the production zone of the hole, where they are typically slotted or perforated to permit the flow of fluids into the well, but they are also used higher in the hole to reduce the amount of casing used, thereby reducing costs. In geothermal wells, the liner is run into the hole on the drill pipe and hung on a liner hanger, and then is cemented in place.[81]

2.2.2.8 Geothermal Drilling Experience

Having a crew with geothermal experience is critical for drilling. The wells themselves require special designs due to their higher temperatures, larger diameters, and other differences from oil and gas wells. Geothermal wells are often hard (240+ MPa compressive strength), abrasive, highly fractured (e.g., fracture apertures of centimeters), and under-pressured. The formations can contain corrosive fluids or high solids content. In general, drilling is difficult with low rates of penetration and short bit life, problematic corrosion, and frequent and severe loss of circulation.[82]

2.2.3 Associated Equipment

A large amount of equipment is typically associated with production drilling and well completion. This section discusses the main equipment utilized, its key characteristics, and how different types of equipment are used in the process.

Table 2-4 aligns the equipment with the different processes. The table also lists the equipment used in both processes.

Table 2-4. Equipment Associated with Production Drilling and Well Completion

	Production Drilling	Well Completion
Associated Equipment	Drill rig	Cement mixer
	Drill bit	Centralizers
	Drill pipe	Packers
	Instrumentation and data logging systems	Float collar and float shoe
	Compressors	Wiper plug
	Mud cleaning equipment	Cementing head
	Water tanks and mud pits	

	Mud pumping systems
	Generators and diesel engines
	Blowout preventer equipment

2.2.3.1 Drill Rig

The drill rig size is based on the hole diameter, depth, and casing design. Rig footprint and capacity are important parameters in the selection process.[83] Figure 2-9 shows a conventional rotary drill rig and top drive system.

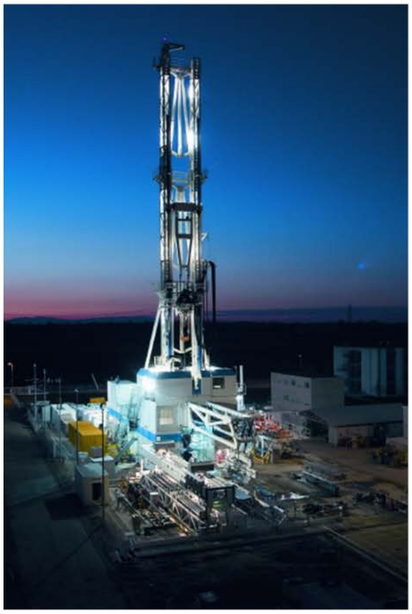
Rotary drill rig with mast height of 180' (55 m)

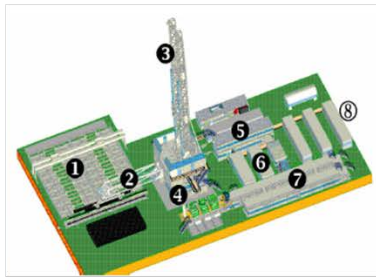
Top drive of rotary drill rig

Figure 2-9. Rotary drill rigs[84]

Most rigs used for geothermal drilling can drill to depths of 15,000 ft. (4,600 m). The basis for this is primarily the mast capacity, and how that compares with the maximum drillstring and casing weight. The average rate of penetration will vary tremendously depending on rock type, bit type, depth, and hole diameter. In the upper parts of the hole with softer rock, rates of 60–80 feet per hour would not be unusual but in deeper, harder rock, the rate could well be 3–5 feet per hour. Average rotational speeds while drilling are 60–100 revolutions per minute (rpm).[85]

Figure 2-11 Figure 2-12 shows a drill rig based on Herrenknecht Vertical’s Terra Invader 350 drilling rig, with innovative characteristics making it particularly suitable for a geothermal well.





InnovaRig main components

1. Pipe rack
2. Pipe handling system
3. Derrick with hydraulic elevator
4. Substructure with rig floor and blow out prevention system
5. Electrical energy transformer
6. Mud pumps
7. Mud conditioning system with mud tanks, shale shakers, centrifuges, desanders, desilters
8. Diesel power plant

InnovaRig operating specifications

Drilling depth	4000 – 5000 m
Regular hook load	3500 kN
Nominal rotary speed	220 rpm
Rotary torque	40 to 75 kN
Wireline coring speed	500 rpm
Wireline coring torque	12 to 18 kNm
Tripping speed	500 m/hr
Hoist cylinder stroke	22 m
Drive power up to	4000 kW
Rig weight approximately	3700 kN
Mud pumps	3 x 1000 kW
Wireline coring mud	1 x 600 kW
Mud pressure maximum	350 bar
Mud tank system	240 m^3
Generator set	3 x 1540 kVA
Drill pipe rack capacity	7000 m
Wireline coring winch	5000 m, d = 12.7 mm

Figure 2-10: InnovaRig[86]

Acronyms: meters (m), kilonewton (kN), revolutions per minute (rpm), kilonewton (kN), kilonewton meter (kNm), meters per hour (m/hr), meters (m), kilowatts (kW), cubic meters (m^3), kilovolt-ampere (kVA), diameter (d), millimeters (mm)

2.2.3.2 Drill Bit

Drill bits are part of the BHA and typically fall into two categories: roller-cone or drag bit (see Figure 2-6). Most roller-cone bits have three cones with milled steel teeth that are part of the cone (i.e., milled-tooth bits) or hard-metal teeth that are inserted into the body of the cone (i.e., insert bits). Although less expensive, milled tooth bits are only suited for softer rock formations, while insert bits can be used in hard rock formations where the size, shape, bearings, and number of inserts can be customized to meet the site drilling requirements. All roller-cone bits must take into account the temperature effects on the bit’s components. Roller-cone bits are able to withstand hard, fractured rock, which makes them the preferred bits for geothermal drilling.

Roller cone bits cut rock by crushing and gouging, but polycrystalline-diamond-compact (PDC) bits cut rock with a shearing action similar to a machine tool cutting metal. It is this shearing action that makes drag bits more efficient than roller-cone bits[87]; however, in geothermal applications, drag bits with PDC cutters have demonstrated short life spans in hard or fractured rocks. Therefore, it has been historically assumed that they were more suited to the soft and medium formations encountered more often in oil and gas drilling.

Advancements in the strength of drag bits have been made in recent years, making them more widely accepted in geothermal drilling.[88] Drag bits also do not contain any moving parts, which makes them further suited for geothermal drilling where temperature limitations on bearings, seals, and lubricants often have an effect on roller-cone equipment. For example, in medium formations, the rate of penetration for PDC and roller-cone bits is similar at 5–160 ft. per hour (1.5–50 m per hour). However, whereas a PDC bit may be run up to 9800 ft (3000 m), a roller-cone bit may need to be replaced every 820–1150 ft (250–350 m).[89] A reduction in the wear on the bit also reduces the wear on other tools such as jars, stabilizers, drill collars, and drill pipe.[90]

2.2.3.3 Drill Pipe

There are multiple factors as outlined in Table 2-5 to consider when determining drill pipe specifications. As with the casing, the drill pipe material will need to withstand the corrosive environment encounter in geothermal reservoirs. Because geothermal wells produce more fluid and are often larger than oil and gas wells, the drill pipe (like the casings) is typically larger than those for oil and gas at the same depth.[91]

Table 2-5. Drill Pipe Considerations[92]

Characteristic	Purpose
Strength	The pipe must have the tensile and torsional strength to be able to pull the drill string out of the hole and the required torque strength to rotate the bit. Internal pressure may need to be considered. In directional drilling, bending strength must also be considered.
Size	Hydraulics drives pipe size selection. Internal diameter of the pipe must be large enough to avoid excessive pressure drops in the circulating drilling fluid and to pass any anticipated logging tools. The outside tool joints diameter must be small enough to allow the use of overshot fishing tools
Corrosion Resistance	Most geothermal formation fluids are corrosive.
H_2S Gas	H_2S gas is present in most geothermal systems, so the pipe must be suitable for H_2S service as well as be National Association of Corrosion

	Engineers NACE 0175 and Industry Recommended Practice (IRP) 1 compliant.
Wear Resistance	Geothermal drilling is extremely abrasive and drill pipes will wear out quickly. Often wear-resistant material is applied to the outside of tool joints in a process known as “hard-banding” in order to protect the tool joints. However, hard-banding can cause casing damage if the drilling time period is prolonged. Drill pipe rubbers may also be placed on the drill pipe that is within the casing to protect the casing.

2.2.3.4 Instrumentation and Data Logging System

A data logger electronically records the drilling project measurements as outlined in the drilling plan. This information should be gathered often and at fairly short intervals to be recorded in the data loggers. The stage of the drilling determines the interval length for data collection. For routine “steady-state” drilling, data may be collected every 5–10 seconds. However, if the drilling is transitory or conditions are unstable, high-resolution and high-speed data can be invaluable.[93] While high-resolution images may cause data storage issues, low-speed collection may not provide the needed information for short-term events. The mud logging company on the project collects this data. Table 2-6 shows surface measures available during drilling and well completion operations.

Table 2-6. Surface Measurements Available from Mud Logging Companies[94]

Surface Measurements Available	
Depth	Pump stroke rates
Block height	Pump stroke counters
Rate of penetration	Totalized pit volumes
Bit depth tracking while tripping	Individual pit volumes
On bottom/off bottom	Trip tank volumes
Hook load	Mud gain/loss
Weight on bit	Mud flow rates
Rotary revolutions per minute and torque	Mud temperature in and out
Top drive revolutions per minute and torque	Mud weight in and out
Standpipe pressure	Mud resistivity in and out
Casing pressure	CO_2 and H_2S

Downhole measurements are more challenging because of the high-temperature conditions found in geothermal drilling. Sensor and memory technologies capable of operating at these temperatures are not as mature. The most important data that can be taken downhole is the temperature log, which can clarify numerous situations for the drilling operator such as lost-circulation zones and whether the operation is approaching the thermal limits of equipment.[95]

2.2.3.5 Compressors

Air compressors convert power into energy by pressurizing air. They are needed when air-based drilling and pressurized downhole hammer drilling are used. Air-based drilling is more or less the same as conventional rotary drilling except that air, instead of drilling mud, is used to clean the hole and lift the cuttings back to surface. Hammer drilling involves the use of a pneumatic hammer that runs by large volumes of compressed air in a manner similar to a jackhammer to break through rock.[96] The higher cost of the compressors and the fuels to operate them, in addition to the increased noise levels and exhaust, are significant disadvantages to both air-based and hammer drilling. These factors should be considered when creating the drill plan.

