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Techno-Economic Analysis of Integration of Low-Temperature Geothermal Resources for Coal-Fired Power Plants

May 2016

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U.S. DEPARTMENT OF ENERGY

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Project Update
Project Deliverable (Task 3)

Techno-Economic Analysis of Integration of Low-Temperature Geothermal Resources for Coal-Fired Power Plants.

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Acronyms and Abbreviations

CCS	CO_2 capture and geologic storage
DOE	U.S. Department of Energy
EIA	Energy Information Administration
FGD	Flue gas desulfurization
LCOE	levelized cost of electricity
MEA	monoethanolamine (considered the standard amine-based CO_2 scrubbing technology)
NETL	National Energy Technology Laboratory
ORC	Organic Rankine Cycle
PC	pulverized coal
TEA	techno-economic (study)
USGS	U.S. Geological Survey

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1.0 Overview

Presented here are the results of a techno-economic (TEA) study of the potential for coupling low-grade geothermal resources to boost the electrical output from coal-fired power plants. This study includes identification of candidate 500 MW subcritical coal-fired power plants in the continental United States, followed by down-selection and characterization of the North Valmy generating station, a Nevada coal-fired plant. Based on site and plant characteristics, ASPEN Plus models were designed to evaluate options to integrate geothermal resources directly into existing processes at North Valmy. Energy outputs and capital costing are presented for numerous hybrid strategies, including integration with Organic Rankine Cycles (ORCs), which currently represent the primary technology for baseload geothermal power generation.

2.0 Key Findings

The results of this study suggest that, where geothermal resources can be accessed by plant operators, direct use of low-grade geothermal resources can increase net power production of coal-fired plants, with the potential to partially or fully offset the efficiency penalties associated with CO_2 capture. Where CO_2 capture is not yet sufficiently incentivized, this reflects an intriguing hybrid approach that could enable more energy efficient power generation from conventional fossil-fired generation units. By leveraging the existing capital present across the U.S. power fleet, this hybrid approach also offers an opportunity to develop low-temperature resources at costs of electricity that outperform generation from these marginal resources using ORC. While this project evaluated a specific coal-fired plant paired with a marginal geothermal resource located very near the plant site, the applicability of this hybrid approach may well be much broader, particularly for the existing gas-fired power fleet, as well as for future fossil-fired generation facilities.

Key findings of this analysis include:

- Direct use of 150°C geothermal water (185,000 bbl/day) is estimated to generate an additional 19 MWe on the reference subcritical coal-fired power plant via boiler feed water preheating alone.[1] First passing the same geothermal water through an ORC prior to using it for preheating is estimated to produce less overall net power than using it solely for boiler feed water preheating.
- Several scenarios were investigated where geothermal water was used to offset the duties associated with a CO_2 capture process installed on a subcritical coal-fired power plant.
  - The modeling cases with MEA carbon capture predicted massive amounts of geothermal water required to fully offset the MEA regeneration energy need. These water flow rates are not considered feasible for a geothermal resource on a single site.
  - A modest geothermal resource (2,700,000 lb/hr) is estimated to offset approximately 7% of a MEA solvent re-boiler duty, resulting in marginal impacts to overall Levelized Cost of Electricity (LCOE) associated with CO_2 capture and geologic storage (CCS).

- o For an advanced carbon capture solvent system such as CO_2BOLs, with a regeneration temperature more than 30°Clower than amines, 90% of the re-boiler duty could be offset by 150°C geothermal water, equating to 123 MWe of extra power generation. The approximately 685,000 bbl/day of geothermal water required in this scenario is significant, but within reason for a single power generation site. Compared to the MEA solvent case, this geothermal-enabled CO_2 capture scenario results in an overall LCOE reduction of of 0.75 cents per kWe-hr, suggesting an opportunity to address CO_2 capture requirements while also expanding the applicability for geothermal energy at costs that could prove to be appealing investments, particularly once financial incentives exist to spur CCS deployment in the U.S. power sector.
- Sensitivity analysis suggests that, as expected, economics are sensitive to geothermal flow rate and resource temperature, although break-even rates and temperatures are expected to be highly project specific.

3.0 Candidate Site Selection

The Task 2 deliverable identified 10 candidate power subcritical 500 to 750 MW plants with geothermal resources between 125 and 150°C at a 3.5 km depth Figure 1 and Table 1. Of those ten, four sites were selected for additional screening.

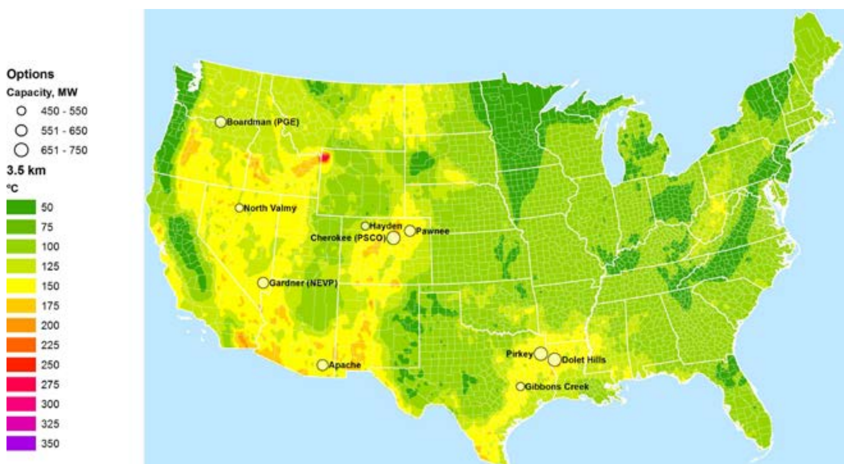

Figure 1. Preliminary options. (Data on coal power stations c. 2011, from Platts; geothermal resource maps, Google Earth / World Energy Explorer.)

The Apache, Boardman, Hayden, and North Valmy plants were selected for the engineering assessments of potential direct-use geothermal integration. Each candidate plant represents a different region of the continental United States, reflecting four unique geologic settings and covering a range of conceptual reservoir models with varying degrees of potential resource availability. Additionally, these plants were selected based on project feasibility, particularly regarding permitting of well drilling and stimulation. It should be noted that many of the 602 coal-fired plants in the continental United States may benefit to some degree the projected benefit from the geothermal integration strategies described in Section 4 but the resource availability may require deeper resource extraction and/or reservoir stimulation, and thus could incur significantly higher extraction costs. The North Valmy plant was chosen for the detailed economics of this study (Section 5) because of the quality of data available on a potential hydrothermal resource at the site. North Valmy reflected the best opportunity to model this hybrid concept using actual plant data paired with a known resource.

Table 1. Preliminary site options

Plant	Capacity (MW)	Location (City, ST)	Vintage (First, Last)	Approx Temp @ 3.5 km (°C)
Apache	627	Cochise, AZ	1963, 2002	150
Boardman	601	Boardman, OR	1980, 1980	125-150
Cherokee	730	Denver, CO	1957, 1988	125-175
Dolet Hills	720	Mansfield, LA	1986, 1986	150
Gardner	637	Moapa, NV	1965, 1983	150
Gibbons Creek	470	Grimes, TX	1983, 1983	150-175
Hayden	465	Hayden, CO	1965, 1976	125
North Valmy	521	Valmy, NV	1981, 1985	150
Pawnee	552	Brush, CO	1981, 1981	150
Pirkey	721	Hallsville, TX	1985, 1985	150

4.0 Summary of Resource Availability and Well Cost Projections (North Valmy)

4.1 Geologic Setting

The North Valmy power plant is located in the Humboldt River Valley and is surrounded by steep mountain ranges that expose a complex geologic history of early accretionary orogenic events followed by rifting and extension of the Great Basin. In the absence of deep borehole investigations within the Humboldt Valley region, the subsurface geology near the North Valmy site can only be surmised from the geology of nearby outcrops, mine pits, and surrounding mountain ranges. Rocks exposed in the surrounding ranges and in the local Lone Tree mine (Figure 2) are dominated by Paleozoic sediments, which include the Valmy Formation, Antler sequence, and Havallah sequence. These rocks formed offshore, and were emplaced by thrust faults onto the western margin of North America in separate events during the Paleozoic and early Triassic. The Ordovician Valmy Formation is generally considered to be an allochthon of the Roberts Mountain Thrust and consists of complexly faulted deep marine siliceous and volcanic rocks. The Antler sequence represents marine transgression and unconformably overlaps the deformed Valmy Formation.[2] Locally, at the Lone Tree mine, the Antler overlap sequence is limited to siltstone and sandstones of the Permian age Edna Mountain Formation.[3] The Havallah sequence is a structurally complex assemblage of thrust packages of upper Paleozoic rocks that were emplaced over rocks of the Antler overlap sequence along the Golconda Thrust. At the Lone Tree mine, the Havallah Formation is divided into two units which include: 1) a chert, argillite, and greenstone unit, and 2) a sandy limestone and a pebble conglomerate unit.[3] Immediately south of the power plant, the low-lying Treaty Hill exposes upper Paleozoic rocks of the Havallah Formation, which are unconformably overlain by late Cenozoic basalt flows.[4]

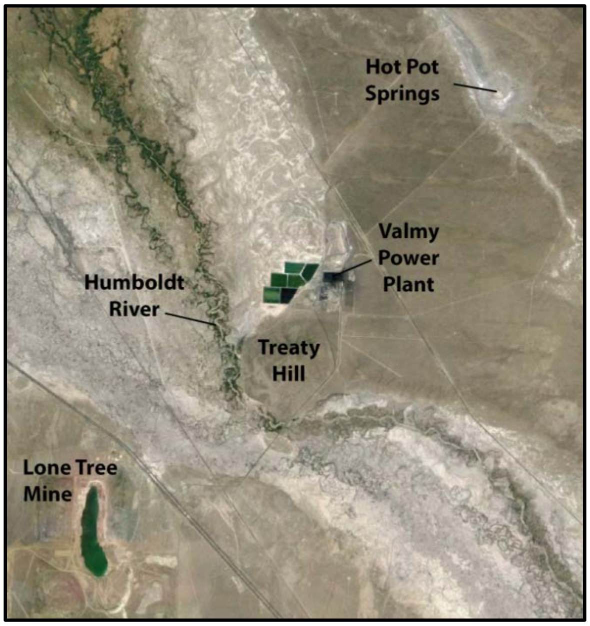

Figure 2. Map showing locations of the North Valmy power plant and other key areas discussed in this analysis.

During the Neogene, north-northwest oriented tectonic rifting led to localized volcanism and the development of extensional basins separated by mountain ranges bound by north-northeast striking normal faults. Neogene strata accumulating during and after basin development within the Humboldt River Valley likely include fluvial sandstone, lacustrine deposits, ash-rich sediments, and andesitic to basaltic lava flows.[5] Neogene basin fill sediments are expected to be less than 1000 ft at the Valmy power plant and are likely covered by a thin layer of quaternary alluvial fan and Humboldt River deposits. These Neogene sediments are a potential geothermal production target elsewhere in the basin where they occur at greater depths, but are likely too shallow to host geothermal fluids at North Valmy. At the Beowawe geothermal field, as potentially at the North Valmy plant, the Valmy Formation would be the primary geothermal reservoir target.

4.2 Quaternary Faulting

Quaternary faults mapped near the power plant are generally oriented north-northwest and are likely associated with active basin wide extension.[6] The majority of these faults are located along the edge of the valley as range-bounding normal faults. Both north-northwest and north-northeast striking fault scarps are documented in the valley just northeast of the power plant. Although no quaternary faults have been mapped along the flank of Treaty Hill, a review of available satellite imagery reveals at least one prominent northwest facing fault scarp striking northeast that appears to offset alluvial fans along the northwest flank of the Hill. This apparent fault scarp (see Figure 3) is inferred to be the surface expression of a deep, northwest dipping normal fault, placing the Valmy power plant on the relative upside (i.e., footwall) block and the cooling ponds on the downthrown hanging wall.

