Injection-Driven Restoration of the Beowawe Geothermal Field

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ABSTRACT

An initial strategy of injecting spent brine largely outside of the Beowawe reservoir caused the reservoir pressure to decline by 110 psi during the first year of plant operation. This decline allowed cold ground water, which was not separated from the geothermal water by any continuous barrier, to flow into and cool the geothermal reservoir. The drilling of a large new production well temporarily restored full plant output but accelerated the reservoir pressure and power plant output declines. After shifting injection directly back into the reservoir the reservoir pressure rapidly increased. This immediately improved the plant output as individual well outputs increased. Reservoir cooling continued unabated for approximately the next two years followed by a sharp reduction in the rate of temperature decline. The change in injection strategy reduced the gross megawatt decline rate of the power plant from 2.66 MW/yr to about 0.4 MW/yr.

Introduction

The Beowawe, Nevada, geothermal field (Figure 1) commenced production in late 1985. The gross power output has varied from 12 to 17 MW (Figure 2). During most of this 11 year production history the fluid-entry temperatures of the production wells declined at a rate of about 8°F/yr. A comprehensive set of reservoir data during the first 7 years of production demonstrated that the cooling was due to cold shallow groundwater entering the geothermal reservoir (Benoit and Stock, 1993).

In early 1994 a fundamental change in injection strategy was implemented wherein the injectate was returned directly to the reservoir. This paper presents the impact that this injection modification had on the reservoir and plant output over the next three years. This paper is a sequel to a 1993 paper by Benoit and Stock and the reader is referred to it for additional background, figures, and references.

Natural State Conditions and Early Exploration

In its natural state the Beowawe reservoir consisted of a 7,000' to 10,000' deep reservoir with a temperature near 415°F located in fractures in Ordivician sandstone, shale, basalt, and chert along the Malpais normal fault. An estimated 285 gpm of fluid from this deep reservoir rose obliquely up the steeply-dipping Malpais normal fault to discharge at the large silica terrace and into 360 to 370°F aquifers in Miocene lava flows beneath the terrace.

During the exploration and initial testing of the Beowawe wells and reservoir it was recognized that the deeper reservoir was largely confined to a single fault or narrow fault zone which consisted of a few large fractures with exceptional permeability-thickness of up to 800,000 md-ft. Interference testing demonstrated extremely rapid pressure responses between all wells except the Batz well, the most easterly of the wells (Figure 1).

These interference results produced an understandable concern about premature return of cool injectate if it were injected into any of the wells in excellent pressure communication with

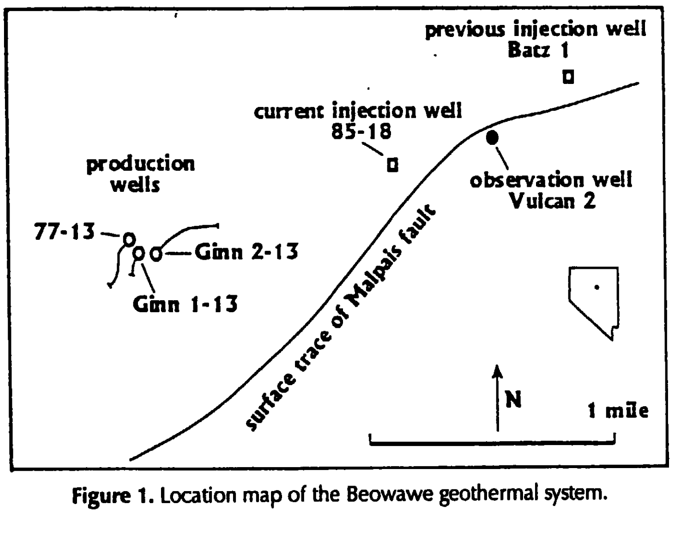

Figure 1. Location map of the Beowawe geothermal system.