2.2.3.6 Mud Cleaning Equipment

Mud cleaning equipment is also part of the fluids circulating system. Once the mud returns to the surface, laden with rock cuttings, it passes through multiple devices to remove the rock. First are the shale shakers that vibrate to catch larger pieces on their screens, which are then deposited into collection containers. Next, hydrocyclones use fluid inertia to swirl the mud, which allows the solids to drop out the bottom, and then a centrifuge spins the fluid to extract the finest particles by differences in their density.[97] Effective mud cleaning is an important factor in performance of the system, as well as a method of controlling costs. Disposing of fluid because it was cleaned improperly is costly in terms of materials and time wasted.

2.2.3.7 Water Tanks

Drilling muds are typically mixed on-site, so there is a need during the exploratory and development phase of the project for both water storage and mud collection. Water storage can be in the form of the tanks. The amount of water needed is significant. In the case of the Newberry project, 18 tanks, each capable of storing 22,000 gallons (83,000 L) of water, were installed as a buffer in the pumping system.[98] Figure 2-12 depicts a 22,000 gallon (83,000 L) tank whose dimensions are 16 ft tall (4.9 m) by 15ft (4.6 m) in diameter.

Figure 2-11. Steel water storage tank[99]

The drilling muds typically collect in a pit. Because there are several ways in which the drilling process could result in additional fluids than calculated, the pit should be three times the hole volume at total depth. Since the pit also serves the purpose of solids precipitation, its design should include baffles for mud flow and solids settlement.[100] In the case of the full-size wells drilled for the Glass Buttes project, the pit would have a capacity of 150,000 ft^3 (4250 m^3). The typical depth of the reserve pit would be 10 feet below ground surface measured from the pit bottom and berm would be constructed around the outer edges of the pit. The berm would measure 4 ft (1.2 m) wide by 2 ft (0.6 m) tall.[101]

2.2.3.8 Mud Pumping Systems

The circulating system of a geothermal drilling project includes the drilling fluids, mud pumps, and mud cleaning equipment. When selecting the equipment, the pumps must have sufficient flow rate and pressure capacity to clean out the bottom-hole; high annular velocity to lift the rock cuttings; and enough hydraulic horsepower to drive downhole motors and bit jets without significant pressure drop.[102]

2.2.3.9 Generators and Diesel Engines

Diesel-operated engines and generators produce electricity for the site and power for the equipment. A small drill rig may require 1,000 horsepower (750 kW) to operate. The rig always has integral diesel generators to provide its own power, but if the site has large additional electrical requirements, it may require auxiliary generators.

2.2.3.10 Blow Out Preventer Equipment (BOPE)

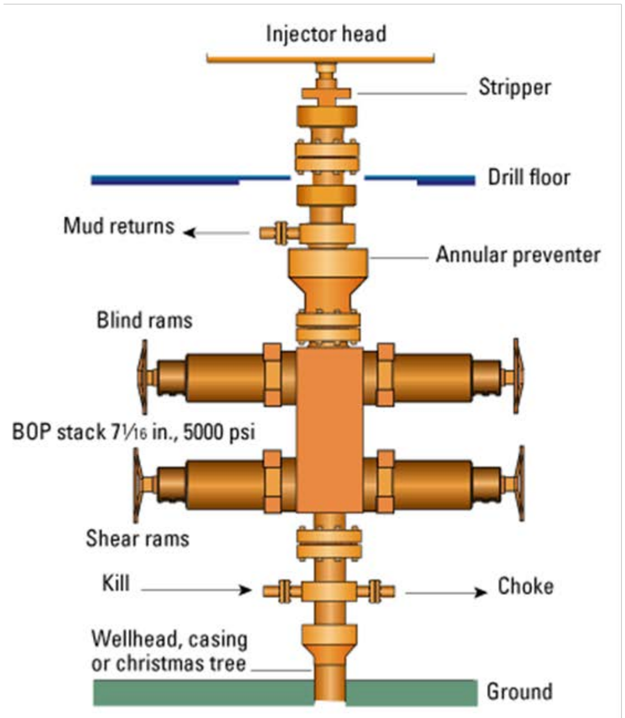
The BOPE consists of rotating heads, annular preventers, pipe rams, blind rams, and shear rams that all shut off the well by different means as described in Table 2-7. This equipment is typically a regulatory requirement, so these regulations drive its design, testing, and installation.

Table 2-7. Operating Methods of the BOPE Shut-Off Devices[103]

Shut-Off Device	Function
Rotating head or rotating BOP	This device forms a seal around the drill pipe and rotates with it. A sealed housing that encases the drill pipe seal and bearings enables this. This is normally a low-pressure device (less than 10.3 megapascals), whose main purpose is to keep hot fluids from reaching personnel on the drill rig.
Annular preventer	This is either an inflatable bladder or an elastomer that a hydraulic piston forces into a conical cavity. Either way, the flexible element seals around the drill pipe, casing, drill collars, or irregularly shaped components of the drill string. Older annular preventers had the next-lowest pressure and temperature ratings of the stack components, but the elastomer types have improved.
Pipe rams	These are two sliding gates, each with a semicircular cutout, that come together from each side of the drill pipe. The hole in the center fits and seals around the outside diameter of the drill pipe. A newer technology, called variable bore rams, has gates that can seal around either the pipe body or the larger tool joint diameter.
Blind rams	These are also sliding gates, but there is no hole in the center; they are used when the drill pipe is out of the hole.
Shear rams	A last resort, the sliding gates have sharp, hardened, overlapping edges and can sever anything hanging in the wellbore. If these are used, then anything cut by them falls into the hole and becomes a fish. Most geothermal BOPE stacks do not include shear rams when drilling, although they can be an important part of work-overs that involve removing a damaged casing from the wellbore.

BOPEs are common on all wells; however, they require modification for geothermal applications. The rubber material is typically rated for 250°F (121°C), but for geothermal applications where there are higher temperatures, rubber materials are rated for 350°F (177°C). Wellhead pressures must also be considered when drilling any type of well.[104] Figure 2-13 shows the typical schematic of BOPE. This equipment is installed on each casing string. If additional drilling is needed beyond a casing string, the drill string is lowered through the BOPE and drilling operations continue for the next string.

BOP Schematic



BOP Stack

Figure 2-12. Typical BOP equipment[105, 106]

Acronyms: inches (in), pounds per square inch (psi).

2.2.3.11 Centralizers

A centralizer is a device used to keep the liner or casing at the center of the wellbore to ensure correct placement of the cement sheath around the casing string. It typically contains a high collar and bowstring, as shown in Figure 2-14, and is placed on the casing as it is run into the hole for cementing.[107] Centralizers help ensure that all voids are filled before cementing, and their spacing depends on the straightness of the wellbore and clearance between the casing and the bore.[108] Jurisdictional regulations can also determine the spacing. Centralizers are most often constructed of corrosion-resistant stainless steel, which will not contaminate the well, and their size is adjustable to meet the needs of the wellbore.[109] Depending on the material of the centralizer, it will either be welded or strapped to the casings; screws should not be used due to their likelihood of corroding and leaving holes in the casing.[110] Because of the high-salinity brines that geothermal drilling project often encounter, composite ceramic centralizers have been tested. These ceramic centralizers have been tested to 450ºF (232ºC) and are nonreactive to alkalis and acids.[111]

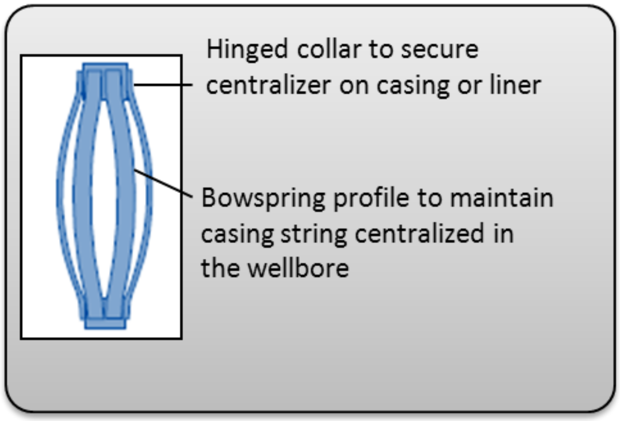


Figure 2-13. Centralizer[112]

2.2.3.12 Packers

In some cases, inflatable devices known as packers isolate particular areas of the wellbore for injection tests and other diagnostics. Usually a logging tool will run through the packer and into the hole below it.

2.2.3.13 Float Collar and Float Shoe

The float collar and guide shoe are used when the casing is run into the hole. The first joint of casing has a guide shoe at the bottom and a float collar at the top. The guide shoe guides the casing into the wellbore. The float collar, which is a check valve that allows flow downward but not upward, allows the casing to be floated into the well. After the cement is displaced, the float collar prevents the heavier cement from flowing back up the inside of the casing.[113, 114] This equipment is of one-time use, as it is not retrieved but drilled through after the cement is set.

The float collar and float shoe are used in conjunction with the casing to set it in the hole. The first joint of the lowered casing has a guide shoe and float collar at the bottom of the casing joint. The guide shoe guides the casing into the wellbore. The float collar allows the casing to float into the well. The float shoe is a check valve that prevents the heavier cement from flowing up the inside of the casing.[115, 116] This equipment is of one-time use, as it is not retrieved but drilled through when the next casing string is placed.

2.2.3.14 Wiper Plugs

There is a top and bottom wiper plug needed for each casing string that is cemented. These plugs serve to isolate fluids in the cementing process and clean the inside of the casing. What is known as the bottom plug is dropped in the casing to wipe muds and push out drilling fluids. It has a diaphragm in its center that ruptures allowing cement to flow. What is known as the top wiper plug is dropped into the casing to wipe cement and push it out into the annulus. The top wiper plug is designed to sit on the bottom wiper plug. It is solid, so the fluid pressure on the backside of the plug will rise when it is seated properly. Wiper plugs are of one-time use, as it is not retrieved but drilled through when the next casing string is placed.[117, 118] The cementing company supplies the wiper plugs.

2.2.3.15 Cementing Head

Cementing heads are a combination of valves and ports installed on the top casing joint to manage the cementing portion of the well completion process. The cementing head has a slurry inlet, a fluid inlet, slurry valves, and a storage area for the wiper plugs. Cement enters the casing through the slurry inlet while the slurry valves provide flow control. Drilling fluids and displacement fluids enter the casing through the fluid inlet. Materials for the cementing head are typical of those used in any cement construction.[119] The cementing company supplies the cementing heads like the wiper plugs.

3. ENVIRONMENTAL IMPACTS AND PERMITTING ISSUES

Section 3.1 defines environmental resource elements and impact criteria. Section 3.2 describes potential environmental impacts on these resource elements resulting from production drilling. Explanations of permitting requirements and issues are in Section 3.3.

3.1 POTENTIAL ENVIRONMENTAL IMPACT ELEMENTS

Environmental impact criteria qualitatively evaluate activities associated with geothermal technologies (see Appendix A, Environmental Resource Element Impact Criteria). The bases for these criteria are often specific environmental resource protection laws. The criteria describe conditions that would lead to potentially significant environmental effects should the activity be implemented. This evaluation includes an assessment of the types of impacts that could result, depending on the type of technology employed, realizing the assessment is not intended to address a specific location or actual project.

