EVALUATION OF WATER USAGE

FOR THE
NEWBERRY EGS DEMONSTRATION

Public Version

February 9, 2011

Submitted by:

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Water Usage

VARIABLES AFFECTING NEEDED WATER VOLUMES

1. Size of EGS reservoir and volume of fracture network – desired long-axis radius of 500m.
2. Enthalpy – the enthalpy of the produced water will dictate steam fraction at the surface. There are many unknowns at this time about the enthalpy of the system including, but not limited to:
    a. Mass-weighted average temperature at injection and production depths – the average temperature that can be expected in the production wells during circulation
    b. Residence time – the time that water takes to travel between the injector and the production well is a function of permeability and tortuosity in the created fracture network. Longer residence times lead to hotter water since the water has more contact time with the hot rock matrix.
    c. Surface area of the reservoir – the area of rock that is contacted by water as it travels between the injector and the producers. The more surface area that is encountered, the hotter the water.
3. Leak-off – Leak –off is a term used to describe how much fluid is lost, in our case from the generated EGS reservoir, to the surrounding host rock. A completely closed system with 0% leak-off is most likely not possible. Other EGS projects worldwide have experienced a wide range of leak-off from 0 to 25%. The Soultz project, along with the Cooper Basin EGS project, do not have to add make-up water to their systems, because it was discovered that deep aquifers are actually contributing to those systems (opposite of leak-off); hence, these systems have 0% leak-off. The hot-dry rock project at Fenton Hill experienced between 5% and 10% leakoff, while the Rosemanowes and Hijiori projects estimated 25% leak-off in their systems. Leak-off is completely dependent on local geology since the dominating variable is in-situ permeability. The 2006 MIT report on EGS utilized a 2% leak-off when calculating the economics of various potential EGS sites (Reference: "*The Future of Geothermal Energy:Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century*," 2006, Massuchusetts Institute of Technology http://geothermal.inel.gov/). We currently do not have enough information about the Newberry rocks at depth to calculate a leak-off coefficient, but the natural injectivity for well 55-29 (and other deep Newberry wells) has been observed to be between 0.03 and 0.05 gpm/psi. Hence, the permeability of the in-situ rocks at depth is extremely low. Therefore, expected leak-off at Newberry should be less than 2%, the percentage utilized by the MIT panel.
4. Test duration – the duration of the connectivity tests between each producer and the injector, as well as the long-term circulation test is undetermined at this time. The single well flow-back test is scheduled to last up to 3 days. The connectivity tests between each producer and the injector will be up to 7 days in duration. We are currently estimating that the long-term circulation test between both producers and the injector will last up to 60 days.

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SOURCES and SINKS

- Sources: Groundwater wells on the Davenport Newberry lease
    - Pad 29 water well is capable of producing 715 gpm for 7 days before the well has to be shut-in for aquifer recovery.
    - Pad 16 water well has not been tested as of yet, but drawdown testing is planned for Spring 2011. A new pump was purchased for this well, and the well is expected to be capable of producing at least 900 gpm.
    - The Ormat water well in section 21 is available to AltaRock if additional water is necessary. No pump is currently installed in this well, but it tested at 200 gpm when it was originally drilled.
- Sinks:
    - Evaporative losses during circulation and connectivity testing - The evaporative losses are a function of producing fluid enthalpy and the estimate ranges from 16.3 to 37.6% steam fraction based on producing temperatures between 350°F and 535°F. Additionally, some of the water will evaporate from the sump during drilling. The mud return temperatures during the drilling of 55-29 reached 170°F near total depth, so it is estimated that up to 50% of the water volume used during drilling may be lost to evaporation over time.
    - Reservoir fill-up during stimulations - The goal of the Newberry 55-29 stimulations is to create three fracture networks within the open-hole interval from 6,462' to 10,060' MD, each approximately 1km in diameter along the long-axis. At Soultz, the GPK2 stimulation created one fracture network of 1 km in long-axis length (estimated from the microseismic cloud) with an injected volume of 5,991,422 gallons (an average rate of 800 gpm was pumped over 5.9 days). Our goal is to create a reservoir three times this size. So, to 'fill-up' the newly created EGS reservoir, we will require approximately 18 million gallons of water, based on the Soultz model. The water that is circulated during drilling might also end up being injected into the reservoir during stimulation. It is estimated that about 14.5% of the drilling mud volumes will be re-injected and used for reservoir fill-up.
    - System leak-off – A loss of water to the in-situ rock permeability is estimated to be 2%. Additionally, it is estimated that up to 35% of the drilling mud volume used to drill the production wells could be lost to underpressured zones through lost circulation during the drilling operation. These drilling losses are a form of leak-off.

TIMELINE OF WATER USAGE

1. Stimulation of 55-29 (Year 2011)

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 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

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length, measured along the long axis (estimated from the dimensions of the microseismic cloud), was created during the GPK-2 stimulation treament. The stimulation lasted 141 hours, and a total of 5,991,422 gallons (18.4 acre-ft) of water was pumped at a maximum rate of 800 gpm. 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 networks at a injection rate of 800 gpm. The Soultz project never exceeded 800 gpm during the GPK-2 stimulation, so our assumption of a maximum rate of 800 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 long axis radius of 500 meters.

