

PLAN OF EXPLORATION, OPERATIONS PLAN AND DRILLING PROGRAM

NEWBERRY VOLCANO EGS DEMONSTRATION PROJECT

**FEDERAL GEOTHERMAL LEASES
OR12437, OR65371, OR45505, OR65470, OR40497,
OR45506, OR53085, OR65470, OR12397**

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The Newberry Volcano EGS Demonstration will develop an EGS reservoir in the high temperature, low permeability resource present on the northwest flank of Newberry Volcano. The project is located outside the Newberry National Volcanic Monument on an existing federal geothermal lease designated for geothermal use by a Citizens' Committee and congressional process, and in the legislation that created and established the Monument. The project team will demonstrate stimulation techniques to induce and sustain fluid flow and heat extraction from an existing injection well and two production wells, culminating in the conceptual design of a commercial-scale wellfield and power plant.

1. PROJECT DESCRIPTION

1.1 Project Objectives

The Newberry Volcano EGS Demonstration project (the “Project”) will develop an Enhanced Geothermal System (EGS) reservoir in the high temperature, low permeability resource present in volcanic formations on the northwest flank of the Newberry Volcano. The project team will quantitatively demonstrate stimulation techniques to successfully induce and sustain fluid flow and heat extraction from one injection well and two production wells, culminating in the conceptual design of a commercial-scale wellfield and power plant. AltaRock Energy Inc. (AltaRock), in partnership with Davenport Newberry Holdings LLC (Davenport), has geothermal rights to the assets of the project site including, but not limited to, the data collected and held by Davenport, the owner and legally designated operator of the BLM geothermal site leases.

In 1976, the Newberry Known Geothermal Resource Area and the Newberry Crater National Natural Landmark were created. These designations served to highlight the potentially conflicting uses of the Newberry caldera area. Overlapping uses and conflicting interests of conservation groups, recreationists, the timber industry, and the geothermal industry prompted these designations. As a result of local grassroots efforts, the central caldera region of Newberry Volcano was proposed for National Monument status in 1989 and a Monument Citizens’ Committee was formed with representatives from all interested groups, including the geothermal industry. In 1990, federal legislation designated the central caldera and a narrower band of land running north to Lava Butte as the Newberry National Volcanic Monument. The legislation included provisions for a geothermal lease swap, whereby existing federal geothermal leases within the new National Monument would be exchanged for leases outside of the boundary. This action excluded geothermal exploration and development within the newly created Monument, but provided that it may occur on land outside the Monument. This agreement was the cornerstone of the consensus reached by the Citizens’ Committee and was pivotal to establishment of the Newberry National Volcanic Monument.

1.2 Project Location

Newberry Volcano is located in Deschutes County in central Oregon, about 35 km (20 mi) south of the city of Bend and approximately 65 km (40 mi) from the crest of the Cascade Range (Figure 1). The entire volcano covers an area greater than 1,300 km² (500 sq.mi.). The summit caldera is about 8 km x 5 km (5 mi x 3 mi).

The proposed project is located on Federal Geothermal Leases (OR12437, OR65371, OR45505, OR65470, OR40497, OR45506, OR53085, OR65470, OR12397) on the western flank of Newberry Volcano in the Bend- Fort Rock District of the Deschutes National Forest, Oregon. Figures 2 and 3 illustrate the location of the proposed project sites within the Newberry Volcano area. All sites are alongside existing USFS roads. No new roads will be constructed.



Figure 1 – Regional Location Map

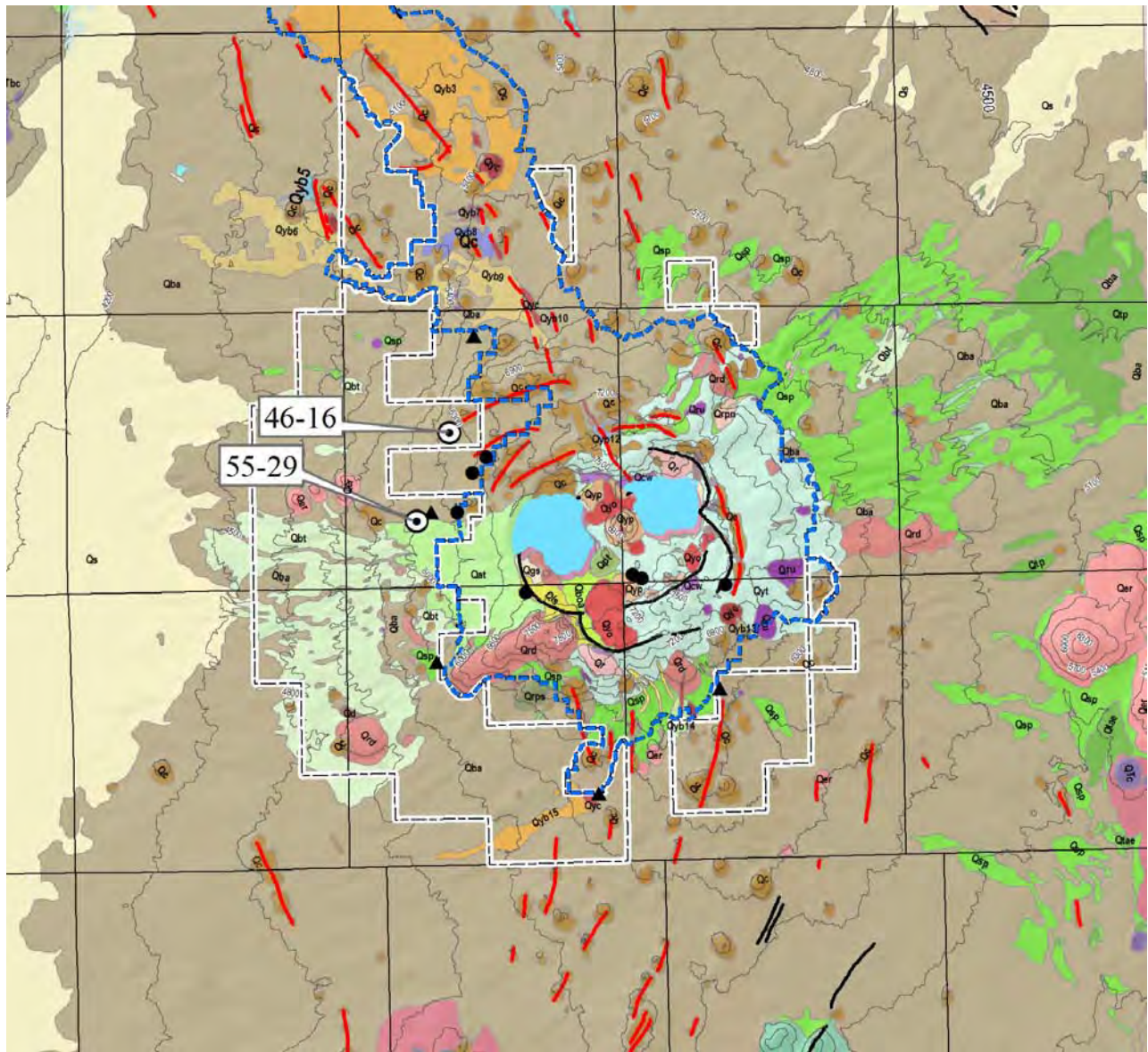


Figure 2 - Geologic Map of Newberry Volcano (from MacLeod et al., 1982) showing the Newberry National Volcanic Monument (blue line), geothermal lease boundaries (white line), and the two Davenport wells NGC 46-16 and NGC 55-29.

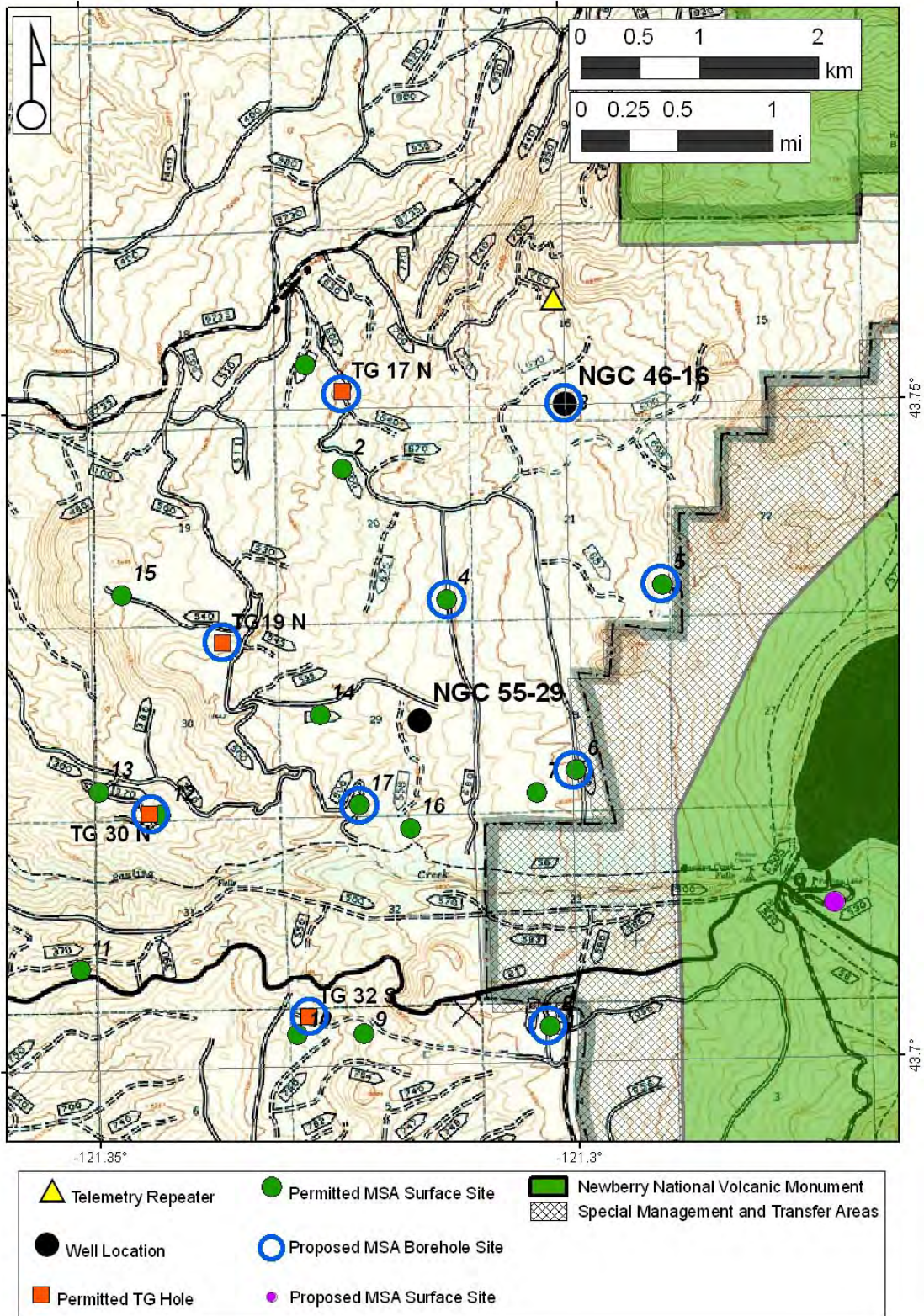


Figure 3 – Potential MSA Surface and Borehole Station Locations

1.3 Project Scope

The Project will be executed in three phases over a period of approximately three years. Phase I, Pre-Stimulation, will integrate all existing geoscience and well data along with any additional flow test and wellbore survey data into a comprehensive geologic model of the project. A detailed stimulation plan will be developed, an initial microseismic array (MSA) will be installed, public meetings and information forums will be conducted, and Phase I and II permits will be obtained. In Phase II, Reservoir Creation and Characterization, an existing deep well will be stimulated using hydroshearing techniques to create a fracture network. The initial MSA may be modified or augmented prior to stimulation. The stimulated injection well and surrounding fracture network will be characterized by a short flow test, and MSA and chemical tracer data will be interpreted to map the fracture locations. Two production wells will be directionally drilled from the same well pad into the mapped fracture network. The first production well will be drilled into one flank of the newly created fracture network, and a connectivity test will be conducted. Groundwater, produced from on-site water wells, will be pumped into the injection well while the production well is flowed to an atmospheric separator, with the steam vented to atmosphere and the residual liquid re-circulated to the injection well. A second, similar production well will be drilled into the opposite flank of the fracture network. If necessary, hydroshearing stimulation of the production wells will be conducted to enhance connectivity. The final Phase II operation will be an extended circulation test to characterize system performance under steady-state conditions. In Phase III, Long-Term Monitoring and Conceptual Modeling, the static EGS system will be monitored to assess fracture evolution and reservoir response to production, and a conceptual model of a commercial-scale EGS wellfield and power generation facility will be developed.

Phase I – Pre-Stimulation

Site and Wellbore Readiness

Davenport completed the drilling of two deep wells, NGC 55-29 and NGC 46-16, in August and November 2008, respectively. After a detailed evaluation of existing well data (wireline logs, well cuttings, drilling history and injectivity tests), one of these two candidate wells will be selected for EGS stimulation as an injection well. The other well may be used for monitoring of reservoir microseismicity and pressure monitoring. NGC 55-29 is completed to 3,066 m (10,060 ft), with an 8.5 inch diameter open hole from 1,790 m (6462 ft) to total depth (Figure 4). This well was open to total depth at the time of the last temperature survey conducted 3 October 2008. NGC 46-16 is completed to 3,553 m (11,599 ft), with a 12-1/4 inch diameter open hole to 2,100m (6,888 ft) and a 10-5/8 inch diameter open hole to total depth. NGC 46-16 has a bridge at about 1,448 m (4,736 ft), making its use as an injector less likely.

Each of the existing wells is located on a five-acre pad (S-29; Figure 5). These well pads have been permitted and are large enough to allow the completion of up to three wells per pad. Each pad includes a 1.4 million gallon sump and a groundwater well capable of producing at least 350 gpm. Existing U.S. Forest Service (USFS) roads allow access to the well sites. As part of site readiness, existing roads will be repaired and maintained as necessary to provide safe access to the project site. The well pad and sump of the target well will be maintained as necessary for the project. Development of the stimulation plan, discussed below, will estimate the water injection rate required for effective hydroshearing stimulation and conducting the circulation test. It is likely that the existing well sumps are not sufficient to contain and transfer the greater water volume in a timely fashion. Therefore, additional groundwater wells will be completed under the existing permit to supply the necessary water production rate.