Impacts may consist of direct or indirect effects. The definition of direct impacts is those caused by the action and occurring at the same time and place. Examples include habitat destruction, soil disturbance, air emissions, and water use. The definition of indirect impacts is those caused by the action, but occurring later in time or farther removed in distance from the action. Examples include changes in surface water quality resulting from soil erosion and alteration of wetlands resulting from changes in surface water quantity.

Additionally, consideration of all connected, similar, and cumulative actions is necessary. More detailed descriptions of each are below.

- A connected action is one that is closely related to the project; an action that cannot or would not proceed unless another action is taken previously or simultaneously; or an action that is an interdependent part of a larger action and depends on the larger action for its justification. For example, treatment and disposal of geothermal wastewater may require construction of a new wastewater treatment plant.
- Similar actions have likenesses with the proposed action that provide a basis for evaluating their environmental consequences together, such as common timing, geography, or purpose. Similar actions can also qualify as connected and cumulative actions.
- Cumulative actions can have collectively significant impacts when viewed with other proposed actions that occur within the same temporal and spatial boundaries. A proposed road-building action by some other agency or entity in the same general areas as the geothermal project would be a cumulative action.

It is often possible to mitigate or reduce these potential effects, but it is at a cost, and often not completely.

3.2 POTENTIAL ENVIRONMENTAL CONSEQUENCES

Discussion of potential environmental consequences is often difficult without being able to consider specific actions. Therefore, where applicable, discussions in this section consider a hypothetical production drilling action as described in Table 3-2. Consistent with the discussions in Section 2, the hypothetical action described in Table 3-1 is only a portion of what would be expected to take place in a full geothermal project. An actual evaluation of environmental consequences would need to consider, to the extent that information was available, the potential effects of an entire project. (There is recognition that the total scope of a typical geothermal project may have to be evaluated in phases. For example, when planning to implement exploratory actions to determine the feasibility of a geothermal resource, it cannot be known whether the project will proceed to the production drilling phase let alone the scope or location of such drilling.)

Table 3-1. Production Drilling Hypothetical Project

Production Drilling: Hypothetical, Representative Project
Existing Conditions: • All exploration activities are complete, and findings support the planned location of a production-scale well. • The proposed well pad location is accessible from an existing dirt road and one-half mile from a paved state road. (That is, access to the well site requires one-half mile of travel on a dirt road.) • A temporary water well located 100 feet from the well pad site has been drilled to the upper aquifer, is capable of providing sufficient water to support the production drilling action, and is available (either through a direct water right appropriation or purchased from a water rights holder).
Activities Included in Production Drilling Project: • Construction of a 5-acre well pad over 3 weeks to support the drilling operations and all of the associated equipment. The well pad is to include a sump pond that is lined with clay or a synthetic liner and to be used for water, cuttings, drilling mud, and other fluids associated with the drilling process, but no hazardous materials. • Water demand during well pad construction is 5,000 gallons per day.

Production Drilling: Hypothetical, Representative Project
• Delivery of drill rig, diesel-powered electrical generators, trailers, tanks, and other equipment to the site. • Drilling operations for 45 days (24-hours per day, 7 days a week) to complete a well to a depth of 10,000 feet. • Water demand during drilling is 33,000 gallons per day. This includes daily demands of 30,000 gallons for drilling, 1,000 gallons for work crew needs, and 2,000 gallons for miscellaneous dust control measures.
Not Included in Scope of Production Drilling: • Well testing or any other such actions that would normally be performed after drilling was complete. • Removal of drill rig or other equipment off the well pad.

It should also be noted that the hypothetical project described in Table 3-1 is intentionally of limited scope in order to facilitate and simplify the discussion. In an actual geothermal project with sufficient exploratory data to warrant progressing to a production-scale well, there would very likely be planning of multiple wells (at a minimum, at least one injection well and one production well would be expected), possibly from multiple well pads. The justification for keeping the representative project at a limited scope is that "more of the same" generally would not be expected to change the environmental impact criteria of potential concern. The intent of this discussion is to identify areas of potential concern rather than the magnitude of those concerns, which would be too location- and project-specific to address via a hypothetical project.

Consistent with implementing regulations and guidance for the *National Environmental Policy Act* (NEPA) of 1969, as amended (42 U.S.C. 4321 *et seq*.), environmental analyses are to focus on topics with the greatest potential for significant environmental impact. For the reasons discussed in Section 3.2.1, drilling of production wells would not be expected to have any measurable effects on certain resource elements; therefore, these resources would not be carried forward for further analysis. Section 3.2.2 provides a more detailed discussion of those resource elements that a production well project could affect.

Table 3-2 provides a summary of which environmental resource elements the action could potentially affect and the ones for which there is no expectation of adverse effects.

Table 3-2. Resource Elements Potentially Affected by a Production Well Project

Environmental Resource Elements	Potentially Affected	Not Affected
Cultural and historic	✓	
Air quality	✓	
Climate change		✗
Water resources (surface and groundwater)	✓	
Floodplains and wetlands	✓	
Coastal zone management		✗
Geology and soils	✓	
Land use	✓	
Biological	✓	
Transportation	✓	
Health and safety	✓	
Noise and vibration	✓	
Natural hazards		✗
Hazardous materials and waste	✓	
Intentional destructive acts		✗
Recreational resources	✓	
Visual	✓	
Socioeconomics		✗
Environmental justice		✗
Utilities		✗
Cumulative	✓	

3.2.1 Resource Elements Not Carried Forward for Further Analysis

There is no expectation that the drilling of production wells would have any measurable effects on certain resource elements; therefore, these resources would not be carried forward for further analysis. This section discusses those resource elements and why there are no measureable effects.

3.2.1.1 Climate Change

Greenhouse gases would be emitted during a production drilling project. The greenhouse gases, primarily CO_2, would be in the exhaust from vehicles and equipment clearing access routes, constructing the well pad, and delivering materials, and from the diesel-powered generators that would provide electricity for the drilling operations, as well as other activities on the well pad. In addition, CO_2 and to a lesser extent methane are frequently present in natural geothermal fluids and can release into the atmosphere when the fluids come to the surface.

All of the greenhouse gases associated with the production drilling would be temporary and all would be from mobile or moveable (the diesel-powered generators would likely be in trailers or pallet-mounted) equipment. The emissions of greenhouse gases associated with production drilling would be relatively minor, and impacts to climate change would be negligible, particularly when compared to the benefits that would be gained from the ultimate construction and operation of a geothermal power plant. Records of greenhouse gas emissions from geothermal power plants have been evaluated and compared to similar emissions from electric power plants that burn fossil fuels. On a comparable basis of greenhouse gases emitted per kilowatt-hour of electricity produced, one study described emissions from geothermal power plants as being a full order of magnitude less than emissions from coal- or oil-fired power plants and about 15% of that emitted by natural gas-fired power plants.[120] Another evaluation described typical greenhouse gas emissions from geothermal power plants as being even smaller in comparison to fossil fuel-fired power plants, in particular, as being less than 5% of those from coal-fired plants and less than 10% of those from natural gas-fired plants.[121] Both evaluations noted that binary power plants, where the geothermal fluid is only put through a heat exchanger before being re-injected, produce no greenhouses gases.

An environmental impact evaluation of the entire geothermal project would address the potential benefits that would result from the overall project. This could be done (as above) by citing reference materials, or by generating project-specific estimates. The Emissions & Generation Resource Integrated Database (eGrid) developed by the U.S. Environmental Protection Agency (EPA) (available online at http://www.epa.gov/egrid) includes air emissions data for almost all electric power generated in the United States. Using this information, which is available by region, estimates can be made of the amount of greenhouse gases that the geothermal power plant would avoid when compared to what electric power plants burning fossil fuels would have otherwise produced. The amount of greenhouses gases produced during the upfront phases of the geothermal project (e.g., exploration, production drilling, construction, etc.) would be minor compared to the long-term offsets that would be gained during power production.

3.2.1.2 Coastal Zone Management

The *Coastal Zone Management Act of 1972* encourages appropriate development and protection of the nation's coastal and shoreline areas and gives the states the primary role in managing those areas. The Act requires participating coastal states to develop management programs; once their programs obtain federal approval, the states have review authority over certain federal agency actions. In such cases, the individual state has authorization to determine whether federal projects, federally funded projects, or activities requiring federal licenses or permits are consistent with the state's coastal zone program.

Production drilling, and geothermal projects in general, would be fully subject to *Coastal Zone Management Act* requirements if their location is in a state's designated coastal zone. However, being subject to and meeting such requirements would be similar to meeting permitting requirements. There is no expectation of adverse impacts; rather the state's review to ensure that projects are meeting its coastal zone management requirements would be expected to result in either a status quo or a reduction in the potential for adverse impacts.

3.2.1.3 Natural Hazards

There is no expectation that production drilling would aggravate natural hazards at the site. One might argue or reason that the presence of a geothermal resource can be considered a natural hazard and that taking actions to harness that resource could change the hazard it presents. This paper addresses the hazards associated with production drilling as a health and safety concern rather than a natural hazard issue. As long as an environmental evaluation appropriately addressed the concerns, it should be of no concern whether it is a natural hazard or a man-made hazard.

3.2.1.4 Intentional Destructive Acts

DOE considers intentional destructive acts (that is, acts of sabotage or terrorism) in its NEPA documentation.[122] Production drilling would not involve the transportation, storage, or use of radioactive, explosive, or toxic materials; therefore, it would be unlikely to present an attractive target to saboteurs or terrorists.

3.2.1.5 Socioeconomics

Potential socioeconomic impacts associated with production drilling would be minor because of its relatively short duration, particularly with the limited scope defined in this paper for the hypothetical project. There could be short-term economic benefits from the work crews staying in the area and through purchases of local materials. However, the drilling crews and most of the materials they use in drilling are fairly specialized and would likely be brought in from outside the local area. Potential socioeconomic impacts are good examples of issues that are difficult to address unless in the context of the entire project. Long-term operation of a geothermal power plant is more likely to have socioeconomic implications rather than any of the upfront steps, but they should be evaluated and described in total.

3.2.1.6 Environmental Justice

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, directs federal agencies to identify and address the potential for their activities to cause disproportionately high and adverse impacts to minority or low-income populations. Environmental justice is another example of an issue difficult to address other than in the context of the entire project. It is also completely site-specific. The limited scope and duration of the hypothetical drilling project evaluated in this case would tend to make the project more acceptable to affected populations. It would be similar to the impacts of a construction project. But, that simply supports the need to consider environmental justice impacts based on the entire project. Even if the project's effects in the immediate area of the well pad would be minor, production drilling at different or more distant sites could affect elements such as air quality, water resources, or visual resources. As a result, the potential for a low-income or minority population to be subjected to disproportionately high and adverse impacts depends on whether such populations are in the vicinity, and if so, at what locations with respect to areas that any impact element could affect. Evaluations of these considerations would be on a case-by-case basis. An evaluation of an actual project would have to consider the potential for such impacts to occur.

