An Empirical Injection Limitation in Fault-Hosted Basin and Range Geothermal Systems

Dick Benoit

Keywords

Basin and Range, injection, case history, Roosevelt, Beowawe, Desert Peak, Dixie Valley, Bradys, Blue Mountain

ABSTRACT

Volumetric methods of predicting sustainable megawatt outputs of fault-hosted geothermal systems in the Basin and Range Province have not been particularly accurate because they cannot assess cooling due to recycling of injectate. Two to three decades of production experience from four fault-hosted geothermal systems empirically shows that it is possible to sustainably extract $\pm$20 megawatts of electrical energy from a mile of fault length with initial production temperatures of 480 to 500 ºF and up to about 15 MW/mile of fault length from reservoirs with initial temperatures near 400 ºF. The most common limiting factor is cooling due to recycling of injectate. The highest injection density to date for a sustainably operating plant supplied from a fault-hosted system is at Beowawe where up to 3600 gpm/linear mile of fault length is occurring. Attempted injection rates of >10,000 gpm/mile of utilized fault length have twice resulted in rapid cooling commencing within weeks to months.

Introduction

The most valuable prediction during the early development of geothermal projects is accurately assessing how many megawatts the field can sustainably generate. Too often the desired answer is not based on geological or reservoir engineering insight. Given the wide range of geologic settings in which geothermal fields occur, no single methodology is capable of accurate prediction. This paper addresses geothermal fields hosted by normal faults or narrow fault zones within the Basin and Range Province in the western United States. Four of these fields have been operational for >24 years and have recently increased their outputs so now is a reasonable time to assess why these fields have been successful and recognize common factors of this success; success being profitability and minimal costly reconfiguration of field facilities.

Historic Prediction Methods

Volumetric Heat in Place

The first predictions of the possible megawatt output of many geothermal systems in the United States were performed by the U. S. Geological Survey in Circulars 729 and 790 utilizing volumetric estimates of heat and fluid in place (White and Williams, 1975; Muffler, 1979). These utilized what were then believed to be reasonable assumptions on the reservoir volumes, temperatures, porosity, etc. and Monte Carlo simulations. The importance of injection in controlling the field lifetimes and megawatt outputs was not yet recognized as the word is not mentioned in either Circular. Both Circulars are widely recognized as over-predicting what the industry has been able to develop.

The most comprehensive use of volumetric heat in place calculations combined with Monte Carlo simulations is the PIER Report (GeothermEx, 2004) which utilized data from 155 geothermal resources in California and western Nevada. Megawatt estimates presented in the PIER Report are smaller than those predicted in the Circulars, but these predictions are still discouragingly far above what industry is delivering. These volumetric heat in place calculations are the basis for the Australian and Canadian geothermal codes in quantifying inferred or indicated resources.

Volumetric heat in place calculations are routinely performed with little or no exploration data. Many of the historic parameter values can be fairly characterized as falling in a theoretically maximum possible category with no guarantee that the heat can be economically extracted. As one overly optimistic example, a volumetric assessment at Baca, New Mexico suggested 400 MW of resource due to a large thermal anomaly. After the drilling of 23 deep wells a revised capacity <40 MW was validated and a purchased 50 MW power plant was never installed (Union Oil Company, 1982).

Areal Extent and Power Density

Only at the largest geothermal fields in the United States has it been possible to drill wells on a grid type of basis to allow utilization of a planar area to predict megawatt outputs. An early rule of thumb at The Geysers was that the power density was $\pm$

50 MW/mi^2 from a dry steam 480 ºF resource with pressures over 400 psi. As wellhead pressures declined to less than 100 psi The Geysers productivity has declined to about 25 MW/mi^2. Grant and Bixley (2011) suggest a typical worldwide power density range of volcanic hosted systems of 26 – 38 MW/ mi^2 with an overall range from 8 to 70 MW/mi^2 (Grant 2000).

Natural Heat Loss

Volumetric calculations treat geothermal systems as static entities but liquid-dominated geothermal systems are dynamic. Wisian et al. (2001) developed an empirical correlation between the total natural state surface heat loss and the maximum energy production from a geothermal system. This relation suggests that the maximum amount of energy that can be reliably produced from a geothermal system expected to last 20 – 30 years is about ten times the natural heat loss from the system. This method requires that the thermal anomaly be outlined with temperature-gradient holes in reasonable detail and that the amount of convective water and/or steam discharge be known. Heat loss output predictions are constrained by data directly relatable to the potency of a geothermal system. However, these heat loss calculations cannot take into consideration inherent inefficiencies in actually developing a project, a major issue being imperfect siting or completion of the wells. Two different and presumably extreme examples illustrate limitations of the areal extent and natural heat loss methods. At the Philippine Mak-Ban field only minor surface manifestations are present yet 458 MW are being produced from about 2.6 mi^2, giving a production density of about 150 MW/mi^2 (Capuno et al., 2010). This may be the greatest such density on earth. At the other end of the spectrum four deep exploration wells failed to find commercial production within a large fumarole infested geophysical anomaly at Sibualbuali in Sumatra. Thus the heat loss can predict megawatt outputs either larger or smaller than those actually obtainable.

Single Fracture Flow Model

In 1974 generic equations were developed to assess possible megawatt outputs of a single flat permeable fracture (Bodvarsson, 1974). However, Bodvarsson recognized that “accurate computations of recovery factors are generally not feasible and one will invariably have to resort to estimates based on little solid evidence… and ... a further discussion without reference to definite field cases appears premature”.