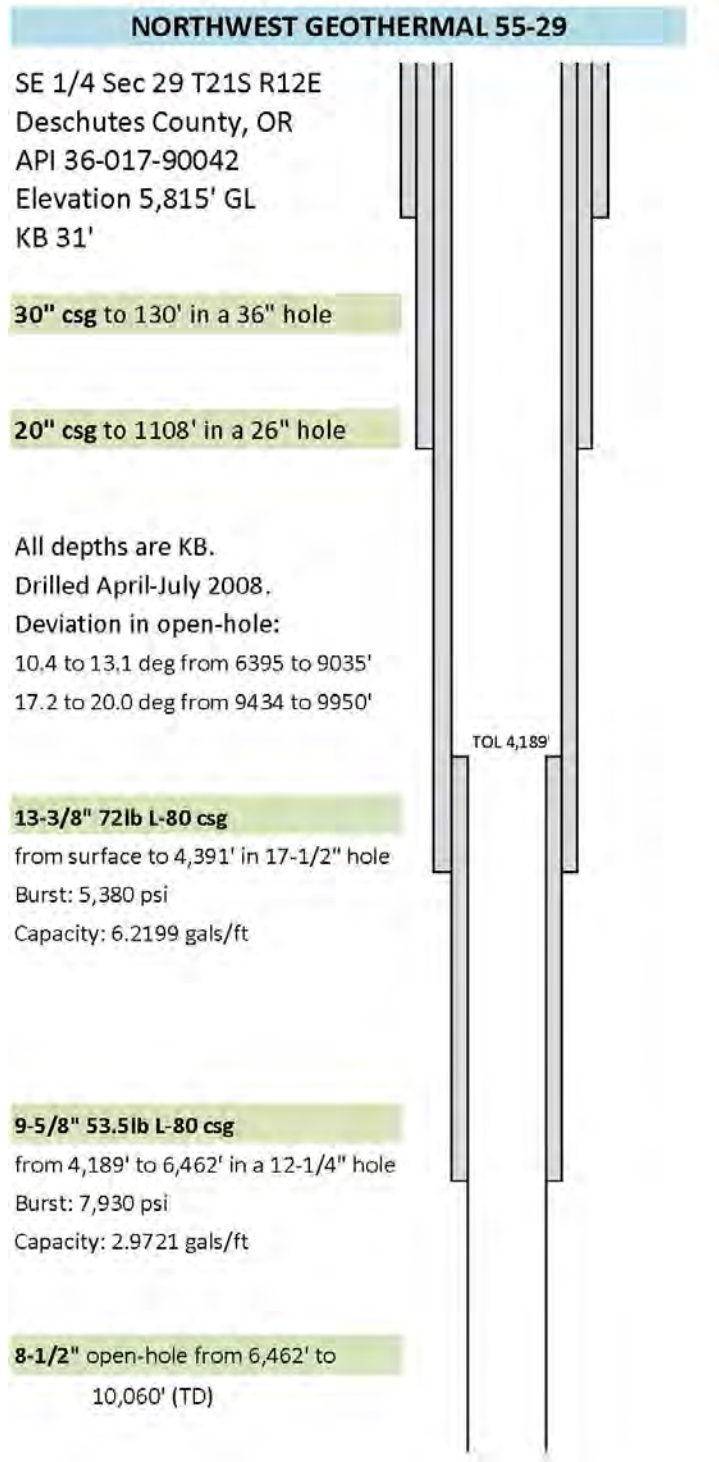


Figure 4 – Davenport Well NGC 55-29 Well Bore and Casing Profile

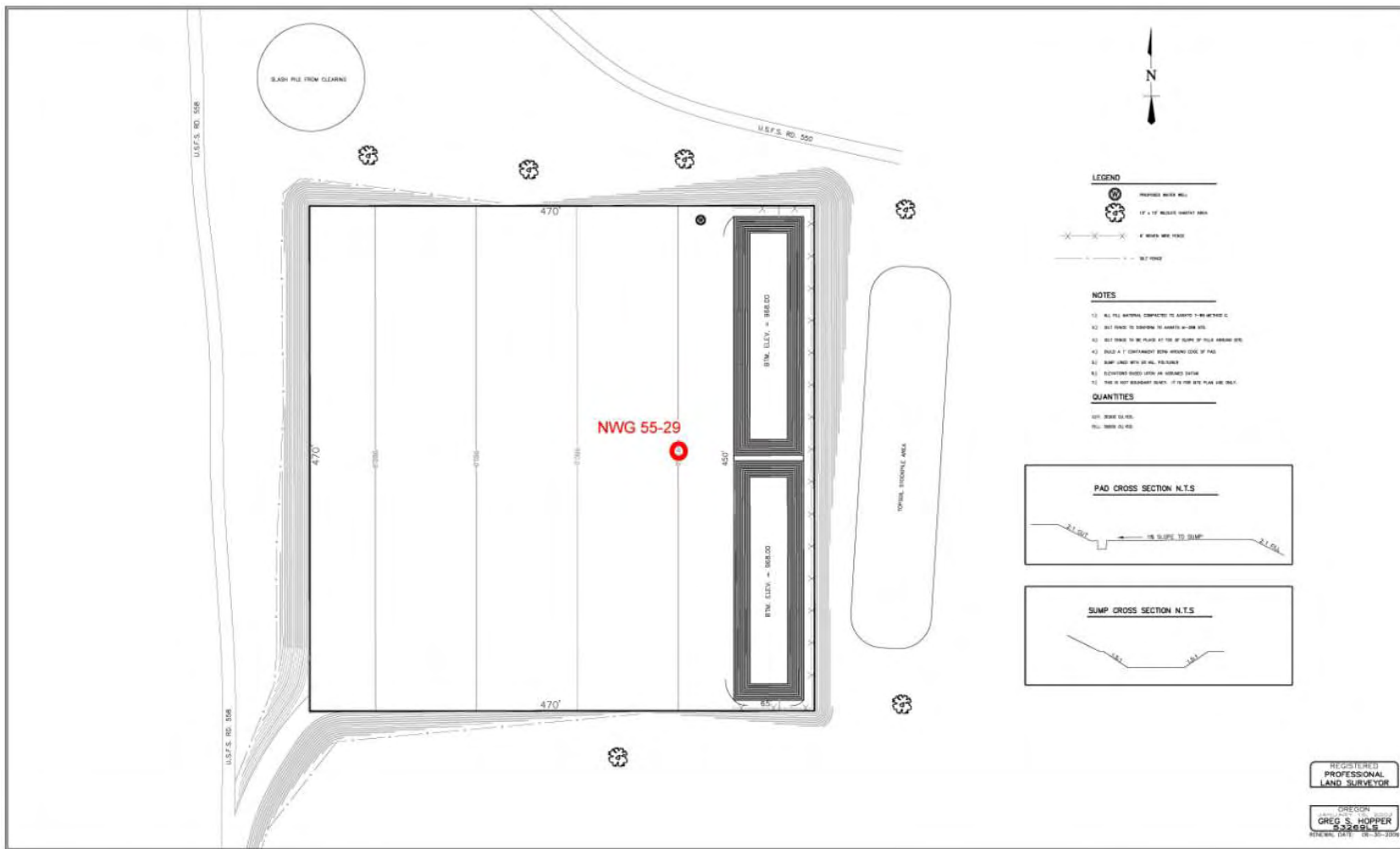


Figure 5 – Well Pad S-29 site plan showing current location of Davenport Well NWG 55-29.

Development of Stimulation Plan

Prior to stimulation, a microseismic array (MSA) will be installed to assess local microseismicity and obtain data for an *Induced Seismicity and Seismic Hazards Report*. This array will include seismometers installed at the project location, within about a 3 kilometer (1.9 mile) radius of the target well NWG 55-29. In addition, up to three additional seismometers will be installed in the region, at a radial distance of about 10-20 miles from the project site, to augment the existing regional network. Monitoring of natural microseismicity will be conducted for a period of three months prior to report preparation, and will continue through stimulation, well drilling and project completion.

Fractures created during stimulation will be mapped by monitoring microseismicity. An MSA will monitor the target well and surrounding area. Initially, up to 12 MSA stations (Figure 6) will be installed, with the seismometers located at the surface or in existing shallow boreholes (Figure 7). Station locations may be adjusted later, based on system response. Prior to stimulation, each MSA station will be equipped with a telemetry system. Telemetry will allow real-time data monitoring, including posting of the data to the Lawrence Berkeley Laboratory DOE-sponsored web site¹. Optimum station location, and the potential need for deployment in boreholes, is highly dependent on local geology and the response of the geology to seismic events, particularly the attenuation of seismic energy from the deep resource. To determine the optimum seismometer array deployment, the response of each potential station location to seismic energy released in the reservoir must be calibrated. Calibration can be accomplished by deploying a tool downhole that will produce a seismic signal measurable at each of the monitoring stations ('downhole calibration') or, conversely, by producing a seismic signal at each of the stations and deploying a seismometer deep in the target well to monitor response ('surface calibration'). The resulting data set will be used to optimize station location and to construct a seismic velocity model of the local geology and its seismic characteristics (e.g., attenuation).

We are currently in consultation with a team of expert seismologists, including several from the U.S. Geological Survey (USGS), to determine to best method for calibration. Although we present a discussion of both methods below, the expert team is skeptical that downhole calibration will be effective; the small net charge is unlikely to produce a signal that will be measurable at the surface, and deploying a significantly larger charge could result in rock sloughing and blockage of the open-hole section of the well bore. Thus, we are currently leaning toward surface calibration, and will obtain BLM approval when the technical plan is finalized.

Downhole Calibration - In the downhole calibration method, seismic energy is produced with a perforating tool. Perforating tools are commonly used in oil, gas and geothermal well completion to create a flow path through steel casing. In this case, the tool is re-purposed for use as a seismic calibration system. The tool would be deployed into the 8-1/2" open-hole section of well NWG 55-29, below 6500 feet (more than 1.2 miles below ground). The wellbore would be filled with water prior to the operation to ensure adequate hydrostatic weight over the tool assembly. The perforating tool uses shaped charges housed in a ten-foot, hollow steel carrier (4-1/2" diameter, wireline-conveyed, high shot-density system) at 12 shots per foot in a radial orientation. Each shot contains 20 grams of explosive material. The charges will be wired together on primer cord to detonate simultaneously. This design equates to 2.4 kg (5.3 lb) of net charge. In conjunction with the perforating tool, a sensor to time the detonation can be placed in line on the surface, or downhole in the cable head if a multi-conductor wireline is used. With additional insulation, the charges are rated for one hour at 519°F, which correlates to a depth of 8,000' in well 55-29. The multi-conductor wireline is rated to 575°F.

Surface Calibration - In the surface calibration method, seismic energy is produced using explosive charges deployed into shallow boreholes up to 10-20 feet in depth. Dr. Rufus D. Catchings, a research

¹ http://esd.lbl.gov/research/projects/induced_seismicity/egs/

geophysicist with the USGS Earthquake Hazards Team, is an expert in this method, and has safely conducted similar operations at hundreds of public and private locations across the country, including environmentally sensitive areas. The USGS can perform these operations under a categorical exclusion from the NEPA process granted by the U.S. Department of Interior, as long as specific ‘exceptional’ conditions do not exist (e.g., endangered or threatened species present, etc.). In this method, a high-temperature seismometer is installed as deeply as possible in the target well NWG 55-29. The depth of installation will be at least 6000 feet, but is limited by the temperature stability of the tool. Other seismometers will be placed on the surface at various locations around the project area, including each of the proposed MSA monitoring sites. All seismometers will be removed immediately after the calibration. The 10-20 foot deep boreholes used to contain the explosive charges will be 2 inches in diameter. A hand-held auger will be used to make the borehole. An explosive charge, probably 5-10 pounds will be placed in the hole, and then covered with native soil, a sheet of rubber, a sheet of aluminum plate, and sand bags. This method allows the detonation to be completely contained in the borehole, with no additional surface disturbance. The charge is detonated and the seismic signal received deep in the target well, and at each of the surface monitoring sites. The seismometer might also be deployed at shallower depths in the target well, and in another existing borehole (e.g., NWG 46-16), and the exercise repeated. The calibration exercise is expected to last about 3 days, including drilling of boreholes, distribution of seismometers, and calibration. A brief, limited calibration exercise may be conducted prior to the full calibration in order to determine the actual amount of explosive charge that will be required. This method requires an exceptionally small surface footprint, and site remediation after calibration will leave no lasting effects. To fully characterize the target well for stimulation, an injection test and wellbore surveys will be conducted (e.g., temperature, caliper, and borehole televiewer). The injection test will be conducted with the tool string at the bottom of the expected stimulation interval prior to the injection testing. During the 12-hour build-up test the wellbore will be shut in and bottom-hole temperature and pressure will be monitored. In-situ temperature, pressure, permeability and skin effects will be derived from the data. A step-rate injection test will be conducted to calculate a baseline injectivity index and to cool the wellbore for additional logging. Injecting Pressure-Temperature-Spinner (PTS) surveys will be conducted. In addition to a baseline indicator, the injectivity test will provide qualitative data on pre-stimulation permeability. If the well can be cooled sufficiently, high-temperature surveys (to 350°F) including sonic, gamma ray and density, acoustic imaging and dipole sonic, may be conducted.

Following collection and analysis of the various data sets, a conceptual geologic model of structure, lithology, temperature, permeability, and stress at depth will be created. The model will allow prediction of the principal stress directions, relative magnitudes (normal, strike-slip or thrust faulting regimes), and open, sealed, and closed fracture orientations. The geologic model results will provide initial inputs to a 3D numerical reservoir model and to the development of a stimulation plan utilizing AltaStim, a proprietary AltaRock software package. AltaStim is used to predict the geometry of the resulting EGS reservoir volume.

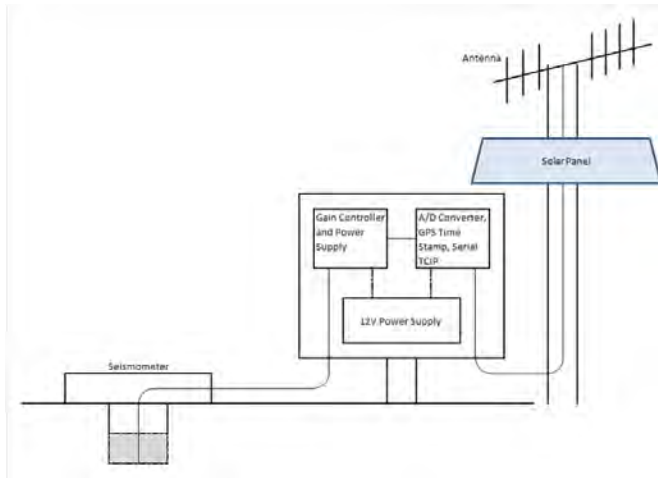


Figure 6 – Schematic diagram of MSA station, including option for telemetry (left) and photo of similar MSA surface installation, showing utility box, solar panel and telemetry antenna (right). Phase I installations at Newberry will not include the mast and antenna above the solar panel.