3.2.1.7 Utilities

Other than the water requirements, which are addressed under water resources, the hypothetical production drilling project would not be expected to affect utilities in the area. If the well pad's location is in an area where connections could be made to area utilities (for example, drinking water systems, sewage collection systems, or the electrical grid), the size of the drilling work crew would not be expected to represent unusual demands or loads. But, if area water and electric utilities were to provide all of the needs for the project through its lifetime, those utilities would need to be evaluated to ensure there was adequate capacity without adversely affecting other users.

3.2.2 Resource Elements Potentially Affected by Production Drilling

Section 3.2.2 provides a more detailed discussion of those resource elements that a production well project could affect.

3.2.2.1 Cultural and Historic Resources

Cultural and historic resources are archaeological sites, historic structures and objects, and traditional cultural properties. Historic properties are cultural resources that are listed in or eligible for listing in the National Register of Historic Places because they are significant and retain integrity (36 CFR 60.4). Section 106 of the *National Historic Preservation Act* (16 U.S.C. §§ 470 *et seq*.; NHPA) requires that federal agencies take into account the effects of their actions on historic properties. Section 101(b)(4) of NEPA requires federal agencies to coordinate and plan their actions and, whenever practicable, preserve important historic, cultural, and natural aspects of the United States' national heritage. Requirements associated with cultural and historic resources as discussed here apply to actions "funded in whole or in part under the direct or indirect jurisdiction of a federal agency, including those carried out by or on behalf of a federal agency; those carried out with federal financial assistance; and those requiring a federal permit, license or approval" (36 CFR 800.16(y) definition of an "undertaking"). In the unlikely event a geothermal project did not qualify as an "undertaking" by the above definition, there could be applicable state or local preservation laws that set similar requirements.

If not already accomplished during the exploration phases of the project, the project site would need to conduct a cultural resource survey before starting any soil-disturbing actions associated with the well pad construction and drilling activities. Concurrent with initiating survey activities, consultation actions required under Section 106 of the NHPA would begin with the appropriate State Historic Preservation Officer (SHPO) and applicable Indian Tribes or Native Hawaiian organizations with current or historic ties to the project site. The regulations at 36 CFR Part 800, "Protection of Historic Properties," describe the process for compliance with Section 106, which includes defining the area of potential effect, identifying resources and evaluating effects, and consulting with interested parties.

The objective of these efforts is to determine if there are resources of concern in the area of the proposed project and, if so, if there is potential for the project to have adverse effects on those resources. If resources are present and there is potential for adverse effects, the goal of the consultation efforts would then ideally be to have all parties work together to develop a project alternative that would eliminate or mitigate those adverse effects in a manner acceptable to all parties. Since the ability to implement directional drilling would normally provide some flexibility in the location of drill sites, moving the project to avoid areas of concern may be a reasonable option. If the potential for adverse effects cannot be resolved, 36 CFR Part 800 also describes the process for resolution including the involvement of the Advisory Council on Historic Preservation.

3.2.2.2 Air Quality

Air emissions during production drilling would consist of vehicle and equipment exhaust emissions and fugitive dust generated during earth movement and vehicle traffic over dirt surfaces. Under the representative project, stationary sources of air emissions would include the following (by pollutant type or types and with estimated or example level of activity):

- Fugitive Dust (particulate matter)
  - Construction (clearing, grading, placing of fill, compacting, etc.) of a 5-acre well pad with a compacted gravel surface
  - Six hundred heavy truck trips delivering earth-moving equipment and fill materials to the well pad
  - Three light vehicle trips per day for three weeks for well pad construction work crew
  - Twenty-five tractor-trailer deliveries for drill rig and supporting equipment
  - Two to three tractor-trailer deliveries per day during 45-day production drilling
  - Twenty service/worker vehicles per day during 45-day production drilling.
- Criteria Pollutants (i.e., sulfur dioxide, nitrogen dioxide, carbon monoxide, ozone, lead, and particulate matter)
  - Exhaust from diesel-fired internal combustion engine (ICE) for the electric power generators operated 24-hours per day for 45 days of drill rig operation
  - Exhaust from diesel-fired ICE on mud pumps (if not powered from the main power plant) operated 24-hours per day for 45 days of drill rig operation.

A list of air emission sources such as the one above can be coupled with published air emission factors to generate an estimate of the amount of air pollutants that the described action would emit. Probably the best source for emission factors is EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, which is available at http://www.epa.gov/ttn/chief/ap42/. The emission factors in AP-42 are generally used in the format of "emission factor × activity rate," but they cover a broad range of sources and, as a result, are based on a wide variety of operational parameters. For example, emissions from ICEs require a rating for the engine's size, such as its horsepower, while estimating particulate emissions from vehicle travel on a dirt road requires estimates of the amount of silt in the dirt and approximate weights of the vehicles. The AP-42 emission factors are perhaps best used by selecting the appropriate or applicable factor and determining the project's operational parameters necessary for its use. Then, the necessary project information can be sought or estimates/assumptions developed.

Without generating specific estimates of emissions from the representative project, it is reasonable to assume that the production drilling project as defined here would be a minor source of air emissions. This is primarily due to the limited scope and duration of the action. There could be state or local permitting requirements applicable to the action, but it should be noted that for an actual project, air quality permitting requirements would have to be addressed based on the entire geothermal project, of which the production drilling would just be a part.

With or without permitting requirements, best management practices would dictate spraying down dirt pads and access roads with water on a recurring basis to minimize dust generation during vehicle travel or other activities. Depending on the site's location and whether it is in a nonattainment area, actions such as specifying ultra-low sulfur for diesel fuel brought to the site might also be an option, or possibly even a requirement.

Conformity: Section 176(c)(1) of the *Clean Air Act* requires federal agencies to ensure their actions occurring in nonattainment or maintenance areas conform to an implementation plan for achieving and maintaining ambient air quality standards. Specifically, federal agencies must ensure such actions do not contribute to new violations of the standards, increase the frequency or severity of existing violations, or delay timely attainment of standards in the action area.[123] If the assumption is that the production drilling action was in a nonattainment or maintenance area and was a federal action (that is, federally implemented, funded, permitted, or otherwise supported), then it would have to be reviewed for conformity as described in 40 CFR Part 93, Subpart B. These regulations [40 CFR 93.153(b)] set specific criteria pollutant threshold emission values that vary depending on whether the site is a nonattainment or maintenance area and, in the former case, the severity of nonattainment. These threshold values can be as low as 10 tons per year for volatile organic compounds or nitrogen oxides in extreme nonattainment areas, but in most instances are in the 50- to 100-ton-per-year range (except that lead has a threshold value of 25 tons per year in all nonattainment or maintenance areas). Formal conformity determinations are required only of actions involving air emissions that would equal or exceed any of the threshold values.

Production drilling would not be expected to involve any actions that would equal or exceed threshold values for a conformity determination, unless the site was in extreme nonattainment for ozone. Continuous operation of a large internal combustion engine for 45 days, as described for the electric power generators, could result in the emission of more than 10 tons of nitrogen oxides (NO_x), an ozone precursor. In addition, as noted previously for air permits in general, conformity requirements for an actual project would need to be addressed based on the entire geothermal project.

As examples of implementing these requirements, DOE guidance is that the conformity determination and NEPA public participation processes be integrated to the fullest extent possible.[124] It is further DOE guidance that if the conformity review process concludes that a formal determination is not required, then the NEPA documentation should include such results. DOI/BLM guidance notes that combining conformity and NEPA analyses may be efficient and convenient in some cases, but that such a link is not required (that is, the conformity requirements can appropriately be met outside of the NEPA process).[125]

3.2.2.3 Water Resources

Potential impacts to water resources, including both surface water and groundwater, from production drilling would consist primarily of the possibility of contaminating clean water resources with discharges or inadvertent losses and depleting clean water resources because of the project's water demands. In this case, "clean water resources" refer to surface water or groundwater resources that are not part of the geothermal fluid reservoir being investigated or developed.

Potential for Contamination: Because construction of the well pad is being considered part of the representative project, stormwater runoff from the construction site is considered a potential source of contamination due to pollutants that may be present on the site and due to the sediments that could be carried off the site. In addition, during production drilling actions, a range of materials that represents potential contaminant sources (per Section 2) likely would be present on the well pad. The following discussion addresses the potential for surface water or groundwater contamination during well pad construction and production drilling.

Construction sites disturbing one or more acres of land are required to obtain a National Pollutant Discharge Elimination System (NPDES) permit for stormwater discharges per 40 CFR 122.26. Most States have obtained authorization to implement these requirements, but in instances where that is not the case, construction projects must obtain the permit from EPA. Briefly, EPA's program consists of a Construction General Permit (CGP), which it issues periodically for a set period. For example, EPA's 2012 CGP replaced the 2008 CGP; EPA issued it for five years. The EPA 2012 CGP implements requirements in a relatively new set of standards that EPA had not yet implemented when it issued the 2008 CGP. The standards are the Effluent Limitations and New Source Performance Standards for the Construction and Development Point Source Category (40 CFR Part 450).[126]

Proponents of applicable construction actions must submit a Notice of Intent to EPA that certifies eligibility for coverage under the CGP and provides information on the construction action and discharges. Proponents must file the Notice of Intent with EPA at least 14 days before earth-disturbing activities are to start, and coverage under the permit starts 14 days after EPA acknowledges receipt of the notice on the Agency's website.[127] One of the primary requirements of the CGP is that the proponent develops a Stormwater Pollution Prevention Plan (SWPPP); in fact, the proponent should develop the SWPPP before submitting the Notice of Intent. Elements (not all-inclusive) that the SWPP should address in some detail are as follows:[128]

- Nature of the construction activities, including the size of the property, the total area the project will disturb, and the maximum area of disturbance at any time
- Sequence of construction activities with estimated dates of their occurrence and duration
- Site map, or maps, showing project boundaries, areas of earth-disturbing activities, stockpiling areas, stormwater discharge locations, locations of surface waters, and areas of federally listed critical habitats for endangered or threatened species;
- An inventory of construction site pollutants and a description of all pollutant-generating activities
- Any non-stormwater discharges
- Buffer documentation, including compliance actions to be taken if any surface water is within 50 feet of earth-disturbing activities
- Description of all stormwater control measures that the project will install and maintain
- Spill prevention and response procedures and waste management procedures;
- Procedures for inspecting and maintaining stormwater control measures and for taking corrective action if needed
- Documentation of staff training
- Documentation of compliance with other federal requirements.