Basin and Range Geothermal Fields

Several of the operating Basin and Range geothermal fields consist of linear well arrays paralleling documented faults. The Roosevelt, Beowawe, Desert Peak, Dixie Valley, Brady’s, and Blue Mountain fields are located along faults with proven production histories and extensive publicly available information. The thickness and width of the permeable portions of these faults are poorly known, making area or volumetric calculations uncertain. However, the utilized permeable lengths of these fault zones can be determined by simply examining wellhead locations on Google Earth images. Most Basin and Range fields are not discussed for the following reasons. The Coso resource is more characteristic of a volcano-hosted system. The Mammoth geothermal field has an exceptionally large hydrothermal recharge of 4750 gpm (Sorey et al., 1978). The Cove Fort and Rye Patch (Humboldt House) fields have little or no production history. The small Wendell, Amedee, and Wabuska plants do not inject. The San Emedio plant lacks published information. The Soda Lake, Stillwater, and Steamboat fields do not have field layouts or publications indicating that they are associated with a single fault. The longer-term success of the recently developed Jersey Valley, McGinnis Hills, Tuscarora, and Salt Wells fields is unknown.

Roosevelt

The Roosevelt geothermal field produces from, and injects into, a portion of the NNE trending Opal Mound fault zone (Moore and Nielson, 1984). A subsidiary part of the field is the E-W trending Negro Mag cross fault, which is also utilized for injection purposes (Figure 1). This cross fault makes the Roosevelt field more complex than a simple single fault but as both permeable features are viewed as faults, the field is treated as a single fault.

The 23 MW single-flash plant commenced operations in 1984 with 4 production wells and 3 injection wells spread along a total Opal Mound fault length of 2.3 miles (Allis and Larsen, 2012). Initial production zone temperatures were slightly above 500 ºF.

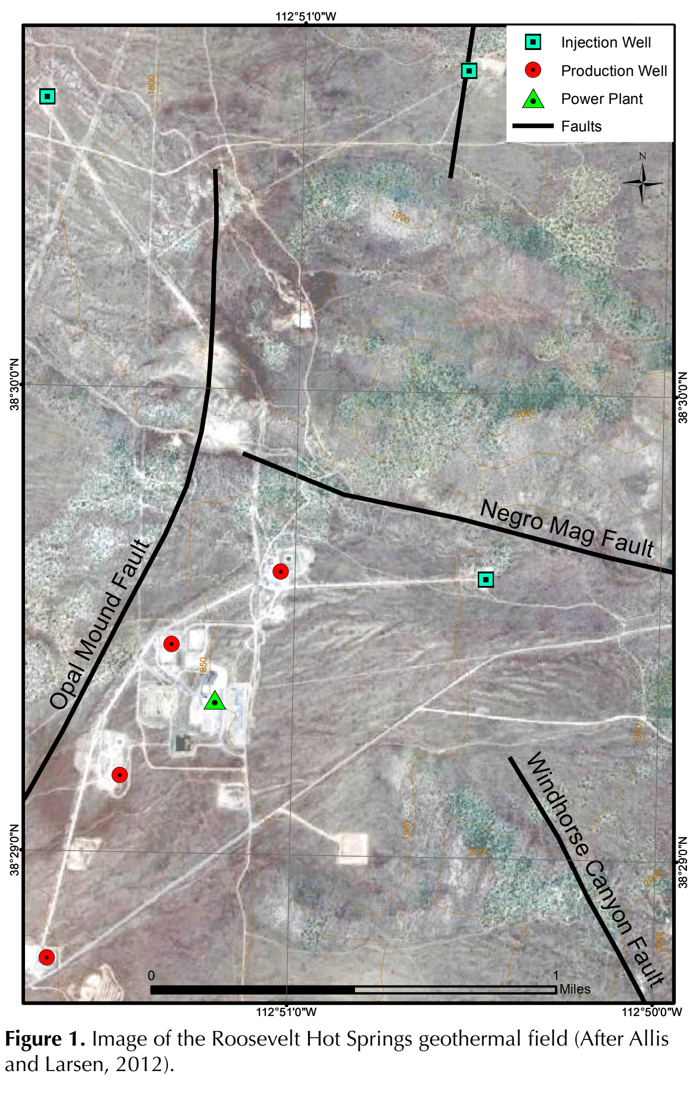

Figure 1. Image of the Roosevelt Hot Springs geothermal field (After Allis and Larsen, 2012).

Cooling of about 1.25 ºF/yr has reduced temperatures to 470 – 480 ºF in 2011. (All geothermal fields which recycle injectate will inevitably suffer cooling.) Only 2 of the 7 original wells have been twinned/replaced. A 10 MW binary plant was installed in 2007 on the injection line.

About 2.3 miles of fault length has sustained 23 MW for 23 years and 33 MW for 6 more years. The plant design was for injection of 3700 gpm (Kerna and Allen, 1984), which equates to 1600 gpm/mile of Opal Mound Fault length. This injection density is actually quite minimal as the southernmost production well is more widely separated but this would be offset by including some length of the Negro Mag fault (Figure 1).

No tracer tests have been performed at Roosevelt. About 17 billion lbs/yr of mass is evaporated through the cooling tower. A reservoir pressure decline of about 600 psi over 29 years is de facto proof the injectors are providing good pressure support (Allis and Larsen, 2012).

Beowawe

The Beowawe field produces from a portion of the NE-SW trending Malpais fault (Layman, 1984). In the natural state, thermal fluid rose obliquely from depth near the production wells to discharge at a large silica terrace (Butler et al., 2001) (Figure 2).