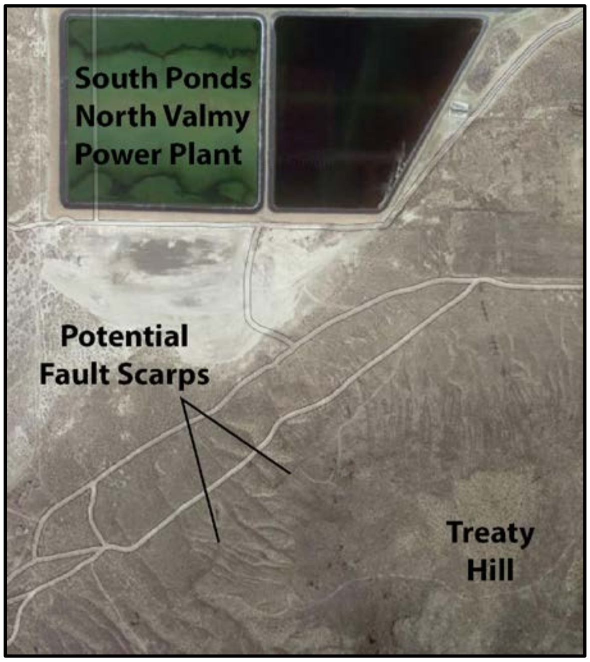

Figure 3. Location of potential Quaternary fault scarps along the northwest flank of Treaty Hill.

4.3 Geothermal Exploration

According to Lane et al., (2012) geothermal exploration of the Valmy area was likely initiated in the early 1970's with considerable interest in developing a resource at the nearby Hot Pot hot springs, located approximately 2 miles northeast of the power plant. During this time, the hot springs were reported to flow to the surface at 70 gpm with recorded temperatures up to 58°C.[4,7,8] However, by the 1980s extensive groundwater withdrawal from the Valmy power plant and dewatering activities associated with local mine operations contributed to lowering the water table and cutting off the surface flow at the hot springs.[5] The current surface expressions of the dried up hot springs are defined by four travertine mounds that are large enough to be seen in the satellite image presented in Figure 1.

Recently, Oski Energy, LLC forged a renewed interest in the Hot Pot thermal anomaly and has recently pursued development of the site as The Hot Pot Project.[5, 9] The Hot Pot Project was initiated in 2009, when Oski acquired geothermal leases along the northeast boundary of the power plant (Figure 3), and began data compilation and initial field surveys including, gravity, soil geochemistry, and a series of six shallow (500 ft; 150 m) temperature gradient holes.[5]

Following initial investigations, Oski secured partial funding from the U.S. Department of Energy (DOE) to perform a two-dimensional seismic study across the Hot Pot area. A five line (23 mile) reflection seismic survey was conducted with the objective to utilize innovative seismic data processing, in conjunction with existing data, to identify high-potential drilling targets and to reduce drilling risk.[5,9] The seismic study was successful at imaging the shallow subsurface stratigraphy above the basement, better defining the Paleozoic basement topography, and identifying deep fault structures that may serve as potential drilling targets within the

Ordovician Valmy Formation. The Ordovician Valmy Formation is well known as a complex mixture of faulted and fractured rock that hosts a highly permeable reservoir at the Beowawe geothermal site. If the seismic study proves to be successful in identifying similar structures at depth at the Hot Pot site, then extending the seismic survey to include additional quaternary fault features that may be present near the power plant property should be considered, if additional field mapping confirms the presence of one or more faults at this location. Extrapolation (to the southwest) of the interpreted seismic cross sections presented by Lane et al.[5] seem to suggest that a well drilled near the Valmy power plant might encounter as much as 1,500 ft of upper to middle Paleozoic basement rocks at a shallow depth before encountering the fractured Ordovician Valmy Formation.

During the 1980s, Trexler et al.[4] drilled a temperature gradient borehole (PVHT-5), located near the Hot Pot hot springs. The PVHT-5 boring encountered a shallow basalt flow at 120 ft and reached a total depth in basalt of 140 ft. The temperature gradient calculated for this boring is relatively high, at 220°C/km. To better characterize the subsurface heat flow conditions at the Hot Pot site, Oski Energy drilled a series of six shallow (500 ft; 150 m) temperature gradient boreholes. Well locations and contours of the calculated thermal gradients are presented in **Figure 4**.[5] These data validate the initial findings by Trexler et al.[4] and confirm that gradients greater than 9°F/100 ft (164°C/km) exist near the center of the Hot Pot thermal anomaly. All but one of the six wells recorded temperature gradients greater than 6°F/100 ft (110°C/km). The southernmost well (27-1), located close to 2 miles west of the power plant, recorded a gradient less than 3°F/100 ft (55 °C/km).

Given the layout of existing temperature gradient boreholes with a high gradient well to the northeast and a lower gradient well to the west, an attempt to ascertain the thermal gradient at the Valmy power plant becomes somewhat problematic and requires a better understanding of the structures controlling migration of heated fluids at depth. Based on available data, the southernmost temperature gradient borehole does not appear to be located near existing fault structures. In contrast, the Valmy power plant is located on strike with a concealed fault (Figure 5; fault C) identified from the Oski seismic survey. This concealed structure roughly aligns with the northeast extension of a possible fault scarp identified along the northwest flank of Treaty Hill. The expression of Treaty Hill above the valley floor in combination with the apparent preserved fault scarps along the northwest flank of the hill suggests that a recently active, deep rooted normal fault could be present, potentially accommodating sufficient secondary fracture permeability to allow migration of geothermal fluids to shallow levels. The inferred fault scarps, however, cannot be confirmed without direct field observations, which should be undertaken prior to extending the Oski seismic survey to cover potential quaternary fault features near the North Valmy plant.

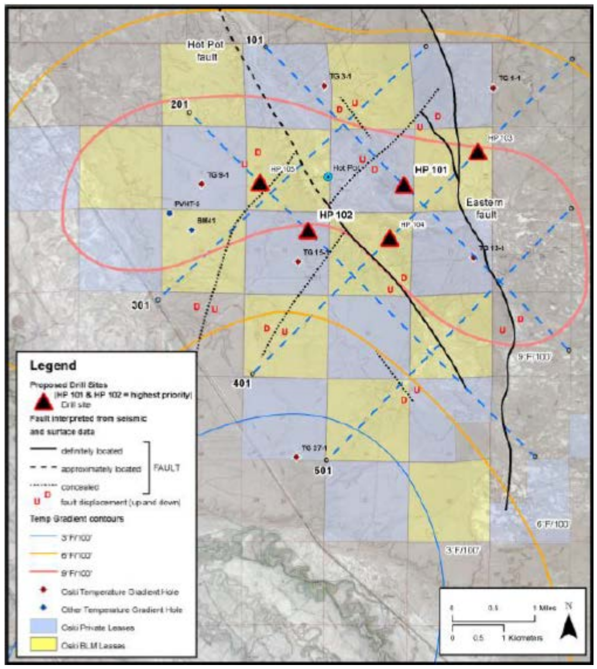

Figure 4. Temperature gradient contours and potential drilling locations at the Hot Pot project (from Lane et al.)[5]

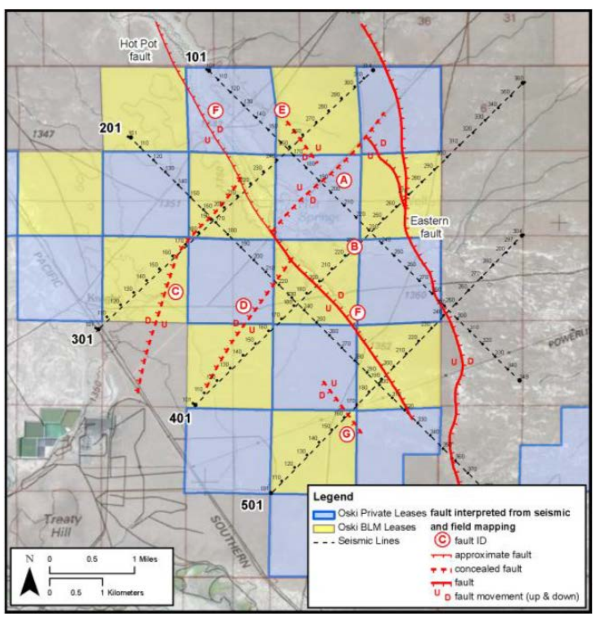

Figure 5. Location of Oski Energy, LLC geothermal leases, the Hot Pot seismic program survey lines, and interpreted structures (from Lane et al.)[5]

4.4 Primary Modeling Scenarios

In order to estimate potential drilling depths to reach a sufficient fluid temperature of 150°C for the various modeling scenarios, a range of conservative gradients of 4°F/100 ft (70°C/km) to

5°F/100 ft (90°C/km) were used to define Cases 1 and 2, respectively. This resulted in drilling depths of approximately 5000 feet (Case 1) and 6600 feet (Case 2). Butler et al.[10] reported that at the Beowawe site, which produces from the same heavily fractured reservoir of interest for this project, initial combined production from the three project wells in July 1991 was around 1.8 million lb/h, or a per-well average of 600,000 lb/h. Assuming that this average rate could be replicated for new project wells at the North Valmy site, process water needs of 2.5 MMlb/h could reasonably be met using four or five production wells.

Based on work published by Shevenell[11] that includes a review of efforts to estimate well drilling costs for geothermal projects in Nevada, we have assumed for this analysis that, in addition to five required production wells, a project would need an additional three injection wells. This is highly site-specific, but reflects a conservative interpretation of average values across the projects surveyed, and is consistent with the 2:1 ratio reported for the Beowawe site. Shevenell estimates production and injection well costs separately,[11] and via relationships developed by several other authors, including Klein et al.[12] Bradys[13] and Augustine et al.[14] The unpublished nature of the Bradys data and the much broader geographic scope of the Augustine work led to a decision in the present analysis to use the depth-based relationships presented by Klein. The Klein relationship also reflects the highest costs of the three cases presented. Resulting costs for Cases 1 and 2 using this relationship, including site-specific parameters used in developing these estimates, are shown in Figure 6.

For the two cases evaluated, average per-well costs for production wells is between \$1.2M and \$1.6M each, with cost variance resulting from increased depth to reach 150°C water in Case 2 (70°C/km) relative to Case 1 (90°C/km). A relationship was developed based on Shevenell's estimates using cost functions derived from Klein's data to estimate an adder on production well costs to account for additional costs associated with reinjection wells. Based on Shevenell's analysis of Klein's data, injection wells appear to cost about 5% more than production wells at the Beowawe site, where flow rates and drilling conditions are most likely to approximate those at North Valmy. This 5% adder was included in injection well cost estimates shown in Table 2.

Table 2. Site-specific cost parameters and resulting cost estimates for production and injection well requirements at North Valmy power plant.

	Case 1	Case 2
Avg Temp Gradient, $^oC/km$	90	70
Desired Temp, ^oC	150	150
Projected Drill Depth, ft	4,922	6,562
Per-Well Flow Rate, lb/h	600,000	600,000
Required Flow Rate, lb/h	2,500,000	2,500,000
Required Wells, Production	5	5
Required Wells, Injection	3	3
Production Well Costs, each	$ 1,274,394	$ 1,618,930
Production Well Costs, total	**$ 6,371,969**	**$ 8,094,651**
Injection Well Costs, each	$ 1,338,114	$ 1,699,877
Injection Well Costs, total	**$ 4,014,341**	**$ 5,099,630**
TOTAL WELL COSTS	**$ 10,386,310**	**$ 13,194,281**

Within the range of expected gradients and flow rates assumed for the North Valmy site, and explicated above, total well costs for this project are likely to fall between $10M and $13M. However, it is important to note that these estimates are based on averages and statistical relationships. The estimates are a function of depth alone and assume average well diameters, typical drilling conditions and standard well completions.