As indicated previously, most states have authority to implement NPDES requirements, and the state programs have to be at least as stringent as the federal program in order to obtain authorization. So, the requirements summarized above would be considered the minimum requirements at any project location because the applicable state may have additional ones. The construction activities associated with the well pad would not involve unusual activities or sources of potential contamination, so common best management practices would be implemented and would be expected to provide appropriate protection for the area's stormwater drainage and receiving waters. Production drilling typically involves periods of management of large volumes of fluids above ground. Drilling fluids or muds would be formulated and staged in ponds or tanks awaiting use in drilling and as they come back up from the drill hole for separation or settling of cuttings. The drilling muds and the additives may not be considered highly toxic, particularly in the concentrations the additives are used, but it is reasonable to assume that they would not be considered acceptable for uncontrolled release to a drinking water source, either surface water or groundwater. The assumption is that these fluids would be managed in tanks or lined pits or ponds. Any action to discharge these fluids as wastewater, with or without interim storage, would require the appropriate permits and authorization.

In addition to the drilling muds and additives used directly in the production drilling actions, there would be quantities of fuels and lubricants stored or in use at all times during operations. These materials normally would be present in tanks, containers, or equipment, but represent potential contaminant threats because of the possibility for spills or leaks to occur, and the resulting runoff or infiltration to surface water or groundwater. To minimize the potential for events that could adversely affect surface water or groundwater, standard practices are to store these materials in closed containers or in tanks with secondary containment; keep equipment in good operating condition; routinely inspect storage tanks, containers, and equipment; and other such actions. In addition, the spill prevention and response procedures required to be in place for the well pad construction should be directly adaptable to the production drilling actions.

With regard to the potential effects to groundwater from use of drilling muds, environmental evaluations need to identify the specific constituents to add to the mud, their concentrations, any associated toxicity information, and their expected fate in the downhole environment. The primary concern would be any drinking water aquifers, possibly at upper elevations, but the evaluation should also address any potential concerns with respect to the geothermal reservoir. The evaluation of constituents added to downhole fluids may be a “worst case” type of evaluation in which very conservative assumptions are made as to the fate of the downhole fluid, the exposures that could result, and the impacts of those exposures. Screening levels for chemical contaminants at superfund sites posted by EPA (http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/index.htm) or similar information from the specific state may help in evaluating the risk associated with downhole fluid additives in these types of worst case evaluations. If the evaluation can present a sound basis for why the additives would be chemically or physically bound to the bentonite matrix and therefore not be available for migration to groundwater, that could be an appropriate conclusion.

Potential for Water Resource Depletion: With regard to water availability, the representative production drilling project would consist primarily of the following water demand:

- 5,000 gallons per day for 21 days to support well pad construction; and
- 33,000 gallons per day for 45 days for production drilling and supporting actions.

The total water demand is therefore about 1.6 million gallons over about 70 days.

To put this volume of water into some perspective, 1.6 million gallons is equivalent to almost 5 acre-feet and the U.S. Geological Survey (USGS) reports that in 2010 the average application rate for irrigated farmland in the U.S. was 2.07 acre-feet per acre.[129] So this quantity of water would only equate to the irrigation of about 2.5 acres of farmland over a year. EPA indicates that the average family of four can use 400 gallons of water every day, or 146,000 gallons per year.[130] Therefore, the total water demand would be enough to supply (after treatment) about 11 families for a year. Compared to these and many other water demands, 1.6 million gallons would not necessarily be considered a large number. The consideration more likely to cause environmental concerns is the rate at which it would be needed.

Water resources are generally managed as renewable or recovering resources, taking into account that groundwater and surface water find replenishment from recharge, runoff, or snowmelt that goes through seasonal cycles. The water needed for the production drilling action is assumed to come from a groundwater source. If the project received water rights for all of the intended uses, or if it purchased the water from a local water rights holder, it is reasonable to assume that the project's water needs, averaged over a year, would not adversely impact the region's water availability; or at least that would appear to be the finding of the area's water management agency. However, there still could be adverse effects in the immediate area that might not be reflected at the larger scale of a watershed or groundwater basin. The types of adverse impacts to consider would be those associated with causing a localized drop in the level of the groundwater or the surface water.

Depending on the productivity or permeability of an aquifer, pumping of a well normally causes a cone of depression at the water table indicating the water is being removed faster than the aquifer's permeability will allow it to be replenished. As indicated by its name, this is a depression in the water table in the shape of a cone, centered on the well. The harder the well is pumped, the deeper and wider the cone extends. If the cone were to extend to other wells or to points of natural discharge in the area, then there is the potential those other wells or discharge points could temporarily dry up.

The study of groundwater hydraulics has developed equations that can estimate the size of the cone of depression based on the permeability of the aquifer and the amount of water pumped. In order to assess potential impacts, the planned pump rate and site-specific aquifer characteristics would be used to calculate an estimated size for the cone of depression that would be created. A site survey and site records could then be used to locate any wells or surface discharges that might exist within the area that could be reached by the extent of the water table depression. The severity of any potential adverse impacts would depend entirely on the nature of water uses and discharges in the area. For example, if there was a nearby wetland fed by seeps or springs that could be affected by the depressed water table, impacts would depend on the nature of the flora and fauna at the site. Although the water table typically rebounds once pumping is stopped, if the project's water demand was expected to be continuous, then the effects of a depressed water table could be long-term.

If the water required for a production drilling project were to come from local surface water (e.g., a river, pond, lake, or reservoir), the evaluation of impacts would again have to consider possible effects of changes in water levels, including the effects such changes might have on flora and fauna or other users of the water. In most cases, groundwater aquifers can be considered as large reservoirs with a reasonable amount of capacity to buffer short-term demands and, to some extent, even long-term demands over which recharge might fluctuate. Depending on its size, this may not be the case for surface water. For example, removal of water over a dry year or years from a small pond or reservoir with only small or seasonal inflow during normal years could have long-term effects.

Section 4 describes several mitigation measures associated with minimizing potential impacts to water resources.

3.2.2.4 Floodplains and Wetlands

The proponent of a geothermal project would be expected to avoid floodplains and wetlands areas if only to reduce costs and minimize regulatory requirements. With the ability to use directional drilling, avoiding such areas would generally not be difficult, unless floodplains or wetlands were very large or there were some other issues that prevented avoidance. However, were the project located in a floodplain or wetlands area, certain requirements and potential effects can be described.

Floodplains: Floodplains are lowland and flat areas adjoining inland and coastal waters. These areas are often prone to flooding and the amount of adjacent land inundated depends on the magnitude of the flooding event. The National Flood Insurance Program administered by the Federal Emergency Management Agency (FEMA) has set the 100-year flood as the national standard for purposes of requiring the purchase of flood insurance and regulating new development.[131] A 100-year flood is a magnitude of flood with a statistical probability of occurring, on average, once every 100 years, or restated, a flood with a 1% chance of occurring during any single year. FEMA has developed Flood Insurance Rate Maps for most of the U.S. that show areas prone to inundation by 100-year floods.

If the project was in a floodplain, well pad construction and production drilling would be relatively temporary and unlikely to affect flood zone boundaries or feel the impact of flooding; that is, unless, the project was in a very flood-prone location. However, the completed well, a subsequent geothermal energy recovery facility, and any part of a well pad left in place for the facility would all represent long-term structures that would be designed or enhanced to incorporate appropriate flood protection measures. This could be no more than making the pad (if remaining) more resistant to flood damage (for example, by paving or revegetating) and keeping at least the operating levels of other structures above flood levels. It is reasonable to assume such actions would be taken because they protect the value of the facility and would likely be required by building permits as well as insurers. If in a floodplain, the well pad and any facility components below the flood level would take up space that would otherwise be available for floodwater. The action would therefore change the height and area of inundation for a given magnitude flood. Depending on the characteristics of the flood zone and the proximity of other facilities, flood level changes could adversely affect other facilities.

Local agencies responsible for issuing building permits would be considering these types of concerns and would be expected to deny building permits or require mitigation measures if potential effects to flood levels were anything but minor. If the representative project was part of a federal action or if it was federally funded, completely or in part, the applicable federal agency would be required to adhere to requirements of Executive Order 11988, *Floodplain Management*. Federal agencies are thus required as a result to take actions to reduce the risk of flood damage; minimize the impact of floods on human safety, health, and welfare; and restore and preserve the natural and beneficial values served by floodplains.

Wetlands: Wetlands are areas periodically or permanently inundated by surface water or groundwater that support vegetation adapted for life in saturated soil. For a location to qualify as a wetland, it must have hydric soils, hydrology indicators, and wetland vegetative species.[132]

If there is the potential for wetlands to be present in the area, qualified personnel need to conduct a survey to determine the presence of wetlands in any project areas. If a wetland is present, personnel must tentatively determine whether or not it is a jurisdictional wetland (that is, associated with a traditional navigable "Water of the United States" or a relatively permanent tributary to one) and whether or not the U.S. Army Corps of Engineers ("the Corps") regulates it under Section 404 of the *Clean Water Act*. A determination through a survey effort can only be tentative because the Corps must make the formal determination. If it is a jurisdictional wetland and if the project cannot avoid it, any action involving discharge of dredge or fill materials into the wetland would have to obtain a permit from the Corps to do so. A requirement to establish, or contribute to the establishment of a replacement wetland at some other location could accompany such a permit.

If a wetland is present, but it is an isolated, non-jurisdictional wetland, there may still be permit requirements if the applicable state regulates such wetlands. In addition, in many states, any wetland action that requires a Section 404 permit from the Corps must also obtain certification from the state pursuant to Section 401 of the *Clean Water Act*. If applicable, the certification often dictates best management practices and possibly monitoring and assessment plans to ensure project actions associated with the wetlands area comply with state water quality standards. If there were any question about the applicability of a Section 404 permit, discussion with the Corps would be the appropriate course of action.

In the unlikely event that either floodplains or wetlands were present in the project area, permitting requirements and anticipated building restrictions would minimize the potential for any serious environmental consequences.

3.2.2.5 Geology and Soils

Production drilling would not be expected to result in effects to deep geology that would affect the surface environment. Production drilling itself would not be expected to impact soils, but construction of the well pad would include the direct disturbance of soils, estimated at about 5 acres for the representative project. As described in Section 3.2.2.3 with regard to water resources, soil-disturbing actions have the potential to increase soil erosion from runoff. It also increases the potential for soil erosion from wind. Actions described in Section 3.2.2.3 for the control of runoff discharges from the disturbed areas and actions to suppress dust formation described in Section 3.2.2.2 would both act to minimize adverse impacts to soils. Although not a part of the representative project addressed in this discussion of potential impacts, the SWPPP requirements described in the preceding section would also include measures to put the disturbed area back into a stable condition. Since the soil disturbances in this instance would be short-term in nature, the long-term solution to returning the site to a stable condition would be to put them back into a natural state. Best management-type practices would therefore include segregating and stockpiling top soil during initial disturbance and restoring the sites as close as possible to their natural conditions once the monitoring sites were installed. The restoration actions would also include revegetation, as necessary, to stabilize the replaced topsoil. Implementing these types of actions would keep adverse impacts to soils at a minimum; implementation of these actions would be in any areas not being put to use for other project elements, such as other production wells or the construction of a power plant.