We desire a long-axis radius of 500m to ensure adequate spacing between the injector and the production wells, but the reservoir will not be allowed to grow vertically shallower than 6,000'. Not only would fractures shallower than 6,000' encounter rocks that are just too cold (<400°F) to economically justify the cost of an EGS project, halting fractures from growing any higher than 6,000' provides a considerably thick impermeable buffer between the top of the EGS reservoir and the bottom of the groundwater aquifer.

We assume that after stimulation the reservoir is filled, with less than 2% leak-off or loss of fluid to natural matrix permeability. This assumption is reasonable because previous well completions at Newberry have demonstrated that natural permeability in the Newberry wells is extremely low.

2. Single-Well Flow Test

After stimulation is completed, the well will be shut-in to allow for reheating. The well will be equipped with flow test equipment prior to stimulation. After sufficient thermal recovery, a single-well flow test (also referred to as a flow-back test) will be conducted to allow productivity measurement, wellbore surveys, and tracer and geochemical sampling. 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 H_2S monitoring equipment. 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. Water will evaporate from the atmospheric well 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 productivity. Based on the measured static 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 16.3% to 37.6% of production fluid (388 to 894 gpm) being converted to steam and emitted to the atmosphere. The remaining liquid water will flow into the sump and be stored for use during production well drilling. No make-up water will be required during the flow back testing. Since no additional groundwater is required for this task, no additional water is attributed to this task in the tables and figures below.

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3. Production Well Drilling (Year 2011 and 2012)

Water use during production well drilling is estimated to be 9.7 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 19.4 acre-ft (9.7 acft/well; 6,304,300 gallons total for drilling and dust suppression on the lease roads). It is estimated that 600,000 gallons of that total were used for dust suppression and 5,704,300 gallons were actually used in drilling operations. The drilling mud volume, comprised of groundwater and additives, is split between three sinks. Slightly more than one-third (34.5%) of the mud volume is lost to rock formations through lost circulation zones. Approximately 14.5% of the mud volume is used for reservoir fill-up (it is stored in the sumps and pumped into the wells during stimulation and circulation). The remaining 50% is lost to evaporation. These estimates are provided by Boart Longyear, a contractor involved in the drilling of wells 55-29 and 46-16 at Newberry, and through careful examination of the mud logs from both wells.

4. Production Well Flow Tests (Years 2011 and 2012)

After the drilling of each production well, the connection between the injection and production well will be tested for for up to 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 (1189 gpm), the necessary injection rate would be 75 Kg/s in a completely closed loop. Because the system is assumed to be somewhat open, we estimate a loss of up to 2%, which equates to 1.5 Kg/s (23.8 gpm), to natural rock matrix and fracture permeability that is unconnected to the circulating system. Hence, the maximum injection rate will be 76.5 Kg/s (1,213 gpm).

Water will evaporate from the atmospheric separator during the connectivity tests. The fraction of produced fluid that will evaporate is a function of atmospheric pressure and flowing enthalpy, which in turn is a function of production well temperature and productivity. 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 16.3% to 37.6% 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 12.5 to 28.7 Kg/s. A minimum estimated rate, 12.5 Kg/s (198 gpm), and a duration of 3 days is assumed in Table 2 calculations. The maximum estimated rate of 28.7 Kg/s (455 gpm) and test duration of 7 days is assumed in Table 3 calculations.

5. Dual Stimulation (Years 2011 and 2012)

If the connection between the injection well and production well is found to be insufficient, a dual stimulation will be executed. 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 of 800 gpm into both wells (based on GPK2 stimulation results). The dual stimulation seeks to overcome any pressure barriers between the wells and enhance connectivity to allow for the desired production rate of 75 Kg/s per producer.

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6. Circulation Test (Year 2012)

After both producers have been drilled, tested and possibly stimulated, the 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 (assumed to be 2%) and atmospheric evaporation (assumed to be 16.3 – 37.6%), so the plan must include make-up water to offset these losses. Hence, the injector will inject at a maximum rate of 153 Kg/s (2,425 gpm) to account for 2% of reservoir leak-off while providing 150 Kg/s for production. Combined evaporative losses from the production wells of 16.3-37.6% will total 24.9-57.5 Kg/s. In Table 3, the circulation test duration is assumed to be 60 days and the evaporative losses are assumed to be 37.6%. These values represent the maximum water usage during circulation testing.

TOTAL ESTIMATED WATER USAGE

From the stimulation of the injection well to the conclusion of the circulation test, the Newberry project may use between 72,530,542 gallons (223 acre-ft) to 141,695,492 gallons (435 acre-ft) gross of groundwater over a period of two years.

Table 1: Soultz stimulation data for GPK2, GPK3, GPK4 and the dual stimulation on GPK3 and GPK4.

Well	Duration, *days*	Injected Volume, *gal*	Injected Volume, *acre-ft*	Max Wellhead Pressure, *psi*
GPK2	5.9	5,991,422	18.4	2103
GPK3	10.6	9,853,617	30.2	2321
GPK4 + GPK3	3.5 + 3.9	2,456,800 + 3,249,316	7.5 + 10.0	2466 + 2030

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.