4.5 Sensitivity Cases

A significant amount of uncertainty exists around the structure and source of the hydrothermal system at the Hot Pot site. While Oski's attempts to resolve this uncertainty using seismic surveys have shed light on the structural setting of the field, the lack of intermediate or deep characterization into the Valmy Formation makes it difficult to determine, with any degree of certainty, the source of the geothermal fluids expressed at Hot Pot. Identifying the best target for production at the site requires assumptions regarding the source of these fluids. If the Hot Pot field is fed by fluids transmitted via the faults imaged in the seismic surveys, then they may well contain waters from the Valmy Formation; however, the faults may also be non-transmissive, which would suggest a different source of the geothermal heat, including the possibility of convective heating. While the geothermometry data from the more recent shallow gradient wells at the site were unavailable for this study, older data published by U.S. Geological Survey (USGS) for the Hot Pot site suggests that mean reservoir temperature in the shallow field may be closer to 112°C ± 6°C (USGS Circular 1978, LJP Muffler (ed)). Geothermometers used in that assessment estimate temperatures from 97°C (chalcedony) to 125°C (quartz). However, the Valmy Formation may indeed have higher temperatures than indicated by the Hot Pot estimates if there is little or no transmission of fluids between the Valmy and the shallow system feeding the Hot Pot field.

It may be possible, then, that 150°C geothermal fluids can be accessed in the Valmy Formation near the North Valmy plant, as modeled in the primary cases for which assumptions are discussed above. However, given the high degree of uncertainty in resource quality, it is important to understand the impact those assumptions may have on overall LCOE. For this reason, cases were evaluated assuming a 125°C fluid temperature at depths that remain quite conservative for the Valmy. Also, because flow rates have been taken from those documented for wells into the Valmy Formation at the Beowawe field, additional cases were used to evaluate the impact of a 50% decrease in per-well flow rate on overall project costs.

5.0 Process Modeling Approach

All simulations were performed using Aspentech: Aspen Plus® and Exchanger Design and Rating. All cost evaluations were performed using Aspentech Process Economic Analyzer (Version 8.4). ASPEN plus was used to calculate net power, heat and material balances in addition to equipment sizing and costing. The first step in the analysis was to recreate models to compare to DOE's coal-fired power plant baselines with and without CCS infrastructure. The benchmark for a subcritical pulverized coal (PC) power plant without CO_2 capture is Case 9 of National Energy Technology Laboratory's (NETL) Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2010/1397. Case 10 burns much more coal to produce the same net power of 550 MW from a subcritical PC power plant with added carbon capture infrastructure. For the sake of a direct comparison, the hybrid geothermal plant configurations were compared against both NETL Case 9 and Case 10. Both Case 9 (Figure S2) and Case 10 (Figure S3) were recreated in ASPEN Plus so that the geothermal elements could be later added (Figure S2) The recreated models both came within 1.4% of the net power projects given in the NETL report, indicating suitable validation for the current analysis. The following subsections give more detail for both Case 9 and 10.

Case 9 is a benchmark PC plant power plant employing typical pollution control devices including a baghouse for particulate control, a selective catalytic reduction for nitrogen oxides control, and a wet flue gas desulfurization unit to control sulfur oxides. The steam cycle is a subcritical cycle with one reheat. This steam cycle is characteristic of the vast majority of operating coal plants in the United States. Steam is produced at a nominal pressure and temperature of 2400 psia and 1050°F; expanded through a high pressure turbine; reheated in the boiler to 1050°F and further expanded in intermediate pressure and low-pressure turbines to about 1 psia; where it is condensed at a saturation temperature of about 101°F. The condensate is pumped through four feed-water heaters, deaerated and pumped through two high pressure heaters where it returns to the boiler to be generated into steam. Heat for the boiler feed water heaters comes from extracting a few percent of the steam at various pressures from the steam turbines. Low-pressure steam is used for the low-temperature condensate and higher pressure steam is required to provide the temperature difference necessary to heat higher pressure condensate. The steam cycle for Case 9 is shown in Figure S1. An ASPEN Plus simulation was developed for the steam cycle with and without geothermal heat input to boiler feed water heaters. As a result of the geothermal heating, the steam extractions are stopped, allowing this steam to flow all the way to the condenser and generate additional power.

Case 10 is another NETL benchmark PC plant as described in Case 9, albeit with installed CCS infrastructure. Case 10 represents as larger front-end boiler and steam turbine to offset the parasitic load associated with the CCS system, thereby netting the same output power of 550 MWe. Major infrastructure installed in Case 10 include an absorber tower, stripper column and cross exchanger and CO_2 compressor pump to deliver CO_2 for permanent storage. The stripper is where the CO_2 capture solvent is regenerated by thermal heating (120 ˚C) adding a large heat duty of 1520 btu/lb of CO_2 captured to the plant. In CCS plants, the intermediate pressure steam is taken out of the steam cycle to power the re-boiler, thus a 20% reduction in net power is observed. For this reason, the re-boiler was the focus of integration strategies. An ASPEN Plus simulation was established for the Case 10 steam cycle with varied levels of geothermal heat input at 150°C water. The results of the energetic and costing for Cases 9 and 10 integrations are summarized in Figure S5 and Figure S6 respectively.

The North Valmy power plant was then modeled in year two for the site-specific analysis and TEA. Efforts to contact operators at North Valmy were unsuccessful, so the team recreated the North Valmy plant in ASPEN Plus using publically available information. Information on North Valmy was taken from the US Energy Information Administration (EIA) filings 923 and 860 from www.EIA.gov. Filing 923 provided detailed electric power data, both monthly and annually on the electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level. Filing 923 also provided more detailed information such as fuel receipts and costs, generator data such as generation, fuel consumption and stocks, fossil fuel stocks, non-utility source and disposition of electricity and all relevant environmental data. Filing 860 contained detailed information regarding the company, facility, unit type, service dates, energy sources, heat content, nameplate capacity and capacity for summer and winter months. All other information needed for recreating the North Valmy plant in ASPEN plus was gathered from the NETL Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2010/1397 and Black and Veatch; Power Plant Engineering: Babcock & Wilcox; Steam: Cheremisinoff; Cooling Towers. Other information was collected from the Class I application review title V Facility-wide operating permit for Sierra Pacific Power CO. North Valmy Generating Station AP4911-0457; from the State of Nevada Department of Conservation and Natural Resources, Division of Environmental Protection Bureau of Air Quality, July 9, 2007.

North Valmy is a PC-fired power plant located in a high desert environment in north central Nevada. The plant has two units that burn low sulfur bituminous and subbituminous coal at an elevation of approximately 4,300 ft in north central Nevada, producing a maximum of 522 MW though annual averages are lower than nameplate capacity (315MW in 2014). North Valmy's two boilers are wall-fired, run PC, with a dry ash system, using a subcritical steam cycle to generate power. Unit 1, operational since December 1981, is a Babcock and Wilcox unit with nameplate of 277.2 MW and seasonal capacity of 254 MW. Unit 2 has been operational since May 1985 and is a Foster Wheeler unit with nameplate of 289.8 MW and seasonal capacity of 268 MW. The plant has two steam turbine generator sets both of which are assumed to be subcritical from their reported heat rates (10,935 Btu/kWh, 31.2% efficiency). In 2014 the Average Generation (EIA) for Units 1 and 2 are 175 MW and 140 MW, respectively.

Groundwater from a nearby mining operation is used at least in part as makeup for mechanical cooling towers. The cooling tower blowdown is delivered to 158 acres of evaporation ponds for disposal. The estimated consumption at rated output of 522 MW is 3,227 million gallons per year with >150 million gallons per year of evaporation from the ponds is required (Figure 7).

Figure 6. North Valmy power plant layout as shown from Google Maps.

Simulations were conducted under a set of site condition assumptions. Site atmospheric conditions used for the analysis were taken from Winnemucca Nevada airport National Oceanic and Atmospheric Administration's 2010 10-year climate normals (46 miles from North Valmy). From this data we set a 12.59 psia ambient pressure and a 1.5 psia condenser pressure. Condenser water is assumed to be 84.2 ˚F at the inlet and 104.2˚F at the outlet, with a 10˚F approach temperature. After the analysis was completed, a restriction in the NV environmental permit was discovered that limits North Valmy cooling water circulation to 2 X 80,200 gallons per minute. In this study a higher circulation rate of 283,000 is assumed.

5.1 Simulations of Geothermal Boiler Feed Water Heating at North Valmy

Compared to the earlier study, which evaluated the integration of this hybrid approach with the NETL Case 9 benchmark with 150°C geothermal water, North Valmy's nameplate capacity is less than Case 9 (522 MW vs. 550 MW) and the steam cycle is less efficient (31.2% vs. 36.8%). As a consequence, the steam flow rate and condenser duty is higher for North Valmy. For all simulations, the geothermal water resource is assumed to be the same 2,695,600 lb/hr flow rate as used in the Case 9 and 10 simulations from the previous year's report. The Case 9 and Case 10 baselines represent hypothetical cases using an assumed 150°C resource temperature, while the North Valmy simulations use the resource-limited 125°C. The lower temperature of the geothermal source in the North Valmy-specific analysis limits the boiler feed water heating to the first three heaters instead of all four low-pressure heaters. It should also be noted that the higher estimated steam flow at North Valmy reduces the condensate fraction that can be heated by the geothermal source to 80%. The remaining 20% is heated in the existing boiler feed-water heaters with extraction steam. The cooled (123°F, 51.6°C) geothermal water is reinjected into the formation for reheating. Here, 80% of the steam previously extracted produces additional power flowing through the low-pressure turbine to the condenser, increasing the condenser duty by the additional amount of steam condensed (2830 MMBTUH to ~3200 MMBTUH).

For this analysis we have modeled heating the boiler feed water using a plate and frame exchanger instead of the shell and tube exchangers typically used as boiler feed water heaters. The initial cost is roughly half a shell and tube cost because the heat transfer coefficient is much higher and a single exchanger can meet the total duty. A single exchanger is assumed as cleaning would be done in normal outages, or the load switched to the existing feed water heaters for cleaning during plant operation. Further, fouling (from scaling) is typically about half that of a shell and tube exchanger.

As explained in Section 4, hot springs were present in the 1970s and subsequent water withdrawal from the North Valmy Power Station and Lone Tree Mining Operations resulted in a drop in the water table and ceased spring flow in the Hot Pot area. Because of its potential to preserve groundwater for other uses, dry cooling was investigated for North Valmy.

Simulations examining combined use of both the air cooler and the existing mechanical draft cooling towers suggest that this combination is sufficient to maintain a 1.5 psia condenser pressure. The projected water savings are very large (Table 3). In this case, the cooling tower is used 2,090 hours compared to the 8,760 hours of the current cooling, with approximately 9% of the makeup required for full wet cooling and 7% of the water delivered to the evaporation ponds.

Table 3. Comparison of water use for All Wet and Wet/Dry Cooling

All Wet Cooling	Makeup	Evaporation	Blowdown	Drift
lb/hr	3,072,040	2,688,042	143,153	240,852
lb/yr	2.69E+10	2.36E+10	1.25E+09	2.11E+09
MMgal/yr	3,227	2,823	150	253
Wet/Dry Cooling	Makeup	Evaporation	Blowdown	Drift
lb/hr	275,551	241,106	10,712	23,732
lb/yr	2.41E+09	2.11E+09	9.38E+07	2.08E+08
MMgal/yr	289	253	11	25
% all wet	8.97%	8.97%	7.48%	9.85%

*Circulation rate for both cases is 160,667,782 lb/hr (84.2 ˚F to 104.2 ˚F).

Dry-cooling systems were modeled in ASPEN Plus using the concept in the U.S. Department of Energy: Advanced Research In Dry-Cooling (Arid); Funding Opportunity No. DE-FOA-0001197; 26-Sep-14. The power plant steam condenser pressure was assumed to be maintained at the 1.5 psia used for the general analysis. The air cooler is arbitrarily designed for 64°F ambient air temperature which is estimated by 10-year climate averages to be ~76% of the hours in the year near North Valmy as shown in the figure below. Optimization of the air temperature was not performed, but optimization of airflow around the design temperature of 64°F was performed (Supplementary Tables). Sizing the air cooler for a 74°F (86% of the year average temperature) was found to require an exchanger nearly four times as large. Dry cooling at 64°F requires an exchanger of approximately 112 acres, which is less than the 158 acres of evaporation ponds currently in use.

The combination of the air cooler and the existing mechanical draft cooling towers was simulated and easily found to keep the cooling water temperature low enough to maintain a 1.5 psia condenser pressure. The projected water savings are very large.