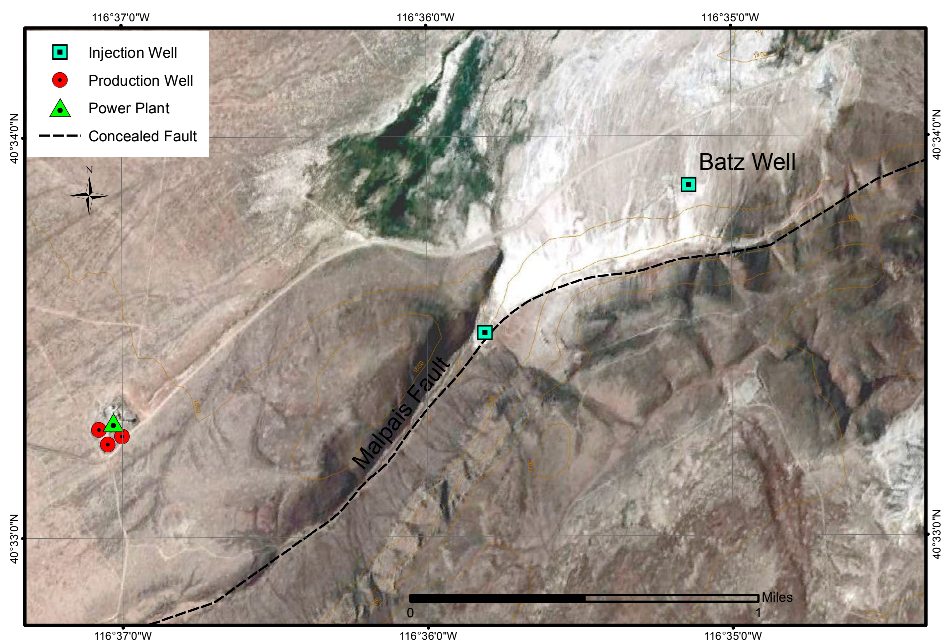

Figure 2. Image of the Beowawe geothermal field.

The 16.6 MW dual-flash Beowawe plant commenced operations in Dec. 1985 with two 410 ºF production wells. All injection was into the Batz 1 well which, by a rare combination of circumstances, accepted large amounts of fluid, lacked pressure communication with the producers, and had limited tracer returns (Rose et al. 1995). This allowed cold groundwater to invade the deep reservoir (Benoit and Stock, 1993). After two years of operation a 7 ºF/yr cooling trend commenced, generating decline rates up to 2.66 MW/yr. These trends were ameliorated by the drilling of a new production well in 1991 and diverting all injection into an existing idle well known to be in pressure communication with the deep reservoir in early 1994 (Butler et al., 2001). By 1997 the cooling rate had declined to about 1 ºF/yr (Benoit, 1997). From mid 1996 to 2000 the enthalpy of the produced fluids and the power plant output was essentially constant (Butler, et al., 2001). Production zone temperatures at the end of the 1990s were in the range of 348 to 365 ºF. Tracer tests have first returns between 5 and 10 days and classical tracer concentration peaks at 17 and 35 days (Rose et al., 1995, 2002) (Table 1). There have been no substantial changes in the field layout since 1994. In January 2011 a 2.5 MW binary plant was commissioned to remove additional heat from the injection line (Dickey, et al., 2011).

The producers and the injection well are about 1 mile apart, proving this mile of fault length with an initial temperature of 410 ºF can sustainably generate 15 MW. The injection rate has been as high as 3600 gpm, giving a horizontal injection density of 3600 gpm/mile of fault. The injection zone at a depth of 1500' is far shallower than the 6700 to 9500' deep production zones so the oblique travel length along the fault is significantly greater than a mile, reducing the injection density to much less than 3600 gpm/mile of fault in 3 dimensions.

Desert Peak

Recent mapping interprets the "blind" Desert Peak field to by hosted by a sand-covered left step in the NNE-striking Rhyolite Ridge fault zone (Faulds et al., 2010)(Figure 3).

A 9 MW dual-flash power plant commenced operations in late December 1985 utilizing 2 producers and 1 injector completed at similar depths. Initial production well temperatures were 406 to 415 ºF (Faulder and Johnson, 1987). A spare injection well saw limited service. The project later converted the smaller diameter and idle discovery well to a producer and operated in this configuration until 2006 when the original power plant was replaced with a 23 MW binary plant. New wells were drilled to support the expansion but are not symbolized on Figure 3. No public data on the temperature decline of this field are available.

Tracers injected into both the injectors in 2008 (some other production wells were in service during this test) had first returns between 4 and 40 days in the original production wells (Rose et al., 2009). Tracer return curves from the 67-21 well were anomalous with multiple sharp peaks and valleys. Sampling was terminated at the 86-21 well after 110 days with no convincing peak. The wide variety in return times and anomalous curves indicate complex pathways.

The two or three producers and one injector utilized during the first 20 years of production are located about 0.75 mile apart and at similar depths giving 12 MW/mile of utilized fault length, a number slightly lower than that from Beowawe with nearly identical initial production zone temperatures. The design injection rate for the 9 MW plant was 1665 gpm (Diddle and Gonser, 1985) giving an injection density of 2220 gpm/mile of utilized fault length.