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Table 2: Minimum water use estimates for all major activities in the Newberry EGS Demonstration

Activity	Estimated Water Usage Rate, *gpm*	Minimum Water Volume, *gal*	Minimum Water Volume, *acre-ft*	Duration, *days*
Single well stimulation[1]	800	24,192,000	74.2	21
Rig use during stimulation[2]	-	210,000	0.6	21
Drilling producer #1[3]		3,152,150	9.7	90
Drilling producer #2[3]		3,152,150	9.7	90
Connectivity test PW1[5]	198	853,829	2.6	3
Dual well stimulation PW1[4]	1600 (split between 2 wells)	11,520,000	35.4	5
Connectivity test PW2[5]	198	853,829	2.6	3
Dual well stimulation PW2 [4]	1600 (split between 2 wells)	11,520,000	35.4	5
Circulation Test[6]	395	17,076,583	52.4	30
Total		**72,530,542**	**223**	

[1]Assumes Soultz GPK2 stimulation volumes and multiplies it by three to achieve our desired network size.
[2]Assumes rig is sitting idle during 21 days of stimulation operations and requires less than 10,000 gpd of water for standby operations.
[3]Davenport Power used 19.4 acre-ft when drilling both well 55-29 and 46-16. We assume that our usage will be similar. The necessary 19.4 acre-ft is split between the two producers.
[4]The dual well stimulation assumes pumping simultaneously at 800 gpm into two wells for a maximum total time of 5 days.
[5]The connectivity tests between the injection well and each individual producer are planned for a duration between 3 and 7 days. It is assumed that 16.3 to 37.6% of the flashing fluid will be lost to the atmosphere. Additionally, it is assumed that 2% of the injected volume is never recovered due to leak-off in the reservoir. The numbers above reflect a water usage rate of 198 gpm for 3 days with 16.3% of evaporative steam loss.
[6]The long-term circulation test is planned to last 30-60 days. It is assumed that 16.3%-37.6% of the production fluid will be lost to the atmosphere. Additionally, it is assumed that 2% of the injected volume is never recovered due to leak-off in the reservoir. The low estimate is listed above and it represents 16.3% evaporation for a 30 day test.

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Table 3: Maximum water use estimate for all major activities in the Newberry EGS Demonstration

Activity	Estimated Water Usage Rate, *gpm*	Maximum Water Volume, *gal*	Maximum Water Volume, *acre-ft*	Duration, *days*
Single well stimulation[1]	800	24,192,000	74.2	21
Rig use during stimulation[2]	-	210,000	0.6	21
Drilling producer #1[3]		3,152,150	9.7	90
Drilling producer #2[3]		3,152,150	9.7	90
Connectivity test PW1[5]	455	4,583,439	14.1	7
Dual well stimulation PW1[4]	1600 (split between 2 wells)	11,520,000	35.4	5
Connectivity test PW2[5]	455	4,583,439	14.1	7
Dual well stimulation PW2 [4]	1600 (split between 2 wells)	11,520,000	35.4	5
Circulation Test[6]	912	78,782,765	241.8	60
Total		**141,695,942**	**435**	

[1]This uses Soultz GPK2 stimulation volumes and multiplies it by three to achieve our desired network size.
[2]Assumes rig is sitting idle during 21 days of stimulation operations and requires less than 10,000 gpd of water for standby operations.
[3]Davenport Power used 19.4 acre-ft when drilling both well 55-29 and 46-16. We assume that our usage will be similar.
[4]The dual well stimulation assumes pumping simultaneously at 800 gpm into two wells for a maximum total time of 5 days.
[5] The connectivity tests between the injection well and each individual producer are planned for a duration between 3 and 7 days. It is assumed that 16.3 to 37.6% of the flashing fluid will be lost to the atmosphere. Additionally, it is assumed that 2% of the injected volume is never recovered due to leak-off in the reservoir. The numbers above reflect a water usage rate of 455 gpm for a full 7 days with 37.6% of evaporative steam loss.
[6] The long-term circulation test is planned to last 30-60 days. It is assumed that 16.3%-37.6% of the production fluid will be lost to the atmosphere. Additionally, it is assumed that 2% of the injected volume is never recovered due to leak-off in the reservoir. The high end estimate is listed above and it represents 37.6% evaporation for a 60 day test.

ESTIMATED PROJECT WATER USE BY YEAR

From the stimulation of the injection well to the conclusion of the circulation test, the Newberry EGS Demonstration may use a maximum of 435 acre-ft gross of groundwater. An estimated timeline for the occurrence of major events in Phase II, as well as event durations, is outlined in the timeline below (Figure 1). The project begins in July 2011 with the stimulation of well 55-29, which will utilize approximately 74.2 acre-ft over a 21-day period. Following the stimulation, a three-day flow-back test of 55-29 will be conducted. This task does not use any additional make-up water. In September 2011, drilling of the first of two production wells will begin. Based on Davenport's experince, we expect that each well will require 90 days to drill and 9.7 acre-ft of groundwater. Following the completion of each producer, the connection between the injector and the producer will be tested for up to 7 days and a 5-day stimulation to enhance that connection will be conducted. Finally, a three-well circulation test between the injector and newly-drilled producers will commence in May 2012. The circulation test is scheduled to last between 30 and 60 days and require up to 242 acre-ft of groundwater. Figure 2 presents the projected monthly water usage between July 2011 and June 2012.