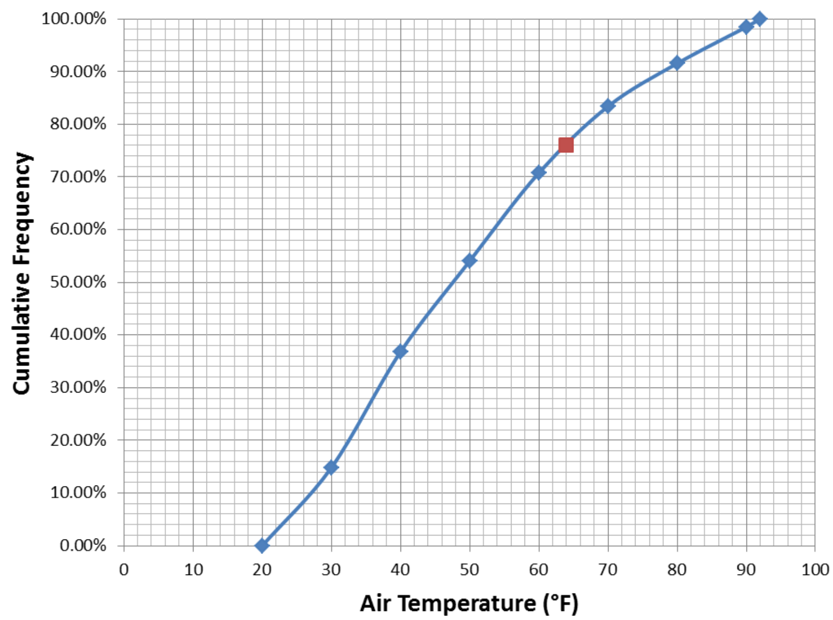

Figure 7. Cumulative air temperature frequency in Winnemucca, Nevada

Over the course of the National Oceanic and Atmospheric Administration's normal year previously mentioned and at the nameplate capacity of 522 MW, the cooling tower is used 2090 hours with only about 9% of the makeup required for full wet cooling and only about 7% of the water delivered to the evaporation ponds.

An alternative to the wet/dry cooling discussed above is to use the geothermal heat for lithium bromide absorption refrigeration or use the additional power produced by the geothermal boiler feed water heating to provide ammonia mechanical refrigeration. The refrigeration produced would then be used to cool the water coming from the air cooler prior to its entry into the condenser. A 24-hour cycle of the highest normal temperature day was run for each of the absorption and mechanical refrigeration cases and it was found that the cooling water temperature could not be maintained at the desired level. The system flow diagrams are shown as the last two supplementary figures.

A number of caveats are worth noting in understanding the cases modeled under this effort. Owing to both its low-rank fuel and low process efficiency, the North Valmy plant's flue stream is better reflected in the NETL Case 9 than Case 10, but it should be noted that Case 9 underestimates both the volume of flue gas and the mass of CO_2 reflected by a simple capacity-basis comparison. As such, the re-boiler duty calculations are compared to Case 9 rather than Case 10 (Table 3). The low efficiency of the plant requires relatively more re-boiler duty and a higher degree of CO_2 capture than for a comparably sized Case 9. It is also possible that the lack of a wet flue gas desulfurization system at North Valmy may require additional cooling for the direct contact cooler, and greater SOx removal than is required under Case 9. Also, the low temperature of the geothermal resource, assumed here to be 125 °C, provides less heat duty than would be provided by a higher temperature resource. However, for an advanced carbon capture system with far lower re-boiler temperature requirements (~70°C), applying the geothermal resource to the re-boiler and doing some boiler feed water heating with the residual energy. The results are described in the table below. As seen in Table 4, assuming the same 2.7 MMlb water per hour, Case 9 would utilize the 150°C (302 ˚F) resource from the first year's study, resulting in 361 MMBtu, which is 22.5% of the re-boiler duty for the plant. Similarly, at Valmy, a 125°C(257°F) resource would be able to provide nearly 240 MMbtu, which is 12.1% of the re-boiler duty. It should be noted that while the flue gas composition is closer to Case 9, the formal TEA analysis for hybrid Carbon Capture cases in the subsequent sections could only be provided for a hypothetical DOE Case 10 base line as it is the only baseline with costs available for comparison.

Table 3. Hybrid direct-use geothermal 125°C water providing carbon capture solvent re-boiler duty

Geothermal Resource as Partial Reboiler Duty Supply			
		Case 9 **	North Valmy
Geothermal Water flow	lb/hr	2,695,600	2,695,600
Flue Gas estimate	lb/hr	5,043,963	6,031,228
90% CO2 removal	lb/hr	934,828	1,154,801
Geothermal water T. in	°F	302	257
Geothermal water T out	°F	168	168
Q available	MMBtu	361.2	239.9
Estimated Q required *	MMBtu	1,605	1,983
% of duty from geothermal		22.5%	12.1%

* Reboiler Duty assumed proportional to CO2 removed

** Case 9 represents a 550 MW retrofit to CO2 capture with comparable flue gas flow to North Valmy

Assumption: Advanced Carbon capture system - 70°C (158°F), 10°F geothermal water approach (168°F)

5.2 Energy and Economic Projections

The energy and cost of electricity projections for all cases modeled in Aspen Plus are tabulated in Tables 5-8. The classes of cases are broken out by type: *No Carbon Capture*, *North Valmy Cases,* and *With Carbon Capture*. For each class of cases there is a reference case provided by recreating NETL's Case 9 (subcritical plant without CO_2 capture), site-specific North Valmy, and then Case 10 (subcritical with CO_2 capture). For the No Carbon Capture cases, we modeled cases for the boiler feed water heating and using the same geothermal resource through an ORC for comparison. With North Valmy, we provide the same boiler feed water heating study but the similar ORC simulation was not performed due to its higher cost and lower power output. The other North Valmy cases investigate dry-cooling cases where air fans could provide the majority of cooling to the plant and save 91% of the plant's water consumption. Valmy may save an estimated 2.9 billion gallons per year, more water than is used for domestic consumption by the residents of the State of Nevada in a week.[15] The last cases are with Carbon Capture, Case 10 with an amine baseline at two levels of boiler duty provided by geothermal resources. It should be noted that all carbon capture models were done based on Case 10 as it is the only benchmark-configured process to be used for analysis. As such, the last two With Carbon Capture cases look at more advanced carbon capture solvents such as CO_2BOLs used in place of MEA. We could not model North Valmy with amine-based Carbon Capture due to heat transfer requirements. The re-boiler temperature requires 130°C water, which is above the 125°C best case resource viability at Valmy. For the advanced solvents a 75°C water could be provided and would provide a similar benefit as the Case 10 hybrid analysis. It should be noted that these simulations assume that all hybrid plants are operated virtually identical to their reference case, whether Case 9, North Valmy or Case 10 albeit with geothermal infrastructure auxiliary draws and capital costs and resource extraction costs.

Table 4. Net electric power and fuel cost estimates for each model case

	No Carbon Capture (NETL Case 9 reference: Subcritical PC)			No Carbon Capture						North Valmy Cases Subcritical PC	With Carbon Capture (Case 10 reference: Subcritical PC with MEA capture solvent)					
Fuel Costs	NETL Case 9 baseline reference case	Case 9 baseline with geothermal for BFW heating	Case 9 baseline w/ geothermal for BFW, through ORC first	North Valmy baseline	North Valmy baseline w/ geothermal for BFW 1300 gpm	North Valmy baseline w/ geothermal for BFW 650 gpm	North Valmy baseline w/ geothermal for BFW 1300 gpm 2X Wells	North Valmy baseline w/ 64 F air cooling - no geothermal	North Valmy baseline w/ 64 F air cooling and geothermal	North Valmy baseline w/ 92 F air cooling and geothermal	Case 10 Only (recreated)	Case 10 with geothermal for BFW, but for 7% of reboiler first	Case 10 with geothermal for BFW, but for 100% of reboiler first	Case 10 with low viscosity CO2BOLs solvent vs. MEA (no geothermal)	Case 10 w/ CO2BOLs, BFW via geothermal but for 90% of reboiler first	Assumptions (list below)
TOTAL (STEAM TURBINE) POWER, kWe	574,331	597,822	588,505	553,418	565,302	559,572	565,302	553,418	565,302	565,302	668,950	695,453	830,588	760,890	807,486	1
Portion of Total Power from ORC, kWe			15,767													
AUXILIARY LOAD SUMMARY, kWe																
Coal Feed, Boiler and Auxiliaries	21,360	21,360	21,360	21,112	21,112	21,112	21,112	21,112	21,112	21,112	30,470	30,470	30,470	30,470	30,470	5
CO2 Capture Plant Auxiliaries											19,231	19,268	19,584	27,660	19,584	1
CO2 Compression											48,790	48,790	48,790	48,790	48,790	9
Condensate Pumps	516	514	512	556	674	680	674	556	674	674	405	432	723	405	707	1
Circulating Water Pumps	4,963	5,844	5,896	5,825	6,427	6,103	6,427	5,825	6,427	6,427	10,199	10,984	14,221	10,199	13,486	5
Ground Water Pumps	540	636	641	366	406	261	406		N/A	282	930	1,001	1,296	930	1,229	1
Cooling Tower Fans	2,770	3,262	3,291	1,869	2,031	1,928	2,031			1,411	7,791	8,383	10,854	7,791	10,293	1
Transformer Loss	1,804	1,878	1,848	1,716	1,752	1,735	1,752	1,716	1,752	1,752	2,337	2,429	2,901	2,337	2,821	1
Air Cooler Fans								10,280	10,280	10,280						
Geothermal Well Injection Pumps		3,039	3,039		779	389	779		779	779		3,039	50,879		7,954	1
TOTAL AUXILIARIES, kWe	31,953	36,532	36,587	31,444	33,181	32,208	33,181	39,489	41,024	42,717	120,152	124,796	179,718	128,581	135,333	2
NET POWER, kWe	542,379	561,289	551,918	521,975	532,120	527,365	532,120	513,929	524,277	522,584	548,799	570,657	650,870	632,309	672,153	2
Net Plant Efficiency (HHV)	36.3%	37.5%	36.9%	31.4%	30.1%	29.8%	30.1%	30.9%	29.6%	29.5%	26.1%	27.1%	31.0%	30.1%	32.0%	2
Net Plant Heat Rate (Btu/kWh)	9,408	9,091	9,245	10,935	11,355	11,457	11,355	11,049	11,525	11,562	13,074	12,573	11,023	11,347	10,674	2
As-Received Coal Feed (kg/h)	198,391	198,391	198,391	247,217	247,217	247,217	247,217	247,217	247,217	247,217	278,956	278,956	278,956	278,956	278,956	5
Thermal Input, kWt	1,495,379	1,495,379	1,495,379	1,663,737	1,770,324	1,770,324	1,770,324	1,663,737	1,770,324	1,770,324	2,102,643	2,102,643	2,102,643	2,102,643	2,102,643	5
Total CO2 Production Rate (kg/h)	471,116	471,116	471,116	581,971	581,971	581,971	581,971	581,971	581,971	581,971	695,954	695,954	695,954	695,954	695,954	5
Percent CO2 Captured	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	90%	90%	90%	90%	90%	5
Geothermal Water Flow (lb/hr)	0	2,695,600	2,695,600		2,695,600	1,347,800	2,695,600		2,695,600	2,695,600	0	2,695,600	37,000,000	0	10,000,000	1
Total Geothermal Duty (MMBtu/hr)	0	517	517		517	517	517		517	517	0	517	2,577	0	1,605	1
Annual Fuel Cost ($MM/year)	$62.2	$62.2	$62.2	$80.4	$80.4	$80.4	$80.4	$80.4	$80.4	$80.4	$87.4	$87.4	$87.4	$87.4	$62.2	2
Utilization Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	5
Fuel Cost (¢/kWe-hr)	1.54	1.49	1.51	2.07	2.03	2.05	2.03	2.10	2.06	2.07	2.14	2.06	1.80	1.86	1.24	2

Assumptions: 1) From Aspen Plus Simulation, 2) Calculated from Table Values, 3) From Aspen Economic Analyzer, 4) Average well cost estimates, 5) Same as Case 9 or Case 10, 6) Assumes 23% of TPC, 7) MEA from Case 10, CO_2BOLs from Pacific Northwest National Laboratory report, 8) Same as Case 9 or Case 10 normalized to new net power.

