

EXAMPLES OF COMBINED HEAT AND POWER PLANTS USING GEOTHERMAL ENERGY

John W. Lund and Andrew Chiasson

Geo-Heat Center
Oregon Institute of Technology
Klamath Falls, OR 97601

ABSTRACT

Examples of combined heat and power plants (CHP) using both high temperature (above 200°C) and low temperature (around 100°C) geothermal resources are described. These installations, some of which have been in operation for over 30 years, make more efficient use of the geothermal resources by cascading the geothermal fluid to successively lower temperature applications, thereby improving the economics of the entire system dramatically. The cascaded use, after being used for power generation, can include space or district heating, greenhouse heating, and aquaculture pond and swimming pool heating. The high temperature geothermal power plants normally use flash steam technology, whereas the low temperature operation use binary or Organic Rankine Cycle (ORC) power units. High temperature power generation with geothermal energy is usually economic as stand-alone plants, but low-temperature power generation is often not economic, with net plant efficiencies normally below 10% due to the low source temperature and relatively high parasitic loads from pumps. Examples of high temperature CHP installation described in this paper include the Sudurnes Regional Heating Corporation plant at Svatsengi, Iceland, and the Nesjavellir Geothermal plant near Reykjavik, Iceland. Low temperature installations described in this paper include ones at Bad Blumau and Altheim, Austria, Neustadt-Glewe, Germany, and at Egat, Thailand.

Key words: combined heat and power, Sudurnes, Nesjavellir, Bad Blumau, Altheim, Neustadt-Glewe, Egat.

INTRODUCTION AND BACKGROUND

Combined heat and power (CHP) plants are not a new use of energy, whether it be from conventional fossil fuels or geothermal energy. In combining uses of heat with power generation, the power plant becomes increasingly more efficient, which in turn improves power plant economics. This is particularly true in geothermal power plants, where thermodynamic efficiencies are typically much lower than conventional power plants, due to the lower working fluid temperatures in geothermal power plants. For example, conventional fossil fuel-fired power plants produce steam on the order of 550°C, while most geothermal power plants operate with source temperatures in the range 90°C-300°C.

To illustrate the advantages of CHP with a geothermal power plant, consider a 10 MWe plant with a resource temperature of 150°C. According to Rafferty (2000), at this resource temperature, a geothermal power plant would have a net efficiency of about 10%. This means that 100 MWt of energy is the combined amount of geothermal energy supplied to the plant plus parasitic equipment requirements (pumps, cooling tower, etc.) plus waste heat rejected to or lost to the environment. With incremental recovery of waste heat for beneficial uses, the efficiency of the whole CHP operation increases dramatically.

More specifically, consider the following examples of using a high temperature resource (150° C) and a low temperature resource (100° C) in a cascaded situation with a volumetric flow rate of 76 L/s. The high temperature resource could sustain a 2.0 MWe geothermal power plant with three employees generating around \$1.0 million USD annually, resulting in a simple payback period of five years. Adding a two-line onion dehydration plant producing 13,600 tonnes of dried onions per year with a load factor of

0.83 (the load factor expresses the equivalent fraction of a year that a system operates at full load) would reduce the simple payback of the combined operation to one year and add 75 employees.

The low temperature resource (100°C and 44 L/s) could sustain a 250 kWe binary geothermal power plant with one employee generating around \$140,000 USD annually, resulting in a simple payback period of five years. Adding a district heating system serving 100,000 m² of floor space with a load factor of 0.25 would reduce the simple payback to four years, but only add about two more employees. If a greenhouse operation of 24 ha with a load factor of 0.25 were added instead, the combined simple payback would be reduced to three years and add 144 employees.

As can be seen from the above examples, applications with a higher load factor result in a more efficient operation and shorter payback period; the higher the load factor, the lower the cost of the delivered heat. Rafferty (2003) examined the cost of delivered heat as a function of load factor for U.S. climates. For example, the cost of energy (including capital, maintenance, and operating costs) is approximately 4 times greater for a small space heating application with a load factor of 0.15 than for an industrial application with a load factor of 0.4, while the cost of energy of a greenhouse with a load factor of 0.22 is about double that of an industrial application with a load factor of 0.4.