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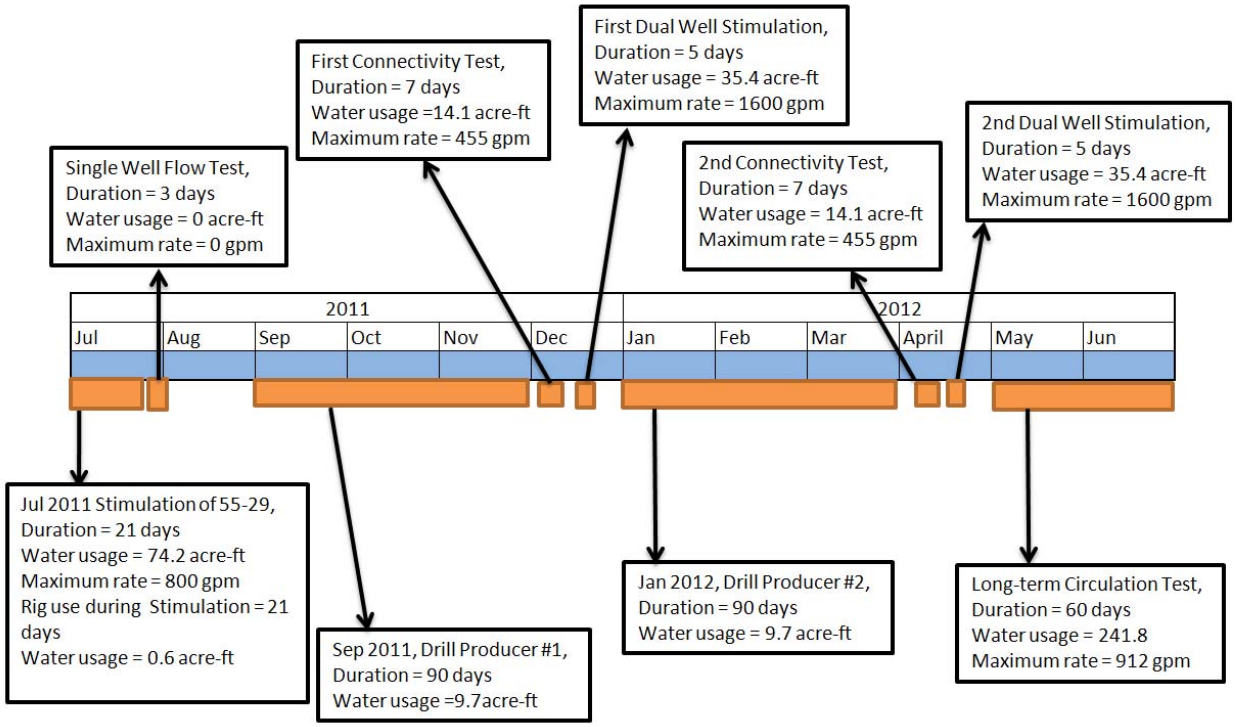

Figure 1: Major events and durations of water use.

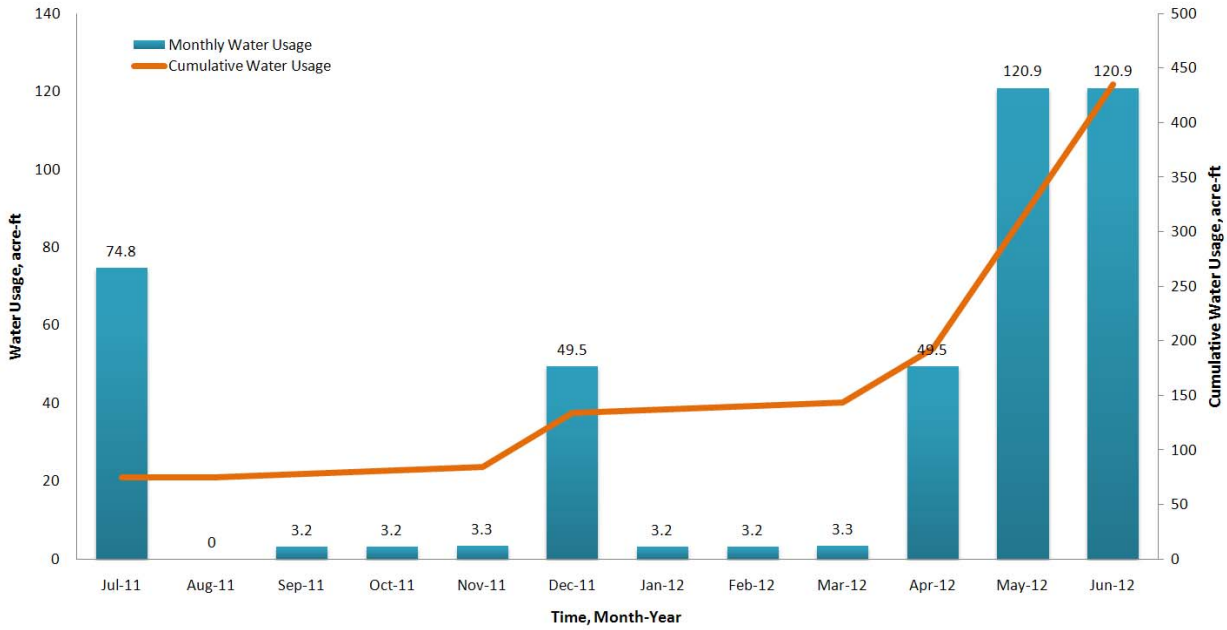

Figure 2: Water usage by month.