5.2.1 No Carbon Capture Cases

The first three cases in Table 3 represent the cases modeled for a generic subcritical coal-fired power plant. The first case is the recreation of NETL's Case 9 baseline to validate the simulations using ASPEN Plus. The second case in Table 3 represents the use of geothermal water for preheating the boiler feed water in Case 9. Here geothermal water at 150°C and a flow rate of 2,695,600 lb/hr is used, resulting in an estimated net power increase of 19 MWe. The third case represents the conditions as the second case, but with the geothermal water first passing through an i-butane-based ORC system. Here, only a 10 MWe increase in net electric power is predicted due the low efficiency of the ORC at 150°C, and the lower grade heat of the resulting water for boiler feed water preheating. Two other ORC cases were modeled using ammonia and propane, but the net electric power increase was even lower than i-butane. This comparison indicates that direct use of the geothermal water into the steam cycle feed water heater provides the highest power output compared to an ORC integration.

5.2.2 North Valmy Site-Specific Cases

The middle five cases in Table 3 outline all site-specific simulations of North Valmy with boiler feedwater heating, with varied parameters for dry cooling. The boiler feedwater hybrid case for North Valmy uses 2.7 million lb/hr of 125 ˚C water, and results in a 10.1 MW capacity increase over the base North Valmy case, at a total capital cost of 26.5 M USD. The lower temperature flow produces 8.9 MW less power than Case 9 with 150 ˚C boiler feedwater heating as only three of the heaters can be replaced at 125 ˚C rather than four heaters at 150 ˚C. A power comparison for a stand alone ORC was not performed with 125 ˚C water as net power would be similarly low as Case 9 with ORC, albeit with a higher capital cost. Halving the flow available at Valmy (1,347,800 lb/hr at 125 ˚C), results in 5.4 MW of capacity. The reduced flow as expected produces a little more than half of the power of the higher flow rate. Separate economic assessments of the reduced flow are described in section 6.

The remaining three cases evaluate a novel approach to reduce ground water use by up to 2.9 billion gallons per year at North Valmy. Here a dry-cooling system was modeled for three cases, the first two assuming 64°F ambient temperatures, with and without geothermal integration. The third case uses a hypothetical 92°F ambient air case where a wet- and dry-cooling system could be implemented, with wet cooling used only in the summer months. Here, the addition of air-cooling represents an 8 MW auxiliary draw to the plant. Using geothermal with the dry cooling enables 10.3 MW more power, bringing the hybrid dry-cooling/geothermal system up a net 2.3 MW over the recreated North Valmy system. Thus, a geothermal hybrid design could more than power the dry-cooling system, potentially saving 2.9 billion gallons of groundwater per year. The last Valmy case considers a combined wet- and dry-cooling system that operates dry 75% of the year. With geothermal integration, this system could provide 0.6 MW of additional capacity, while consuming only 7% of the cooling water. Projected costs and auxiliary power draw as a function of airflow were performed in ASPEN Economic Analyzer. The amount of airflow (500 MMlb/hr) was set based on the lowest of the capital expenditures of $48 M USD for 20 cooling fans.

5.2.3 With Carbon Capture Cases

The remaining cases in Table 3 represent a generic coal-fired power plant with CO_2 capture. The first two reference a recreation of Case 10, which is based on amine-based (MEA) carbon capture and sequestration. The fifth case shows the same geothermal water flow as the two earlier cases (2,695,600 lbs/hr) is estimated to provide 7% of the MEA re-boiler duty in addition to providing heat to the first four steam cycle feed-water heaters. This integration strategy results in an estimated 21 MWe of net power over Case 10. The sixth case is similar but considers as much larger geothermal source (37,000,000 lbs per hr) in order to supply 100% of the MEA re-boiler duty. Although this geothermal water rate is deemed infeasible, the net power projections in this case suggest potential for 101 MWe net output increase over Case 10.

The final two modeling cases in Table 3 evaluate the CO_2BOLs advanced solvent platform. The CO_2BOLs solvent has a much lower projected regeneration temperature and would, therefore, potentially be more amenable to lower grade geothermal resources. Indeed, the last case in Table 3 shows that 10,000,000 lbs/hr of geothermal water (at 150°C) could potentially be used to offset 90% of the CO_2BOLs regeneration duty, producing an estimated 40 MWe more power than CO_2BOLs alone, and 121 MWe more power than Case 10.

The other parameters besides energy that contribute to economic projections for modeled cases include variable and fixed costs, as well as capital costs. Estimates for these values are shown in Tables 4 and 5.

Tables 4 and 5 highlight the variable costs, previously modeled cases, and the new site-specific North Valmy cases. We point out that Variable and Total Capital costs for the Valmy system could not be gathered from site operators, so we used the values from the Case 9 study. This enables us to provide a comparison between Case 9 and North Valmy for the TEA, which the results are tabulated in Table 6 and illustrated in Figure 9. It should be noted that these numbers are to be used as a *relative* not *absolute* comparison of cost impacts on the aforementioned hybrid designs in this study.

Table 5. Variable and fixed cost estimates for each model case

	No Carbon Capture (Case 9 reference: Subcritical PC)			No Carbon Capture Subcritical PC North Valmy Cases						With Carbon Capture (Case 10	0			CO2BOLs Updated Predictions -
Variable Costs ($k/yr)	Case 9 Only (recreated)	Case 9 with geothermal for BFW heating	Case 9 Only with geothermal for BFW, but through ORC [i-Butane] first	North Valmy (recreated)	North Valmy baseline w/ geothermal for BFW 1300 gpm	North Valmy baseline w/ geothermal for BFW 650 gpm	North Valmy baseline w/ geothermal for BFW 1300 gpm 2X Wells	North Valmy 92 F air cooling with Geothermal wet/dry cooling	Case 10 Only (recreated)	Case 10 with geothermal for BFW, but for 7% of reboiler first	Case 10 with geothermal for BFW, but for 100% of reboiler first	Case 10 with low viscosity CO2BOLs solvent vs. MEA (no geothermal)	Case 10 w/ CO2BOLs, BFW via geothermal but for 90% of reboiler first	Assumptions (list below)
Non-Capture System:														
Maintenance Material Cost	$8,763	$8,763	$8,763	$8,763	$8,763	$8,763	$8,763	$8,763	$8,763	$15,644	$15,644	$15,644	$15,644	$15,644
Water	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$2,712	$2,712	$2,712	$2,712	$2,712
MU & WT Chem	$1,103	$1,103	$1,103	$1,103	$1,103	$1,103	$1,103	$1,103	$1,103	$2,100	$2,100	$2,100	$2,100	$2,100
Limestone	$3,496	$3,496	$3,496	$3,496	$3,496	$3,496	$3,496	$3,496	$3,496	$5,043	$5,043	$5,043	$5,043	$5,043
Ammonia (28% NH3)	$3,136	$3,136	$3,136	$3,136	$3,136	$3,136	$3,136	$3,136	$3,136	$4,446	$4,446	$4,446	$4,446	$4,446
SCR Catalyst	$593	$593	$593	$593	$593	$593	$593	$593	$593	$832	$832	$832	$832	$832
Flyash Disposal	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,882	$2,882	$2,882	$2,882	$2,882
Bottom Ash Disposal	$512	$512	$512	$512	$512	$512	$512	$512	$512	$720	$720	$720	$720	$720
Capture System:														
Solvent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,106	$1,106	$1,106	$1,106	$4,826
NaOH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,062	$1,062	$1,062	$1,062	$4,071
H2SO4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$324	$324	$324	$324	$496
Corrosion Inhibitor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7	$7	$7	$7	$0
Activated Carbon	$0	$0	$0	$0	$0	$0	$0	$0	$0	$616	$616	$616	$616	$617
Total ($k/yr)	$21,078	$21,078	$21,078	$21,078	$21,078	$21,078	$21,078	$21,078	$21,078	$37,496	$37,496	$37,496	$37,496	$44,391
Variable Operating Cost (¢/kWe-hr)	0.52	0.50	0.51	0.54	0.53	0.55	0.54	0.54	0.52	0.88	0.77	0.80	0.75	50675.02
Fixed Operating Costs ($k/yr)														
Operating Labor	$5,524	$5,524	$5,524	$5,524	$5,524	$5,524	$5,524	$5,524	$5,524	$6,445	$6,445	$6,445	$6,445	$6,445
Maintenance Labor	$5,842	$5,842	$5,842	$5,842	$5,842	$5,842	$5,842	$5,842	$5,842	$10,430	$10,430	$10,430	$10,430	$10,430
Administrative & Support Labor	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$4,219	$4,219	$4,219	$4,219	$4,219
Property Taxes and Insurance	$17,849	$17,849	$17,849	$17,849	$17,849	$17,849	$17,849	$17,849	$17,849	$32,367	$32,367	$32,367	$32,367	$32,367
Total	$32,057	$32,057	$32,057	$32,057	$32,057	$32,057	$32,057	$32,057	$32,057	$53,460	$53,460	$53,460	$53,460	$53,460
Fixed Operating Cost (¢/kWe-hr)	0.79	0.77	0.78	0.82	0.81	0.84	0.82	0.82	0.78	1.26	1.10	1.14	1.07	61027.64

Table 6. Capital cost estimates for each model case

	No Carbon Capture (Case 9 reference: Subcritical PC)			No Carbon Capture				North Valmy Cases Subcritical PC			With Carbon Capture (Case 10 reference: Subcritical PC with MEA capture solvent)					
Total Capital Costs ($, Million)	**NETL Case 9 baseline reference case**	**Case 9 baseline with geothermal for BFW heating**	**Case 9 baseline w/ geothermal for BFW, through ORC first**	**North Valmy baseline**	**North Valmy baseline w/ geothermal for BFW 1300 gpm**	**North Valmy baseline w/ geothermal for BFW 650 gpm**	**North Valmy baseline w/ geothermal for BFW 1300 gpm 2X Wells**	**North Valmy baseline w/ 64 F air cooling - no geothermal**	**North Valmy baseline w/ 64 F air cooling and geothermal**	**North Valmy baseline w/ 92 F air cooling and geothermal**	**Case 10 Only (recreated)**	**Case 10 with geothermal for BFW, but for 7% of reboiler first**	**Case 10 with geothermal for BFW, but for 100% of reboiler first**	**Case 10 with low viscosity CO2BOLs solvent vs. MEA (no geothermal)**	**Case 10 w/ CO2BOLs, BFW via geothermal but for 90% of reboiler first**	**Assun (list b**
Non-Carbon Capture Components:																
Coal & Sorbent Handling	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$50	$50	$50	$50	$50	
Coal & Sorbent Prep & Feed	$19	$19	$19	$19	$19	$19	$19	$19	$19	$19	$24	$24	$24	$24	$24	
Feedwater & Misc. BoP Systems	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$99	$99	$99	$99	$99	
PC Boiler	$267	$267	$267	$267	$267	$267	$267	$267	$267	$267	$339	$339	$339	$339	$339	
Flue Gas Cleanup	$135	$135	$135	$135	$135	$135	$135	$135	$135	$135	$174	$174	$174	$174	$174	
Combustion Turbine/Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
HRSG, Ducting & Stack	$39	$39	$39	$39	$39	$39	$39	$39	$39	$39	$42	$42	$42	$42	$42	
Steam Turbine Generator	$114	$114	$114	$114	$114	$114	$114	$114	$114	$114	$129	$129	$129	$129	$129	
Cooling Water System	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$65	$65	$65	$65	$65	
Ash/Spent Sorbent Handling Sys	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$16	$16	$16	$16	$16	
Accessory Electric Plant	$52	$52	$52	$52	$52	$52	$52	$52	$52	$52	$84	$84	$84	$84	$84	
Instrumentation & Control	$21	$21	$21	$21	$21	$21	$21	$21	$21	$21	$26	$26	$26	$26	$26	
Improvements to Site	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$16	$16	$16	$16	$16	
Buildings & Structures	$62	$62	$62	$62	$62	$62	$62	$62	$62	$62	$63	$63	$63	$63	$63	
Carbon Capture Components:																
CO2 Removal System											$443	$443	$443	$445	$445	
CO2 Compression & Drying											$50	$50	$50	$50	$50	
Geothermal Components:																
Well Costs		$13	$13		$13	$13	$26		$13	$13		$13	$181		$49	
Geothermal Pipeline		$7	$7		$7	$7	$14		$7	$7		$7	$19		$11	
Geothermal Return Pumps		$2	$2		$2	$2	$4		$2	$2		$2	$22		$4	
Cooling Tower Addition		$4	$4		$4	$4	$8		$4	$4		$3	$12		$10	
Heat Exchangers (including ORC)		$1	$10		$1	$1	$1		$1	$1		$12	$11		$5	
Air Cooling Addition:								$48	$48	$48						
ORC expander, generator, transformer			$3													
Owner's Costs	$205	$211	$214	$205	$211	$211	$218	$216	$223	$223	$372	$381	$428	$373	$391	
Total Overnight Cost	$1,098	$1,131	$1,147	$1,098	$1,131	$1,131	$1,163	$1,157	$1,190	$1,190	$1,991	$2,037	$2,291	$1,994	$2,091	
Capital Charge Factor	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.124	0.124	0.124	0.124	0.124	
Capital Cost (¢/kWe-hr)	3.17	3.15	3.25	3.29	3.32	3.32	3.42	3.52	3.55	3.56	6.06	5.96	5.88	5.26	5.19	