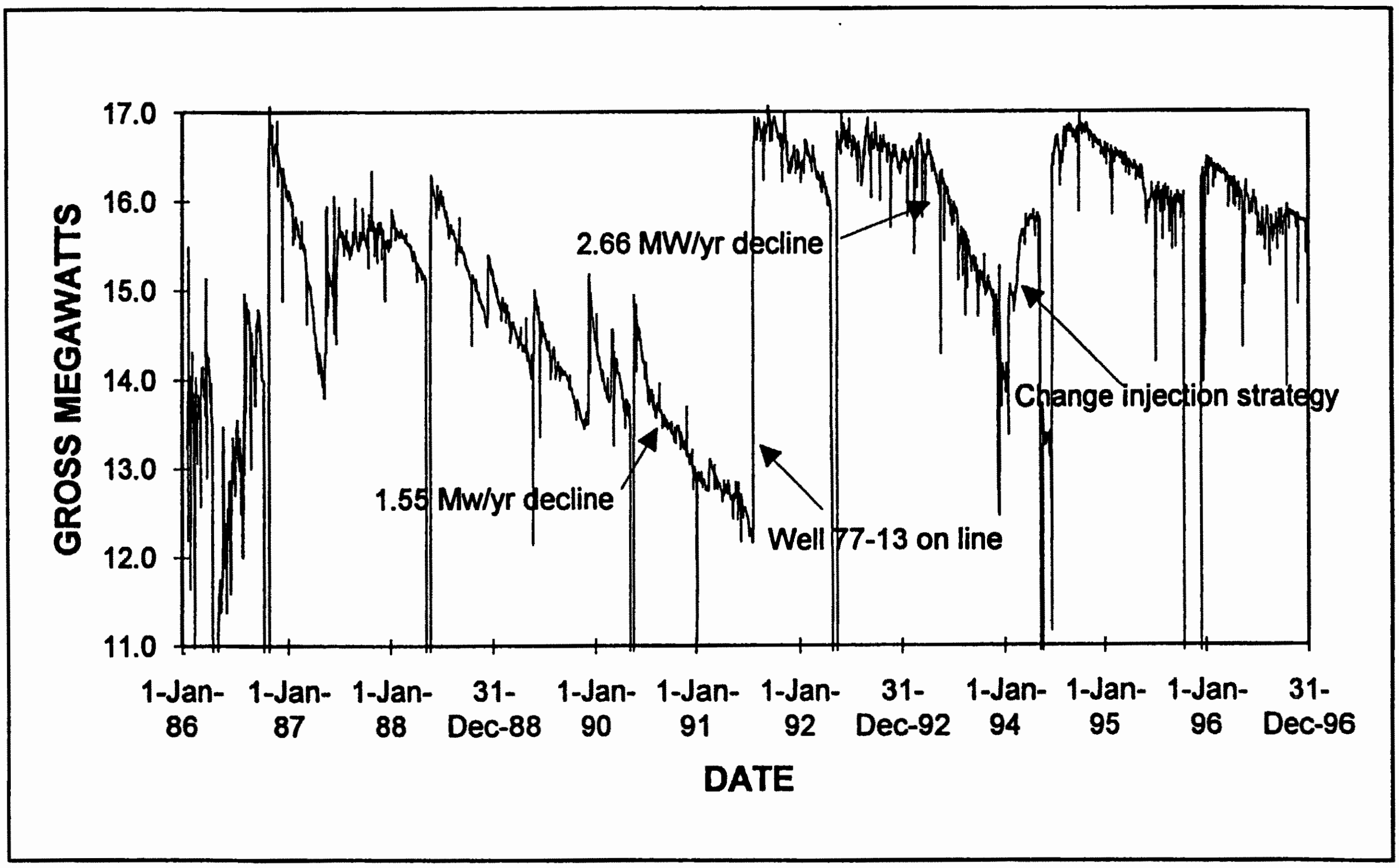

Figure 2. Beowawe gross megawatt output 1986 through 1996.

the deep production wells. This concern was so overwhelming that it dictated the injection strategy in spite of predictions of the field being capable of producing hundreds of megawatts. The decision was made to inject the spent brine into the Batz well and hope for the best. There apparently was no concern at the time for potential problems other than cooling caused by rapid injection returns. Although crude by standards of the mid 1990s, this reasonably represented the "state-of-the-art" for injection strategy in the United States in the early 1980s.

What was not appreciated or understood in the early 1980's was the relationship between the shallow groundwater system and the geothermal system. Extensive testing and monitoring of the geothermal wells in 1981 did not detect any reservoir limits (Epperson, 1983). However, there was no monitoring of cold groundwater wells during this testing. In 1987 Rush and Olmsted postulated that the geothermal system and shallow groundwater were parts of a single groundwater system extending from the water table to depths of several kilometers. This first raised the possibility that much of the perceived large volume of the geothermal reservoir was actually occupied by cold water.