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The water usage breakdown by year is summarized in Tables 4 and 5 below. Groundwater usage in 2011, 31% of the total, is estimated to be a maximum of 43.7 million gallons. The majority of the project's water use, 69%, will occur in 2012. Usage in 2012 is dominated by the long-term circulation test. Table 5 and Figure 3 break down the estimated usage by sink type. Evaporative losses are the dominant sink, utilizing 58% of project water. Water that is used to 'fill' the reservoir during stimulation and drilling is estimated to use 34% of the project water budget. Losses due to leak-off account for the remaining 8%.

Table 4: Summary of maximum water usage by year.

Year	Water Usage, *gals*	Water Usage, acre-ft	Percent of Total Usage
2011	43,657,589	134	31%
2012	98,038,354	301	69%

Table 5: Maximum water use for all major activities in the Newberry EGS Demonstration categorized by year of consumption and sink type.

Activity	Water Volume, *acre-ft*	Year	Sink Type
Single well stimulation[1]	74.2	2011	Reservoir fill-up
Rig use during stimulation[2]	0.6	2011	Evaporative
Drilling producer #1[3]	4.9 1.4 3.4	2011	50% Evap 15% Res fillup 35% Leak-off
Drilling producer #2[3]	4.9 1.4 3.4	2012	50% Evap 15% Res fillup 35% Leak-off
Connectivity test PW1[5]	12.7 1.4	2011	90% Evap 10% Leak-off
Dual well stimulation PW1[4]	35.4	2011	Reservoir fillup
Connectivity test PW2[5]	12.7 1.4	2012	90% Evap 10% Leakoff
Dual well stimulation PW2 [4]	35.4	2012	Reservoir fillup
Circulation Test[6]	217.6 24.2	2012	90% Evap 10% Leakoff
Total	**438**		

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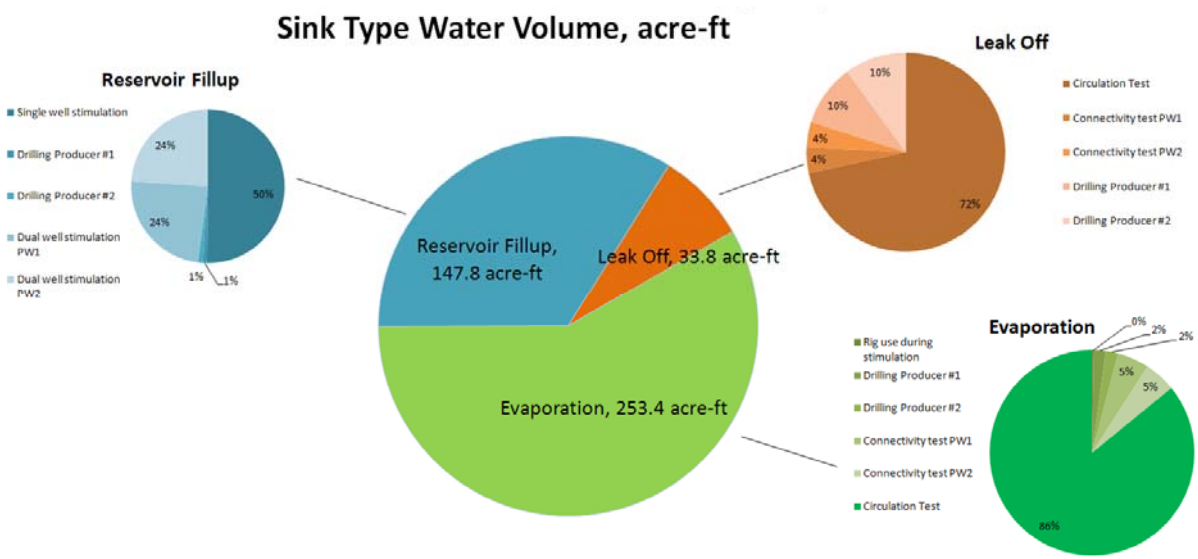

Figure 3: Water consumption by type of sink

MATERIALS ADDED TO THE WATER AT EACH STAGE

1. During stimulation:
   a. Tracers – thermally-reactive, sorptive, diffusive, and conservative fluid tracers that are injected intermittently during the stimulation as pulses. In a typical tracer test during stimulation, 25 kg each of one or more 'reactive' tracers and one conservative tracer are mixed with approximately 100 gal of water and injected as a pulse over a duration of a few minutes. The pulse is then followed by one or more wellbores of water in order to disperse the tracer throughout the near-wellbore reservoir formation. After a shut-in period that may extend for several hours to a few days, the well is made to flow and the tracer concentrations measured at the wellhead. An inversion of a numerical flow model based on tracer data is then used to estimate the near-wellbore fracture surface area. The tracer concentrations will be approximately 10 to 100 parts per thousand in the injected pulse, and approximately 0.1 to 100 parts per billion when produced at the wellhead. These tracers are typically detectable at the part per trillion level. For each tracer test used during stimulation, only 25 kg of one conservative tracer (a naphthalene sulfonate) will be used in combination with 25 kg of one to three reactive tracers (e.g., rhodamine WT, 1,3,6,8-pyrene tetrasulfonate, or safranin T). Eight naphthalene sulfonate tracers were listed in Table 6 but only 4 will be used during the three stimulation experiments and the one circulation experiment. Eight of the ten tracers that will potentially be used during the Demonstration are commonly used to monitor groundwater aquifers (Table 6).
   b. Diverters – solid material that is injected in slugs between each stimulation stage*.
   c. Friction reducer – we don't expect to use friction reducing additives in the stimulation fluid, but it is an option if surface pressures need to be reduced. Typically, FR26-LC is used to reduce

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pipe friction at higher pumping rates. FR26-LC is a hydro-treated, light petroleum distillate that is added at concentrations of 0.5-1.0 gallons per million gallons of water. See product bulletin below.