Table 7. Levelized cost of electricity estimates for each model case

	No Carbon Capture (Case 9 reference: Subcritical PC)			No Carbon Capture (North Valmy reference: Subcritical PC)							With Carbon Capture (Case 10 reference: Subcritical PC with MEA capture solvent)					
Summary of Costs (¢/kWe-hr)	**NETL Case 9 baseline reference case**	**Case 9 baseline with geothermal for BFW heating**	**Case 9 baseline w/ geothermal for BFW, through ORC first**	**North Valmy baseline**	**North Valmy baseline w/ geothermal for BFW 1300 gpm**	**North Valmy baseline w/ geothermal for BFW 650 gpm**	**North Valmy baseline w/ geothermal for BFW 1300 gpm 2X Wells**	**North Valmy baseline w/ 64 F air cooling - no geothermal**	**North Valmy baseline w/ 64 F air cooling and geothermal**	**North Valmy baseline w/ 92 F air cooling and geothermal**	**Case 10 Only (recreated)**	**Case 10 with geothermal for BFW, but for 7% of reboiler first**	**Case 10 with geothermal for BFW, but for 100% of reboiler first**	**Case 10 with low viscosity CO2BOLs solvent vs. MEA (no geothermal)**	**Case 10 w/ CO2BOLs, BFW via geothermal but for 90% of reboiler first**	**Assumptions (list below)**
Fuel Cost	1.54	1.49	1.51	2.07	2.03	2.03	2.03	2.10	2.06	2.07	2.14	2.06	1.80	1.86	1.24	2
Capital Cost	3.17	3.15	3.25	3.29	3.32	3.42	3.32	3.52	3.55	3.56	6.06	5.96	5.88	5.26	5.19	2
Variable Cost	0.52	0.50	0.51	0.54	0.53	0.53	0.53	0.55	0.54	0.54	0.92	0.88	0.77	0.94	0.89	2
Fixed Operating Cost	0.79	0.77	0.78	0.82	0.81	0.81	0.81	0.84	0.82	0.82	1.31	1.26	1.10	1.14	1.07	2
Transp, Seques & Monitoring (TSM)	——	——	——	——	——	——	——	——	——	——	0.59	0.57	0.50	0.51	0.48	8
Total	**6.02**	**5.91**	**6.06**	**6.73**	**6.69**	**6.79**	**6.69**	**7.01**	**6.97**	**6.99**	**11.01**	**10.72**	**10.06**	**9.71**	**8.87**	2
Cost increase versus baseline	——	***-1.9%***	***0.6%***	——	***-0.5%***	***0.9%***	***-0.5%***	***4.3%***	***3.6%***	***4.0%***	***83%***	***78%***	***67%***	***61%***	***47%***	2

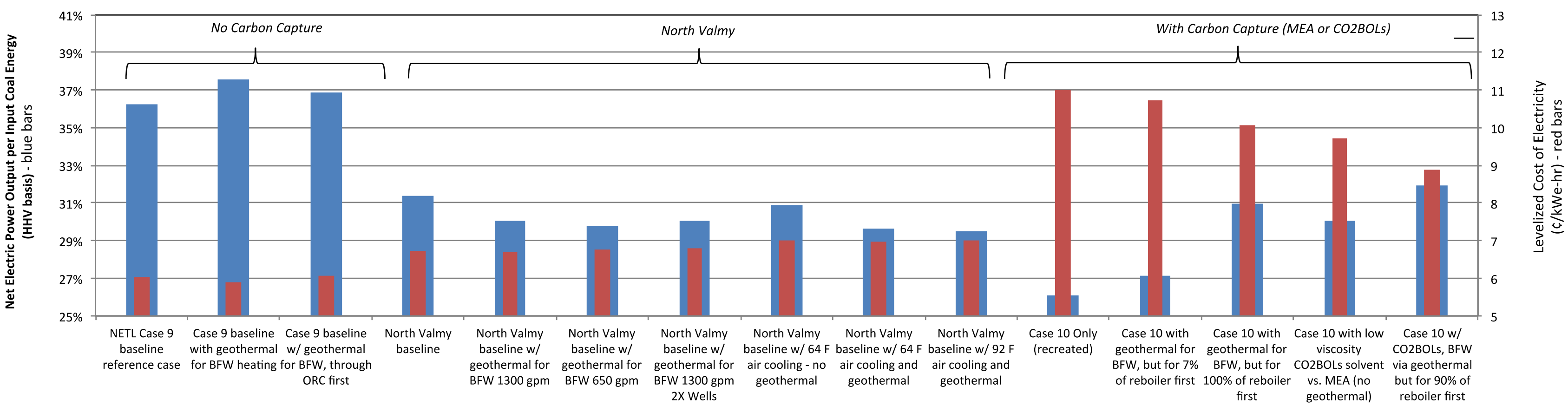

Figure 8. Comparison of net electric power and levelized cost of electricity estimates for each model case

We calculate the site-specific North Valmy cases as we had for the Case 9 and 10 designs from the previous year's study. We provide the LCOE values for each of the modeled cases, based on the sub-elements of fuel, capital variable, fixed and transportation, sequestration, and monitoring costs from the preceding tables. A graphical representation of the LCOE values and net plant efficiency are plotted in Figure 9, along with the net power output per input coal energy for each of the modeled cases.

The key takeaways from the previous study are listed again for reference:

- Using 150°C geothermal water for boiler feed water preheating appears to offer a higher net electric power, at a comparable LCOE, compared to a stand-alone Case 9 subcritical power plant option. Also, as mentioned above, first passing the geothermal water through an ORC prior to using it for boiler feed water preheating is estimated to produce less overall net power than using it for boiler feed water preheating alone.
- The modeling cases with MEA carbon capture indicate the current challenges around the economics associated with carbon capture. Unfortunately, massive amounts of geothermal water are required to fully offset the MEA regeneration energy need, which are not feasible amounts of geothermal resource for a single site.
- A modest geothermal resource (2,695,600 lb/hr) is estimated to offset ~7% of a MEA re-boiler duty in Case 10, resulting in ~1% of recovered net electric power lost to the overall CCS parasitic load, but at a similar (high) LCOE to CCS alone.
- The CO_2BOLs cases indicate a more significant opportunity for 150°C geothermal water use than with the MEA solvent, with ~0.75 cents per kWe-hr projected LCOE savings and ~2 points of net electric power increase versus CO_2BOLs alone. This opportunity reflects the lower regeneration temperature and duty for CO_2BOLs and similar advanced solvents.
- It is important to note that the model case result could significantly change with higher (or lower) geothermal water temperatures. Economic sensitivities to geothermal temperature may be worth exploring in subsequent efforts.

The key takeaways from the site-specific North Valmy analysis are as follows:

- North Valmy is less efficient than the NETL Case 9 plant, with net efficiency of ~31% and a LCOE (assuming identical capital and variable costs as Case 9) of 6.06 cents per kWe-hr.
- If 125°C water is available at North Valmy at the rates assumed in this study, boiler feed water heating could enable 10.1 MW gains in net power, though this is smaller than the 19 MW estimated if 150°C water is available under the plant.
- LCOE for 125°C boiler feed water integration is 1% increased efficiency for the plant with 0.04 cents per kWe-hr decrease.
- Half-flow of 125 ˚C water produces 5.4 MW of power with the same capital expenditures of the full flow case, resulting in a 0.06 cents per kWe-hr increase.

- Assuming half the flow of resource at 125 ˚C, doubling the number of wells to reach full flow of 125 ˚C water results in the 10.1 MW of power with a doubling of geothermal capital (53 MM USD total), resulting in a LCOE increase of 0.10 cents per kWe-hr.
- The addition of dry cooling to the plant could save an estimated 2.9 billions of gallons of ground water per year at the cost of 48 million USD at a modest power draw of 8 MW with smaller land requirements (112 acres) than the evaporating ponds currently in use (150 acres).
- The power gains from integrating geothermal boiler feed water heating are enough to power the dry cooling, offering an increase in efficiency over the recreated North Valmy case by <1%, at a slight COE increase of 0.28 cents per kWe-hr.
- Wet and dry cooling also saves 2.9 billion gallons of water per year at comparable plant efficiencies with a modest 0.24 cents per kWe-hr increase.

Given the uncertainty in assumed flow rates for the Valmy Formation at the plant site, two cases were modeled to examine the impact of halving per-well flow rate on overall economics at North Valmy. The first case reflects a scenario in which only half the flow rate is available from the same number of wells; in the second, the same rate is maintained by doubling the well infrastructure, and associated capital expenses. In the reduced-production case, less power is produced, resulting in a 0.06 ¢/kWh increase in LCOE. In the higher-capital case, where twice as many wells are required to produce the same amount of water, LCOE increases 0.10 ¢/kWh due to both higher capital costs and higher operating costs. In either case, a 50 percent reduction in the flow rate per well has significant negative impacts on overall cost of electricity.

6.0 Discussion

Sitting atop a known (albeit poorly characterized) hydrothermal system, the North Valmy plant is unique among the U.S. coal-fired power fleet. However, taking North Valmy as a case study for quantitative evaluation of how and where geothermal fluids might be integrated into conventional, industrial system designs, and what costs and benefits might derive from this, suggests that low-temperature geothermal resources may offer a complementary and adjunct application of geothermal energy in the near-term. While these resources fall below the temperature range necessary to make ORC generation cost effective, they are far more widely distributed than the high temperature geothermal resources of interest for current and near-term development as baseload power. But, as shown in this study, by leveraging the enormous capital investments already present in the fossil-fired generation fleet, geothermal energy can be used to provide a significant net increase in nameplate capacity at modest incremental costs. As modeled at the North Valmy plant, applying low-temperature geothermal fluids for boiler feedwater preheating results in an increase in overall plant capacity up to 10.1 MWe, for an overnight capital cost of $53 M USD, with an LCOE decrease of only $0.04 cents per kWe-hr.

In the U.S. and beyond, the potential geographical match between existing, conventional power or other industrial facilities and low-grade geothermal resources may offer opportunities to implement geothermal hybrid approaches to address process-specific heat needs, improve efficiency, and increase utilization of renewable, zero-emission geothermal resources. The marginal increases in the cost of power, under the conditions assumed in this study, are quite small, on the order of only a few percent in most cases. In the longer view, as greenhouse gas emissions become more heavily regulated in the United States and abroad, capacity increases to conventional fossil-fired power generation that can be effected via renewable hybridization, without a significant net increase to CO_2 emissions, could be increasingly attractive.

While beyond the current scope, the results of this study suggest a need to understand the extensibility of this approach to natural gas- and biomass-fired power generation, as well as energy intensive industrial processes. Such an understanding could help clarify the degree to which a potential market exists for hybridized geothermal systems, and could help to focus work on those sectors with the greatest potential for large-scale commercial adoption. Based on this preliminary case study, however, it appears that coupling low-temperature geothermal resources to industrial processes like power production may hold significant promise to meet the Geothermal Technology Office cost performance targets of $.06/kWh and contribute meaningfully toward GTO's 300 MW installed capacity goal.