A groundwater budget (Olmstead and Rush, 1987) gvies an estimated 1,100 gpm recharge of cold groundwater into Whirlwind Valley. This is four times greated than the estimated 285 gpm discharge of thermal fluid in the natural state. What is not known is the volume of cold ground water in storage near the geothermal system. The 1981 testing program may have in effect measured it as unlimited.

Faulder et. al, (1997) have recently described the shallow parts of the Beowawe geothermal system as a rising tongue of thermal water intruding into, and in delicate balance with, a large volume of cold groundwater in Miocene volcanic rocks. Very high negative static temperature gradients in some wells, such as the Batz, indicate that there are localized barriers to vertical flow in the silica terrace area. However, the preponderance of evidence suggests that fluid can circumvent these localized barriers. There is no recognized extensive physical barrier or separation between the waters of the geothermal system and the shallow groundwater system.

Production History 1986-1994

The plant commenced operations with initial fluid-entry temperatures near 415°F in two production wells. Two years into production, in early 1988, a noticeable cooling trend began with decline in the calculated fluid enthalpy derived from total steam and brine flows. This marked the beginning of a substantial decline in megawatt output (Figure 2). Three years into production, downhole temperature measurements undeniably confirmed that cooling of both production wells was under way. However, the Kuster tool values provided enough scatter of the data that it was periodically believed, or hoped, that the cooling had somehow either stopped or reversed.

Reservoir pressures as measured in the idle Vulcan 2 well declined rapidly by 110 psi in the first year of operation and then more or less stabilized for the next four years (Figure 3). This demonstrated excellent pressure support for the reservoir, in spite of injection intended to be outside the reservoir. The total production rate between 1987 and 1991 was fairly steady at about 2,700 gpm with about 600 gpm lost to the atmosphere and surface. The constant pressure during this time means that the total recharge to the geothermal reservoir also must have been about 2,700 gpm. Therefore, the minimum natural recharge rate had to be at least 600 gpm (assuming all the injectate was somehow returning to the reservoir) and possibly approaching 2,700 gpm.

The flowing downhole pressures in the production wells showed a significant increase which is a good indication of the cold water invasion making the column of water in the reservoir heavier.

It is also interesting to note that in many instances where there are high near-surface temperatures, a decline in reservoir pressure results in increased thermal activity on the surface, primarily steam features such as steaming ground, fumaroles, and mud pots. At Beowawe the existing thermal features largely disappeared shortly after production commenced. This indicates that very rapid cooling of the shallow reservoir due to the groundwater influx overcame the tendency to boil as pressure was reduced.

The temperature decline from January 1988 through mid 1991 resulted in a gross plant output decline from a maximum of 16.6 to 12.2 MW (Figure 2). In the last half of 1990 and the first half of 1991 the gross megawatt decline rate was 1.55 MW/yr. Late in 1990 only 8% of a tracer injected into the Batz well slowly returned to the production wells (Rose et.al 1995). This reconfirmed that injection into the Batz well was not appreciably supporting the reservoir pressure.

In mid 1991 a third production well, 77-13, was drilled. This well with 16" casing and 9 5/8" liner was exceptionally successful in that it could initially generate 16 MW. This reconfirmed the exceptionally high permeability of the deep Beowawe reservoir. After 77-13 was completed there was abundant excess steam which gradually diminished over the next two years while the plant ran at full output (Figure 2). By mid 1993 the excess steam no longer existed and the plant output again began to decline. This time, at a higher rate of 2.66 MW/year.