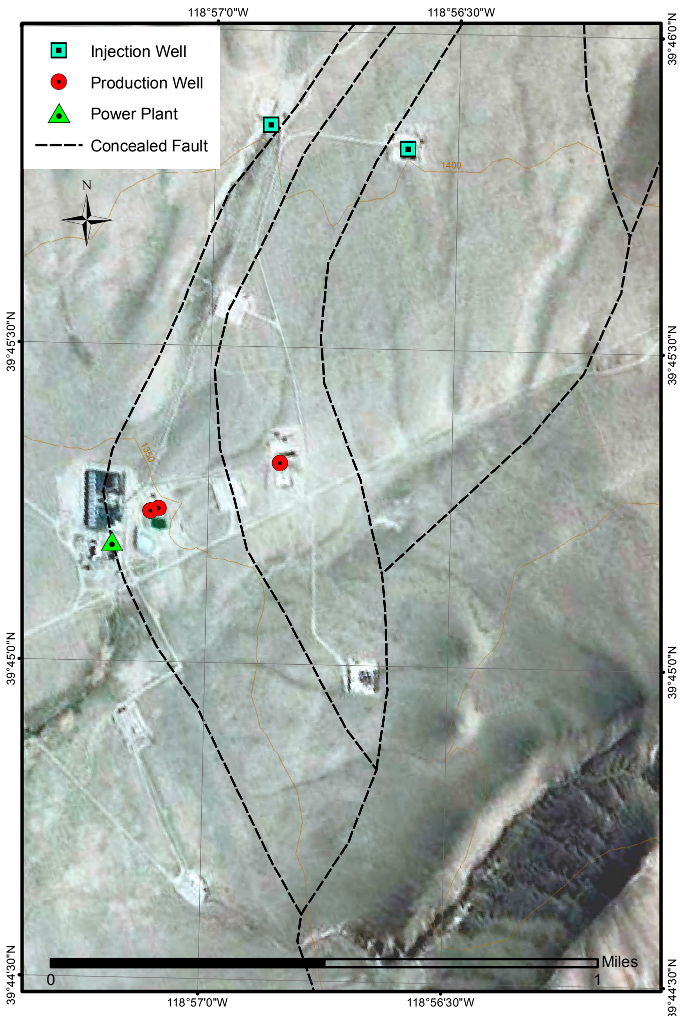

Figure 3. Image of the Desert Peak geothermal field. Faulting is from Faulds et al., 2010. Only wells utilized during the first 20 years of production are symbolized. Newer production wells are located on the pads south, ENE, and NE of the power plant.

Dixie Valley

The Dixie Valley field utilizes the Stillwater Fault zone over a length of 3 3/8 miles, making it the longest utilized fault length in the Basin and Range Province (Figure 4). The Stillwater fault zone is a classical normal fault zone bounding the east side of the Stillwater Range with a vertical offset of up to 11,000 feet (Blackwell et al., 2007). This section of the Stillwater fault zone is exceptionally linear with the only complicating factor being a lateral outflow zone in Miocene basaltic rocks in the southern part of the field that is utilized by three injectors (Benoit, 1992).

The 62 MW gross Dixie Valley dual-flash plant commenced operations in mid 1988 with 6 production wells and 4 injectors. Initial production temperatures were 480 ^{o}F. Over the next few years 4 existing and new wells were added to the injection system and three 13 3/8" producers were drilled to replace 9 5/8" diameter producers. This was in part due to a decision to operate the field 6 MW above its initial contract rate. By 1995 it was obvious that evaporative losses of 1600 gpm were reducing the reservoir pressure and the operator had adequate experience to plan for augmenting injection with shallow groundwater. In 1997 the injection augmentation program commenced (Benoit et al., 2000) and has been so successful in maintaining the reservoir pressure that no new deep wells have been drilled since then. For over 24 years the Dixie Valley geothermal field has sustainably produced about 62 gross MW from 3 3/8 miles of fault, giving an energy density of 18.4 MW/mile.

Extensive tracer testing at Dixie Valley has shown a rather complex pattern with an apparent semi-permeable barrier separating the Section 33 production wells from most of the rest of the field (Rose et al., 2002). Initial tracer returns were between 30 and 150 days. Tracer peak times are among the longest ever measured in any geothermal field, varying from a low of about 100 days to over 300 days. These long times also reflect the several thousand feet of vertical separation between some injectors and producers that is not indicated on Figure 4.

The Dixie Valley project reached full injection of all liquids in late 1991 at 9000 gpm. This gives an injection density of 2700 gpm/mile of fault. With augmentation, the injection density is as high as 3260 gpm/mile. There is no published information on the cooling of the Dixie Valley field. However, the cooling rate must be low as the plant owner invested in a 5 MW bottoming cycle plant in 2012 to remove additional heat from the injectate.