2. During production well drilling:
   a. Mud additives – see well 55-29 mud report in the appendix. It is assumed that very similar mud additives will be used in the drilling of the two production wells.
3. During circulation and connectivity testing:
   a. Tracers.
   b. Friction reducer – FR26-LC or similar.

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Table 6: Tracer additives to system throughout Newberry Demonstration Project.

Additive Name	Type of Additive	Time of Use	Quantity Injected	Concentration	Breakdown Products
***1,5-naphthalene disulfonate, disodium**	tracer	Stimulation	25 kg	Variable	1,5-naphthalene disulfonate anion, Na^+
***2,6-naphthalene disulfonate disodium**	tracer	Stimulation	25 kg	variable	2,6-naphthalene disulfonate anion, Na^+
***1,6-naphthalene disulfonate disodium**	tracer	Stimulation	25 kg	variable	1,6-naphthalene disulfonate anion, Na^+
***2,7-naphthalene disulfonate disodium**	tracer	Stimulation	25 kg	variable	2,7-naphthalene disulfonate anion, Na^+
***1-naphthalene sulfonate disodium**	tracer	Stimulation	25 kg	variable	1-naphthalene sulfonate anion, Na^+
***2-naphthalene sulfonate disodium**	tracer	Stimulation	25 kg	variable	2-naphthalene sulfonate anion, Na^+
***1,3,6,8-pyrene tetrasulfonate tetrasodium**	tracer	Stimulation	25 kg	variable	1,3,6,8-pyrene tetrasulfonate anion, Na^+
Safranin T disodium	tracer	Stimulation	25 kg	variable	Safranin T anion, Na^+
***Rhodamine WT disodium**	tracer	Stimulation	25 kg	variable	Rhodamine WT anion, Na^+
***Lithium Bromide**	tracer	Stimulation	100 kg	variable	Li^+, Br^-
***Cesium Bromide**	tracer	Stimulation	100 kg	variable	Cs^+, Br^-
***Rubidium Bromide**	tracer	Stimulation	100 kg	variable	Rb^+, Br^-
***Lithium Iodide**	tracer	Stimulation	100 kg	variable	Li^+, I^-
***Cesium Iodide**	tracer	Stimulation	100 kg	variable	Cs^+, I^-
***Rubidium Iodide**	tracer	Stimulation	100 kg	variable	Rb^+, I^-
***1,3,5-naphthalene trisulfonate trisodium**	tracer	Circulation Testing	100 kg	variable	1,3,5-naphthalene trisulfonate anion, Na^+
***1,3,6-naphthalene trisulfonate trisodium**	tracer	Circulation Testing	100 kg	variable	1,3,6-naphthalene trisulfonate anion, Na^+
***Fluorescein disodium**	tracer	Circulation Testing	50 kg	variable	Fluorescein anion, Na^+
safranin T disodium	tracer	Circulation Testing	100 kg	variable	Safranin T anion, Na^+

*Denotes tracers that are commonly used in groundwater aquifer monitoring.

1.For each tracer test used during stimulation, only 25 kg of one conservative tracer (a naphthalene sulfonate) will be used in combination with 25 kg of one to three reactive tracers (e.g., rhodamine WT, 1,3,6,8-pyrene tetrasulfonate, or safranin T).

2. Only four naphthalene sulfonate tracers will be used during the three stimulation experiments and the one circulation experiment.

3. Eight of the ten tracers that will potentially be used during the Newberry project are commonly used to monitor groundwater aquifers.

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Diverter Use in EGS Stimulation*

Purpose of Diverters

The creation of EGS reservoirs has historically involved the stimulation of a single fracture set around an existing well bore. This is due to the fact that during stimulation the existing fracture with the lowest hydroshearing pressure will open when water is pumped from the surface and pressure is applied in the injection well, and other existing fractures that require a higher shear pressure are not affected (Figure 1).