The megawatt decline rate was higher with well 77-13 on line because the total mass production rate increased by about 900 gpm to 3,600 gpm and this increased fluid loss from the reservoir resulted in a second decline in reservoir pressure of 70 psi between mid 1991 and early 1994 (Figure 3). The reservoir pressure decreased by an additional 70 psi in the 2 1/2 years between mid 1991 and early 1994 but did not stabilize. This is in contrast to the one year it took for the initial stabilization after

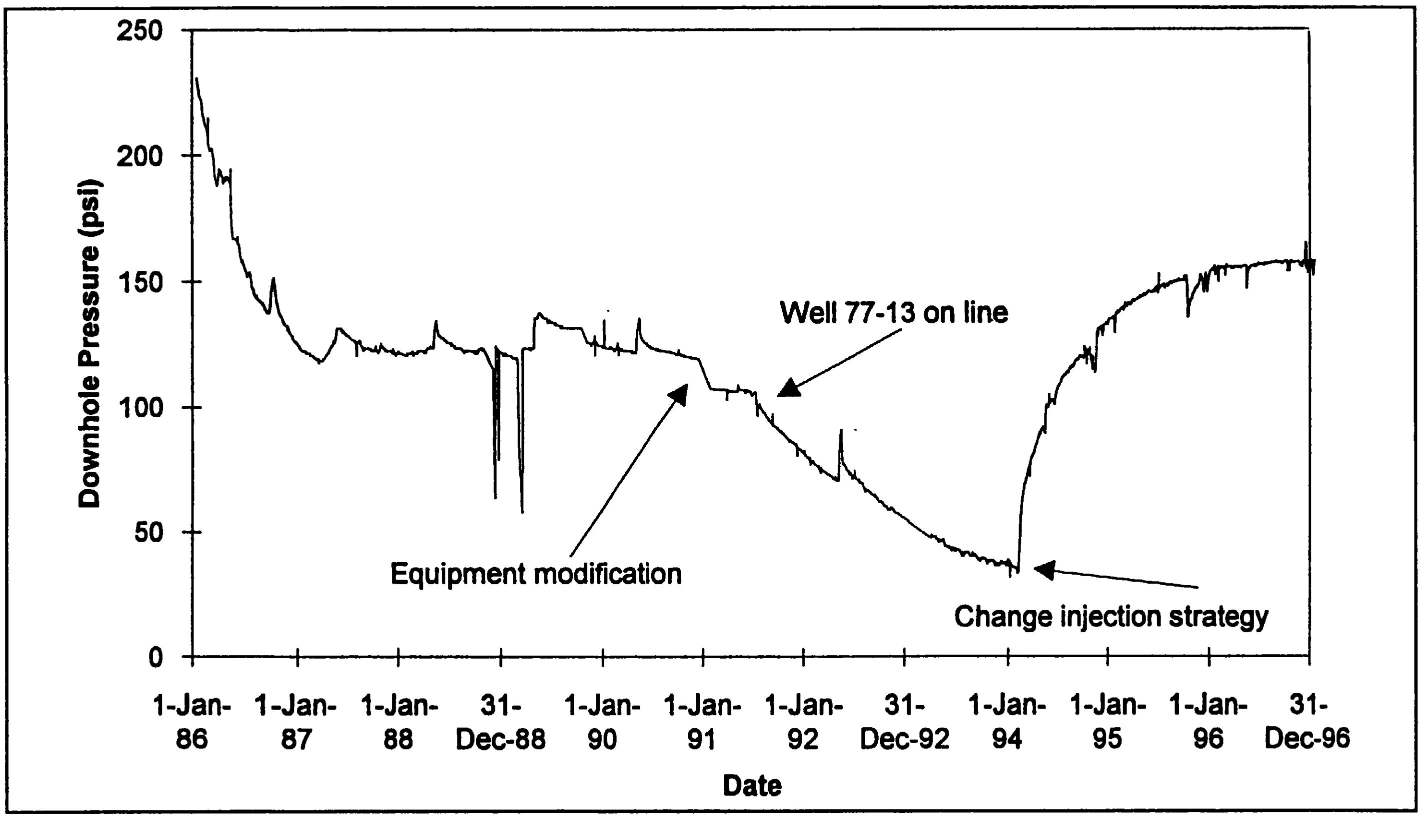

Figure 3. Downhole pressures in Beowawe Vulcan well.

the 110 psi decline at the start of production. Apparently the 900 gpm increase due to 77-13 production was more of a strain on the entire system, both hot and cold.

By late 1991 it was obvious that the initial success of 77-13 would be relatively short-lived and that some fundamental change in reservoir management was required for the Beowawe reservoir to have a productive life measured in decades rather than years. No numerical model of the reservoir existed at this time so possible fixes were evaluated on a qualitative basis. A number of possibilities were considered and discarded for primarily economic reasons. Fortunately, the least-cost possibility also offered a truly fundamental change in strategy. This option was to inject the spent brine directly into the reservoir via the idle 85-18 well.