Another important factor to consider in adding a cascaded direct-use application is the distance from the source water, as the pipeline cost strongly impacts the capital cost of the project. Installed costs of pre-insulated hot water pipelines range from about \$500,000 USD per km for a 100-mm diameter pipeline to about \$1,000,000 USD per km for a 300-mm diameter pipeline (NRC, 2005). Adding a direct-use application, in most cases, provides substantial additional employment opportunities, which is an economic benefit to the community that is difficult to quantify. The remainder of this paper describes actual examples of geothermal CHP cases.

EXAMPLES OF COMBINED GEOTHERMAL HEAT AND POWER PLANTS

Sudurnes Regional Heating Corporation, Svartsengi, Iceland

The Svartsengi plant (Figure 1) supplies hot water to a district heating system (hitaveita) serving about 20,000 people on the Reykjanes Peninsula (Thorolfsson, 2005, Ragnarsson, 2005). In addition it also serves about 25,000 inhabitants in Hafnarfjörður and other communities with electricity. The total installed generating capacity of the combined plant is 46.4 MWe providing about 370 GWh/yr, and 200 MWth providing about 2,700 TJ/yr in the form of hot water for district heating. The plant is located close to the town of Grindavík about 50 km to the south west of the capital Reykjavík. It is located on an active mid-Atlantic spreading center with active earthquake swarms, volcanic craters and open fissures and faults. The plant is built on a lava field which dates from a volcanic eruption in the year 1226. The first well was drilled in 1972, with the number of drilled wells currently at 20. Of these, 12 are production wells and one well is used for reinjection. The reservoir fluid is a brine at 240°C. Most of the waste water flows into the adjacent lava field, where due to silica precipitation sealing the disposal pond, the famous "Blue Lagoon" bathing area was formed, visited by almost 200,000 tourists annually.

A flow diagram of the Svartsengi Power Plant is shown in Figure 2. The first heat exchanger experiments started in 1974 in a small-scale pilot plant. Based on the results of this research, a second pilot plant was built in 1976 which supplied the town of Grindavík with 20 L/s of hot water. The first electric plant, Power Plant I, was built in 1976-78. At the time, it was the first of its kind in the World, providing both geothermal electric energy and space heating for a district heating system simultaneously. This provided 150 L/s for the district heating system, which amount to 50 MJ/s (MWth) thermal power and two 1-MWe back-pressure steam turbine generators. Subsequently, 75 MWth of thermal energy and 6 MWe back-pressure turbines were installed in 1981. This was followed by three 1.2 MWe binary power units in 1989 with water-cooled condensers and four 1.2 MWe binary power units in 1993 with air-cooled condensers. Finally in 1999 a 30-MWe condensing steam turbine was commissioned and in 2000 the district heating increased to 75 MJ/s (MWth). With retirements and improvements of existing equipment,

the electrical generating system now consists of 12 turbines, five of which are steam units and seven are binary (organic Rankine cycle).

The plant maintenance and operating staff consists of 22 persons, who also operate 20 geothermal wells and wellheads, 70 control valves, 100 pumps, 20 km of pipelines and thousands of valves. Two 50-MWe power plants were installed in 2006.

Nesjavellir Power Plant, Reykjavik Energy, Iceland

The Nesjavellir Power plant (Figure 3) , located just to the west of Lake Thingvalla, provides electricity and district heating energy to the city of Reykjavik 27 km away (Lund, 2005; Ragnarsson, 2005). This field with temperatures as high as 380°C, has been operating a co-generation power plant since 1990.

The primary purpose of the co-generation plant is to provide hot water for the Reykjavik area. The plant capacity is 270 MWe generating 2,100 GWh/yr of electric energy, and provides 1,100 L/s of 83°C hot water for district heating with a capacity of 290 MWt which provides about 4,500 TJ/yr. Freshwater from nearby wells is heated by steam and water in a heat exchanger for the district heating system. In 1998 the power plant came on-line with two 30 MWe steam turbines. In 2001 the plant was enlarged to 90 MWe with the installation of a third turbine. In 2005, a fourth turbine came on line bringing the capacity to 270 MWe.