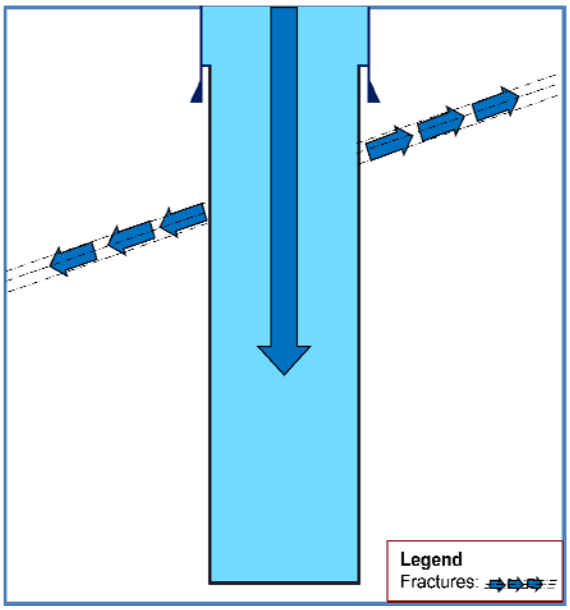

Figure 1: Stimulation of a single fracture set

The stimulation of multiple fracture sets in a single injection well will increase EGS efficiency. To create multiple fracture sets in a single well requires hydraulic isolation of each fracture network after it has been stimulated. To provide hydraulic isolation for the creation of multiple fractures a diverter material can be used (Figure 2). After the stimulation of the first fracture set, a diverter material is applied to temporarily seal the fracture network from accepting additional fluid. Additional pressure is then applied to the well and a second set of fractures will be stimulated. After multiple fractures are created injection is discontinued and the well bore is allowed to reheat to the original well temperature. This causes the diverter material to dissolve, leaving all fractures open for circulation and flow during the operation of the EGS system.

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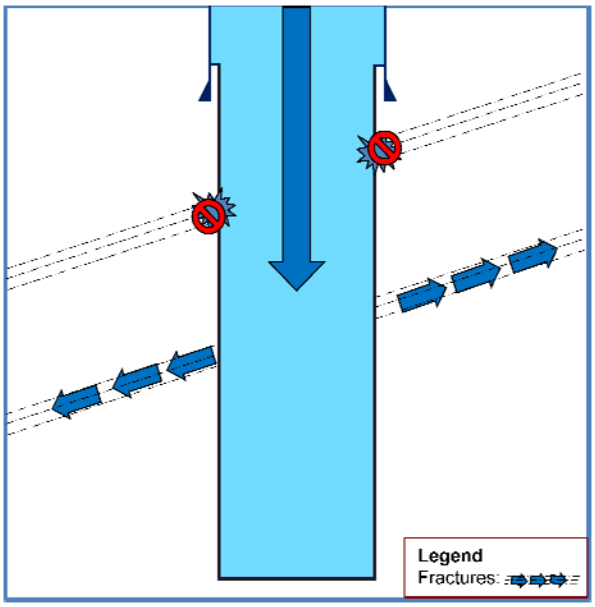

Figure 2: Stimulation of second fracture set after diverter application to first fracture set.

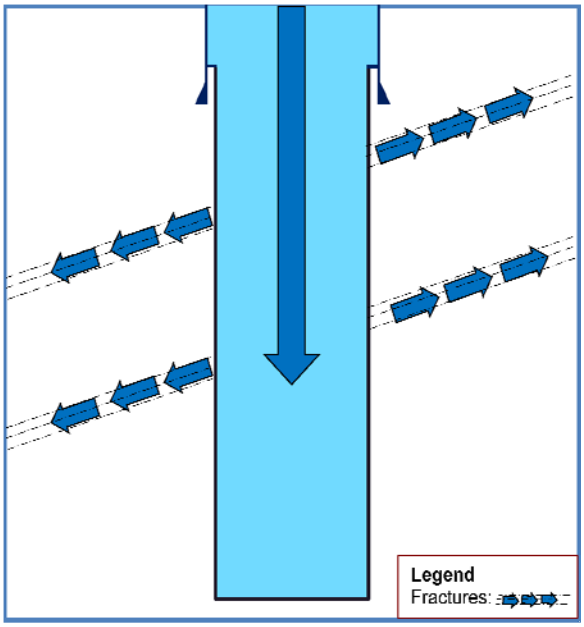

Figure 3: EGS well with multiple fracture sets after diverter dissolution.

Differences between EGS Stimulation and Oil and Gas Hydraulic Fracturing

Oil and gas well (O&G) hydraulic fracturing (fracking) is significantly different from EGS stimulation. There are two major differences that should be understood. The first is that O&G fracking typically involves applying enough pressure and stress on the formation rock to cause tensile failure and the creation of new fractures. In EGS hydroshearing stimulation, pump pressure is maintained at the shear failure pressure and is carefully controlled and limited to prevent tensile failure. EGS hydroshearing stimulation results in the 'opening' of existing fractures and prevents the creation of new fractures.

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Once the fracture is opened, the rock faces can then slip past each other. When the fractures close slightly after stimulation pressure is relieved, the irregularities and disparities between the shifted rock faces do not allow the fractures to close completely, leaving a path for water flow.

Another major difference is that in O&G fracking sand and chemicals are purposefully pumped into the open fractures to hold the fractures open and to aid in the stimulation treatment. A typical O&G fracking treatment may contain the materials listed in Table 1.

Table 1: A Typical 2000 Barrel Oil and Gas Fracking Operation[1]

Material	Amount
Sand	300,000 lbs
Guar or other gelling agent	2520 lbs
KCl	14,000 lbs
Borate	84 gal
pH Buffer (NaOH or acetic acid)	84 gal
Surfactant	84 gal
Sodium persulfate (breaker)	84 lbs

In EGS hydroshearing, only water, with small concentrations of non-toxic, non-carcinogenic, non-mutagenic and environmentally benign fluorescent tracers, is pumped into the injection well and fractures. Particulate diverter material is pumped into the well between stimulation treatments. This material is designed to pack off at the fracture face inside the wellbore. After EGS hydroshearing, the stimulated well is allowed to re-heat, the diverter materials degrade and dissolve into the wellbore fluid, and are then produced back to the surface when the well is allowed to flow.