A review of the existing idle wells at Beowawe showed that well 85-18 was in excellent pressure communication with the deep production wells and appeared to have adequate permeability to accept 3,000 gpm of spent brine. It was also located relatively close to the injection line. After negotiations with the well's owner, consent to utilize the well was obtained in late 1993.

A rework of the 85-18 well was mandatory as casing damage in the top several hundred feet of the well was allowing groundwater to flow into the wellbore. The well would not pass a required mechanical integrity test in that condition. A 9 5/8" tieback casing string was successfully cemented in place and mechanical integrity was proven late in 1993. After completion of the mechanical integrity test, a new segment of injection line was quickly built and well 85-18 was accepting 3,600 gpm of 215°F water in early February 1994. The cost of placing this well in service was about 10% of the cost of drilling the 77-13 production well.

Production History 1994-1997

The 85-18 well accepts all the injectate at lower wellhead pressures than the Batz well so this was an immediate benefit in terms of parasitic power losses. In addition, the pipeline to the 85-18 well was shorter than the line to the Batz well so this saved additional pumping power. As soon as it was known that the 85-18 well would be placed in service as an injector, plans were made to conduct a tracer test to determine the potential impact of this well on the reservoir and in particular possible impacts to the fluid-entry temperatures of the production wells. However, for logistical reasons, the test did not begin for five months.

Immediately upon commencing injection into 85-18 the pressure in the Vulcan 2 well increased as rapidly as 3 or 4 psi/day and the flow rates of the production wells and plant output increased (Figures 2 and 3). The rapid rise in pressure closely paralleled the initial rapid decline in reservoir pressure. This provides a qualitative confirmation that the effective volume of the reservoir is not great since a few days of production or injection had a significant pressure impact.

In mid 1994 tracers were injected into well 85-18. This test documented a rapid return of tracer to all three production wells with first returns of 4 to 9 days and peak returns of only 17 to 35 days (Rose, et. al 1995). A calculated reservoir volume of 2.4 billion gallons was based on eight months of data. Continued sampling and analysis indicates that the 2.4 billion gallon figure was erroneously small. The current revised calculated volume based on two to three years of data is 17 billion gallons or 140 billion pounds (Rose, in press, 1997). The total volume of a 2.4 billion gallon reservoir would be produced every year at the current production rate of 4,300 gpm. The volume of a 17 billion gallon reservoir would be produced every 7.5 years and seems relatively large when compared with the rapid tracer return times. This may be reflecting the dichotomy between the relatively small hot actively convecting reservoir and the surrounding and/or overlying more static cold water regime.

In the seven months following the change in injection strategy the plant output increased by 1.9 MW. Over two years the reservoir pressure increased by 120 psi. The fluid-entry temperatures in the production wells continued cooling at the rate of 7 to 8°F/yr for the next two years (Figure 4). Therefore, the short-term increase in plant output was due solely to increased reservoir pressure.

In late 1995 or early 1996 the rate of fluid-entry temperature decline of the production wells substantially diminished (Figure 4). The overall fluid-entry temperature in well Ginn 2-13 has either stabilized or is possibly increasing. It took two years for the cooling trend to commence (1986-1988) so it is probably no coincidence that it took approximately two years for the temperatures trends to moderate following the injection into well 85-18.

By 1996 the reservoir pressure had stabilized. During 1996 there was only a couple of psi increase (Figure 3). This is despite the 650 gpm loss of the entire steam fraction of the produced fluid through the cooling tower or as surface discharge. Therefore, there must be an ongoing natural recharge of approximately 650 gpm of water to the reservoir in addition to the injectate to maintain the constant pressure.

This pressure stabilization allows a simple mass and thermal balance to be calculated to show the relative importance of hot vs cold recharge to the geothermal reservoir. Currently the reservoir is producing 4,250 gpm of water with an average temperature near 360°F. This amounts to 10.46 million Btu/min. The injection of 3,600 gpm of 215°F fluid returns 5.26 million Btu/min to the reservoir giving a net heat withdrawal rate of 5.2 million Btu/min. If it is assumed that the 650 gpm of recharge is all 70°F groundwater this brings in only 0.21 million Btu/min to the reservoir. Alternatively, if the entire 650 gpm of recharge is 415°F thermal water it would be bringing in 1.81 million Btu/min or about 1/3 of the difference between the Btu's produced and injected and would be an important contribution to the reservoir. Undoubtedly the natural recharge is a mixture of the two fluids.