3.2.2.6 Land Use

Constructing a well pad and undertaking production drilling represent a long-term commitment to the project site and the development of geothermal energy at that site. As such, the environmental evaluation should address potential impacts to land use and, possibly, more specifically, potential conflicts with existing or planned land use in the area. This type of evaluation is entirely site-specific and the representative project used for discussions in this paper is not intended to support this level of detail. However, there is some general information, if available, that a land use evaluation should address. It should identify ownership of the project site and land around the project site. The evaluation should describe the type of information presented in the community’s zoning ordinance if the project were within, or adjacent to a community. Zoning can always change over time, but at least it represents a picture of what the community thinks is appropriate development by land area at a point in time. If the site is not in or adjacent to any community, a historical view of the region and how the historical uses may have changed in recent times may limit the characterization of the land. If any such changes are ones that might continue in the future, then the evaluation should address that trend as a potential land use that could affect the project site in the future.

The evaluation in this case needs to address more than the well pad construction and production drilling; it also needs to address land use in relation to a geothermal energy plant. Although beyond the scope of the representative project that this paper is evaluating, the geothermal energy plant would be the long-term use of the land that would warrant the more detailed evaluation, with regard to present and possible future land use.

3.2.2.7 Biological Resources

The representative project assumes that the proponent has already performed exploration actions in the area, so the project proponent should already have a good indication of the flora and fauna in the project site. However, construction of a well pad would very likely represent the largest land disturbance in a single location that the proponent has proposed for this stage of the project. Thus, it would have more potential to affect wildlife species and habitats adversely. If not already done, the project proponent needs to determine whether there are either federal- or state-designated threatened or endangered species and/or habitats in the project area that it could affect. One can find federally listed species or habitats for any area of the country on the U.S. Fish and Wildlife Service's website (http://www.fws.gov/endangered). States generally make their lists available online also.

If a federal agency funds, authorizes, or carries out an action, Section 7(a)(1) of the *Endangered Species Act of 1973* requires the agency to review the action and determine whether it may affect federally listed and proposed species or proposed or designated critical habitats. If the action potentially affects either species or habitat, the federal agency must enter into consultation with the U.S. Fish and Wildlife Service ("the Service"). Either the consultation will conclude informally with a written concurrence from the Service or, if the Service determines it is necessary, it will designate the consultation as formal, and it will develop a biological opinion. Federal agencies must also consider: (1) the *Migratory Bird Treaty Act of 1918* and Executive Order 13186 (signed 2001), which reinforces the need for federal agencies to implement the act; and (2) the *Bald and Golden Eagle Protection Act*, which prohibits the taking of these eagles (and includes causing injury, decreasing productivity, or creating other disturbances). In some instances, measures to avoid adverse impacts could involve restrictions on activities or noise levels during certain times of the year when species might be particularly sensitive, such as during nesting.

In addition to the normal effects from land disturbance, noise, and heavy equipment operations, the representative project would have two unique or different elements that could potentially affect wildlife. The first is the potential for birds to collide with the drill rig derrick, or mast. This may be a particular concern for birds migrating through the area at night. If Federal Aviation Administration lighting requirements are applicable, there is also some evidence that the steady-burning red lights that might be required on the masts may disorient migrating birds more than flashing lights.[133]

The second area of potential concern is associated with the open sump pond that would be constructed as part of the well pad for management of drilling muds or other fluids. A synthetic liner or clay would line this pond to prevent seepage. These structures could affect wildlife by providing a catch basin for rainwater, but they could also contain minerals and chemicals from downhole fluids that could be toxic to wildlife. Further, some species may fall into the pits or go into them intentionally for water, and be unable to get out because of the slick liner material. The installation of some type of wildlife escape structure as has been developed for watering troughs and other water structures might mitigate this latter concern.[134] Such a structure may be no more than a climbable, low-angle surface that extends down to the bottom of the pond. Whether an escape structure would be appropriate would depend on the site, the accessibility of the pond to wildlife, and the wildlife that the pond could affect. Of course, these identified concerns become more serious if they could affect threatened or endangered species or state species of concern.

3.2.2.8 Transportation

As presented in the air quality discussion (Section 3.2.2.2), construction of a well pad and production drilling would involve a notable amount of traffic, particularly large truck traffic, and it would be heaviest during transportation of fill material to the well pad construction site. Estimates are that it would take roughly 600 round trips by large, 15-cubic-yard dump trucks to deliver the necessary fill to the construction site. Over a three-week period, seven days per week, this would require roughly 30 round trips per day. For most main artery roads, this would be a minor amount in comparison to normal daily traffic levels, but this would be very dependent on the specific site. Online searches of the appropriate state's department of transportation records can often lead to traffic flow studies that include traffic count data. If such information is available for the road, or roads, that would carry the truck traffic, the proponent can make comparisons that would help gauge the effects of the added traffic. Of more concern may be the access and exit points on the main roads and whether there are double lanes, turning lanes, or possibly even signal lights that would better allow other traffic to keep safely moving in spite of the trucks trying to get onto or off the road.

The description of the representative project (Table 3-1) includes the assumption that final access to the well pad site would be over one-half mile of existing dirt road. The truck traffic described above may represent a minor increment on a main artery road, but it is probably reasonable to assume this would not be the case for an existing dirt road. Evaluating potential impacts to traffic on this road would require learning more about the composition of the traffic. This might be done through conversations with people familiar with the area, by observation of the road, by evaluation of the nature of the areas to which the road provides access, or a combination of such actions. In this case, the primary concern would likely be whether the truck traffic can safely integrate with existing traffic (i.e., adequate line of sight, typical speeds, room for two-way traffic, etc.) The project proponent may have to consider if upgrades to the dirt road need to be part of the project and would likely have to commit to repairing any damage to the road as a result of the heavy-weight traffic.

3.2.2.9 Health and Safety

Construction of a well pad and production drilling would involve, for the most part, typical worker health and safety concerns for those types of activities. A different safety concern associated with geothermal well drilling as opposed to other types of drilling, of course, would be the hazards represented by the high-temperature and high-pressure geothermal fluids being sought. As described in Section 2, production drilling involves a process of repeatedly going through well completion and cementing steps as greater depths are reached and the well telescopes downward in casing size. This and the associated installation of BOPE (also described in Section 2) are the industry standard for protecting the operation from out-of-control conditions.

With the BOPE installed, risks to public health and safety would be similar to those posed by typical construction and industrial activities. Encounters with moving vehicles, equipment, and machinery would be the primary concerns. The well pads for deep drilling operations are large (5 acres in the case of the representative project) and, by themselves, provide a physical buffer between the work actions and any member of the public during those operations. Directional drilling would be pursued if necessary to provide an adequate safety buffer between members of the public and operations on the well pad or subsequent power plant operation. The potential for adverse impacts, both to aquifers and drinking water sources, represents a public health and safety concern. The water resources discussion is inclusive of this point.

3.2.2.10 Noise and Vibration

Potential impacts from noise and vibration would be wholly dependent on the proximity of receptors to the well pad site. During the well pad construction, noise levels would be typical of a construction site and would likely involve the highest amount of vibration concerns from activities such as grading and compaction. In general, though, most people know what to expect with regard to noise and vibration from construction activities, plus these activities would be relatively short-term in nature.

Production drilling, on the other hand, would be of longer duration, and if there were people within the vicinity of the project, they would probably be less apt to know what sounds, or sound levels, to expect from a large drilling operation. One study measured sound levels at three different gas well drilling sites that used three different drill rigs. The rigs had drill depth capacities ranging from 12,000 to 15,000 feet, so they would be comparable to the drill rig needed to support the representative project. Results of the sound measurements indicated the diesel-powered generators were the individual pieces of equipment that generated the highest sound levels at about 102 A-weight decibels (dBA) at a distance of 10 feet. On the drill rig floor, combined noise levels were as high as 105 dBA at 10 feet. At 200 feet from the rig, the average drilling sounds ranged from 71 to 79 dBA.[135] The noise levels in the low 100s would be similar to some typical, noisier home power tools, while the low end of the range at 200 feet is comparable to a business office, and the upper end would be similar to heavy truck traffic.

The sound levels described above would not be expected to generate serious issues at most locations, but if the drill rig were to be in a community—particularly if there were sensitive receptors such as schools, hospitals, residences, and other sleeping locations, etc., in close proximity to the project site—there could be problems. The study referenced above also installed and tested several sound mitigation measures, including acoustical blankets, improved engine mufflers, and noise-reducing materials in the mechanical brakes of the draw works, and it reported significant improvements.[136]

An evaluation of potential noise and vibration impacts would not only have to identify sound levels that the specific project equipment would produce, it would also have to identify and characterize nearby receptors, including sensitive receptors. If the project's location was in or near a community, there may be noise ordinances that set maximum noise levels. The biological resources discussion in this paper best addresses potential noise effects to area wildlife.

3.2.2.11 Hazardous Materials and Waste

Hazardous materials or potential contaminants present during construction of the well pad and during production drilling would include fuels and lubricants used in the equipment. During drilling, materials of potential concern would also include the drilling muds and the various additives described in Section 2 that would likely be on hand to adjust the mud's properties or to add to the hole if the drilling team encounters unexpected downhole conditions. Similar to the drilling muds, cement and various additives would also be present for well-completion actions. These materials would include both liquids and solids and likely would be stored to some extent at the site pending their use. Minimum requirements would specify the use of secondary containment for any storage tanks or drums containing hazardous liquids.

Management of hazardous materials or any materials that might be considered pollutants during construction actions would be subject to a general NPDES permit for storm water discharges. This would also include adherence to the SWPPP required as terms of the general permit. These requirements include measures to ensure the proper management of any hazardous materials stored at the site, to minimize the potential that runoff could carry any hazardous materials off the site in runoff, and to maintain procedures and equipment to respond to and clean up any inadvertent spills or leaks. Neither production drilling nor a geothermal power plant is one of the industrial categories that automatically require a NPDES permit during operations, per federal regulations, but the specific state may have additional requirements. In any case, best management practices should dictate the appropriate management of any hazardous materials stored at the site, and the appropriate equipment and procedures should have been established during construction actions when they were required measures.

Large volumes of excess materials such as drilling muds, drill cuttings, or extra cement mixtures would be managed in tanks or lined sumps. These materials would be maintained in these contained conditions until their characterization and appropriate disposition or until the water evaporated off and the dry materials scooped out. Any on-site disposal of these materials would require approval of the applicable regulatory agency.