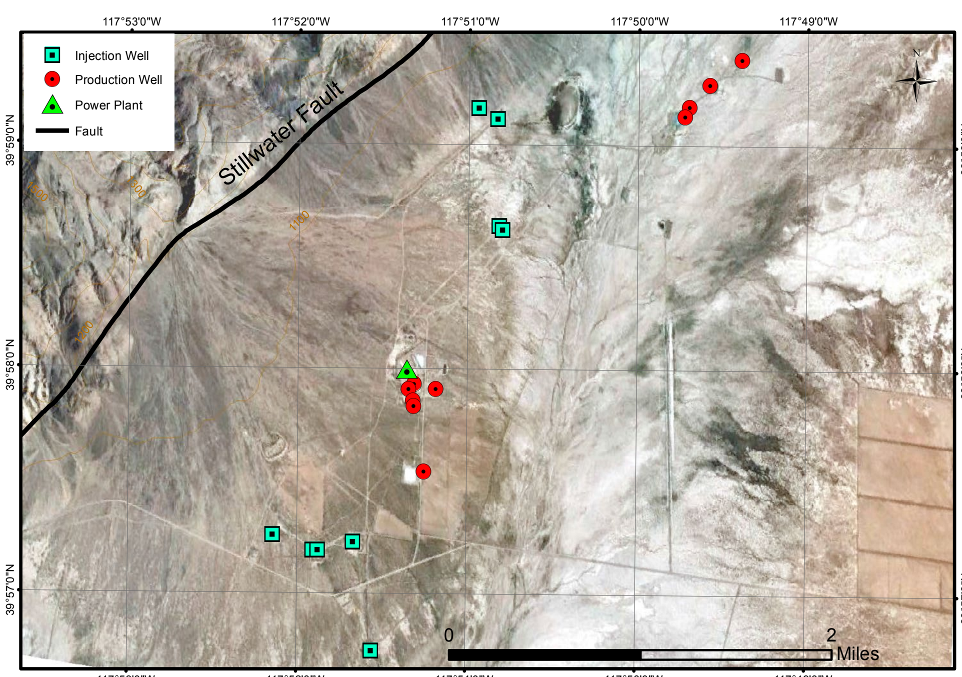

Figure 4. Image of the Dixie Valley geothermal field.

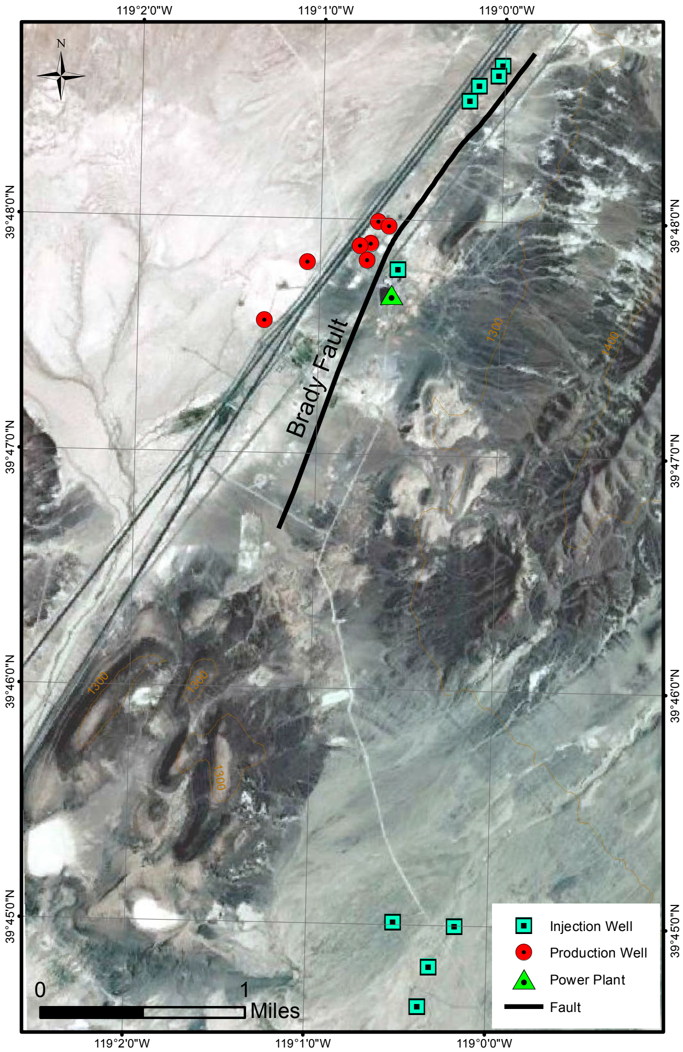

Figure 5. Image of Brady's Hot Springs geothermal field. The initial production and injection wells are located between the Brady's fault and the freeway.

Brady's

The Brady's project, located 4 miles NW of the Desert Peak plant, produces from the Brady's normal fault (Faulds et al., 2010). A 21.1 MW pumped dual-flash plant commenced operations in mid 1992 with a design brine injection rate of 11,350 gpm. At startup the field consisted of eight closely-spaced $\pm$ 2000' deep production wells with initial temperatures of 355 ºF and four $\pm$ 500 foot deep injectors along the Brady's fault centered 0.85 mile NNE of the production area (Figure 5). A tracer test performed during partial load startup operations with the field in this configuration had first returns in as little as 2 days. Temperature decline rates as high as 25 ºF/yr required numerous changes to the field during its first two years of operation to increase the effective separation between the producers and injectors. Two $\pm$ 5000' deep 370 ºF new wells were drilled west of the freeway, initially utilized as injectors, but later converted to producers. A tracer test involving one of these deeper injectors had initial returns between 5.5 and 11 days with peaks between 20 and 37 days but this injection configuration was short lived. A 4 mile-long pipeline was later constructed specifically to export injectate to 4 new injectors in a small geothermal system located between the Brady's and Desert Peak geothermal fields (Figure 5). 7 of the 8 original production wells have been disconnected from the gathering system. The project was unsuccessful for the original developer and was sold. A bottoming cycle binary plant was added to reduce the abnormally high injection temperatures of 250 ºF, increasing the total generation capacity to 26.1 MW.

The 2007-2011 Nevada Division of Minerals production figures show the Brady's net output declining from 11.3 to 8.1 MW indicating that temperatures are most likely continuing to decline. Currently the Brady's project is utilizing 1 ¾ miles of the Brady's fault giving 4.6 MW/mile in 2011. The injection distribution history at Brady's is not publicly available. However, additional temperature and injection histories are needed to give any real meaning to this number. In spite of these issues Brady's has now operated for over 20 years.