A flow diagram of the plant is shown in Figure 4. A total of 22 wells have been drilled to depths ranging from 1,000 to 2,200 m. The steam-water mixture from the wells is separated and the steam piped to the turbines at 12 bars at 190°C. The separated hot water is passed through shell-and-tube heat exchangers to heat the incoming cold water. This cold water at 4°C for the district heating system is obtained from five wells near Lake Thingvalla, which is then heated through condensers and heat exchanger to 85 to 90 °C. Since the freshwater is saturated with dissolved oxygen that would cause corrosion after being heated, it is passed through deaerators; where, it is boiled at low pressure to remove the dissolved oxygen and other gases, cooling it to 82-85°C. Finally, a small amount of geothermal steam containing acidic gases is injected into the water to rid it of any remaining oxygen and lowers its pH, thereby preventing corrosion and scaling.

Water for the district heating system is pumped through an 800-mm diameter pipeline to storage tanks overlooking Reykjavik. From the storage tanks, the water is fed through pipelines to the communities which are served by the district heating system (Orkuveita Reykjavíkur). The pipeline, 27 km in length, has fixed and expansion points every 200 m, and is designed to carry water at 96°C at a rate of 1,870 L/s. At 560 L/s, the water takes about seven hours to cover the distance, losing only 2°C. At the higher rates of flow, the loss is only 1°C. The 8-to-10 mm thick steel pipe is insulated with 100 mm of rock wool and covered with aluminum sheets where it lies above ground, and insulated with polyethylene and covered with PEH plastic where it lies underground.

Bad Blumau, Austria

Bad Blumau, a resort community, is located in east Austria in the Styrian Basin which is a sub-basin of the Pannonian Basin (Goldbrunner, 2005). The Basin has heat flow values up to 95 mW/m² and temperatures of more than 100°C at depths of 2,000 m. The geothermal project at Bad Blumau has its origins in drilling for hydrocarbons. This exploration, with drilling to 3,046 m in well Bad Blumau 1a, encountered fluids of 100°C at 17 L/s. Two wells were then drilled for geothermal fluids, Bad Blumau 3 to 1,200 m producing 1.5 L/s at 47°C and Bad Blumau 2,360 m producing 80 L/s at 110°C. The geothermal fluids of the deeper wells are sodium-bicarbonate-chloride type with a total dissolved solids (TDS) of 17.9 g/L. Due to the potential for carbonate precipitation, polyphosphate is added at the well.

A process schematic of the Blumau geothermal project is shown in Figure 5. A 250 kW geothermal binary (organic Rankine) cycle power plant was installed in 2001. The plant used brine at

110°C to generate a net 180 kW. The existing water at 85°C is fed into the district heating system, providing heat for the Rogner Bad Blumau Hotel and Spa (Figure 6). The spent water is then returned to a 3,000-m deep injection well. The spa with pools of 2,500 m² is provided geothermal water at 1.5 L/s. The heating of the spa complex and hotels (1,000 beds) is established by a geothermal doublet using well 1a and 2. Since the water is high in CO₂, 1.5 t/h of liquid gas is being extracted. The total capacity of the space heating is 3.5 MWth and the pools at 1.6 MWth for a total of 5.1 MWth. The electric power plant produced around 1.56 million kWh over three months in 2003.

The spa was built entirely with private investments of €55 million with the local government providing €20 million for the drilling of wells and improving the local infrastructure. The overnight stays are around 40,000 annually, with 340 jobs in the thermal resort hotel and 170 jobs in regional services being created.

Altheim, Austria

Altheim is a municipality in the Upper Austrian “Inn-region” with 5,000 inhabitants. A well for the district heating system was drilled in 1989. The well produced geothermal fluids flowing from an aquifer about 2,300 m deep. The artesian flow from the well was 46 L/s at 104°C, but, with downhole pumps can produce 85-100 L/s at 106°C. The district heating system capacity is 10 MWth supplying heat to 650 consumers, or about 40% of the inhabitants of Altheim. About 80% of the thermal energy is used for these homes, and the remainder is used for heating a school and swimming pool. A schematic of the power plant and district heating system is shown in Figure 7.