3.2.2.12 Recreational Resources

As with many of the other resource elements, potential impacts to recreational resources must be evaluated based on the characteristics of a specific site. Recreational resources of potential concern would include federal, state, or local parks; other areas where groups of people might congregate, such as sports fields, nature parks, or public gardens; or areas where people participate in recreational actions alone or in small groups such as hiking, biking, camping, picnicking, or hunting. If there are water bodies in the area, recreational activities such as fishing, boating, or swimming should also be characterized. The evaluation would then be with regard to what kind of effects the proposed action could have on these types of activities. Most potential effects would be expected, of course, to be proportional to the distance between the recreational use and the project site, but in some cases, the impact may be based on the line sight. For example, there may be more effect at the location of a scenic overlook with a clear view of the project, than at a park closer to the project site but located out of sight. The evaluation is primarily an attempt to gauge how disruptive the proposed project would be to the recreational areas and uses within the vicinity. If only the sound levels from a project would affect a sports field with lots of yelling and cheering, for example, that may not be much of an impact.

As might be expected, there may be overlaps between potential impacts to recreational resources and resource elements such as land use, noise and vibration, and visual resources.

3.2.2.13 Visual Resources

The primary source of visual impact during production drilling would be the drill rig, and more specifically the drill mast. Construction dust clouds and equipment smoke, such as might occur during the startup of diesel engines, may be visible at times, but these would generally be considered short-term effects, and implementation of measures such as spraying down dirt areas would minimize dust. However, the drill mast, which could be upwards of 200 feet in height, would be present during most of the setup period and all of the drilling operations and, at most sites, would be visible for some distance.

The visual impacts of the drill mast and other elements of the project would depend totally on the characteristics of the specific site. The proximity of residences, urban areas, or groups of people are examples of conditions that could determine visual impacts. Another site characteristic of possibly more significance might be the visual values already attributed to the site. For example, if there were parks or recreational areas nearby that were valued for their scenic qualities, these would represent significant evaluation criteria.

The Visual Resource Management (VRM) system used by BLM should be considered in evaluating potential impacts to visual resources. This might be done by determining if nearby public lands have already been evaluated or by applying VRM guidelines to the site to gauge what normally might be considered compatible uses or visual conditions. Evaluation of visual resources at a proposed geothermal drilling site could become a significant consideration in choosing the well pad layout and even its location.

3.2.2.14 Cumulative Impacts

As Section 3.1 described, typical environmental evaluations would address other proposed actions that may occur within the same temporal and spatial boundaries as the primary action being evaluated and which, therefore, may result in cumulative impacts. Since the intention of this paper is to address only a specific element of an overall project, there is no basis for a discussion of cumulative impacts in this instance. At a minimum, an evaluation of environmental consequences from production drilling would have to be in the context of the overall geothermal project. That is, production drilling would be part of, and in a sense cumulative with, a larger project. The evaluation of an actual geothermal project would include the production drilling as well as other, related or unrelated proposed actions that could involve cumulative impacts.

3.3 PERMITTING REQUIREMENTS AND ISSUES

3.3.1 Regulatory Permitting Requirements

Any geothermal drilling project, whether it be for slim hole to production drilling for well field development, requires that the developer have an approved geothermal drilling permit (GDP) and be the lessee or hold operating rights on the geothermal lease. In order for the GDP to gain approval, the proposed drilling and operations plan must be in conformance with federal laws and regulations; land management plans and policies of federal agencies; and state and local governmental regulations and requirements.

Table 3-3 contains a potential list of regulatory permits and approvals necessary for project approval. The permits required by individual state agencies vary; detailed information on federal, state, and local permitting is available at the Geothermal Regulatory Roadmapping website on OpenEI: http://en.openei.org/wiki/GRR.

Table 3-3. Potential Regulatory Permits and Approvals for Geothermal Development

Regulatory Agency	Required Permits or Approvals
Federal	
BLM Field Office	GDP (Form 3260–2)
	National Historic Preservation Act Section 106 compliance
	Native American Graves Protection Act cultural resources permit
	American Indian Religious Freedom Act cultural resources permit
	Cultural resource use permits – survey/recordation permit
	NEPA – EA and decision record
	Geothermal Sundry Notice
	Bond (43 CFR § 3216.18)
Surface Management Agency	Consultation and coordination
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 compliance
State (general listing – agencies and permits vary see OpenEI for individual state agencies and permitting process)	

Regulatory Agency	Required Permits or Approvals
Wildlife department	State-listed endangered species review
Conservation/resources, etc.	Waivers for temporary use of groundwater Application for permit to appropriate public waters
Transportation	Encroachment and/or occupancy permits
Minerals/water engineer	State well permit, geothermal injection well permit, sundry notice, project permit
Water pollution control	Underground Injection Control Permit Class V wells, discharge permits, storm water general permits, NPDES
Health/environment	Radiological logging
Fire marshal/health	Hazardous materials permit
State Historic Preservation Officer	*Historic Preservation Act* Section 106 compliance in accordance with Programmatic Agreement for NHPA compliance between the BLM, BOR, and SHPO
Local	
County	Special use permits, grading permit, encroachment permit, building permit

3.3.2 Geothermal Lease Stipulations

Lease stipulations are attached to a geothermal lease when it is determined, during the land use planning process, that a conflict of resource values with geothermal operations exists that cannot be adequately managed under the BLM Standard Lease Terms (Offer to Lease and Lease for Geothermal Resources, Form 3200-24a). Land use management plans serve as the process for determining the necessity for lease stipulations (BLM Manual 1624) and is documented and disclosed in planning documents or through site-specific analysis.

However, the federal land management agencies, principally the BLM and USFS, through their land management planning process evaluate various proposed alternatives to identify lands closed or open for geothermal leasing and the level of resource protection necessary to protect or mitigate potential impacts to specific resources. Geothermal lease stipulations are developed and identified as part of a land use decision, and they may identify circumstances where stipulations may be eligible to be waived, incorporate an exception, or be modified.[137] The stipulations are intended to be “consistent with the goals and objectives for natural resources within the planning area.”[138] For those lands open for leasing, stipulations include the following:

- **Controlled Surface Use:** Allows the BLM or USFS to require that a future activity, drilling or development, be modified or relocated from a proposed location to achieve the level of resource protection required. The agencies must approve modification, or they will not allow surface occupancy on the lease.
- **Timing Limitations:** Is essentially a seasonal restriction that provides for the protection of resources, that are sensitive to disturbance during certain periods and may be specific to areas, seasons, and resources.
- **No Surface Occupancy:** Use of the surface of all or a portion of the leasehold is prohibited for exploration or development to protect identified resources.

Changes to the lease stipulations may only be granted upon a written request from the lessee or operator that documents and demonstrates that the protections provided by the stipulation are no longer justified or that the proposed operation will not cause any unacceptable impacts and are described as follows:

- **Exception:** A one-time exemption of a stipulation for a specific site on the leasehold. The exception is determined on a case-by-case basis and does not apply to all other sites within the leasehold.
- **Waiver:** A permanent exemption of a stipulation that applies to the entire leasehold.
- **Modification:** A change to the provisions of a stipulation. The modification may be either temporary or extend for the term of the lease, and may not apply to all of the leasehold. Lease stipulations may only be permanently modified or removed by amending the NEPA document, which initially identified them.

3.3.3 Conditions of Approval

Conditions of approval (COAs) include special provisions applied to a GDP or sundry notice approval. COAs are typically developed during an on-site inspection and environmental review. The on-site inspection is conducted with participation from the BLM and surface management agency representatives, the operator (or permitting agent), and those parties associated with processing the permit application, which may include the operator’s contractors, agency resource specialists, surveyors, utility/pipeline company representatives. The surface owner will be invited if the project is on split estate lands.

Identification and negotiation of site-specific COAs will occur during the on-site inspection. In addition, discussions and decisions of which best management practices are suitable to mitigate those impacts will be incorporated within the permit approval.

3.3.4 Geothermal Drilling Permit Process

A geothermal operator must obtain an approved GDP (Form 3260–2) prior to drilling a well on BLM jurisdictional lands (43 CFR 3260 through 3267). In addition, a geothermal operator must secure an approved geothermal drilling permit or well construction permit from the appropriate state agency, prior to initiating any surface-disturbing activities or drilling operations.

Prior to submitting the GDP or plan of development, the operator is encouraged to engage the BLM and the surface management agency or surface owner, if there are split estate lands; state and local government agencies; and stakeholders to gain a better understanding of applicable policies and regulations and establish positive working relationships. A detailed geothermal permitting process that includes flowcharts and associated content for federal and state agencies has been developed: http://en.openei.org/wiki/Gateway:Geothermal.

A complete GDP includes both a drilling program and an operations plan (Table 3-3). An operator has two options for obtaining approval to drill a geothermal well by filing a Sundry Notice (Form 3260–3) that includes an operations plan or by filing a GDP that includes both an operations plan and a drilling program. Approval of the first option, Sundry Notice, allows the operator to begin operations to build the drill pad(s) and access roads; however, drilling operations may not commence until a drilling program attached to the GDP has been approved. Under the second option, the approval of the GDP authorizes the applicant to begin construction of well pad and access roads and the drilling and testing of the well.

Table 3-4. Drilling and Operations Plan Checklist[139]

43 CFR § 3261.13 What is a drilling program?	43 CFR § 3261.12 What is an operations plan?
A drilling program describes all the operational aspects of the proposal to drill, complete, and test a well. It should include the following:	An operations plan describes how you will drill for and test the geothermal resources covered by your lease. Your plan must tell the BLM enough about your proposal to allow them to assess the environmental impacts of your operations. This information should generally include the following:
(1) A detailed description of the equipment, materials, and procedures you will use	(1) Well pad layout and design;
(2) The proposed/anticipated depth of the well;	(2) A description of existing and planned access roads;
(3) If you plan to directionally drill your well, also send:	(3) A description of any ancillary facilities;

43 CFR § 3261.13 What is a drilling program?	43 CFR § 3261.12 What is an operations plan?
(a) The proposed bottom hole location and distances from the nearest section or tract lines;	(4) The source of drill pad and road building material;
(b) The kick-off point;	(5) The water source;
(c) The direction of deviation;	(6) A statement describing surface ownership;
(d) The angle of build-up and maximum angle; and	(7) A description of procedures to protect the environment and other resources
(e) Plan and cross section maps indicating the surface and bottom hole locations;	(8) Plans for surface reclamation
(4) The casing and cementing program;	(9) Any other information that the BLM may require
(5) The circulation media (mud, air, foam, etc.);	
(6) A description of the logs that you will run;	
(7) A description and diagram of the BOPE you will use during each phase of drilling;	
(8) The expected depth and thickness of fresh water zones;	
(9) Anticipated lost circulation zones;	
(10) Anticipated reservoir temperature and pressure;	
(11) Anticipated temperature gradient in the area;	
(12) A plat certified by a licensed surveyor showing the surveyed surface location and distances from the nearest section or tract lines;	
(13) Procedures and durations of well testing; and	
(14) Any other information required.	

Prior to starting any operations, evidence of an acceptable surety or personal bond must be filed with the BLM. Minimum bond amounts are a lease bond for $10,000 a statewide bond of

$50,000, or a nationwide bond of $150,000.[b] Bonding for a geothermal unit to cover operations on committed leases can be determined by the BLM or as a writer to a statewide or nationwide bond.