The geochemistry of the injectate and produced fluid from 1994 through 1996 provides some hints as to the makeup of the natural recharge. The pre-flash chloride concentrations of the Beowawe thermal water are characterized by low quantities

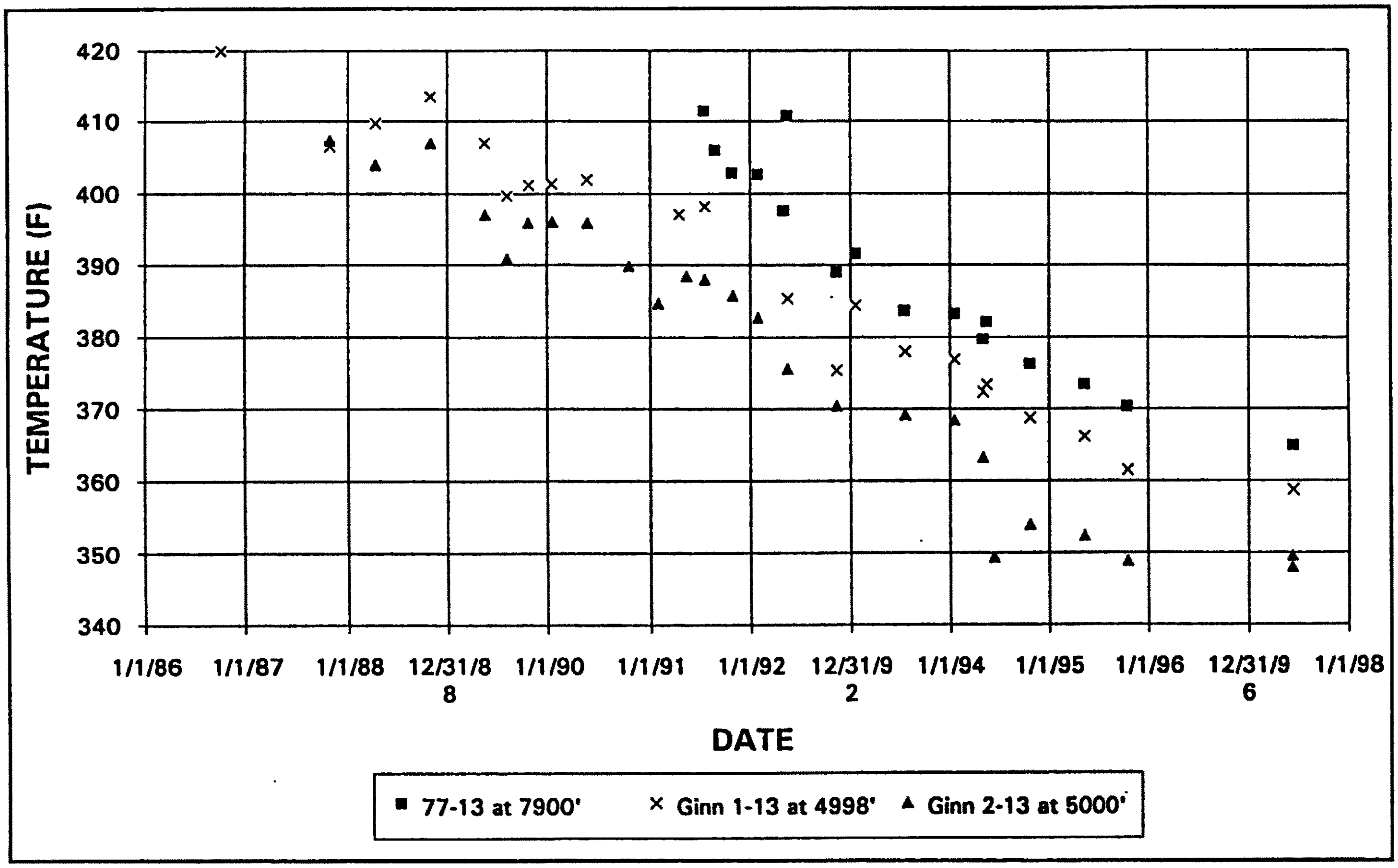

Figure 4. Beowawe downhole tempeatures.