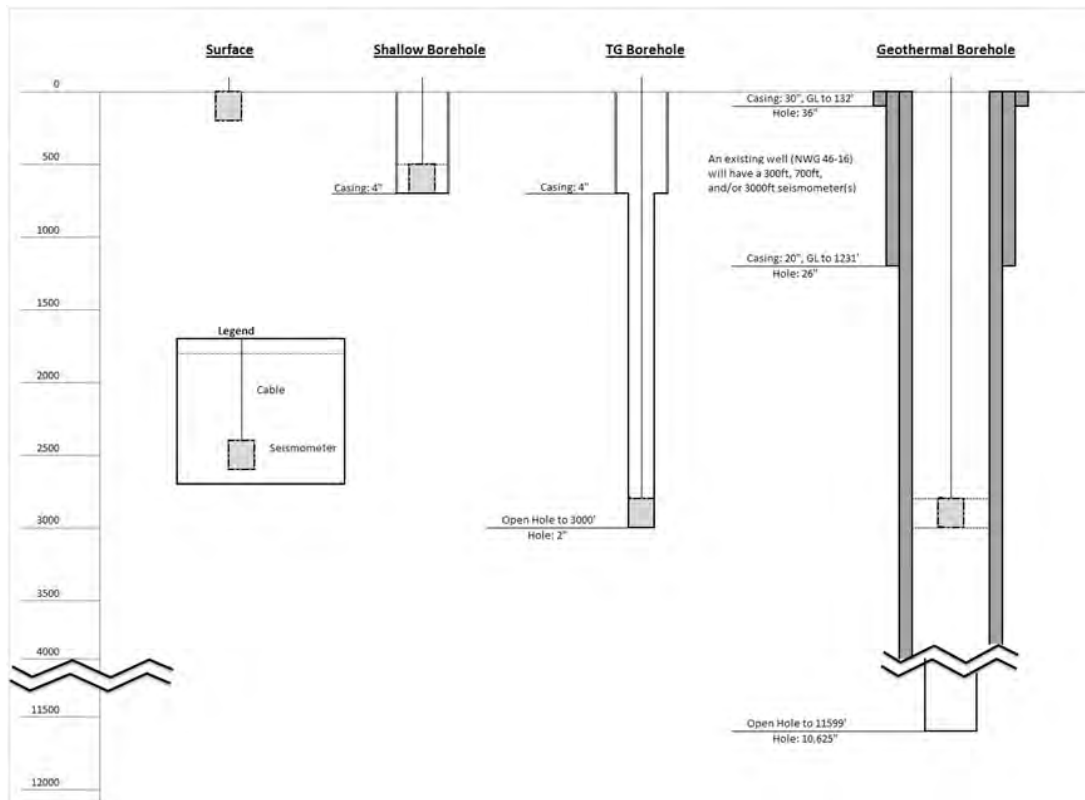


Figure 7 – Schematic diagrams of possible seismometer installations.

Phase II – Reservoir Creation and Characterization

Tasks to be completed in this phase represent the heart of the EGS reservoir development effort, including four principal subtasks: 1) stimulation and testing of the target injection well; 2) drilling, possible stimulation, and testing of the first production well; 3) drilling and possible stimulation of the second production well; and, 4) conducting a circulation test involving the injection well and both production wells. Each major task will be prefaced by a Go/No-Go decision or Stage Gate Review by DOE, and the analysis of seismic, reservoir and financial risk to determine if the next phase of the project is technically feasible and environmentally safe. There is no guarantee that one step will lead to the next; this is a demonstration project to evaluate EGS viability and feasibility.

At the outset of Phase II, the initial MSA installation may be modified to optimize data collection for Phase II operations, including the addition of telemetry to enable real-time, 24/7 continuous monitoring. Real-time data will be publicly available, as described above. If individual monitoring stations are moved or added, a second exercise may be conducted to calibrate this deployment. This final array is expected to allow optimal event detection and evaluation, and will remain in this final configuration until the completion of the activities related to the project. All equipment will be removed upon completion of all activities related to the project.

Install Additional Downhole Seismometers (contingent)

Seismometers may need to be placed downhole, either in existing wells, or in newly drilled boreholes. Up to ten MSA boreholes would be drilled to a depth of up to 700 feet using a truck-mounted rotary drilling rig. The potential MSA borehole sites are shown in Figure 3. All sites are accessible from existing USFS roads; no new roads will be necessary. Site dimensions for the drilling and completion operations are expected to average about 50 feet by 50 feet to accommodate a drill rig and water truck. The steps involved in drilling and completing these MSA boreholes are described below:

1. Prepare sites for drill rig access. All sites are alongside existing roads. The sites are all relatively flat. Only minor grading will be required at each site to accommodate the rig. Some removal of vegetation will be required.
2. Drill 6-1/4-inch outside diameter boreholes to approximately 700 feet using a truck-mounted rotary rig. Surface casing may be necessary to prevent near-surface collapse in poorly consolidated surficial materials. The holes will be cased with 4-inch diameter PVC or steel closed-end casing and cemented from the bottom to the surface. Water for drilling will be trucked in from existing groundwater wells on pads S-16 and S-29. Expected drilling time at each site is 1 to 3 days. Cuttings will be disposed of in accordance with BLM requirements. No pits will be constructed on the pad site. All mud and cuttings will be contained in troughs and disposed of at BLM-approved receiving sites off of USFS land.
3. Install microseismic monitoring equipment downhole and place approximately 3 feet by 3 feet weatherproof housing on surface at the sites. Install adjacent solar panel and 10-40 foot telescoping telemetry poles (and guy wires for the larger poles) for transmittal of data. Solar panels and telemetry poles at some sites could be as much as 300 feet from the seismic station. These poles will be connected to be borehole surface equipment by hard wire. An additional telemetry repeater station (to relay data) may be installed in Section 16, just north of pad S-16, including pole, solar panel and battery. Installation of poles is accomplished with a two- person crew. Depending on the height of the pole, a hole is dug with a shovel to about 2 feet deep, then a posthole digger is used to go another approximately 2 feet (for the taller poles) and the pole is cemented into place. The taller poles require guy wires that are pounded into the ground. If possible, the telemetry equipment can be attached to a nearby tall tree, thereby eliminating the need for the installation of a pole. Installation will take 1 or 2 weeks, followed by calibration and testing for about 2 weeks.
4. Upon completion of activities related to the project, the boreholes will be plugged and abandoned according to BLM/DOGAMI specifications. The MSA equipment, all associated wires, telemetry poles

and cement footings, solar panels and batteries will be removed, and the sites will be restored to simulate pre-existing conditions and blend in with the surrounding environment.

Stimulate and Test Injection Well

The injection well and, if necessary, the production wells, will be stimulated using a process termed **hydroshearing**. The goal of hydroshearing stimulation is to create multiple hydraulic fracture network zones in crystalline rock to create the heat exchange area of an EGS system. Hydroshearing is the process of hydraulically inducing shear failure in subsurface rock formations along existing natural fractures. Hydroshearing requires that stimulation pressure be maintained at levels less than formation breakdown pressure, unlike traditional oil and gas fracturing techniques. Exceeding the formation breakdown pressure can result in tensile failure, which can lead to short-circuiting in hot, dry rock formations. Inducing shear failure offers the greatest potential for creating an EGS reservoir that will provide sufficient surface area and residence time for injected fluids to reach optimum production temperature and maximize reservoir life by minimizing short-circuiting and premature injection fluid breakthrough. To create a network of optimum fracture width, density and overall dimension, hydroshearing stimulation is conducted at multiple levels in the target well. The advantages of multiple stimulations include:

- Creation of a larger reservoir volume, thereby doubling or tripling available heat exchange area.
- Enhancing system permeability and connectivity to allow for higher production rates and lower injection pressures, thereby increasing the economic viability of the project.
- Establishing a single-well production total mass flow rate 75 Kg/s.
- Forming a fracture network ‘half-length’, or radius, of 500 meters.

The objective of stimulation is to create up to three separate and stacked fracture networks. Well stimulation will use (1) rig-off with chemical diverters and/or (2) rig-on with mechanical and chemical diverters. In either case, stimulation will be accomplished by pumping groundwater into the injection well at relatively high pressure (but at a pressure low enough to prevent tensile failure and formation breakdown) to hydroshear the shallowest pre-existing wellbore fractures below the casing shoe. Chemical and mechanical diverters are used to direct the stimulation fluid to specific areas of pre-existing fractures, previously identified by borehole televiwer surveys. Chemical diverters, commonly and safely used in oil and gas operations, are used to temporarily block open fractures, but are later removed by thermal degradation or the addition of other chemical additives. Mechanical diverters are plugs and other tools used to isolate specific sections of the well bore. The Phase I Stimulation Plan will define the approach AltaRock will use, and will be reviewed and approved by BLM and DOE prior to field operations.

Because the existing sump volume is insufficient to contain the water required for the entire stimulation, up to three additional groundwater wells may have to be drilled on the existing pad. Davenport already has one water well on Pad S-29 and one well on Pad S-16. These wells will be pumped simultaneously to continuously supply stimulation pumps.

Microseismicity will be continuously monitored along with surface injection rates and pressures. A fiber optic monitoring system will be deployed in the wellbore to provide real-time distributed temperature information and bottomhole pressure. The orientation and shape of the fractured reservoir created by stimulation, controlled by the in situ stress regime at any given depth, will be determined by interpretation of MSA data. After the well has thermally recovered from stimulation, a three-day, single-well flow test will be conducted to characterize the newly created reservoir through tracer sampling and analysis. All resulting data (e.g., microseismic, hydraulic, fiber optic and flow back test data) will be thoroughly analyzed. The thermo-, hydro-, mechanical-, chemical-model of the reservoir will then be updated.

After the necessary permits are in place and the risk of induced seismicity determined to be acceptable, water will be injected using triplex pumps to shear the shallowest set of pre-existing fractures. The water

will be tagged with thermally reactive and conservative chemical tracers to aid in determination of reservoir surface area, average temperature and fluid travel time. These tracer compounds, used widely throughout the geothermal industry and elsewhere, are not radioactive and are environmentally safe. Microseismicity, water injection rate, and injection pressure will be continuously monitored during stimulation. A fiber optic monitoring system will be deployed in the wellbore to provide real-time distributed temperature information and bottomhole pressure. The orientation and shape of the fractured reservoir created by stimulation is controlled by the in situ stress regime at any given depth. The typical EGS reservoir geometry observed by microseismic mapping of stimulation treatments at other projects sites is an oblate spheroid, or flattened oval, elongated in one direction. Because previous studies have shown that the fracture system will grow in relatively equal proportions in opposite directions from the wellbore, a three-well configuration (one injector, two producers) is ideal to take advantage of the entire fracture network created by stimulation. A one-injector, two-producer system provides the following advantages over a one-producer system:

- Reduced fluid loss due to the use of an extraction well on each side of the created reservoir.
- Cost of injection well drilling and completion is spread over more than one production well.
- Increased production from one major hydraulic treatment; hence, half of the stimulation cost is not wasted.
- Increased power generation by doubling the productive capability of one injector.

Once a fracture geometry with a long axis radius of about 500 meters is achieved, a high-temperature, chemical diverter will be pumped in an attempt to redirect the hydraulic treatment to the next set of natural fractures. The resulting temperature, microseismic and pressure data will be analyzed to determine if the diversion has been successful. If the chemical diverter does not provide sufficient zonal isolation to allow creation of multiple fracture networks, a rig will be mobilized and a mechanical isolation device, such as a scab liner, will be installed in the well to ensure that at least two separate fracture networks are created.

After stimulation is completed, the well will be shut-in to allow for reheating. Thermal expansion of the injected water can result in continued fracture stimulation after pumping is discontinued. If continued fracture growth is indicated by microseismicity, wellhead pressure will be relieved by flowing the well to the atmospheric separator and well pad sump until fracture growth ceases. After sufficient thermal recovery, a single-well flow test will be conducted to allow productivity measurement, wellbore surveys, and tracer and geochemical sampling. Flow test equipment will be installed on the well pad. The flow test configuration will include a flow tee, flow control valve, flow line with temperature and pressure monitoring instruments, a James tube with lip pressure monitoring, atmospheric separator, and weir box routed to the well pad sump. Ancillary equipment will include a geochemical sampling separator and H₂S monitoring equipment. Continuous abatement of H₂S emissions will be applied is measured concentrations and flow rates indicate an emission rate greater than 5 lb/hr. A James tube and weir box assembly will be used to measure total mass flow and enthalpy. Liquid and non-condensable gas samples will be collected for geochemical analysis. A suite of production well surveys will be conducted to identify flow zones, calculate the flow contribution of each fracture zone, and to measure heat flow as the well warms up after injection. After a three-day flow test, the well will be shut-in while the microseismic, hydraulic, fiber optic and flow test data is analyzed. A second borehole televiewer survey of the injection well may be conducted after stimulation and initial testing to visualize the fracture network wellbore interface.

Drill, Stimulate and Test First Production Well

The first production well will be directionally drilled from the existing S-29 (NWG 55-29) well pad to intersect the shallowest fracture network created by stimulation. A detailed drilling program is presented in Appendix A. Once the drilling operation reaches the reservoir rock, a formation injection test will be conducted to determine the upper constraints for a hydroshearing treatment design by defining the

magnitude of the minimum horizontal principal stress. This will identify the tensile failure pressure of a specific formation resulting from high pressure, low volume injection, so that formation breakdown pressure can be avoided during the main stimulation treatments. This stress magnitude is a critical component of volcanic stress regime and can only be identified through formation injection test analysis.

After well drilling reaches the planned depth, a series of wireline surveys including a sonic, gamma ray, density tool, and acoustic borehole televiewer will be conducted. The fracture network connection will be tested by conducting an injection and production well circulation test of sufficient duration to allow relatively stabilized flow, probably 3-7 days. The reservoir and test system will be filled with groundwater, with makeup water supplied by groundwater wells. Circulation testing will include the use of chemical tracers and frequent analysis of fluid chemistry. The fiber optic monitoring system will be deployed in the production well to observe bottomhole temperatures, pressures and flow zone contributions. If the system is found to have too much skin damage or too little transmissivity, a stimulation treatment of the production well will be designed and executed, similar to that discussed above for the injection well. Circulation test data will be evaluated and the numerical reservoir model will then be updated.

Drill, Stimulate and Test Second Production Well

The second production well will also be directionally drilled from the S-29 well pad into the second ‘wing’ of fractures created during stimulation of the injection well. Drilling, logging and possible stimulation of the second production well will be similar to the procedure used for the first production well, described above. A 3-7 day flow test will be conducted, similar to that described above for the first production well.

Long-Term Circulation Test

A 30-60 day circulation test of the injection well and both production wells will be conducted. This test will attempt to establish near-steady state operation of the circulating system with respect to injection and production flow, temperature, pressure and enthalpy, makeup water consumption, and gas and liquid geochemistry. A longer test period is not deemed feasible due to environmental and cost constraints; the large amount of heat that must be emitted or consumed would result in excessive visual impact or energy consumption, respectively. Based on our experience in existing hydrothermal systems, 1-2 months of steady-state operation will provide a data set sufficiently robust to project long-term performance.

The long-term circulation test will collect data on fluid temperature, pressure, flow rate, fluid chemistry, fluid pathways and well connectivity to demonstrate the capability of the EGS reservoir to sustain heat extraction, and allow forward modeling of performance over the theoretical life of a power generation facility. The entire test facility will be contained on the S-29 well pad (Figure 8); no new surface disturbance is anticipated. The test system will not use geothermal energy to produce electricity. Electrical power will be provided by diesel generators. Water will be supplied from the groundwater wells described above.