3.3.4.1 Geothermal Drilling Program

A drilling program contains the elements described in Table 3-2 and includes all aspects of the drilling, completions, well testing, any planned stimulation operations, as well as intermediate and final reclamation plans.

Operations Plan for Geothermal Drilling and Well Testing: The Nevada BLM developed specific guidance for the processing of geothermal permits on BLM-managed lands.[140] The BLM and industry stakeholders jointly developed the guidance to improve the permitting process and have a developed process model to follow.

Geothermal Sundry Notice to Begin Construction of Well Pads and Access Roads: Approval of geothermal drilling operations will require the preparation of an environmental analysis. Depending on previous land-use planning and subsequent NEPA documentation, the approval will require that a determination of NEPA adequacy or an environmental assessment (EA) be conducted.

However, if during initial review of the proposed action or via an EA it is determined that the proposed action will have significant effects (defined by NEPA and 40 CFR § 1508.27), it may be necessary to prepare an environmental impact statement, providing that the proposal cannot be modified to mitigate identified impacts.

Geothermal Drilling Operations on Split Estate Lands: Split estate refers to the situation where different parties own the surface rights and subsurface rights (i.e., mineral rights) for a land unit. When a different party owns the mineral rights, the mineral estate is the dominant estate. While the mineral estate is dominant, it is not mutually exclusive, and the surface owner must receive consideration.

The BLM has issued a policy to deal with mineral development on split estate lands that only deals with federal mineral ownership and private surface ownership.[141] This policy requires the operator to exert a good-faith effort to obtain a surface owner agreement. The agreement can be for access, a waiver for access, or an agreement regarding compensation. If a surface owner agreement cannot be reached, the operator may post a surface owner protection bond. Bond

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[b] 43CFR § 3214.14 provides information regarding situations when it may be appropriate for the BLM to increase a bind above the minimums specified.

coverage varies in accordance with the statute under which the lands were patented, but under the *Stock Raising and Homestead Act*, the minimum bond is $1,000 to cover reasonable and foreseeable damages to crops and tangible improvements.

For a split estate case when the BLM manages the surface and another party owns the mineral estate, a rights-of-way (ROW) special use permit to occupy the surface and drilling permits and other permits from state and local agencies would be required. The ROW process involves submitting an application and a NEPA analysis prior to permit approval.

Environmental Issues: Since this document previously covered a detailed description and discussion of environmental issues, they will not be discussed in any detail. Those environmental issues are typical of the issues and concerns identified for GDP permit approvals.

4. POTENTIAL MITIGATION MEASURES

The BLM requires that decisions be implemented in accordance with the appropriate NEPA decision document (Decision Record/Finding of No Significant Impact). Monitoring is necessary to ensure that actions taken comply with the terms, conditions, and mitigation measures identified in the decision. The BLM would fulfill this responsibility by monitoring the implementation of mitigation measures adopted as COAs to the submitted operations plan and GDPs, as well as the stipulations attached to the geothermal lease.

4.1 GENERAL MITIGATION MEASURES/CONDITIONS OF APPROVAL

The following recommended mitigation and monitoring measures are representative of those identified through the analysis conducted in this TWP:

- Reserve pits shall maintain a minimum 2 feet of freeboard at all times.
- The operator is not to conduct initial ground-disturbing activities that would not be conducted during the periods identified in timing limitation stipulations(s) unless necessary, and only after a qualified biologist first conducts inventories for species present. The operator would coordinate with the BLM or appropriate state officials, as applicable, to develop appropriate protection measures, which may include avoidance, construction constraints, and/or the establishment of buffers.
- Any wellhead production facilities and equipment left on the drill site following the completion of drilling would be painted a color which would blend with the landscape, pursuant to the BLM Instructional Memorandum (IM) 2007-021[142] and the Gold Book.[143] Prior to paint selection, operator will contact the appropriate BLM Field Office Project lead for concurrence.
- Maintain dark sky conditions; that is, an effort will be made to protect the current dark skies from light pollution. All drill rig and facility lights will be limited to those required to assure that the operations proceed safely.
- The operator must minimize the potential for the spread of noxious and invasive weeds in the project area. Prior to arrival at the drill site, construction vehicles and equipment are to be cleaned of all soil and plant material using high-pressure air or water equipment.
- The drill site and access roads are to be monitored for the life of the project to identify the presence of invasive, noxious, and non-native species. Invasive, noxious, and non-native species identified during monitoring will be promptly treated and controlled. A Pesticide

Use Proposal will be submitted to the appropriate BLM Field Office for approval prior to the use of herbicides.

- A site abandonment and reclamation plan would have been submitted with the GDP operations plan, reviewed, and any COAs and recommendations will have been discussed and identified in the NEPA document. If the well is commercial or will be temporally abandoned, the operator will be required to conduct interim reclamation to leave only those areas necessary for future operations.

4.2 WATER MANAGEMENT PLAN

The purpose of a water management plan for the site is to identify any potential impacts to both surface and groundwater. The collection of geochemical data should occur prior to stimulation on the ground water in shallow aquifers, the groundwater in all geothermal production, monitoring, and observation wells and any geothermal features in the immediate area to establish a baseline. Recommended analysis in addition to geochemistry should include water resistivity (conductivity), pH, temperature, and hydrostatic head in non-flowing wells.

A water management plan is an essential component of any drilling operation. The plan must be specifically designed for the hydrologic basin in which the project is planned to address both surface and ground waters. The plan should include an understanding of the federal and state laws, regulations, and policy governing both surface and ground water use. This includes the *Clean Water Act*, and the implications of state water laws for the acquisition and use of water for the project.

Consultation and outreach with surface and water rights holders should be initiated early in the planning process for the project and development of the water management plan. While most of the BMPs that have been developed were specifically for oil and gas, they are applicable to the development of geothermal resources. The application of a particular BMP is evaluated during the NEPA process to develop mitigation measures and developed to reduce or eliminate site-specific impacts.

4.3 WELL STIMULATION ACTIVITIES

4.3.1 Seismic Monitoring

Microseismic events may result from the stimulation of pre-existing fractures during the hydro-stimulation process. An array of microseismic monitoring equipment located on the surface and within boreholes would accomplish the monitoring and mapping of the microfractures. Positioned strategically and carefully, these microseismometers would effectively monitor and receive the scientific data.

4.3.2 Protocol for Induced Seismicity

A protocol for addressing induced seismicity has been in use since DOE introduced the protocol.[144] Steps described in the protocol include the following:

- Step 1: Perform a preliminary screening evaluation
- Step 2: Implement an outreach and communication program
- Step 3: Review and select criteria for ground vibration and noise
- Step 4: Establish local seismic monitoring
- Step 5: Quantify the hazard from natural and induced seismic events
- Step 6: Characterize the risk of induced seismic events
- Step 7: Develop a risk-based mitigation plan

4.3.3 Tracer Testing

The use of tracers in evaluating the effectiveness of the hydro stimulation is to determine the connectivity and permeability between injection and production wells. Two common tracers used in evaluating geothermal reservoirs are naphthalene sulfonates and uranine. Naphthalene sulfonates are not toxic or carcinogenic and are characterized as environmentally benign,[145] while uranine is a fluorescent dye that degrades over time and is commonly used in hydraulic studies in caves and municipal water systems to detect leaks.

4.3.4 Mechanical Integrity Testing

In order to verify the effectiveness of the cement bond between the well bore and the casing, a cement bond log (CBL) and analysis are required prior to the operator requesting approval to stimulate a well. The CBL process is to ensure that fresh water aquifers are isolated and adequately protected from potential contamination.

4.3.5 Pressure Monitoring

The operator will also need to continuously monitor pressure(s) within the well and keep a record of the pressures during the stimulation.

4.3.6 Fluids Handling and Storage

To prevent contamination of surface and aquifers stimulation and flowback, fluids should be contained in either lined pits or steel tanks. The use of lined pits would not require any additional surface disturbance since the pit would have already been constructed to receive flowback fluids during the initial drilling operation. The use of steel tanks would most likely not result in any new surface disturbance and would be preferred and result in total containment of the fluids. This is because there may be some infiltration of fluids when using a pit.

If open pits are used, there are potential impacts to water quality and wildlife. Mitigation of these impacts typically consists of placing pit liners for water quality. Fencing and netting is also typical to prevent wildlife from entering the pit.

5. FUTURE CONSIDERATIONS AND CONCLUSIONS

This section describes any pending or foreseeable changes in either the technologies or permitting and regulations associated with production drilling and well completion. This section is meant to serve as guidance of other factors that may need to be explored in the future.

5.1 U.S. OFFICE OF INSPECTOR GENERAL, DEPARTMENT OF THE INTERIOR BLM GEOTHERMAL PROGRAM RECOMMENDATIONS

DOI's, Office of Inspector General (OIG), published an evaluation, "Bureau of Land Management's Geothermal Resources Management," on March 7, 2013.[146] The OIG recommended and BLM concurred that they will be implementing the following recommendations: 1) Review and update existing Geothermal Resource Orders, 2) Develop and incorporate induced seismicity protocols into the orders, 3) Develop an inspection and enforcement policy for geothermal operations, that includes drilling operations, and 4) Conduct a study to evaluate staffing levels of inspectors. These recommendations should be considered in future production-drilling projects.

5.2 HYDRAULIC STIMULATION

Current concerns and issues with the hydraulic stimulation technology focus on the "hydro-fracturing" process used by the oil and gas industry. The BLM reported that about 90% of wells spudded on federally managed lands in 2013 were hydraulically stimulated.[147] The stimulation of water wells and oil and gas wells by hydraulic fracturing ("hydro-fracturing") is a proven method that is commonly used to enhance the productivity of reservoirs; it has recently become a major issue in the development of oil and gas in low permeability shale formations. Because of the controversy, many state oil and gas regulatory agencies are developing or are in the process of revising their regulations.

The California Division of Oil, Gas, and Geothermal Resources (DOGGR) has initiated revision of its hydro-fracturing regulations and is currently in the public participation/scoping phase. On March 20, 2015 BLM published the first revisions to its rules governing hydraulic fracturing since 1988.[148, 149] The final rules (43 CFR 3162.3-3) cover chemical disclosure, well construction and cementing requirements, and flowback management plans. The new regulations are limited to fracturing activities (defined in 43 CFR 3160.0-5) and not to broader stimulation activities

Legislation has been introduced in both the House of Representatives (H.R. 1084) and the Senate (S. 587). The *Fracturing Responsibility and Awareness of Chemicals Act of 2011(FRAC Act)* repeals the hydraulic fracturing exemption of the *Energy Policy Act of 2005*. It revises the term *underground injection* to include the fluids employed in hydraulic fracturing operations for oil and gas production and disclosure of chemicals used in the process. This revision of the underground injection definition would authorize the regulation of hydraulic fracturing by EPA. Each bill was introduced and referred to its respective committees during March 2011—no further action was initiated. To date, all of the legislative and regulatory initiatives have focused on oil and gas.

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