A second well was drilled in 1994 was deviated for a total length of 3,100 m at a vertical depth of 2,200 m (Figure 8). This well produces 100 L/s at 93°C. This well is now used as the injection well receiving the spent water at 65°C. About half of the water from the original production well goes to the district heating system. The other half of the flow is used to power a 2.5 MWe binary (organic Rankine) cycle generator installed in 2000 with a peak output capacity of 1.027 MWe. Presently only about 500 kWe producing around 100,000 kWh/month is supplied to the grid, with the remaining power used for the various pumps and other auxiliaries.

The district heating system, operating about 1,200 hours/year charges about €0.04/kWh (\$0.05 USD/kWh) based on a 30°C temperature drop in the water. However, the customers usually achieve a greater temperature drop, thus paying less per kWh. There is of course, a significant reduction in air pollution, based on using fossil fuel prior to 1989. These amount to between 58 and 72% reduction in greenhouse gases for the community, saving about 2,500 t/year of equivalent fossil fuel.

Neustadt-Glewe, Germany

The Neustadt-Glewe geothermal heating plant, located in northern Germany, was commissioned in 1995, supplying exclusively the base load for a district heating system. The total output of the system is 11 MWth of which geothermal supplies 6 MWth; the remainder provided by a gas-fired boiler unit that covers the peak load. In 2003, a 210 kWe gross geothermal electric power unit was added to the system. A schematic of the CHP system is shown in Figure 9.

The geothermal electric power unit, a binary (organic Rankine) cycle, uses 98°C water from a 2,300-m deep well. The plant uses n-perfluoropentane as a working fluid, and the parasitic loads due to pumps and fans amount to 31 kW. The production pump in the well is not included in the parasitic load. The production pump is a speed-controlled electric submersible set at 260 m.

The plant supplies heat and power using a parallel-series connection of power plant and heating station. The heating station takes priority over the power plant. The incoming flow rate of the brine at 110 m³/h, is split and a part is fed to the power plant. The brine leaves the power plant at a constant outlet temperature where it joins the upstream flow to the heating station. The minimum mixing temperature required in the summer is 73 °C, and to meet the heating demand in wintertime 98°C is required. Thus, the power plant is fed with variable mass flow rate of brine at constant temperature;

while, the heating station is provided with a constant mass flow rate at variable temperature. After use, the fluid is returned to an injection well around 50°C.

The total district heating project cost was €9.45 million (\$12.3 million USD) of which €6.44 million (\$8.37 million USD) was for the geothermal side of the system. The electrical generation plant cost €950,000 (\$1.24 million USD). As of 1998 1,300 households, 20 trade consumers and one industrial enterprise are supplied with heat from the plant. During this time, 15,900 MWh of heat of which 15,042 MWh was geothermal (95%) was supplied to the customers. The system saved about 1.7 million m³ of natural gas/yr and reduced the emission of CO₂ by 2,700 tonnes.

Fang Geothermal Plant, Egat, Thailand

This combined operation was commissioned in 1989 and consists of a single-module 300 kWe binary power plant that has a water cooled condenser with once-through flow (Ramingwong, et al., 2005). A photograph of the geothermal power plant is shown in Figure 10.

The net power output varies with the season from 150 to 250 kWe (175 kWe average) producing 1.2 GWh/yr. This multipurpose project (Figure 11) then cascades the water from the power plant for refrigeration (cold storage) crop drying and a spa, with an installed capacity of 480 kWt producing 0.92 TJ/yr. The artesian well provides approximately 8.3 L/s of 116°C water. The well requires chemical cleaning to remove scale about every two weeks. Plant availability is 94% and the estimated power cost is from \$0.063 to \$0.086 USD per kWh. This is very competitive with diesel generated electricity which runs \$0.22 USD to \$0.25 USD per kWh.