Blue Mountain

The Blue Mountain geothermal field, occurring at the intersection of a regional NE striking normal fault system and a major WNW trending left step in that fault system, appears to have a more complex fault setting than the previously discussed fields but it still has many of the characteristics of a range-front fault system (Faulds and Melosh, 2008, Casteel et al., 2010). The fault zone may be on the order of 1 km wide and there is a large shallow upflow plume in the eastern part of the field used for production

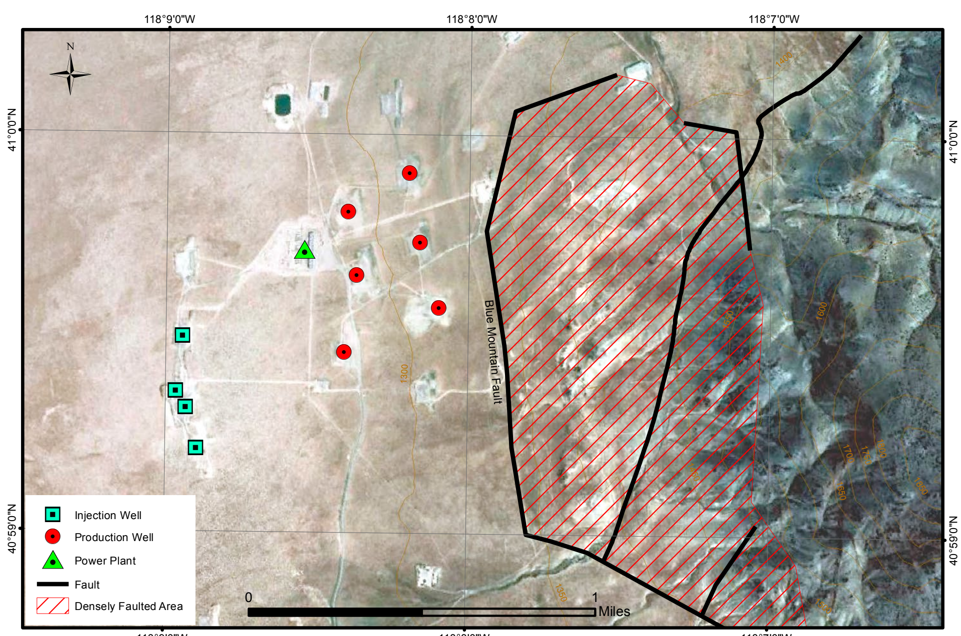

Figure 6. Image of the Blue Mountain geothermal field at plant startup (after Casteel et al., 2010). Wells drilled after the plant startup are not symbolized but the pads are visible.

(Casteel et al., 2008). Prior to startup a volumetric heat in place calculation indicated a minimum value of 40 MW net and a most-likely value of 57 MW net (GeothermEx, 2008; NGP Press Release April 24, 2008).

Production commenced in November 2009 with 5 closely-spaced pumped production wells and 4 closely-spaced injection wells supporting the 49.5 MW binary power plant (Figure 6). The intended flow for the plant was about 15,000 gpm (Casteel et al., 2010). Almost immediately after startup production temperatures began to decline and three new injection wells were drilled in the first half of 2010. Two unsuccessful step-out exploratory wells were drilled. A 3 well drilling program planned for 2012 was never implemented. The production rate was voluntarily reduced as another method of increasing the residence or reheating time between producers and injectors. By late 2012 modeling predicted ongoing base case temperature declines of 8 ºF/year with the megawatt output declining from 34 MW in 2012 to 15 MW by 2020 (NGP Press release Sept. 25, 2012). The project changed ownership in early 2013.

The active wellfield is just over a mile long in a N-S direction. The predicted 15 MW in 2020 gives a power density of 15 MW/mile of utilized fault length. The maximum fluid-entry temperature known at Blue Mountain is 416 ºF, virtually identical to Beowawe and Desert Peak so it is not surprising that the predicted future megawatt output is similar. The area containing all the active wellheads is about 2/3 mi^2. If only the wellheads in service at plant startup are considered then the active field area was about 1/2 mi^2. Comparing this to The Geysers at about 25 MW/mi^2 a predicted value of 15 MW also appears credible.

The wellfield at Blue Mountain, for a variety of reasons, is developed differently than the other fields described in this paper in that the deeper and hotter wells are utilized for injection purposes. A similar strategy was tried at Bradys but was quickly reversed as it did not improve the sustainability. The injection strategy at Blue Mountain consisted of placing the injectors at least ½ mile from the nearest production well (GeothermEx, 2008). Tracer testing results are not publicly available from the Blue Mountain field.

Table 1. Summary of Tracer Testing Results.

Field	First Return Times (days)	Peak Return Times (days)
Roosevelt	-	-
Beowawe	5 - 10	17 – 35
Desert Peak	5 - 40	20? - > 110
Dixie Valley	30 - 150	100 - > 300
Bradys	2 - ?	?
Blue Mountain	-	-

Discussion

The four more successful long-term fault-controlled projects, Roosevelt, Beowawe, Dixie Valley, and Desert Peak all have the common features of initial resource temperatures above 400 ºF and injection at rates less than 3600 gpm/mile of utilized fault length. Each of these faults have recognized geological differences and a wide range of tracer return characteristics. Beowawe has the most rapid tracer returns of the successful projects but to date has proven as durable as the Dixie Valley field with its order of magnitude longer initial and peak tracer returns (Table 1). Initial tracer returns of 2 to 3 days in some wells at Bradys must have contributed to the rapid initial temperatures declines.