7.0 References

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8.0 Supplemental Information

The flow diagrams recreated by Pacific Northwest National Laboratory are shown below in Figures Supplementary (S) 1-3. Here, the Case 9 flow diagram is shown with feed water pre-heat (S1) and compared to an ORC (S2). The steam cycle for Case 10 is shown below in Figure S(3). Also, the geothermal well layout from ASPEN plus is shown in Figure S(4). The net power calculations and results of the simulations are provided in Figures S(5) and S(6).

Figure S(1). Aspen plus model of the DOE Case 9 subcritical steam cycle with feed water preheat

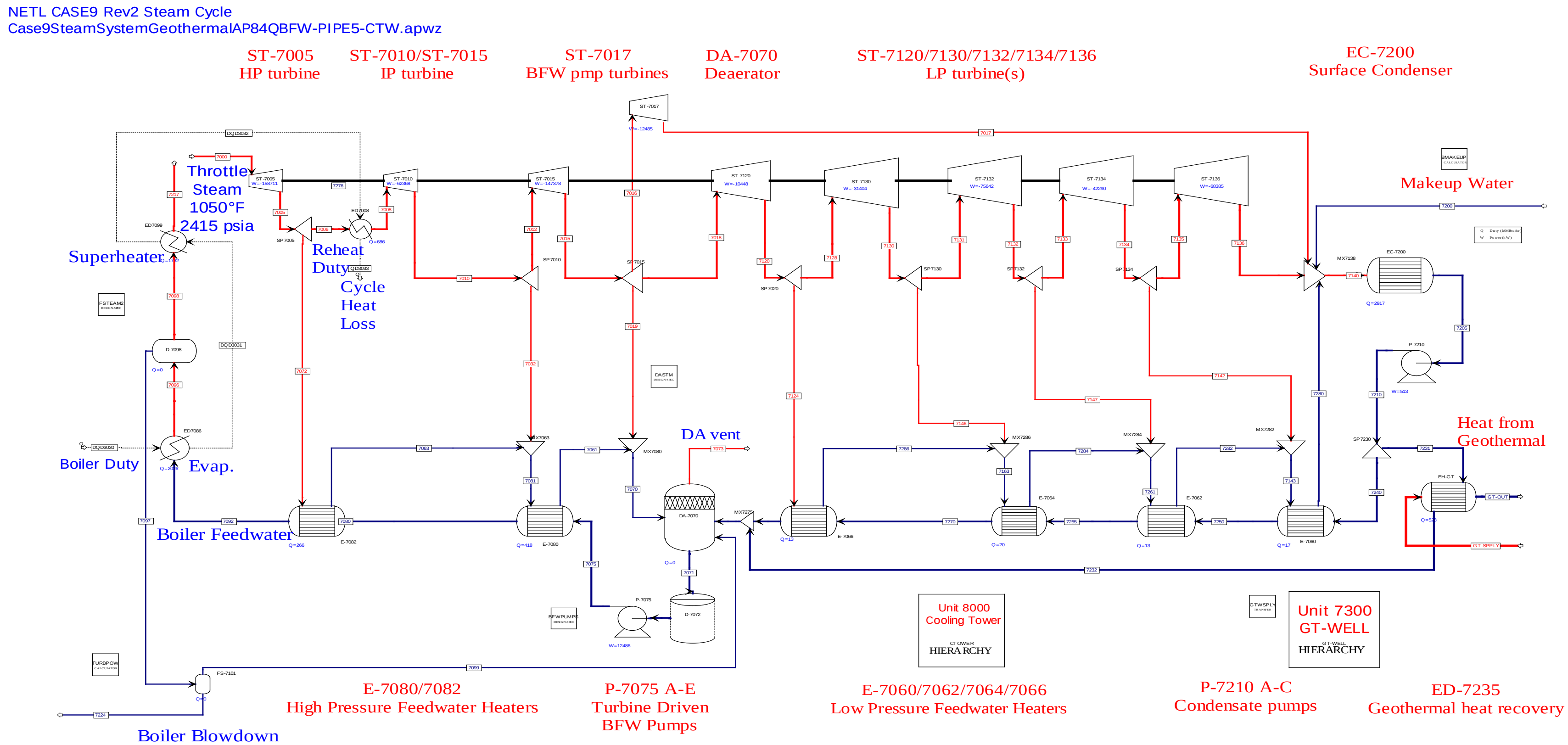

Figure S(2). Aspen plus model of the DOE Case 9 subcritical steam cycle with ORC

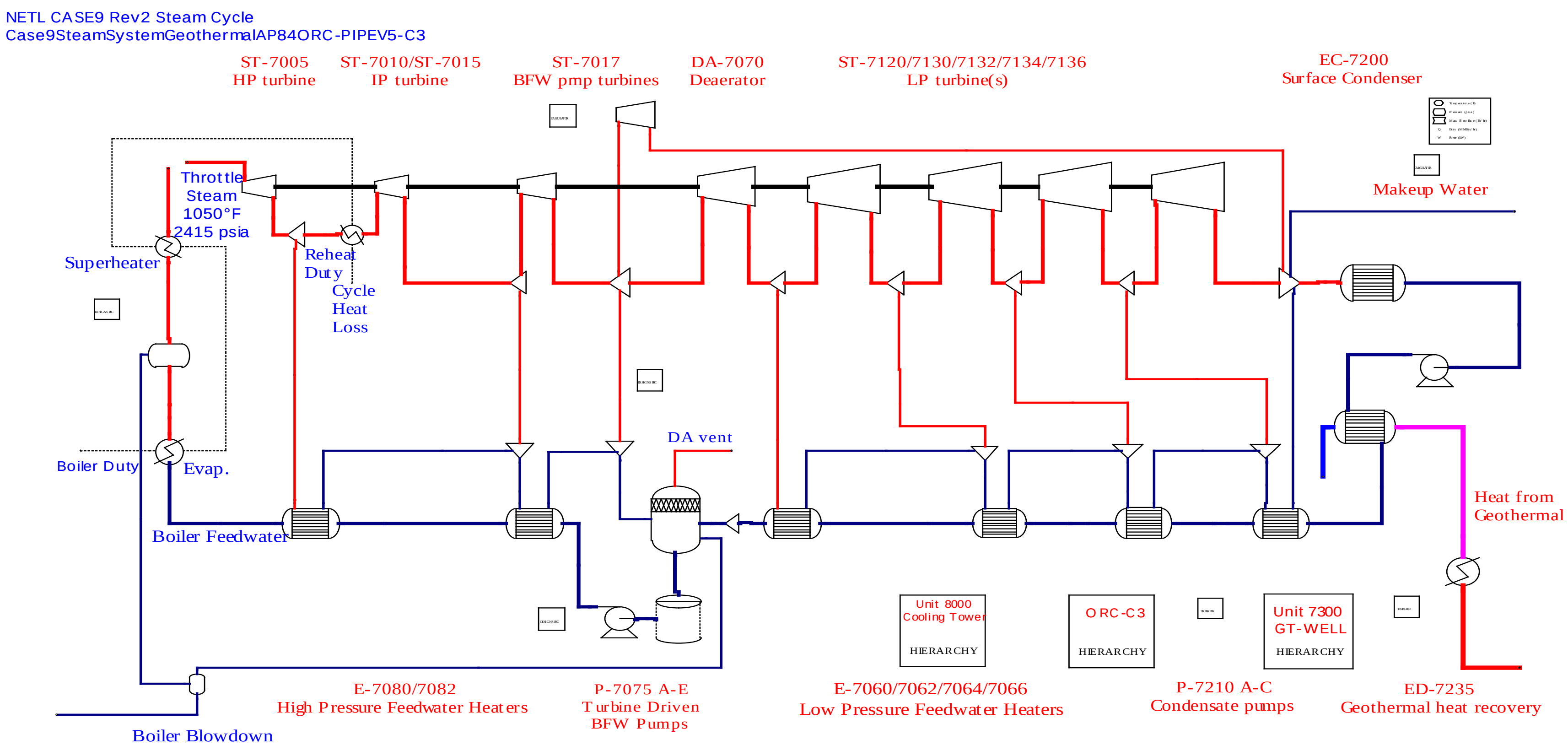

Figure S(3). Aspen plus model of the DOE 10 subcritical steam cycle

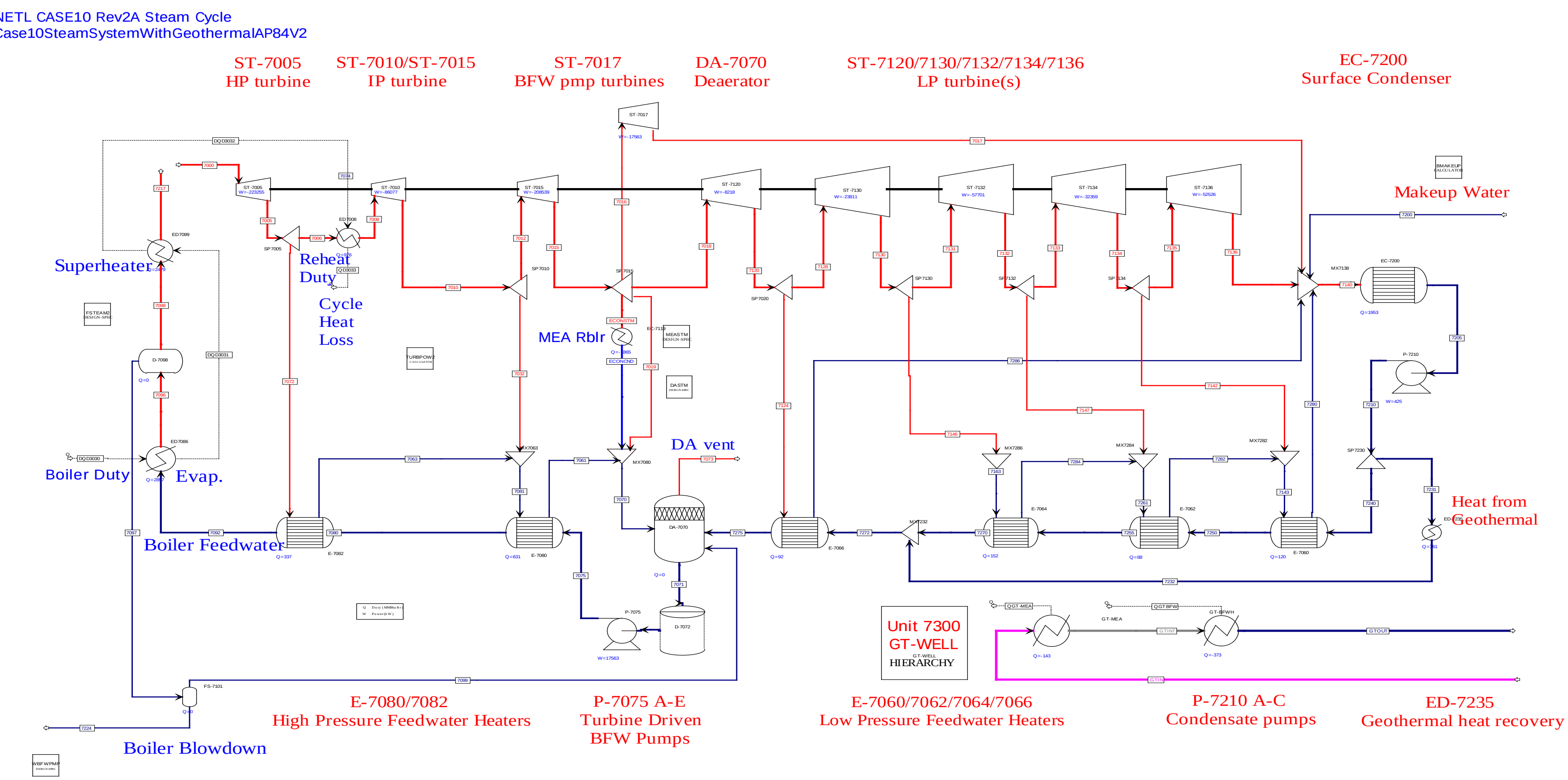

Figure S(4). ASPEN plus model geothermal well diagrams

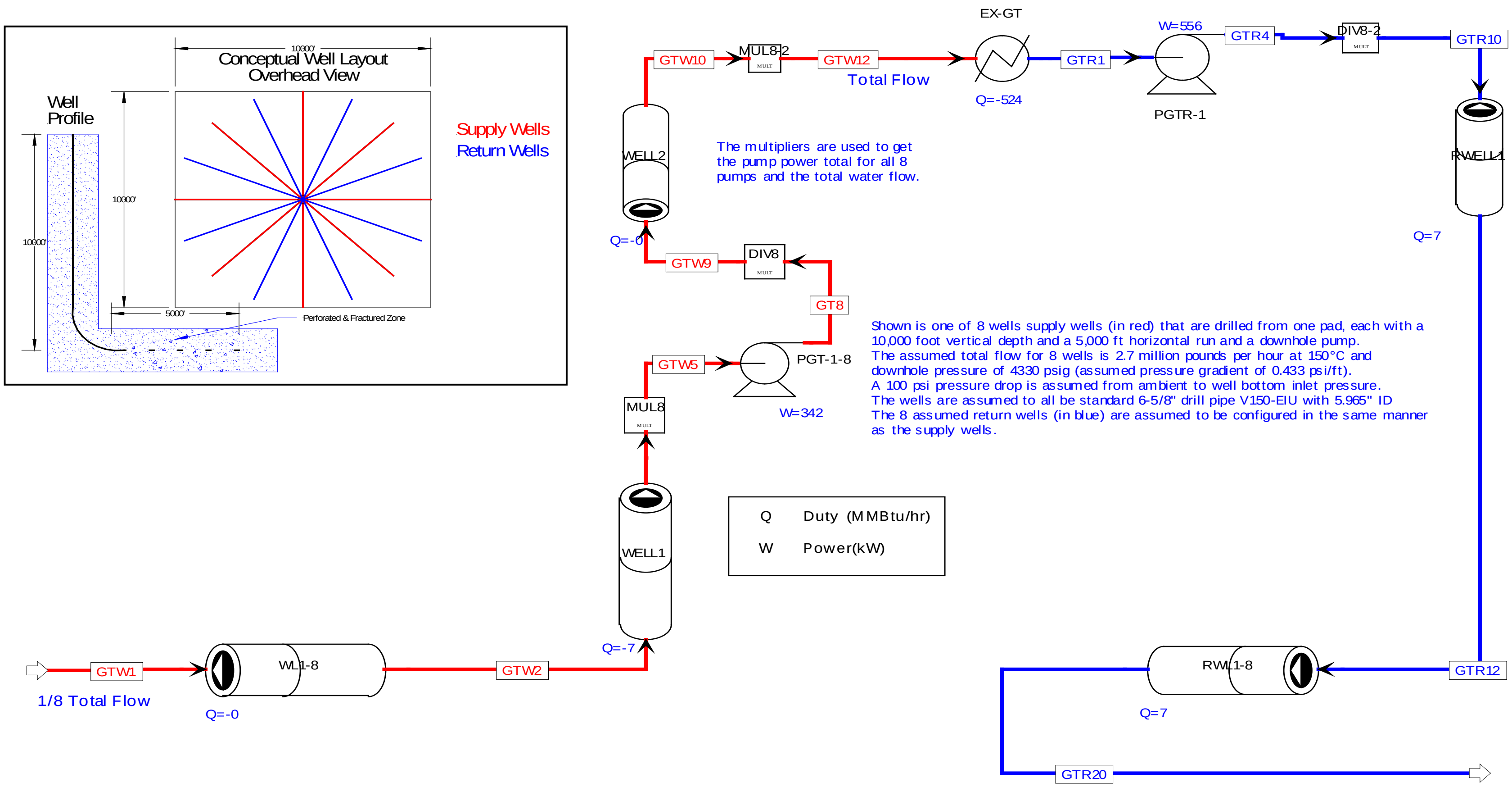

Figure S(5). Summarized projections for Integration of geothermal /coal-fired plants hybrid plants vs. standalone ORC

Power Summaries - No Carbon Capture Power in kWe Duty in MMBtu/hr	NETL CASE 9	PNNL Case 9 No Geothermal	PNNL Case 9 Geothermal BFW Heating	PNNL Case 9 Geothermal ORC - Ammon	PNNL Case 9 Geothermal ORC - Propan	PNNL Case 12 Geothermal ORC - i-Butane
AREA7100.ST-7005		158,711	158,668	158,453	158,453	158,453
AREA7100.ST-7010		62,572	62,555	62,233	62,233	62,233
AREA7100.ST-7015		147,858	147,818	147,058	147,058	147,058
AREA7100.ST-7120		10,515	10,476	10,273	10,291	10,352
AREA7100.ST-7130		30,464	31,488	29,762	29,815	29,991
AREA7100.ST-7132		69,391	75,845	67,792	67,912	68,313
AREA7100.ST-7134		37,393	42,403	36,531	36,596	36,812
AREA7100.ST-7136		57,427	68,568	59,073	59,178	59,527
AREA7100.ORC turbine	N/A	N/A	N/A	12,101	15,810	15,767
Gross Steam Turbine Power * kW	582,600	574,331	597,822	583,274	587,346	588,505
Coal & Miscellaneous Auxiliaries *	21,360	21,360	21,360	21,360	21,360	21,360
CTW circulating pumps	5,250	4,963	5,844	5,938	5,922	5,896
Cooling Tower fans ***	2,720	2,770	3,262	3,314	3,305	3,291
Geothermal Well injection pumps	N/A	N/A	3,039	3,039	3,039	3,039
Transformer loss ***	1,830	1,804	1,878	1,832	1,845	1,848
Condensate pumps	890	516	514	508	509	512
Ground Water pumps ****	530	540	636	646	644	641
Total Auxiliaries kWe	32,580	31,953	36,532	36,637	36,623	36,587
Net Power Production kWe	550,020	542,379	561,289	546,637	550,723	551,918
Cooling Water Duty MMBtu/hr	2,432	2,477	2,916	2,963	2,955	2,942

* NETL Case 9 is net of BFW pumps