CONCLUDING SUMMARY

This paper has described examples of combined heat and power plants utilizing geothermal energy. Examples of high temperature CHP installation described included the Sudurnes Regional Heating Corporation plant at Svatsengi, Iceland, and the Nesjavellir Geothermal plant near Reykjavik, Iceland. Low temperature installations described included ones at Bad Blumau and Altheim, Austria, at Neustadt-Glewe, Germany, and at Egat, Thailand.

The installations described, some of which have been in operation for over 30 years, make more efficient use of the geothermal resources by cascading the geothermal fluid to successively lower temperature applications, thereby improving the economics of the entire system dramatically. The cascaded use, after being used for power generation, can include space or district heating, greenhouse heating, aquaculture pond heating, swimming pool heating, space cooling, and refrigeration.

From a simple economic analysis, it was shown that the greater the load factor for the direct-use application, the more efficient the operation and the shorter the payback period of the combined heat and power project. A higher load factor essentially spreads the capital cost over a greater quantity of heat over the annual cycle, and thus results in a lower cost of delivered heat. This implies that in cold climates, district heating applications are more economically favorable than in warmer climates. Higher load factors are usually achieved with industrial operations using high temperature resources that are not entirely dependent on weather factors, and thus operate more frequently during the year. Another benefit of some direct-use applications is job creation.

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Figure 1. Aerial view of the Svartsengi Power Plant and "Blue Lagoon".

Figure 4. Flow diagram of the Nesjavellir Power Plant.

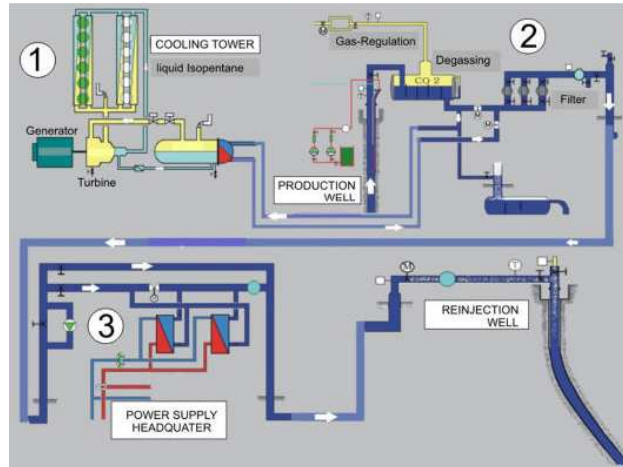


Figure 5. Blumau geothermal project. (1) ORC, (2) CO₂-gas, and (3) district heating.



Figure 6. Rogner Bad Blumau spa and outdoor pools.

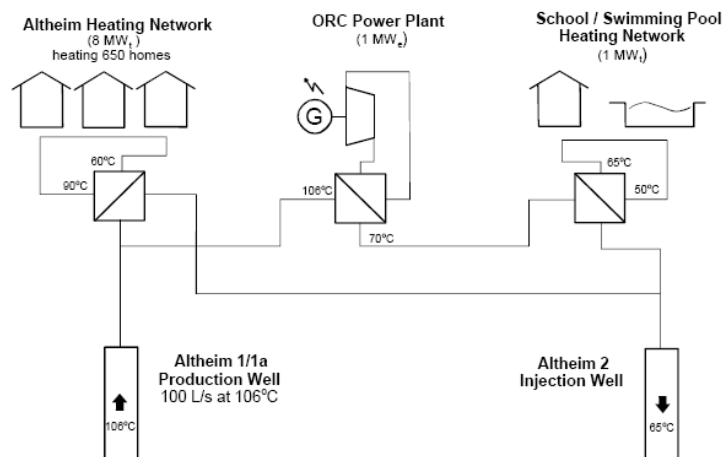


Figure 7. Schematic of the Altheim Power Plant and district heating system.