These case histories demonstrate that fields with temperatures near 400 ºF can produce 12 – 15 MW/mile of utilized fault length for more than 25 years. The 480 ºF Dixie Valley field has sustained production of 18 MW/mile and the underdeveloped Roosevelt field has produced 23 – 33 MW from 2.3 miles of fault length. The over sized and less successful Bradys and Blue Mountain projects had lower fluid temperatures, which make the fields more susceptible to cooling declines with larger injection rates. Attempted injection rates >10,000 gpm/mile of utilized fault length quickly resulted in serious temperature declines.

Another possible factor in the initial lack of success at Bradys and Blue Mountain may be the tight clustering of multiple production and injection wells, both in plan view and in terms of depth. This lack of both production and injection diversity meant that once an operation limitation was evident there was no partially tested fallback strategy readily available for implementation. At the most fundamental level the field changes at Brady and Blue Mountain were intended to increase the separation between injectors and producers. This can be accomplished by either reduced injection rates or by increased diversification of the production and/or the injection. Production and injection wells at Dixie Valley are tightly clustered in plan view but there are two widely spaced production clusters and the injection wells have great depth diversity. The price of this diversity is a 10 mile-long gathering and injection system. Dixie Valley had the advantage of being able to surface discharge large volumes of fluid during its early years as the injection program was refined. The wells at the smaller Beowawe and Desert Peak fields are clustered but with only 3 producers in each of these smaller fields this does not appear to present a problem. More recent drilling at Desert Peak has greatly spread out the production.

This is the first tranche of field cases to offer empirical evidence as to how many megawatts the industry has actually been able to produce from crudely planar fractures with a known length of utilization, albeit four decades after the question was first mathematically addressed by Bodvarsson (1974). The constraints imposed by this small data set suggest a crude rule of thumb that injection exceeding about 3500 gpm along fault-zone hosted geothermal systems is risky. This is a far more constraining predictive tool than volumetric-type calculations or natural heat loss measurements.

Not all Basin and Range geothermal systems are or will prove to be dominated by a single relatively narrow fault or fault zone. Obvious examples of other geothermal fields that would not apply to this methodology are Coso, Long Valley, and the Steamboat Terrace area where either fracturing is much more extensive or recharge is abnormally large.

Conclusions

Four successful geothermal fields located along faults or narrow fault zones show that it is possible to sustainably produce 20 or more megawatts per mile of utilized fault length if the initial production temperatures are 480 to 500 ºF and 12 to 15 MW per mile may be sustainably produced with temperatures near 400

^{o}F. Sustainably producing more than 20 MW from fault-hosted resources with temperatures less than 400 ^{o}F has to date been unsuccessful. The primary factor controlling these megawatt numbers is the ability to inject without rapid cooling of the resource. The four successful geothermal fields all inject less than 3600 gpm/mile of utilized fault length and lack large clusters of closely spaced and nearly identical production and injection wells. Tracer testing has shown initial return times of only 2 or 3 days most likely will result in unacceptably rapid cooling. Surprisingly two fields with initial return times as short as five days have allowed production wells to operate for over 25 years. Output predictions from as yet undeveloped fault-hosted geothermal systems based on volumetric heat-in-place calculations and natural heat loss measurements should be compared against these injection rates per mile of utilized faults as tests of their credibility.

Use of fault length is a practical method that ultimately focuses on the heat exchange surface area for systems with relatively simple fracture geometry and reservoir phase conditions. Although the set of fields available to constrain the MW/mile or gpm of injection/mile is limited, the spread of the numbers between the fields analyzed in this paper is much less than the widely scattered volumetric or power density results reported for volcanic-hosted fields (Grant, 2000). This approach can be utilized very early in the exploration effort and is strongly based in a reservoir process that can be linked to well observations and geologic models. Perhaps it can also be utilized to promote better understanding of other more three dimensional fractured reservoirs.

Acknowledgements

The author gratefully acknowledges the time spent by Cathie Hickson, Glen Melosh, Jim Stimac, David Sussman, and Pete Rose in reviewing and discussing aspects of the paper. Oscar Cerritos provided assistance with the figures and Alterra Power Corp provided time for writing the paper.

References

Allis, R., and Larsen G., 2012, Roosevelt Hot Springs geothermal field, Utah – Reservoir response after more than 25 years of power production, Proceedings, Thirty-Seventh Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 30 – February 1, 2012, 8 p.

Benoit, 1992, A case history of injection through 1991 at Dixie Valley, Nevada, Geothermal Resources Council Transactions, Vol. 16, pp. 611 – 620.

Benoit, D., and Stock, D., 1993, A case history of injection at the Beowawe, Nevada geothermal reservoir, Geothermal Resources Council Transactions, Vol. 17, pp. 473 – 480.

Benoit, D., 1997, Injection-driven restoration of the Beowawe geothermal field, Geothermal Resources Council Transactions, Vol. 21, pp 569 – 575.

Blackwell, D. D., Smith, R. P., and Richards, M C., 2007, Exploration and development at Dixie Valley, Nevada: summary of DOE studies, Proceedings, Thirty-Second Workshop on geothermal reservoir Engineering Stanford University, Stanford, California January 22 – 24, 2007, 8 p.

Bodvarsson, G., 1974, Geothermal resource energetic, Geothermics, Vol. 3 No. 3, pp 83 – 92.

Butler, S. J., Sanyal, S. K., Robertson-Tait, A., Lovekin, J. W., and Benoit, D., 2001, A case history of numerical modeling of a fault-controlled geothermal system at Beowawe, Nevada, Proceedings, Twenty-Sixth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 29 – 31, 2001, 6 p.