** Coal Handling, Ash Handling, Pulverization, Primary, Forced Draft and induced draft fans through FGD From Case9 (not simu
*** Cooling tower fan power is ratioed from cooling water duty
**** Ground water pump power is ratioed from cooling water duty

Note: Aspen simulations in general produce less power and require substantially more compression power than NETL report numbers
Note: BFW pumps are turbine driven and neither turbine drive power nor BFW pump power appear in the net power calculation.

Figure S(6). Summarized projections for Case 10 integration strategies of geothermal /coal-fired plants hybrid plants

Power Summaries With Carbon Capture Power in kWe Duty in MMBtu/hr	NETL CASE 10	PNNL Case 10 No Geothermal	PNNL Case 10 Partial Reboiler Duty & BFW Htg	PNNL Case 10 Max Reboiler Duty & BFW Htg	PNNL Case 10 10MMlb/hr GT 70 °C Reboiler
AREA7100.ST-7005		223,255	224,408	224,408	225,322
AREA7100.ST-7010		86,077	86,522	86,522	86,874
AREA7100.ST-7015		208,539	210,083	210,083	209,766
AREA7100.ST-7120		7,781	8,292	14,716	14,356
AREA7100.ST-7130		22,542	23,775	42,193	41,378
AREA7100.ST-7132		51,077	57,615	102,248	95,258
AREA7100.ST-7134		27,499	32,311	57,342	51,285
AREA7100.ST-7136		42,181	52,447	93,077	83,246
Gross Steam Turbine Power kWe *	672,700	668,950	695,453	830,588	807,486
Coal & Miscellaneous Auxiliaries **	30,470	30,470	30,470	30,470	30,470
MEA or other CC agent ***	22,400	19,231	19,268	19,584	19,584
CO2 Compression ****	48,790	48,790	48,790	48,790	48,790
CTW circulating pumps	11,190	10,199	10,984	14,221	13,486
Cooling Tower fans ^	5,820	7,791	8,383	10,854	10,293
Geothermal Well injection pumps ^*			3,039	50,879	7,954
Transformer loss ^**	2,350	2,337	2,429	2,901	2,821
Condensate pumps	700	405	432	723	707
Ground Water pumps ^***	1,020	930	1,001	1,296	1,229
Total Auxiliaries kWe	122,740	120,152	124,796	179,718	135,333
Net Power Production kWe	549,960	548,799	570,657	650,870	672,153
Cooling Water Duty		5,025		7,047	6,683
Total Reboiler Duty ^****	2008	2,008	2,008	2,008	1,500
Geothermal Reboiler Duty		-	143	1,967	1,357
Total Geothermal Duty		-	517	2,577	1,605
Geothermal Water Flow lb/hr			2,695,600	37,000,000	10,000,000
Geothermal Water flow Bbl per day			184,693	2,535,115	685,166

* At generator terminals
** Coal Handling, Ash Handling, Pulverization, Primary, Forced Draft and induced draft fans through FGD From Case10 (
*** MEA or other carbon capture agent. The last column has a hypothetical agent with 80% reboiler duty of MEA and 70°C
**** CO2 Compression from stripper overhead pressure to 2215 psia from Case10 (Aspen simulation is always higher ~
^ Cooling Tower Fans for PNNL @ 0.5 inches water (NETL Case 10 is lower)
^* Geothermal well injection
^** Transformer loss (0.003493 * Gross Steam Turbine Power)
^*** Ground water pumps are ratioed to cooling tower duty

Figure S(7). LiBr cooling simulations

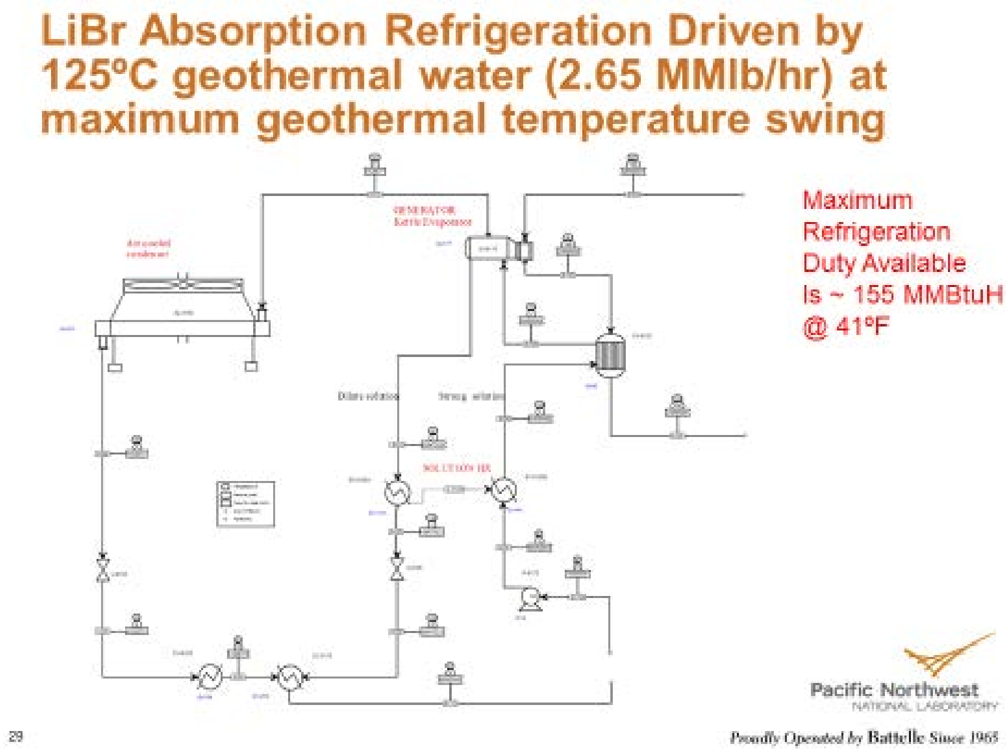

Figure S(8). NH_3 mechanical refrigeration