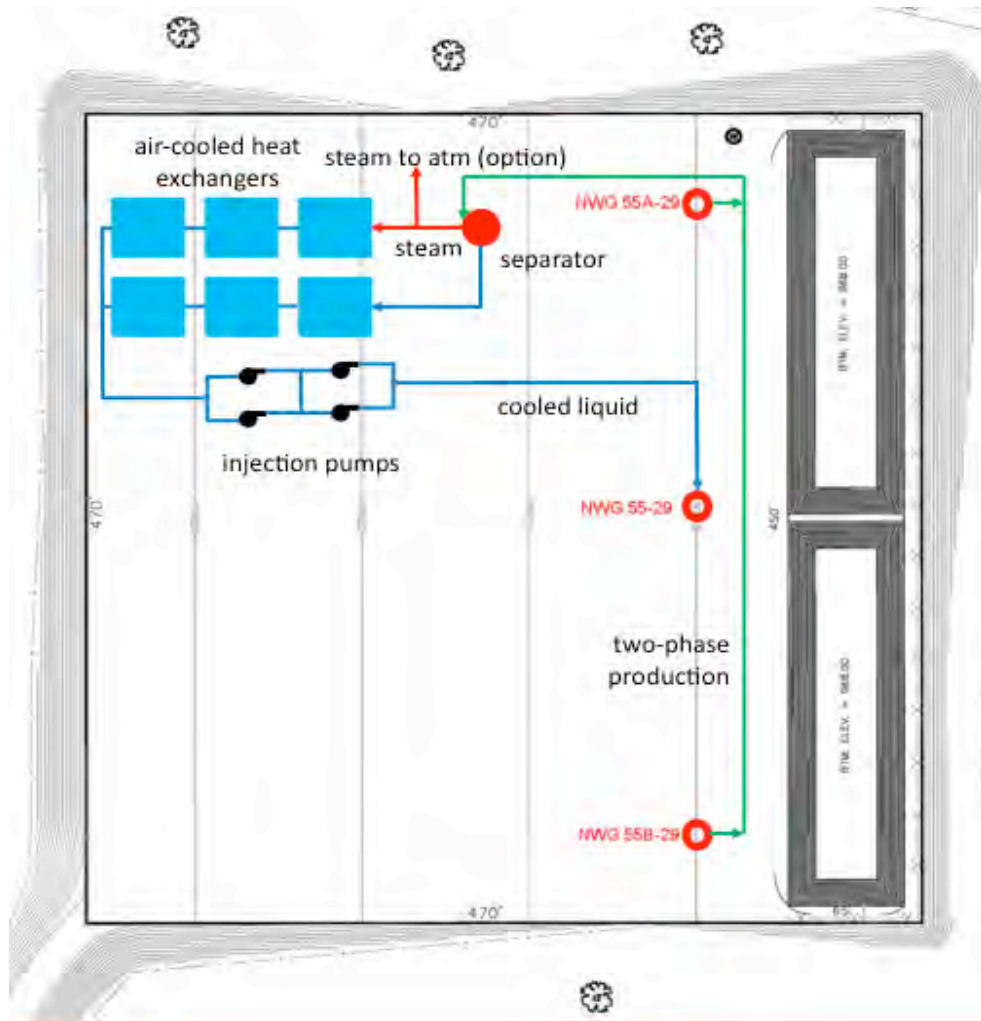


Figure 8 – Circulation Test Facility Conceptual Configuration

The test facility will utilize conventional geothermal fluid processing methods. The facility will be designed by a licensed mechanical engineer with extensive experience in geothermal fluid process, and will be assembled by a licensed mechanical and electrical contractor. The test system will be heavily instrumented to allow continuous, real-time, local and remote monitoring of temperature, pressure, flow, mechanical systems status and other parameters necessary for comprehensive data collection and operational safety. Fluid chemistry will be analyzed daily, at a minimum. The system will be designed for semi-automatic operation, but will be staffed continuously by at least two process control operators.

The two production wells are expected to produce a total of up to 150 Kg/s (1,191,000 lb/hr) of total mass flow, depending on reservoir performance. Production flow will be sustained either by flashing or submersible pump, to a flash separator. The best method for sustaining production flow is highly dependent on the enthalpy of the total flow, which is dependent on several variables related to reservoir performance and well design. The flash separator will separate the steam from the liquid at a likely pressure of 0-100 psig and temperature of 194°-335°F. The flash separator will be a closed, cylindrical code-stamped pressure vessel, approximately 5-15 feet in diameter and 20-40 feet in height (or length if installed horizontally). The use of a closed vessel will allow more accurate steam flow measurement than an open vessel, and will allow more effective H₂S abatement, if required. It may be positioned vertically or horizontally. We estimate that 17.5%-54% of the total production will be produced as steam, with the remainder as residual liquid. The separated steam will be discharged to the atmosphere or condensed in an

air-cooled heat exchanger (Figures 9-10). Discharge to the atmosphere will result in greater visual impact and increased make-up water consumption, while condensing in an air-cooled heat exchanger will result in higher diesel generator noise and exhaust, and significantly higher operating cost. If atmospheric discharge is utilized, H₂S abatement will be applied if prior flow test results indicate potential H₂S emissions greater than 5 lb/hr.

The separated liquid may be routed to an air-cooled heat exchanger. Cooling of the separated liquid (and possibly steam condensate) may be required to allow injection pressure to remain below the pressure that will result in additional fracture growth in the reservoir. Because the system is demonstrating the ability of the EGS reservoir to heat fluid for power generation, the water needs to be injected at sufficiently low temperature to test the thermal efficiency of the engineered reservoir heat exchanger. In addition, the system operates in part through thermal siphon and, therefore, requires a sufficient difference in temperature between the injection and production wells. Cooling of the separated liquid will decrease pump size, but increase air-cooled heat exchanger demand, with both affecting diesel generator use. The residual liquid, and steam condensate if air cooling of the steam is utilized, will be routed to a set of variable-speed injection pumps. Pumps might be arranged in series and/or parallel to provide adequate flexibility in terms of flow rate and injection pressure. Make-up water will be routed from nearby groundwater wells to the injection pumps to replace any liquid lost to the reservoir or atmosphere. This water will be added to the injection pump suction piping. The make-up water will also provide additional cooling of the bulk fluid flow. The pump discharge liquid will be returned to the injection well and recirculated through the EGS reservoir, back to the production wells.



Figure 9 – Cooling fans used in EGS circulation testing at Soultz, France. Shown here prior to installation, these will be positioned over or adjacent to the heat exchangers for operation.



Figure 10 – Process fluid heat exchangers used in conjunction with cooling fans at Soultz, France.

The test system will be designed for safe, quiet, reliable and continuous operation. The equipment will be fully instrumented to provide continuous, real-time data collection and distribution. The system will be sufficiently automated to allow 24/7 supervision and operation by a minimum of two experienced plant operators. The system will be fully self-contained, using no external utilities, including water or electricity. As design progresses, all necessary operating permits will be secured from regulatory agencies. Following construction and startup, the system will be operated until steady-state conditions are achieved, or for up to 60 days. Additional data collection will include well logging surveys, geochemistry, and MSA monitoring. The final design of the test system will be highly dependent on the results of injection well stimulation and production well performance. Therefore, we will continue to refine the test system design as results become available and continue to consult with BLM, USFS and other concerned parties.

Phase III – Long-Term Monitoring and Conceptual Modeling

Long-Term Data Collection and Conceptual Modeling

Phase III tasks include continued monitoring of a successful EGS fracture network subsequent to circulation testing, and the development of a conceptual model for a fully developed wellfield and power plant.

After completion of the Long-Term Circulation Test, the MSA will be monitored to detect continued growth or contraction of the fracture network. Following completion of activities related to the project, the MSA will be removed. Data collection will also include injection and production well monitoring. Long-term data collection results will be incorporated into the final reservoir numerical model to accurately reflect native state, operating, and post-operational reservoir conditions.

A conceptual model of a commercial-scale wellfield and power plant (e.g. 15-50 MW) will be developed using the results of all project data. Injection and production well performance will be used to determine injection well spacing, number of production wells and proximity to injectors, well depth and casing design. Well productivity, including mass flow and enthalpy, will guide the appropriate power cycle (e.g., flash or binary). EGS reservoir and cooling water consumption will guide options for long-term water

supply and demand. The conceptual design set will include detailed process flow diagrams, heat and mass balance calculations, wellfield configuration plans, well bore design, capital and operating cost projections, and theoretical project schedule. These elements may be used to plan and propose future projects—any of which would be subject to environmental review and approval by regulatory agencies.

2. ENVIRONMENTAL CONCERNS

Most Project activities will occur on or below existing well pads, resulting in very little new surface disturbance. The only new surface disturbance will result from the drilling and installation of downhole MSA boreholes at up to 10 locations. These sites are expected to average about 50 ft. x 50 ft per site for a total disturbed area of less than 1 acre.

Induced Seismicity and Seismic Hazards

AltaRock will implement the *Protocol for Induced Seismicity Associated with Geothermal Systems*², which includes the following steps:

- Evaluation of applicable laws and governing regulations
- Establishing a microseismic monitoring network
A microseismic array (MSA) will be designed by a team of highly qualified seismologists and will be installed as part of Phase I operations. A permit has already been secured for installation of this network. The network will surround the target well. Initially, seismometers will only be installed at permitted surface locations and in existing well bores. Data will be downloaded manually and periodically from each site to provide input to the assessment of natural seismic hazards, discussed below. As part of Phase II, and prior to stimulation, the MSA will be modified to include telemetry and real-time data monitoring, and may be modified with the drilling of additional bore holes with seismometers installed in well bores.
- Assessment of natural seismic hazard potential; and
- Assessment of induced seismicity potential
Assessment of natural seismic hazards and induced seismicity potentials will be conducted by an independent consultant approved by the BLM and DOE, with results presented in a report to be completed at the culmination of Phase I, prior to any stimulation activities. Natural seismic hazard potential will be assessed by reviewing the seismic history available from permanent local and regional seismometer installations, from at least two seismic profiles conducted in and around Newberry Volcano (USGS and University of Oregon), and from data collected from monitoring of seismometers installed in Phase I.
- Establish a dialogue with regional authority;
- Educating stakeholders; and
- Interacting with stakeholders
An extensive public relations and outreach program will be conducted, intended to educate and inform authorities and other interested stakeholders, and to respond to stakeholder concerns.
- Implement Procedure for Evaluating Damage
Procedures for responding to reports of induced seismicity and evaluation of property damage will be included in the Phase II Stimulation Plan issued at the conclusion of Phase I.

AltaRock commits to the following safeguards at all EGS Projects:

1. Prior to EGS activities, AltaRock will
 - Install a microseismic array (MSA) around the injection well to monitor EGS growth
 - Install a strong motion sensor (SMS) in the nearest local community to monitor the effect, if any, on the local community

² Majer, E., Baria, R. and Stark, M. (2008). Protocol for induced seismicity associated with enhanced geothermal systems. Report produced in Task D Annex I (9 April 2008), International Energy Agency-Geothermal Implementing Agreement (incorporating comments by: C. Bromley, W. Cumming, A. Jelacic and L. Rybach). Available at: <http://www.iea-gia.org/publications.asp>.

- Study the existing seismic hazards and background seismicity to develop appropriate safeguards for the project.
 - Define appropriate buffers and exclusions zones in order to protect water resources (groundwater and surface).
 - Define appropriate buffers and exclusions zones in order to prevent interaction with faults capable of damaging earthquakes.
 - Communicate plans with local stakeholders and provide educational opportunities for the public.
2. During and after EGS reservoir creation activities (hydroshearing, circulation testing and production), AltaRock will
- Use the MSA to constantly monitor the growth of the EGS zone to prevent growth into buffer and exclusion zones.
 - Provide timely updates to regulators and the public about the locations of induced micro-seismic events and the development of the EGS reservoir with respect to the project goals and limitations.
 - Slow or stop injection in the safest manner possible, if microseismic events reach any buffer zone or if measured ground accelerations at the SMS reach shaking levels capable of damage.

Cultural Resources

Existing Forest Service cultural resource records will be reviewed and, if needed, field surveys will be conducted at site-specific locations where new ground disturbance will occur. Also, if needed, an archaeologist will be present during ground disturbing activities to monitor and identify any findings. The cultural resources in the area tend to be local and limited in size, thus impacts can often be mitigated by simply avoiding known sites or by monitoring in areas where subsurface deposits could occur.

Noxious Weeds/Invasive Species

Project activities have the potential to introduce Noxious Weeds/Invasive Species into the area. In order to mitigate this possibility, drill rigs, tanker trucks, trailers and other heavy equipment will be pressure washed prior to their first entrance into the project area. Additionally, annual weed monitoring visits will be conducted to ensure that weeds do not become established on the drilling sites.

Wildlife Resources

A recent Biological Evaluation in the project area determined that No Endangered, Threatened, Proposed, or Candidate species or Species of Concern occur within the project area.³ There is suitable habitat or potentially suitable habitat in or near the proposed project area for Cooper's hawk, northern goshawk, sharp-shinned hawk, red-tailed hawk, northern flicker, hairy woodpecker, and flammulated owl.

Drilling activities have the potential to disrupt nesting attempts and/or remove nesting, foraging, or fledgling habitat at the well pads and proposed MSA borehole locations. Any disturbance to a known nesting pair within ¼ mile of a drilling location will be mitigated by timing restrictions during the breeding season (March 1- Aug 31 for goshawk).

Water Usage and Water Quality

Water Usage

Stimulation

All Project tasks that will utilize groundwater resources are included in this discussion. To estimate the water usage during the stimulation of NWG 55-29, the EGS project in Soultz, France was used as an analogy. Soultz was the first EGS project to successfully demonstrate hydraulic connection between an

³ Biological Evaluation for Environmental Assessment DOI-BLM-OR-P000-2010-003-EA, February 15, 2010

injection and production well couplet. The stimulation treatments conducted at Soultz on wells GPK-2, GPK3 and GPK4 are summarized in Table 1. A fracture network of just over one kilometer in length, measured along the long axis in a single fracture (estimated from the dimensions of the microseismic cloud), was created during the GPK-2 stimulation treatment. The stimulation lasted 141 hours, and a total of 6.0 million gallons (18.4 acre-ft) of water was pumped at rate of no more than 800 gpm. This volume of water was used in the formation of one fracture zone. A primary goal in this Project is to create three fracture zones. Therefore, for project planning purposes, we estimate that the hydroshearing treatment of NWG 55-29 will require up to 21 days of stimulation treatment to create three separate fracture zones at a pump rate of 420-1260 gpm. With these assumptions, stimulation water consumption is estimated to range from 12.7-38.1 million gallons (39.0-116.9 acre-ft; Table 2). The Soultz project never exceeded 800 gpm during the GPK-2 stimulation, so our assumption of a maximum pump rate of 1260 gpm ensures that enough hydraulic horsepower and water resources are dedicated to the stimulation treatment to accomplish the objective of creating three separate fracture networks with a radius of 500 meters. Another Soultz example is the stimulation of GPK-3, which continued for 10.6 days and created one fracture system 2.25 km in long-axis length (estimated from the microseismic cloud). Total volume pumped during the GPK-3 stimulation was 9,853,610 gallons (30.2 acre-ft). We assume that after stimulation the reservoir is filled, with minimal leak-off or loss of fluid. This assumption is reasonable because previous well completions at Newberry have demonstrated that natural permeability in the Newberry wells is extremely low.

Production Well Drilling

Water use during production well drilling is estimated to be 12.5 acre-ft for each well. This assumption is based on the recent drilling of wells NWG 46-16 and NWG 55-29, which consumed a total of 19.3 acre-ft. We conservatively increase this volume by 25% to a total expected usage of 25 acre-ft to account for the additional directional work, and possibly longer well trajectory, that may be required.