Use and Application of Diverters for Newberry EGS Demonstration

Proprietary diverters primarily developed by AltaRock will be used in the Newberry EGS Demonstration between pumping of the stimulation treatments for each fracture set. Diverter materials are selected to be benign and to have benign breakdown products. The diverters will be selected from two classes of materials: biodegradable plastics and naturally occurring minerals. Biodegradable plastics are plastics that will decompose in natural aerobic (composting) and anaerobic (landfill) environments. They may be composed of either bioplastics, which are plastics with components derived from renewable raw materials, or petroleum-based plastics which utilize an additive. The use of bio-active compounds, compounded with swelling agents, ensures that, when combined with heat and moisture, they expand the molecular structure of the plastic and allow the bio-active compounds to break the polymer chains into their component, soluble parts. These smaller components can then be metabolized if they are in the biosphere.

For example, one of the diverter materials made from renewable biologic raw materials that AltaRock has used is BioVert™, a polymer of lactic acid, or PLA. This material is a hard plastic which is available as

[1] Reference: SPE Monograph 12, Recent Advances in Hydraulic Fracturing

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grains which can be sorted by size. When heated, the chains in the polymer break down to lactic acid, a soluble substance found in human and animal tissue as a normal product of metabolism and exercise. Three of the other biodegradable plastics which could be used on the Newberry project are also made from biologic materials. Two others are derived from petroleum, but break down into small components that are bioactive and can be metabolized in the environment. Biodegradable plastics would be selected based on the temperature at which they melt and then the temperature at which they disassociate.

The wells at Newberry are very hot, but will be cooled by injecting water for the stimulation. The diverter material selected needs to stay in place long enough to stimulate the remaining zones. The first zone stimulated may not be cooled enough to make it possible to use a biodegradable plastic as a diverter. If this is the case, one of the mineral diverters would be selected for that zone. The mineral materials that may be used at Newberry are all naturally occurring materials that would be ground into particles and mixed with water to pump into the well. They are chosen for their low solubility at low temperatures and higher solubility at high temperatures. One possible mineral that has been tested is calcium carbonate (calcite). Because any natural mineral material can have contaminants that are toxic, AltaRock always uses materials that have been quality controlled and tested to have no or very low contaminants. The calcite chosen for use as a diverter is a very pure, with greater than 99% calcium carbonate and less than 0.3% quartz.

Water will be pumped for about seven (7) days to stimulate each fracture set. Stimulation of at least three fracture sets is planned, for a total of twenty-one (21) days of pump time. When the desired water volume has been pumped and the target fracture volume has been stimulated, a suspension of diverter particles in water will be mixed up and pumped into the well. The amount of diverter material is expected to be 200 pounds per diverter treatment. The particles will be carried down to the fractures that are currently accepting water. The particles will pack off in the fractures at the well bore face and seal off additional flow into the fractures (Figure 2). Additional pump pressure will be applied and a new set of fractures, typically below the first set of fractures, will be stimulated by hydroshearing. Pumping will continue until the second fracture set grows to the target volume. This process will be repeated again to stimulate a third fracture set.

Handling and Storage of Diverter Materials

Diverter materials are granular solids of various particle sizes. Materials will be stored on location in sacks, drums or super sacks (one cubic meter polyethylene bags). Material will be protected from the weather with plastic wrap, covering, and storage in a protected area. A total of 1000-2000 pounds of each selected diverter will be on hand at the well location.

Composition of Potential Diverters and Their Degradation Products

Below is a list of potential **proprietary** diverter materials that might be used in the Newberry EGS Demonstration. One or more of these proprietary products may be used during the Demonstration based on the results of ongoing proprietary site investigations and laboratory testing of diverter

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performance. We expect to pump three stimulation stages by using 200 pounds of diverter between stimulations, with one diverter treatment pumped between the first and second stimulation, and another treatment pumped between second and third stimulation. Thus, we expect to use a total of about 400 pounds of diverter material.

Table 2. Diverter Material and Expected Degradation Products (AltaRock Proprietary)

Material	**Class of Material**	**Composition of Degradation Byproducts**
BioVert™	Biodegradable polymer	Lactic Acid monomers, dimers and trimers
AltaVert ™ 150	Biodegradable plastic from petroleum	Carbon dioxide and a diol. This formulation of the material does not contain bisphenol.
AltaVert 200	Magnesium mineral	Mg^{2+}, Cl^{-}, MgO
AltaVert 201	Magnesium mineral	Mg2+, $(SO_4)^{2-}$, MgO
AltaVert 250	Calcium Mineral	Ca^{2+}, $CO3^{2-}$, $HCO3^{-}$
AltaVert 300	Oxide glass	H_4SiO_4, H_3SiO^{4-}, OH^{-}, H^{+}, Na^{+}, Ca^{2+} Na_2O, CaO, Al_2O_3 , silica polymerization Tobermorite, $Ca_5Si_6O_{16}(OH)_2{\cdot}4H_2O$, reported as a solid residue
AltaVert 301	Natural mineral	H_4SiO_4, H_3SiO^{4-}, OH^{-}, H^{+}, silica polymerization
AltaVert 151	Biodegradable bioplastic	Hydrolysis produces the corresponding hydroxyacids that are mostly non-toxic
AltaVert 152	Biodegradable cellulosic fiber	oligosaccharides and hexoses (mainly glucose)
AltaVert 153	Biodegradable bioplastic	glycolic acid

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