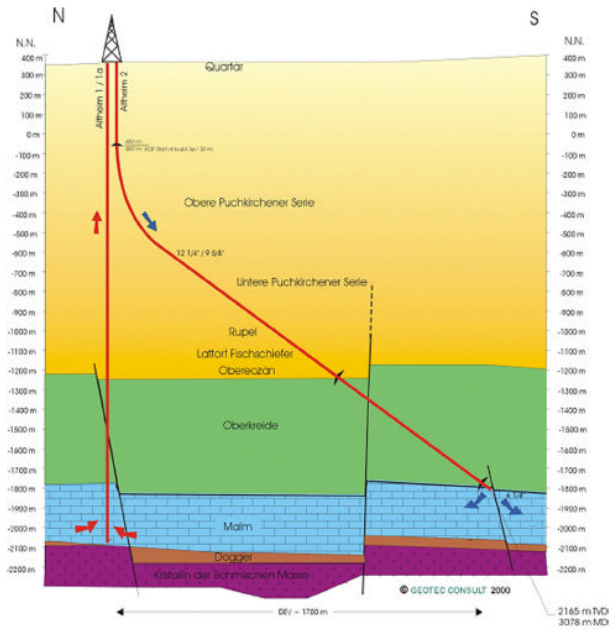


Figure 8. Geologic cross-section showing production and injection wells at Altheim.

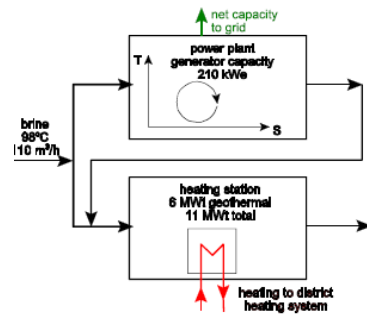


Figure 9. Process schematic of the CHP project in Neustadt-Glewe.



Figure 10. Fang binary geothermal power plant in Egat, Thailand.

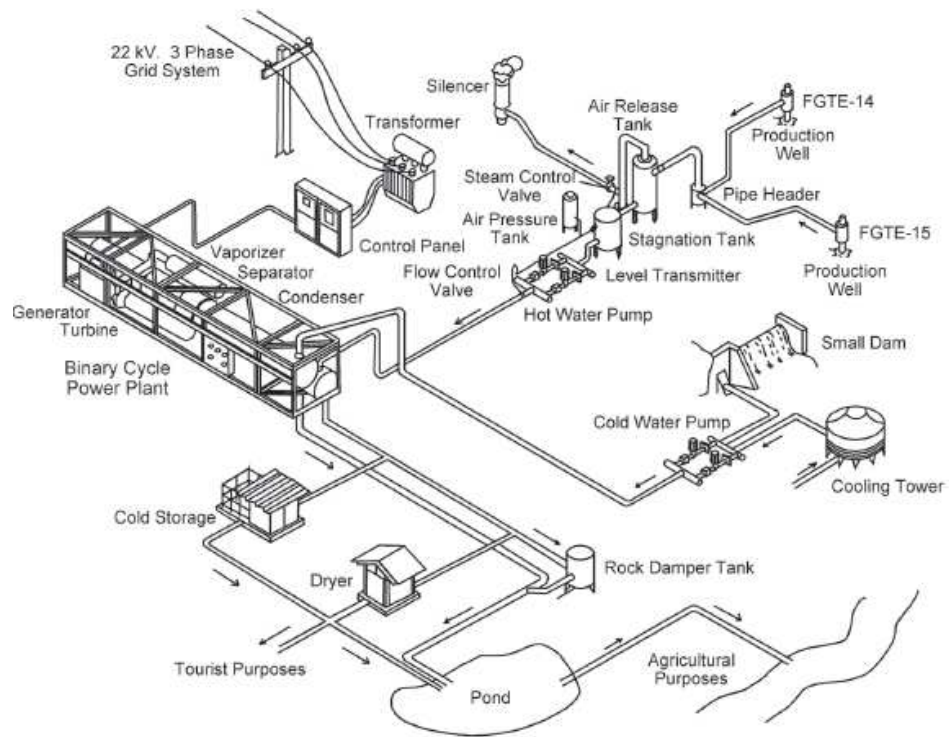


Figure 11. Process schematic of the Fang Geothermal CHP project in Egat, Thailand.