Production Well Connectivity Test

After the drilling of each production well, the connection between the injection and production well will be tested for about 3-7 days. During the connectivity test, it is assumed that the reservoir is already filled and does not need any additional make-up water. Also, it is assumed that the system is not a closed loop. Because the desired production rate is 75 Kg/s, the necessary injection rate would be 75 Kg/s in a completely closed loop. However, loss of up to 10% of injected water to the surrounding formation or undrained areas of the reservoir will consume 8.5 Kg/s. Hence, the maximum injection rate will be 83.5 Kg/s (1,324 gpm).

Water will also evaporate from the atmospheric separator during the test. The fraction of produced fluid that will evaporate is a function of flowing enthalpy, which in turn is a function of production well temperature and permeability. Based on the measured temperature profile in NWG 55-29, we estimate that the production well temperature will range from 350° to 535°F. This will result in about 17.5% to 54% of production fluid being converted to steam and emitted to the atmosphere. Therefore, to maintain a filled reservoir volume the injection well must be continuously supplied at a rate of 30.1 to 57.5 Kg/s. This range of loss is used to calculate flow test water consumption in Table 2. The low estimate reflects a duration of 3 days and a make-up rate of 30.1 kg/s. The high estimate reflects a duration of 7 days and a make-up rate of 57.5 kg/s.

Dual Stimulation

If the connection between the injection well and production well is found to be insufficient, a dual stimulation will be executed. The dual stimulation seeks to reduce pressure barriers between the wells and enhance connectivity to allow for the target production rate of 75 Kg/s per production well. During a dual stimulation, the injection well and the production well in question are stimulated simultaneously for a up

to 5 days at a rate between 420 and 1260 gpm per well. If the pump rate into both wells is 420 gpm for 5 days, approximately 6.0 million gals (18.6 acre-ft) of water will be utilized.

Circulation Test

After both production wells have been drilled, tested and possibly stimulated, a long-term circulation test will be conducted. The test will be conducted until the circulating system is in relative equilibrium, which is estimated to be 30-60 days. During the circulation test, water will be pumped into the injection well and simultaneously produced from both production wells, with the residual water recirculated to the injection well. In a perfectly closed system, the desired production rate of 75 Kg/s per each well would be matched by an injection rate of 150 Kg/s. As discussed above, the circulating loop will have losses in the form of reservoir leak-off (up to 10%) and atmospheric evaporation (assumed to be 17.5%- 54%), so the plan must include make-up water to offset these losses. Hence, the injector will inject at a maximum rate of 167 Kg/s (2,647 gpm) to account for 10% of reservoir leak-off while providing 150 Kg/s for production. Combined evaporative losses from the production wells of 17.5%-54% will total 26-81 Kg/s. The low estimate in Table 2 represents 17.5% evaporative losses for a 30 day test, while the high estimate represents 54% losses for 60 days.

Total Estimated Project Water Use

From the stimulation of the injection well to the conclusion of the circulation test, the Newberry project may use between 66,718,646 gallons (204.8 acre-ft) and 168,224,260 gallons (516.3 acre-ft) gross of groundwater. Net consumption is expected to be much lower since most of the water is absorbed back into the earth.

Well	Duration, hr	Injected Volume, gal	Injected Volume, acre-ft	Max Wellhead Pressure, psi
GPK2	141	5,991,422	18.4	2103
GPK3	255	9,853,617	30.2	2321
GPK4 + GPK3	83 + 95	2,456,800 + 3,249,316	7.5 + 10.0	2466 + 2030

Table 1: Soultz stimulation data for GPK2, GPK3, GPK4 and the dual stimulation on GPK3 and GPK4. Reference: Dorbath et.al., “Seismic response of the fractured and faulted granite of Soultz-sous-Forets (France) to 5 km deep massive water injections.” *Geophysic Journal International* (2009) 177, pp 653-675.

Activity	Maximum Rate (gpm)	Water Volume (gal)	Water Volume (acre-ft)
Single well stimulation ¹	420 - 1260	12,700,800 – 38,102,400	39.0 – 116.9
Rig use during stimulation ²	-	210,000	0.6
Drilling Production Well 1 ³	-	4,073,111	12.5
Drilling Production Well 2 ³	-	4,073,111	12.5
Connectivity test PW1 ⁵	1324	2,061,029 – 9,186,849	6.3 – 28.2
Dual well stimulation PW1 ⁴	420 - 1260	6,048,000 – 18,144,000	18.6 – 55.7
Connectivity test PW2 ⁵	1324	2,061,029 – 9,186,849	6.3 – 28.2
Dual well stimulation PW2 ⁴	420 - 1260	6,048,000 – 18,144,000	18.6 – 55.7
Circulation Test ⁶	2647	29,443,566 – 134,207,880	90.4 – 411.9
Total		66,718,646 – 235,328,200	204.8 – 722.2

Table 2: Estimated water usage for all major activities.

¹This assumes that a pump time of up to 21 days will be required to achieve the desired reservoir size. The injection rate is assumed to be between 420 gpm and 1260 gpm.

²Assumes rig is sitting idle during 21 days of stimulation operations and requires less than 10,000 gpd of water for standby operations.

³Davenport Power used 19.3 acre-ft when drilling wells 55-29 and 46-16. We assume that our usage will be 25% higher because of the necessary directional work. The necessary 25 acre-ft is split between the two producers.

⁴The dual well stimulation assumes pumping simultaneous into two wells for a maximum total time of 5 days.

⁵ The connectivity tests between the injection well and each individual producer have a planned duration of 3 to 7 days. It is assumed that 17.5 to 54% of the flashing fluid will be lost to the atmosphere. Additionally, it is assumed that 10% of the injected volume is not recovered due to leak-off in the reservoir. The numbers above reflect the maximum injection rate of 1324 gpm for a full 7 days over a range of 17.5 to 54% of evaporative steam loss.

⁶ The long-term circulation test is planned to last 30-60 days. It is assumed that 17.5%-54% of the production fluid will be lost to the atmosphere. Additionally, it is assumed that 10% of the injected volume is never recovered due to leak-off in the reservoir. The low end estimate represents 17.5% evaporation for 30 days. The high end estimate represents 54% evaporation for a 60-day test.

Water Quality

Mitigation measures will be implemented to minimize the possible impact of project activities on surface and ground water resources in the area. All drilling wastes will be contained in the drilling sump and any potential runoff from the drill pad will also be directed to the sump. These existing sumps are double lined with HDPE liners and clay. Drilling fluids will be formulated from non-toxic components. All non-thermal groundwater and all lower-temperature (below desired production temperature) geothermal water will be cemented and cased off. This will both protect groundwater resources and prevent degradation of the geothermal production fluid within the well bore.

Vegetation/Timber Resources

The project area lies primarily within lodgepole pine plant associations, with some ponderosa pine trees and white fir also present. Forest stands in the general vicinity have suffered considerable mortality due to mountain pine beetle infestations and tend to be fairly open in appearance. A large portion of the area is second growth timber, which was established following widespread logging in the early and mid 1900's.

Many areas have also been logged and thinned over the past 50 years, and harvest and thinning activities continue to take place.

Most Project activities will occur on existing well pads or below ground inside existing wells, resulting in no new surface disturbance. Any other locations needed will be located alongside existing low standard or spur roads, within existing open areas or where there is minimal existing vegetation, and where no merchantable timber would need to be removed. Sites that have been previously disturbed or used for logging activities, such as landings or skid roads, will be used where possible. Proposed MSA borehole sites would be quite small, no larger than approximately 50 feet by 50 feet in size, and will be discretely located within the existing landscape. Siting requirements for microseismic arrays are relatively flexible and therefore can be located discretely, further limiting need to remove vegetation.

Visual Resources

The Project is located within an area that has had a number of timber sales, thinning, and other timber management projects in the recent past, which have shaped the appearance of the landscape. A combination of natural features plus the past forest management activities (including roads, fire, and logging) dominate the scenery and contribute to the visual interest. Variations such as small openings, either natural or created, are common.

Most operations will occur on existing well pads or below ground, resulting in no new surface disturbance. Where surface disturbance may occur, sites with the least amount of vegetation will be utilized, such as skid trails and landings from past logging operations. No new openings will be created, no large trees will need to be removed, and no permanent structures will be constructed.

The drilling rig mast will be approximately 140 feet in height and may be visible from Paulina Peak (approximately 4 miles from well pad S-29). This will be temporary in nature, as the drilling rig will not be permanently on site.

A steam plume resulting from flow testing the wells may be visible from nearby viewing points, particularly during cooler seasons. This will be temporary in nature, as flow testing is anticipated to be up to approximately 80 days in total.

Placement of equipment, such as that associated with the MSA, will be temporary and small in size. Careful siting and the limited small scale of the activities will allow the operations to be as inconspicuous as possible and subordinate to the landscape. Distance, topography, heights of surrounding trees, and existing landscape variation will also contribute to screening the Project and making the operations not readily seen from roads or viewpoints, either inside or outside of the Monument.

Air Quality and Emissions

The project will have minimal impact on the air quality of the project area. Fugitive dust emissions, diesel exhaust emissions from the drilling rig, and possibly increased hydrogen sulfide concentrations, will have a temporary impact on air quality. Mitigation measures will be implemented to decrease the impact on the surrounding environment. Dust from the road and drill site will be suppressed by watering as necessary. Chemical abatement will be utilized to mitigate the potential affects of any hydrogen sulfide that may be encountered.

Electricity Transmission

No power plant or electrical transmission will occur. All power will be supplied by gas or diesel generators, batteries, or solar panels.

Reclamation

Upon completion of activities related to the project, all sites will be restored to pre-existing conditions and blend in with the surrounding environment. Restoration of the sites will include plugging and

abandoning the wells to BLM and DOGAMI standards, re-grading where necessary, and planting of vegetation as specified by the Forest Service.

Appendix A: Drilling Program

Production Wells NWG 55A-29 and NWG 55B-29

1. WELL TARGET

Two production wells, tentatively designated NWG 55A-29 and NWG 55B-29⁴, will be drilled to intersect an EGS reservoir created around the existing well NWG 55-29. Both wells will be directionally drilled from the NWG 55-29 well pad S-29 (Figure A1). The EGS reservoir is expected to develop in the shape of an oblate spheroid with a radius of about 500 meters (1,640 feet), oriented in a north-south direction, and the vertical extent of the EGS fracture network is expected to range from 6,000-12,000 feet.

2. WELL DESIGN

Because the reservoir dimensions will partially be a function of rock mechanics, which will be more thoroughly characterized prior to stimulation, several possible well profiles are included in the engineering design. The final well design will be determined after careful examination of EGS stimulation results. The casing sizes and depths of the model cases are shown in Table A1 and Figure A2.

Table A1 – Model Well Casing Depth and Sizes

	1	2	3	4	5
Case	Base	Liner	Shallow	Deep	Large
Conductor	50	50	50	50	50
Surface	1,000	1,000	1,000	1,000	1,000
Intermediate 1	4,500	4,500	4,500	4,500	4,500
Intermediate 2 (top)	0	3,700	3,700	3,700	3,700
Intermediate 2 (btm)	7,500	7,500	6,000	7,500	7,500
Open hole diam	8.5	8.5	8.5	8.5	10.625
Total Depth	10,000	10,000	8,000	12,000	10,000

The Base case (1) is completed with 9-5/8” casing cemented from surface to 7,500 feet, and 8-1/2” open hole to TD. The Liner case (2) is identical to the base case with the exception of the 9-5/8” liner hung from 3,700 feet rather than being cemented to surface. This may be necessary to accommodate a conventional geothermal production pump, but this cannot be determined until drilling and initial testing is complete. The Shallow case (3) has the open hole below 6,000 feet, rather than 7,500 feet in the base case, and a shallower TD of 8,000 feet. Conversely, the Deep case (4) allows for deeper fracture formation, with the TD and open hole extending to 12,000 feet. The Large case (5) uses the same depths as the base case, but larger casing diameters to allow sufficient diameter for a conventional line shaft submersible pump. As in the base case, running the 9-5/8” liner to surface is also an option in cases 3-5 if a larger well bore is not desired for pump installation.

All casing strings have been selected to accommodate the temperature, pressure and stresses that might be encountered during stimulation and production, with additional safety margin consistent with standard engineering practice and American Petroleum Institute specifications. While high stimulation pressures are not anticipated, the casing design will be planned to support higher than normal pressures. Final drilling plans, including casing configuration and engineering calculations will be thoroughly reviewed by the Bureau of Land Management as part of the Drilling Permit process for each well.

⁴ The appropriate Kettleman designation will be assigned when the final bottomhole target is identified.

3. DRILLING EQUIPMENT, MATERIALS AND PROCEDURES

Drilling operations will specify a National 110-class drilling rig. Design ratings, and experience in geothermal drilling, has proven the National 110-class rig to be capable of safely drilling to more than 12,000 ft. National 110-class rigs are rated at 1500 HP, usually with two PZ 9 pumps, with mast ratings of 600,000-800,000 lb. Detailed specifications for a drilling rig in this class are presented in Attachment I. The smaller National 80-class rig has insufficient pump horsepower and mast capacity to safely install 5000 feet of 72 lb/ft 13-3/8 casing (i.e. 360,000 lbs plus allowance for over-pull of 100,000 lb). Higher pump flow rate and pressure also enhances the utility of the National 110-class rig.

Conductor Interval (0-50 feet)

A cellar, approximately 8 feet by 8 feet by 4 feet deep, will provide for rainwater runoff to the adjacent sump. A local water well driller will drill to 50 feet, and then run and cement the 36" x 30", 3/8"-wall, welded line pipe conductor. The required cement volume of 108 ft³ will require approximately 5 cubic yards of ready-mix concrete.

Surface Interval (50-1,000 feet)

Enter the hole with a 26" bit and BHA and drill to 1,000 feet. Adjacent well NWG 55-29 encountered severe circulation losses in upper 1,000 feet. Therefore, this interval may be drilled with aerated drilling fluids to overcome losses. Shallow loss zones are often 'pressure balance losses', or losses to fill up a subsurface void, so lowering the effective mud weight should permit drilling ahead. It is important to clear the hole of cuttings to prevent stuck pipe such as was reported in NWG 55-29 in this interval. Foam or viscous slugs will be used to frequently clear the hole. The bottomhole assembly (BHA) will consist of:

- 26" bit
- motor (if necessary)
- 26" full gauge, near-bit stabilizer, 6-pt roller reamer
- 30' x 9" non-magnetic drill collar
- 26" full gauge, string stabilizer, welded blade
- 30' x 9" drill collar
- shock sub
- 4 - 30' x 8" drill collars
- jars

A shock sub will be used to reduce unnecessary bit cutter damage. Jars will be run to mitigate stuck pipe problems. Single shot surveys will be taken every 60 ft (every two joints) to ensure a straight hole, with a vertical deviation of no more than 2°.

Run and cement the 20", 106.5 lb/ft, K55, buttress thread casing. A contract casing crew will be used to run the surface casing string. The casing pressure, assuming 1,000 feet of 9.6 lb/gal drilling fluid, will be 500 psi. The use of 106.5 lb/ft K55 casing, with a collapse rating of 770 psi, provides a safety factor of 1.5, well in excess of the maximum recommended API collapse safety factor of 1.125. The temperature at 1,000 ft is estimated to be 110°F. Cementing will use direct circulation foam.