Capuno, V. T., Sta. Maria, R. B., and Minguez, E. B., 2010, Mak-Ban geothermal field, Philippines: 30 years of commercial operation, Proceedings World Geothermal Congress 2010 Bali, Indonesia, 25 – 29 April 2010, 7p.

Casteel, J., Trazona, R., Melosh, G., Niggemann, K., and Fairbank, B., 2010, A preliminary conceptual model for the Blue Mountain geothermal system, Humboldt County, Nevada, Proceedings World Geothermal Congress 2010 Bali, Indonesia, 25 – 29 April 2010, 6p.

Diddle, C. P., and Gonser, W. C., 1985, Project development Desert Peak, Geothermal Resources Council Transactions, Vol. 9 – Part II, pp. 127 - 131.

Dickey, H. K., Forsha, G., Forsha, M., and Linden, B., 2011, A new high efficiency binary expander design: low temperature geothermal application bottoming Beowawe geothermal flash plant, Geothermal Resources Council Transactions, Vol. 35, pp. 1295 – 1299.

Faulder, D. D., and Johnson, S. D., 1987, Desert Peak geothermal field performance, Geothermal Resources Council Transactions, Vol. 11, pp. 527 – 533.

Faulds, J. E., and Melosh, G., 2008, A preliminary structural model for the Blue Mountain geothermal field, Humboldt County, Nevada, Geothermal Resources Council Transactions Vol. 32, pp. 384 – 389.

Faulds, J. E., Coolbaugh, M. F., Benoit, D., Oppliger, G., Perkins, M., Moeck, I., and Drakos, P., 2010, Structural controls of geothermal activity in the Northern Hot Springs Mountains, Western Nevada: the tale of three geothermal systems (Brady's, Desert Peak, and Desert Queen), Geothermal Resources Council Transactions, Vol. 34, 2010, pp. 675 – 683.

GeothermEx, 2004, PIER Report, New geothermal site identification and qualification, Report Prepared For: California Energy Commission, April 2004, 264 p.

GeothermEx, 2008, Status of resource development at the Blue Mountain geothermal project, Humboldt County, Nevada, Report prepared for Nevada Geothermal Power Inc., 21 April 2008, 124 p.

Grant, M. A., 2000, Geothermal resource proving criteria, Proceedings World Geothermal Congress 2000, Kyushu – Tohoku, Japan, May 28 – June 10, 2000.

Grant M., A., and Bixley, P. F., 2011, Geothermal reservoir engineering 2nd edition, Elsevier, Amsterdam, 359 p.

Kerna, M. J., and Allen, T. S., 1984, Roosevelt hot springs unit development a case history, Geothermal Resources Council Transactions Vol. 8, pp. 75 – 77.

Layman, E. B., 1984, A simple Basin and Range fault model for the Beowawe geothermal system, Nevada, Geothermal Resources Council Transactions Vol. 8, pp. 451 – 456.

Melosh, G., Casteel, J., Niggeman, K., and Fairbank, B., 2008, Step-out drilling results at Blue Mountain, Nevada, Geothermal Resources Council Transactions, Vol. 32, pp. 49 – 51.

Moore, J. N., and Nielson, D. L., 1994, An overview of the geology and geochemistry of the Roosevelt Hot Springs geothermal system, Utah, Utah Geological Association Publication 23, p. 25 – 36.

Muffler, L. P. J., ed, 1979, Assessment of geothermal resources of the United States – 1978, Geological Survey Circular 790, 163 p.

Rose, P. E., Adams, M. C., and Benoit, D., 1995, A tracer test at the Beowawe geothermal field, Nevada, using fluorescein and tinopal CBS, Geothermal Resources Council Transactions Vol. 19, pp. 217 – 221.

Rose, P. E., Benoit, W. R., Kilbourn, P. M., 2001, The application of the polyaromatic sulfonates as tracers in geothermal reservoirs, Geothermics, Vol. 30, pp. 617 – 640.

Rose, P. E., Johnson, S. D., Wong, Y. L., Carter, T., Kasteler, C., and Kilbourn, P., 2002, Sub part-per-trillion detection of a fluorescent tracer at the Dixie Valley and Beowawe geothermal reservoirs, Geothermal Resources Council Transactions, Vol. 26, pp. 113 – 117.

Rose, P. E., Benoit, D., Johnson, S. D., Kilbourn, P., and Kasteler, C., 2002, Tracer testing at the Dixie Valley geothermal reservoir, Dixie Valley Workshop at the Desert Research Institute Reno, Nevada June 12 -14, 2002, 21 p. Power Point.

Rose, P. E., Leecaster, K., Drakos, P., and Robertson-Tait, A., 2009, Tracer testing at the Desert Peak EGS project, geothermal Resources Council transactions, Vol. 33, pp. 241 – 244.

Sorey, M. L., Lewis, R. E., and Olmsted, F. H., 1978, The hydrothermal system of Long Valley Caldera, California, U. S. Geological Survey Professional Paper 1044-A, 60 p.

Union Oil Company of California, 1982, Baca project: geothermal demonstration power plant final report, U. S. Dept. of Energy Report DOE/ET/27163/T2 (DE84004766).

White, D. E., and Williams, D. L., eds., 1975, Assessment of geothermal resources of the United States—1975, U. S. Geological Survey Circular 726, 155 p.

Wisian, K. W., Blackwell, D. D., and Richards, M., 2001, Correlation of surface heat loss and total energy production for geothermal systems, Geothermal Resources Council Transactions Vol. 25, pp. 331 – 336.