- Job will be pumped through drill pipe inner string that is stabbed into a float collar at the bottom of the 20 inch casing
- Cement volumes will be calculated to include at least 50% excess material to ensure that the hole is completely filled
- Circulation of foam cement will occur until cement returns are seen at surface
- Un-foamed shoe cement will be pumped in place at end of job

- Accelerated cap cement will be pumped down the annulus at the end of the job to provide high density cement at surface and minimize the chances of cement fall back and the need for a top job
- Cement blends will contain at least 35% silica to prevent strength regression when the wells are put on production
- No retarder in the cement.
- Wait 8 hours after the job for cement to set before resuming operations.
 - Perform top job to accommodate fall back, if needed. Wait at least 4 hours after primary job
 - Use Tremmie pipe to place top job

Drill out the cement, plus 10 feet, by entering the hole with a 17-1/2" bit and slick assembly of six 9" drill collars. Perform a formation injection test to determine the fracture gradient. Determine minimum horizontal stress magnitude by inducing tensile failure of the rock through high pressure, low rate and low volume injection.

Intermediate Interval (1,000-4,500 feet)

Enter the hole with a 17-1/2" bit and BHA and drill to 4,500 feet. The BHA assembly will include:

- 17-1/2" bit
- 17-1/2" full gauge bit, crossover connection
- 17-1/2" 6 pt, roller reamer
- 9" drilling motor, slow speed model
- 1 - 30" non magnetic drill collar
- 1 - 30' x 9" drill collar
- shock sub
- 17-1/2" full gauge stabilizer, welded blade
- 1 - 30' x 9" drill collar
- 17-1/2", 1/8" under-gauge stabilizer, welded blade
- jars
- 5 - 8" drill collars
- 6 - 5" heavy-weight drill pipe
- 5" or 5-1/2" drill pipe (contractors drilling string)

Shock subs, jars and non-magnetic directional collars will be substituted based on the directional survey instruments to be used.

High temperature, polymer based drilling fluids will be used in this interval. The drilling fluids engineer will specify the composition and mud check frequency, and specify operating parameters for treatment in this interval. Temperature will increase significantly in this interval, so careful attention will be paid to changes in the mud properties.

Run and cement the 13-3/8" casing. The 13-3/8" casing pressure, assuming 4,500 feet of 9.6 lb/gal drilling fluid, will be 500 psi. The use of 72 lb/ft HC L80 casing, with a collapse rating of 3470 psi, provides a safety factor of 1.5, well in excess of the maximum recommended API collapse safety factor of 1.125. A contract casing crew will be used to run the intermediate casing string. The casing string will include:

- guide shoe
- 1 jt 13-3/8", 72 lb/ft, HC L80, buttress shoe track
- float collar with stab-in inner liner feature
- remainder 13-3/8" casing (4,500 ft, 72 lb/ft, HC L80, buttress thread)

Note the recorded mud return temperature and blend cement accordingly. The expected static bottomhole temperature at 4,500 ft is expected to be approximately 320°F. Circulation temperature is expected to be below 200°F.

Cement job placement method will be reverse circulation to minimize circulation pressure during placement, aid in minimizing retarder loading in upper hole interval, and reduce cement set time. Allow 8-12 hours for the cement to set before performing a top job, if needed. Use Tremmie tubes to ensure that the top job cement is placed directly on the cement top. Allow 8 hours for the top job cement to set completely. Drill out the cement in the shoe track, plus 20 feet, using the following assembly.

- 12-1/4" bit
- 6 - 8" x 2-3/4" drill collars

Perform a formation injection test to determine the fracture gradient. Determine minimum horizontal stress magnitude by inducing tensile failure of the rock through high pressure, low rate and low volume injection.

Production Casing Interval (4,500-7,500 ft)

Enter the hole with a 12-1/4" bit and BHA and drill to 7,500 feet. The BHA will include:

- 12-1/4" bit
- 6 pt roller reamer
- 15 ft pony sub, 8" x 2-3/4" collar
- 1 - full gauge, welded blade string stabilizer
- 1 - 30 ft, 8" x 2-3/4", non-magnetic drill collar
- 1 - 1/8' under gauge, welded blade stabilizer
- 6 - 30' x 8" x 2-3/4" drill collars
- 3 - 30" x 5" heavy-weight drill pipe
- drill pipe to length

Run and cement the 9-5/8" casing or liner. A contract casing crew will be used to run the production casing string. The casing pressure, assuming 7,500 feet of 9.6 lb/gal drilling fluid, will be 3,744 psi. The use of 53.5 lb/ft L80 casing, with a collapse rating of 6620 psi, provides a safety factor of 1.8, far in excess of the maximum recommended API collapse safety factor of 1.125.

If a liner is run, a liner cement job will be required. If a casing is run, an inner string (stab-in drill pipe) reverse circulation foam cement job will be used to provide cement that has a reduced modulus of elasticity. The foam cement will accommodate thermal variations better than standard cement. It also reduces circulation pressure during placement to reduce risk of lost circulation. Reverse circulation also provides a means of reducing retarder loading in upper stages of the cement, which results in a faster setting time for cement at the surface.

The casing will be installed by a casing service company. The 9-5/8" casing will be stacked as follows:

- guide shoe
- 1 joint 9-5/8" casing
- Float collar with stab in available
- Remainder of the casing string (9-5/8", 53.5 lb/ft, L80, premium thread)
- centralizers

Centralizers will be installed on the first three collars and every three (3) casing collars thereafter, to the vertical portion of the well path, or as needed to provide centralization of the casing to ensure uniform placement of the cement slurry.

Open-Hole Interval (7,500-10,000 ft)

Enter the hole with an 8-1/2” bit and BHA and drill to 10,000 feet or until permeable fractures are intersected. In this drilling interval the directional program will initially determine the BHA. For conventional 8-1/2” drilling, which may occur once the direction is set, the following BHA will be used:

- 8-1/2” Bit
- bit sub
- 6 pt roller reamer, full gauge
- 1- 30 ft, 7”, non-magnetic drill collar
- 1 - full gauge, welded blade string stabilizer
- 1 - 30’ 7” drill collar
- 1- 1/8” under gauge, welded blade stabilizer
- 1 - 30’ 7” drill collar
- 9 - 5” heavyweight drill pipe
- drill pipe to length

It is likely that the directional program will require additional course changes drilling into the fractured volume. Motors are expected to be part of the BHA, as well as either a steering tool or MWD for directional course monitoring.

The drilling fluid condition will be monitored closely and the viscosity reduced in the bottomhole drilling. It is most desirable to drill into the fractured void with near clear water to prevent formation damage from cuttings and any clay carried in the drilling fluids. Aerated drilling fluids can be used to drill into the fractured volumes to mitigate contamination.

No casing or cementing is planned in this interval. This will be an open-hole completion.

4. DIRECTIONAL DRILLING

The production well will be drilled from the same pad as the stimulated injection well. A precise well target will not be known until EGS stimulation of the injection well is complete and the fractured reservoir volume is definitively mapped using microseismic methods. Directional drilling will guide the well bore into the mapped fractures. The essence of the directional program will be to drift away from the pad, and then direct the well course to intersect the fractured volume in the most advantageous angle and direction. For planning purposes, the directional program assumes bottomhole targets north and south of existing well NWG 55-29, 500 meters (1,640 feet) from the casing shoe at 6,462 ft, extending to the total depth of 10,000 ft. The directional programs are displayed graphically for NWG 55A-29 and NWG 55B-29 in Figure A3 and Figure A4, respectively. Directional drilling will be initiated at ±2,500 feet, reaching a build angle of 2°. Bottomhole locations and other pertinent data is listed in the following table.

Well	MD (ft)	Incl (deg)	Azimuth (deg)	TVD (ft)	Vert Section (ft)	North (ft)	East (ft)	Lease Line (ft)	UTM East (m)	UTM North (m)
NWG 55A-29	10000	12	90	9383.45	2287.03	1590	1643.9	60	636142.97	4843375.55
NWG 55B-29	10000	12	90	9383.45	2287.03	-1590	1643.9	150	636142.97	4842296.45

A dogleg severity of less than 3 degrees per 100 feet will be maintained to the extent possible. Directional drilling tools will be in use below this depth and the directional drilling engineer will be consulted on all bottomhole assemblies and configurations. The components of the directional bottomhole assembly will be specified by the directional drilling service consultant on site. High formation temperature can be a problem with downhole directional steering and measurement while drilling (MWD) tools. Formation temperatures are expected to range from 175°F below 2500 feet to 625°F at 10,000 feet, so mud circulation and effective cooling is essential. Aerated drilling fluids will not be used in the directionally drilled intervals, so mud cooling is expected to be effective.

5. WELL LOGS

Directional surveys will be conducted to monitor the trajectory of the wellbore. The hole will be maintained within 2° of vertical to 2,500 feet, and dogleg severity will be limited to less than 3° per 100 feet through the remainder of the well bore.

A lithological log will be maintained from surface to total depth. Mud loggers will record information about the penetrated lithologies and formation fluids by analyzing the returned drill cuttings and the returning fluid. Zones of lost circulation and steam entry will also be recorded on the mud log. The mud log will also record information about circulating fluids, including temperature and concentrations of noncondensable gas. After the well is completed to total depth, a casing integrity log will be run in the cased hole section.

6. BLOWOUT PREVENTION EQUIPMENT

30" Conductor

Prior experience on this pad and nearby wells indicates that there is no artesian flow or sufficient temperature to require a BOP stack while drilling the interval from surface to 1000 feet. A provision to divert flow from the well to the sump will be provided.

20" Surface Casing

A 21-1/4" geothermal stack will be installed on the cemented 20" casing and will be used while drilling from 1,000-4,500 feet (Figure A5). This is a California Division of Oil Gas and Geothermal Resources Type LO well control arrangement. From the casing upward the BOP stack will comprise:

- 20" SOW casing head, welded
- 20" to 21-1/4" DSA
- Drilling cross / spacer spool
- Slab gate valve
- 21-1/4" double gate ram preventer
 - Lower ram is CSO
 - Upper ram set is 5" drill pipe
- Banjo box for aerated drilling fluids
- 21-1/4" annular preventer
- Rotating head, 500 psi

13-3/8" Intermediate Casing to Total Depth

A 13-5/8" geothermal stack will be installed on the cemented 13-3/8" casing and used during drilling from 4,500 feet to TD (Figure A6). This assembly will also be used after running the 9-5/8" casing. The hanger spool and alignment bowl will be needed to centralize the 9-5/8" casing in the wellhead.

- 13-3/8" SOW casing head / welded
- 13-3/8" x 13-5/8" DSA
- 13-5/8" drilling spool / cross / spacer
- full opening slab gate valve (must pass 12-1/4" bit)
- 13-5/8 double gate ram preventer, 5000 psi
 - Lower ram set is CSO
 - Upper ram set is 5" drill pipe
- 13-5/8 annular preventer, 3000 psi
- Williams rotating head, Model 9000

7. OCCURRENCE OF GROUNDWATER

Groundwater in the area of Pad S-29 is encountered in shallow porous basalt from about 325 to 890 feet depth according to water well completion reports. The existing groundwater well on Pad S-29 (Well #93031) has four water bearing zones between 400 and 570 feet. Observations of the depth of water bearing zones is generally in good agreement with the circulation loss zones in geothermal, and do not appear to extend deeper than approximately 1,000 ft. Some lost circulation losses were reported at greater depths but the presence of water was not detected.

8. RESERVOIR TEMPERATURE AND PRESSURE

The well will be drilled from the same pad as the existing well NWG 55-29, so formation temperature and pressure is expected to be similar. Several temperature and pressure surveys have been conducted in NWG 55-29. Formation temperatures range from 175°F below 2,500 feet, to 625°F at 10,000, and as high as 700°F at 12,000 feet. Below about 4,500 feet, the conductive temperature gradient is 5.5°F per 100 feet. Reservoir pressure increases linearly to 3,500 psi at 10,000 feet, and to 4,250 psi at 12,000 feet.

9. ANTICIPATED CIRCULATION LOSSES

Circulation losses are expected to be similar to those measured while drilling NWG 55-29, or in other nearby wells, including NWG 46-16 located 3 kilometers (1.9 mi) to the north-northeast, or the two wells drilled by CalEnergy, located 2-3 kilometers (1.2-1.9 mi) to the northeast. Below the surface interval, permeability has been demonstrated to be extremely low, making this area attractive for EGS development.

Surface Interval (50-1,000 feet)

Extreme to total loss of returns from 135 to 674 ft were reported in NWG 55-29. Stuck pipe and lost circulation problems were time consuming and costly. The top surface casing interval for 55A-29 and 55B-29 will be drilled with 26" tools using aerated drilling fluids to mitigate fluid loss. Well NWG 55-29 was drilled with 17-1/2" and then hole-opened to 26". This opened up the loss problem twice, and proved to be very time consuming and therefore costly. Top-hole loss zones are most often 'pressure balance losses' so that lowering the effective mud weight should permit drilling ahead. It is very important to clear the hole of cuttings. Foam and viscous slugs will be used to clear the hole on a routine scheduled basis. To help minimize mud loss, lost circulation material will be added to drilling fluid. If needed, conventional or foam cement plugs will be used to seal off loss zones.

Intermediate Interval (1,000-4,500 feet)

The intermediate interval in existing well NWG 55-29 had minor circulation losses in the intermediate interval, but much less severe than in the surface interval. Losses included 35 barrels at 4,384 feet and 10 barrels at 4,910 feet. Lost circulation material will be used to retard losses. Should that prove to be inadequate, aerated drilling fluids will be used to reduce fluid density, or cement or foam cement plugs will be emplaced, as necessary.

Production Casing Interval (4,500-7,500 ft)

Circulation losses in NWG 55-29 included 22 barrels at 6,969 feet, 25 barrels at 7,295 feet, and 30 barrels at 7,400 feet. On each of these occasions, the losses were limited in volume and appear to be 'fill the void'-type losses. After the losses, drilling resumed with full returns.

Open-Hole Interval (7,500-10,000 ft)

Circulation losses in NWG 55-29 included 15 barrels at 8,411 feet, 91 barrels at 8,628 feet and 560 barrels at 9,660 feet. As with the previous interval, drilling resumed with full returns after these voids were filled.

10. TESTING PROCEDURES

After drilling is complete, the well will be induced to flow to the surface for a period of approximately three days, or until test parameters reach equilibrium. The flow test is necessary to calculate deliverability and conduct geochemical sampling. The three-day flow test procedure is detailed below, along with the tracer injection and geochemical sampling plans.

1. Conduct safety meeting with all personnel involved at the site. Ensure that all personnel are familiar with the safety supervisor on site, outfitted with appropriate personnel protective equipment, and are aware of safety requirements and escape routes.
2. Rig up flow test equipment. The produced liquid will be recycled to NWG 55-29 using a welded steel line. The steam will vent to atmosphere. Rig up liquid return line to NWG 55-29 injection pump. If necessary, a compressor will be used to compress the liquid column in the well to induce flow. A James tube and weir box assembly will be used to measure total flow and enthalpy.
3. Inspect flow line equipment and valve line-up to ensure all valves are closed.
4. Open wellhead master valve (slab gate). Inspect wellhead equipment for leaks upstream of flow control valve.
5. Slowly open the throttle valve. Inspect flow line equipment for leaks.
6. Allow well flow to stabilize at a low rate.
7. Record James tube lip pressure and weir box liquid level.
8. Calculate total mass flow and enthalpy. Ensure that total flow does not exceed silencer design maximum flow rate.
9. Continue to slowly open throttle valve to maximum well capability or maximum separator design flow rate, whichever is less.
10. Allow well flow to stabilize.
11. On an hourly basis, record all flow test data, including wellhead pressure and temperature, throttle valve position, particulate scrub water rate, flow line pressure and temperature, James tube lip pressure, weir box liquid level, tank levels, pump discharge pressure, makeup water rate, and pump flow rate.
12. Conduct step-rate flow test. Collect data at five separate flow rates for the same time-step (at least two hours at each rate) to build a productivity curve.
13. Collect fluid samples for tracer testing and geochemical analysis three times daily during the flow test. Steam and NCG samples will be collected from the flow line upstream of the silencer. Liquid samples will be collected at the weir box.
14. Shut well-in after test period. Rig down flow test equipment.

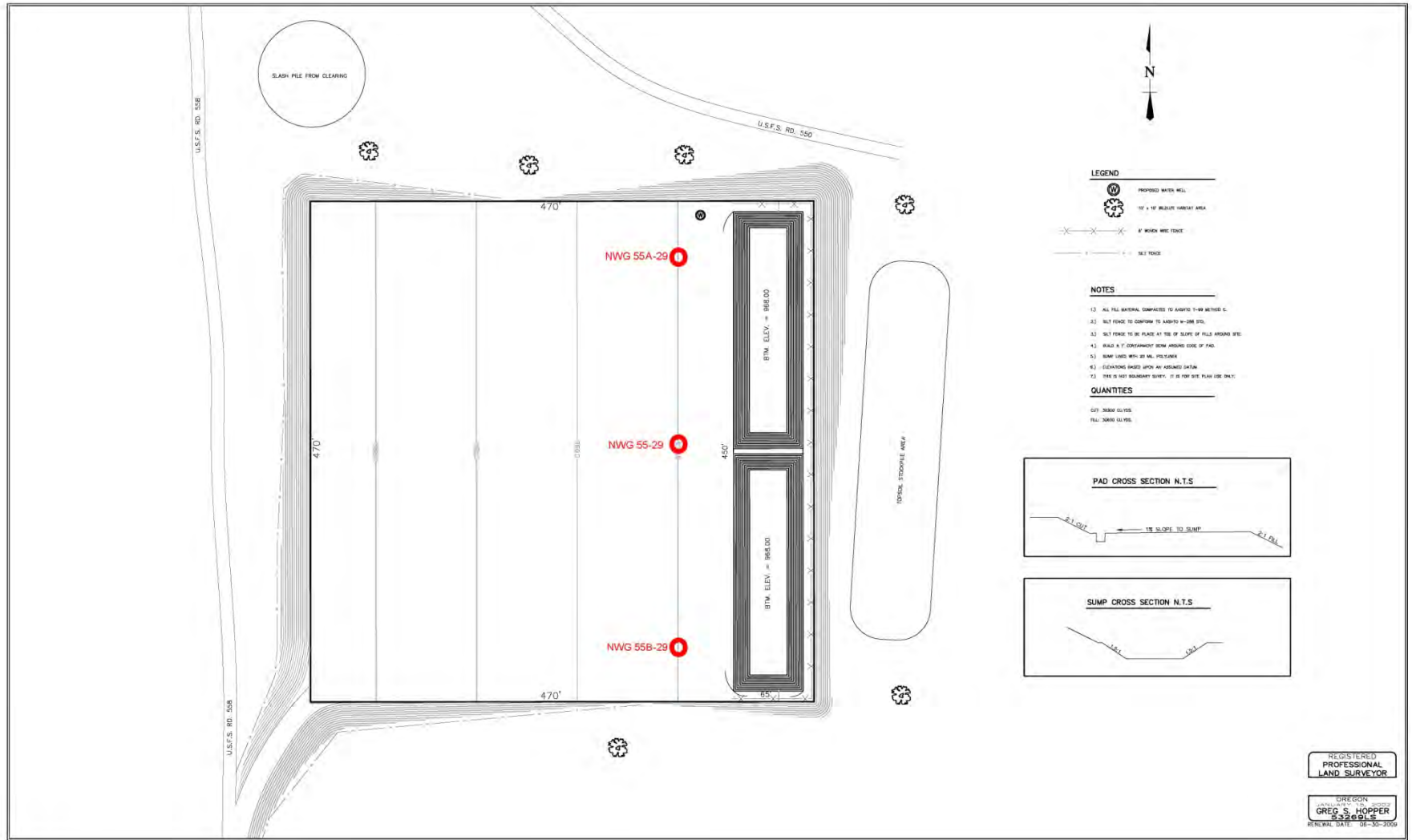


Figure A1 – Well Pad S-29 showing existing well NWG 55-29 and proposed wells NWG 55A-29 and NWG 55B-29

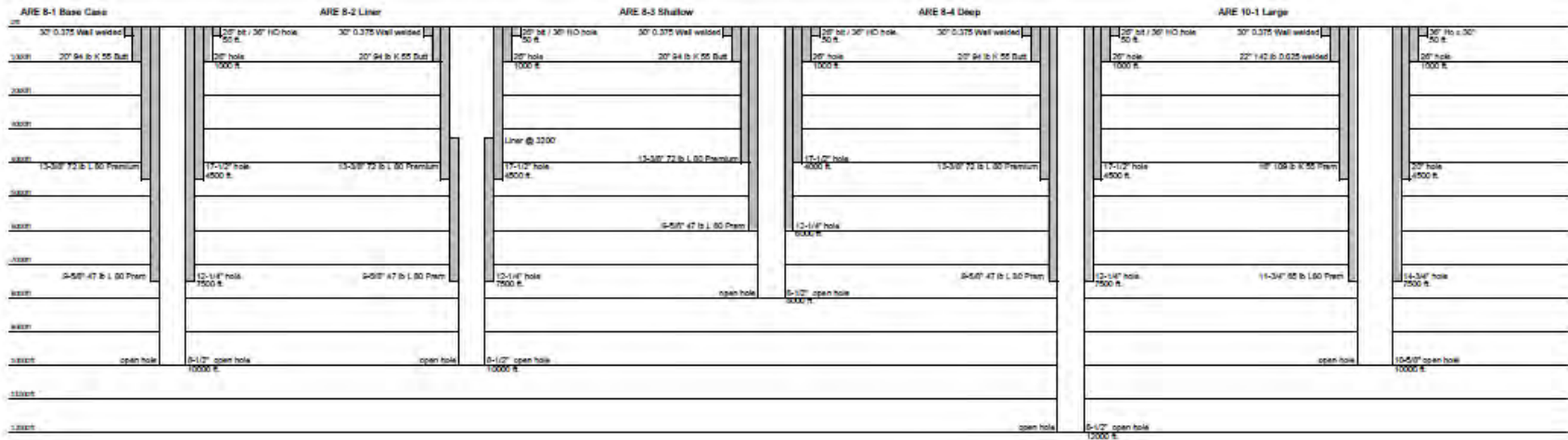


Figure A2 – Production Well Profiles

ALTAROCK ENERGY

Location: OREGON
 Field: Newberry -KGRA
 Facility: SECTION 29 T21S R12E

Slot: NWG 55A-29
 Well: NWG 55A-29
 Wellbore: NWG 55A-29 (A.0)



Rotoreference wellpath is NWG 55A-29 (A.0)	Grid System: NAD83 / UTM Zone 10 North
True vertical depths are referenced to Rig on 55-29 (RT)	North Reference: Grid north
Magn. and dip. are referenced to Rig on 55-29 (RT)	Scale: True distance
Rig on 55-29 (RT) to Mean Sea Level: 5366 feet	Depths are in feet
Mean Sea Level to Mud line (Facility: SECTION 29 T21S R12E): 0 feet	Created by: bondurant on 5/12/2010
Coordinates are in feet referenced to Slot	

Design Comment	MD (ft)	Itc (°)	Az (°)	TVD (ft)	Local N (ft)	Local E (ft)	DLS (1100ft)	VS (ft)
Tie On	0.00	0.000	28.711	0.00	0.00	0.00	0.00	0.00
End of Tangent	2500.00	0.000	28.711	2500.00	0.00	0.00	0.00	0.00
End of Arc (S)	4922.26	46.719	28.711	4922.26	87.66	404.98	2.00	892.43
End of Tangent(S)	4922.26	46.719	28.711	4922.01	87.66	406.59	0.00	917.02
End of 3D Arc (S)	7052.12	12.000	30.000	6500.00	1590.00	1091.00	2.00	1846.46
End of Tangent	10000.00	12.000	30.000	9363.45	1590.00	1649.50	0.00	2287.02

News	Start MD (ft)	End MD (ft)	Interval (ft)	Start TVD (ft)	End TVD (ft)	Start Local N (ft)	End Local N (ft)	Start Local E (ft)	End Local E (ft)	Wellbore
36in Open Hole	0.00	80.00	80.00	0.00	80.00	0.00	0.00	0.00	0.00	NWG 55A-29
30in Conductor	0.00	80.00	80.00	0.00	80.00	0.00	0.00	0.00	0.00	NWG 55A-29
20in Open Hole	80.00	1000.00	920.00	80.00	1000.00	0.00	0.00	0.00	0.00	NWG 55A-29
30in Casing	0.00	1000.00	1000.00	0.00	1000.00	0.00	0.00	0.00	0.00	NWG 55A-29
17.5in Open Hole	1000.00	4500.00	3500.00	1000.00	4500.00	0.00	0.00	0.00	0.00	NWG 55A-29
10.25in Casing	0.00	4500.00	4500.00	0.00	4500.00	0.00	0.00	0.00	0.00	NWG 55A-29
12.25in Open Hole	4500.00	7500.00	3000.00	4500.00	7500.00	898.08	698.71	301.26	1124.12	NWG 55A-29
9.625in Casing	0.00	7500.00	7500.00	0.00	7500.00	0.00	0.00	0.00	0.00	NWG 55A-29
8.5in Open Hole	7500.00	10000.00	2500.00	6988.08	9383.45	1590.00	1124.12	1590.00	1649.50	NWG 55A-29

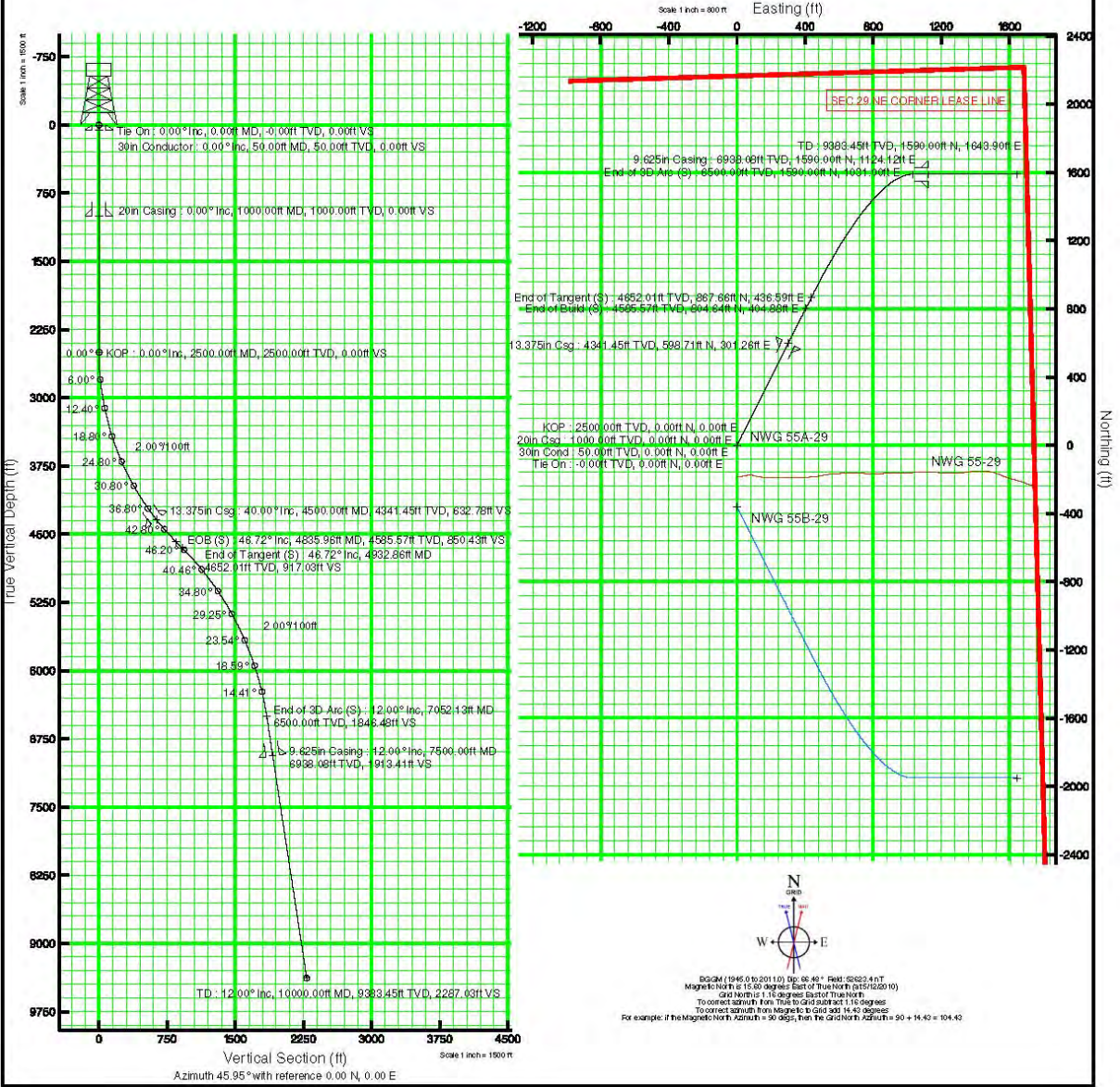


Figure A3 – Well NWG 55A-29 Directional Drilling Plan

ALTAROCK ENERGY

Location: OREGON
 Field: Newberry -KGRA
 Facility: SECTION 29 T21S R12E

Slot: NWG 55B-29
 Well: NWG 55B-29
 Wellbore: NWG 55B-29 (A.0)



Pit reference wellbore: NWG 55B-29 (A.0)		Grid System: NAD83 / UTM Zone 10 North	
True vertical depths are referenced to Rig (RT)		North Reference: Grid North	
Measured depths are referenced to Rig (RT)		Scale: True distance	
Rig (RT) to Mean Sea Level: 50.42 feet		Depths are in feet	
Mean Sea Level to Mud line (Facility: SECTION 29 T21S R12E): 0 feet		Created by: bondiani on 5/12/2010	
Coordinates are in feet referenced to Slot			

Design Comment	MD (ft)	Inch / 1	Az (°)	TVD (ft)	Local N (ft)	Local E (ft)	DLS (ft/100ft)	VS (ft)
Tie On	0.00	0.000	183.289	0.00	0.00	0.00	0.00	0.00
End of Tangent	2500.00	0.000	183.289	2500.00	0.00	0.00	0.00	0.00
End of Build (S)	4585.57	46.719	183.289	4585.57	404.84	414.86	2.00	861.46
End of Tangent (S)	4652.26	46.719	183.289	4652.01	407.68	416.90	0.00	917.00
End of 3D Arc (S)	7052.13	12.000	90.000	1590.000	-1590.000	1031.00	2.00	1546.46
End of Tangent	10000.00	12.000	90.000	9382.46	-1590.000	1640.30	0.00	2287.02

Name	Start MD (ft)	End MD (ft)	Interval (ft)	Start TVD (ft)	End TVD (ft)	Start Local N (ft)	Start Local E (ft)	End Local N (ft)	End Local E (ft)	Wellbore
26in Open Hole	0.00	50.00	50.00	0.00	50.00	0.00	0.00	0.00	0.00	NWG 55B-29
30in Conductor	50.00	50.00	0.00	50.00	50.00	0.00	0.00	0.00	0.00	NWG 55B-29
26in Open Hole	50.00	1000.00	950.00	50.00	1000.00	0.00	0.00	0.00	0.00	NWG 55B-29
20in Casing	0.00	1000.00	1000.00	0.00	1000.00	0.00	0.00	0.00	0.00	NWG 55B-29
17.5in Open Hole	1000.00	4500.00	3500.00	1000.00	4500.00	4041.45	0.00	-596.71	301.26	NWG 55B-29
13.375in Casing	0.00	4500.00	4500.00	0.00	4500.00	4041.45	0.00	-596.71	301.26	NWG 55B-29
12.25in Open Hole	4500.00	7500.00	3000.00	4041.45	4308.08	-596.71	301.26	-1590.00	1124.12	NWG 55B-29
9.625in Casing	0.00	7500.00	7500.00	0.00	4308.08	0.00	0.00	-1590.00	1124.12	NWG 55B-29
8.5in Open Hole	7500.00	10000.00	2500.00	4308.08	3085.45	-1590.00	1124.12	-1590.00	1640.30	NWG 55B-29

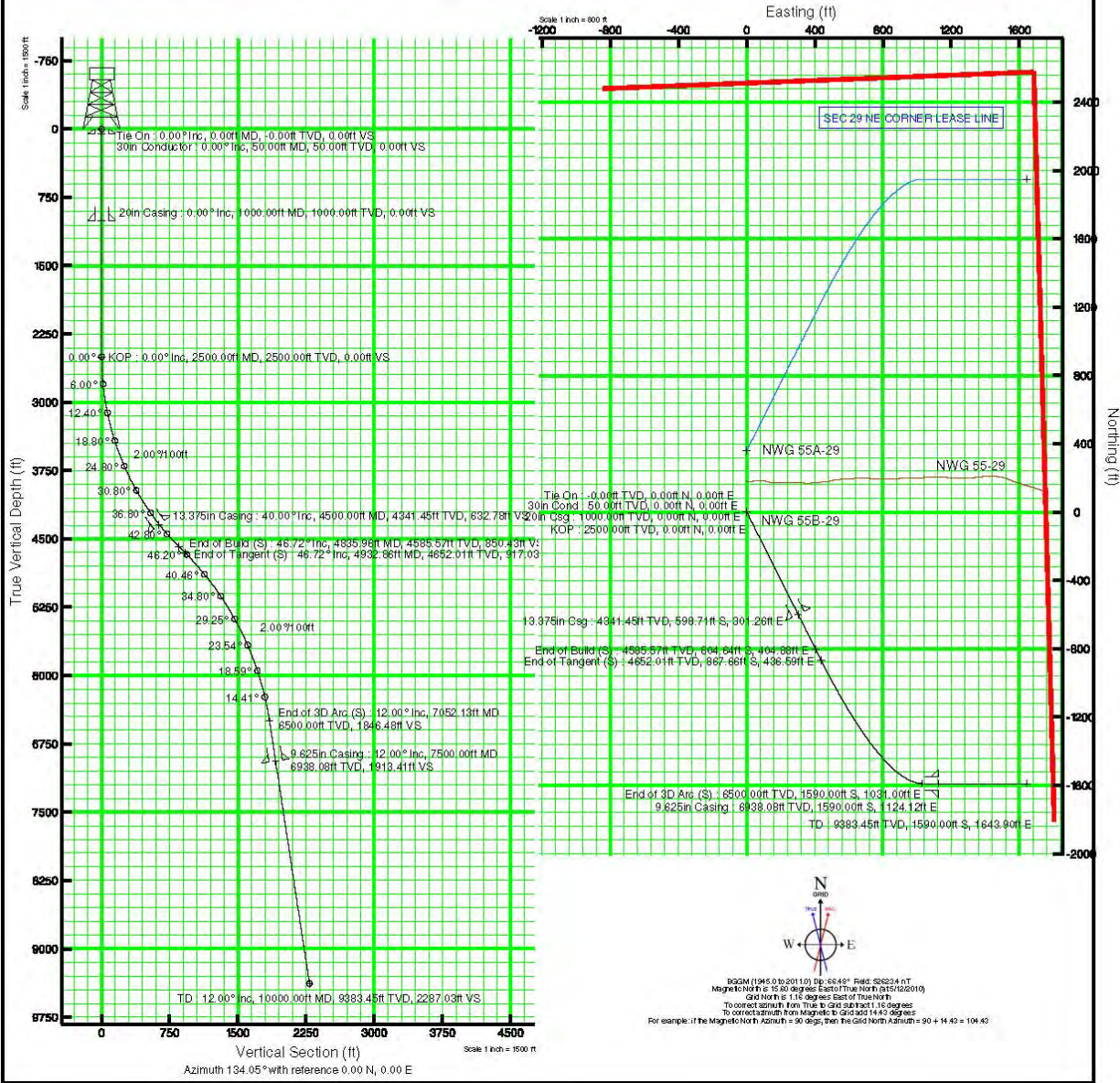


Figure A4 – Well NWG 55B-29 Directional Drilling Plan

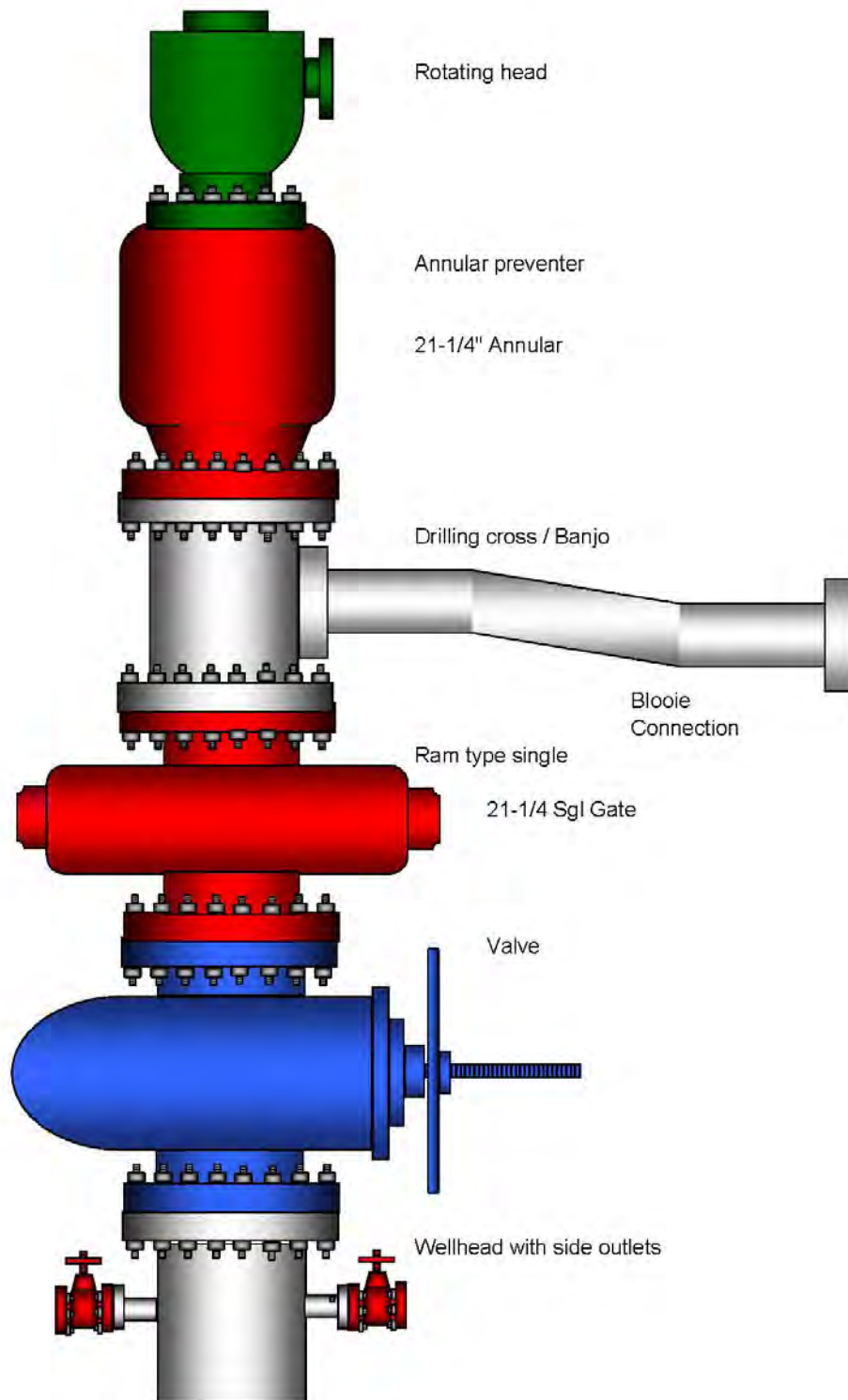


Figure A5 – 21-1/4" BOP Stack

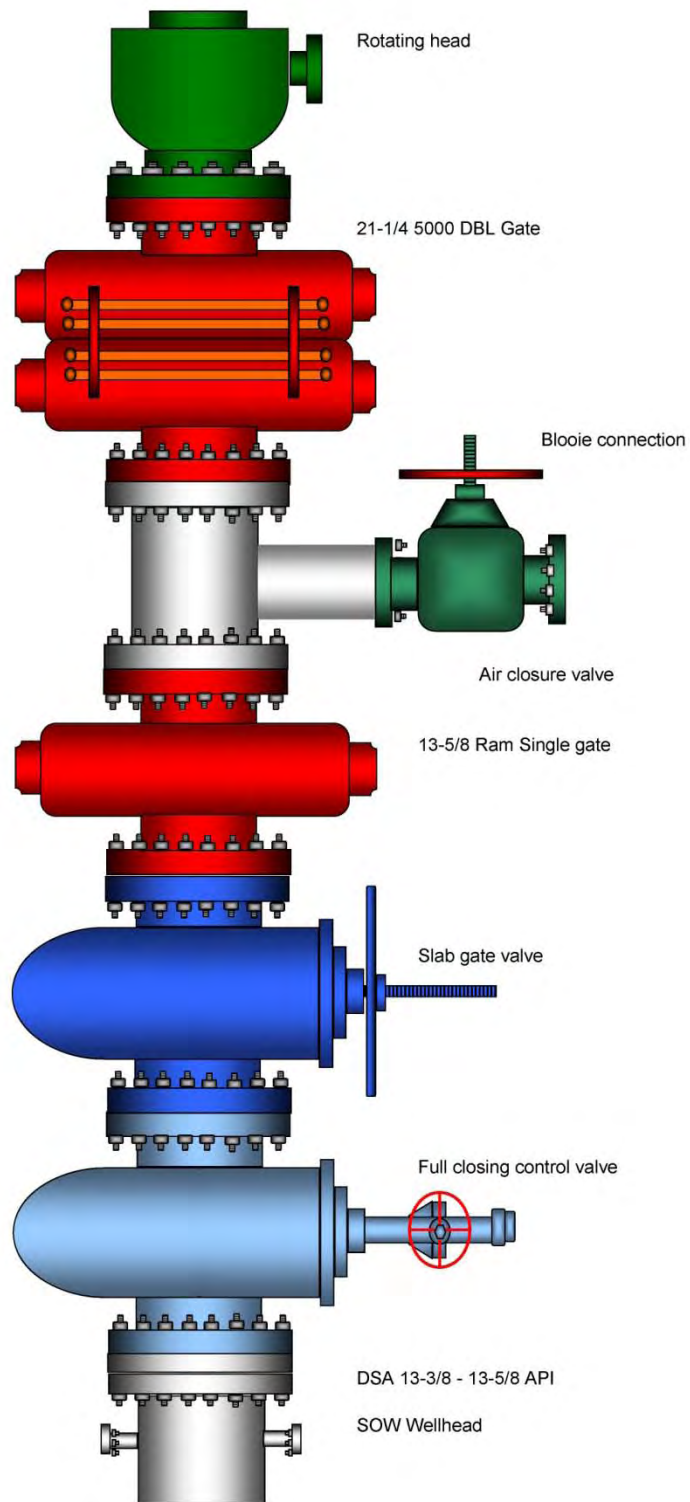


Figure A6 – 13-5/8” BOP Stack

Attachment I



International Energy Services



RIG # 28 **NATIONAL 110UE SCR**



GENERAL PARTICULARS

Depth rating: 16,400 ft
 Horsepower: 1,500 HP
 Max. Hookload: 670,000 lbs
 Year of construction/total refurbishment: Refurbished 1996.
 Total no. of loads: 65 loads

DRAWWORKS

Type: National
 110-UE
 HP rating: 1,500 HP
 Drilling line: 1 3/8" EIPS
 Auxiliary brake: Baylor 6032 Electric
 Drive Type: GE-752 (x2)
 HP Rating: 750 HP (x2)

MAST Lee C Moore
 Type: 930 Cantilever
 Height: 136 ft
 G.N.C.: 800,000 lbs
 Max. hookload: 670,000 lbs w 12 lines

TOP DRIVE Tesco
 Type: 500 HS hydraulic
 Rating: 750 HP
 Torque: 39,000 ft lbs

POWER GENERATION
 Gen type: Cat SR-4 (x4)
 Gen rating: 1,400 HP (x4)
 Engine type: Cat D-399 (x4)
 HP rating: 1,250 HP (x4)

SCR Ross Hill
 Type: 1400 SCR

BOP'S
 Annular: Hydril, 21 1/4" MSP, 2,000 psi.
 BOP's: Cameron 21 1/4" type U, double gate, 2,000 psi
 Annular: Shaffer, 13 5/8", 3,000 psi
 BOP's: Cameron, 13 5/8" type U, double + single, 3,000 psi.

SUBSTRUCTURE Lee C Moore
 Type: Box on box
 Height: 26 ft
 Casing load: 550,000 lbs
 Setback load: 450,000 lbs
 Skidding system: Hydraulic

ROTARY TABLE National
 Type: C-375
 Table opening: 37 1/2"

MUD PUMPS Oilwell
 Type: A -1400 PT (x2)
 HP rating: 1,400 HP (x2)

MUD SYSTEM
 Active system capacity: 1,670 bbls
 Reserve system capacity: 370 bbls
 Shale shakers: DFE SCR1 (x3)
 Pressure rating: 5,000 psi

SPECIAL FEATURES Rig skidding system
 50 man, fully acclimatised camp.