($\pm$50 ppm) with relatively large scatter ($\pm$ 5 - 10 ppm) and difficulty in obtaining repeat values due to some type of interference (Ruth Kroneman pers. comm). The chloride data show only a weak and variable trend of increasing concentration. The sodium contents show a more clearly defined trend of increasing concentration since 1993 (Figure 5). However, this increase amounts to only 10 or 20 ppm out of an initial concentration of 180 ppm and has not returned the sodium contents even to the original 1986 concentrations in the fluids. There is no apparent increase in the sodium content of the injectate since 1993. Qualitatively, the recharge of dilute groundwater is great enough to largely mask the recycling of the more saline injectate.

Cold groundwaters at Beowawe have approximately 40 ppm of sodium and the pre-flash thermal water now contains about 190 ppm. The injectate now contains about 215 ppm which fortunately happens to equal the initial sodium content of the reservoir in 1986 (and the presumed current sodium content of the hot recharge). This allows a simple two component mixing calculation rather than a three component mixing. Therefore, the approximate fraction of cold recharge can be calculated at 15% of the total flow to maintain 190 ppm of sodium in the produced fluid [(215 ppm)(.85)+ (40 ppm)(.15)= 190 ppm]. It just so happens that 15% of the 4250 gpm flowing from the reservoir amounts to 637 gpm which is virtually identical to the 650 gpm currently discharged to the surface and atmosphere. The 50 gpm increase of surface discharge since 1991 is due to a greater fraction of low pressure steam supplying the turbine which requires additional mass to maintain a constant generator output. This implies that most of the natural recharge to the reservoir continues to be cold groundwater. However, the fact that sodium contents are increasing does show that there is some component of thermal recharge.

Between late 1994 (when MW output peaked) and the end of 1996 the overall megawatt decline rate was 0.4 MW/yr which is presumably attributable to the continuing slow cooling of production wells 77-13 and Ginn 1-13. This decline is a marked improvement over the previous 2.66 Mw/yr value and also includes some degradation in turbine output due to scaling and a modification in plant operation to emphasize net output over gross production.

The Future

Change has been the central theme of the Beowawe reservoir history. If the reservoir temperature and pressure do not change then the plant output, barring mechanical changes, should also remain stable. The relatively rapid return of the tracer to the three production wells in an uncooled reservoir is an indication that future cooling of the reservoir can reasonably be expected, assuming no changes in management. The rate of any such cooling is not currently predictable. However, the large amount of previous cooling due to the shallow groundwater intrusion greatly complicates any qualitative predictions of the future fluid-entry temperatures at Beowawe. Over the long term, additional cooling of the reservoir can reasonably be expected. The increase in temperature of a large fraction of the reservoir recharge from as low as 70°F (the shallow groundwater temperature) to 215°F (the injectate temperature) in early 1994 should have no short-term negative impact on the reservoir. It is even possible that fluid-entry temperatures might temporarily increase.

The reservoir pressure has now more or less stabilized in response to the current injection strategy. Nothing can be economically done to boost the pressure further without lowering the injectate temperature. Injection of cooler water could be expected to accelerate reservoir cooling. This leaves the only future improvement to the injection strategy as being dispersal of injectate through additional wells. This would allow flow through additional fractures to more effectively mine the heat remaining in the formation.

Numerical modeling of the Beowawe reservoir is currently underway to try to more accurately predict the future reservoir performance.

Conclusions

The initial injection strategy at Beowawe was to dispose of the fluid outside of the geothermal reservoir. This was driven by concern about premature return of cool injectate to the production wells. Rapid returns from tracer testing in 1994 demonstrated these concerns were valid.

During the first year of production, injection outside of the reservoir lowered the reservoir pressure by approximately 110 psi. This allowed cold shallow groundwater to flow into the geothermal reservoir. The cold water inflow tended to stabilize the reservoir pressure but over a period of eight years it reduced the fluid-entry temperatures of the production wells by as much as 70°F. Even the drilling of a very large new production well could not overcome the relentless cooling trend for more than two years.

A change of injection strategy, wherein the fluid is returned to the reservoir resulted in a rapid pressure increase which

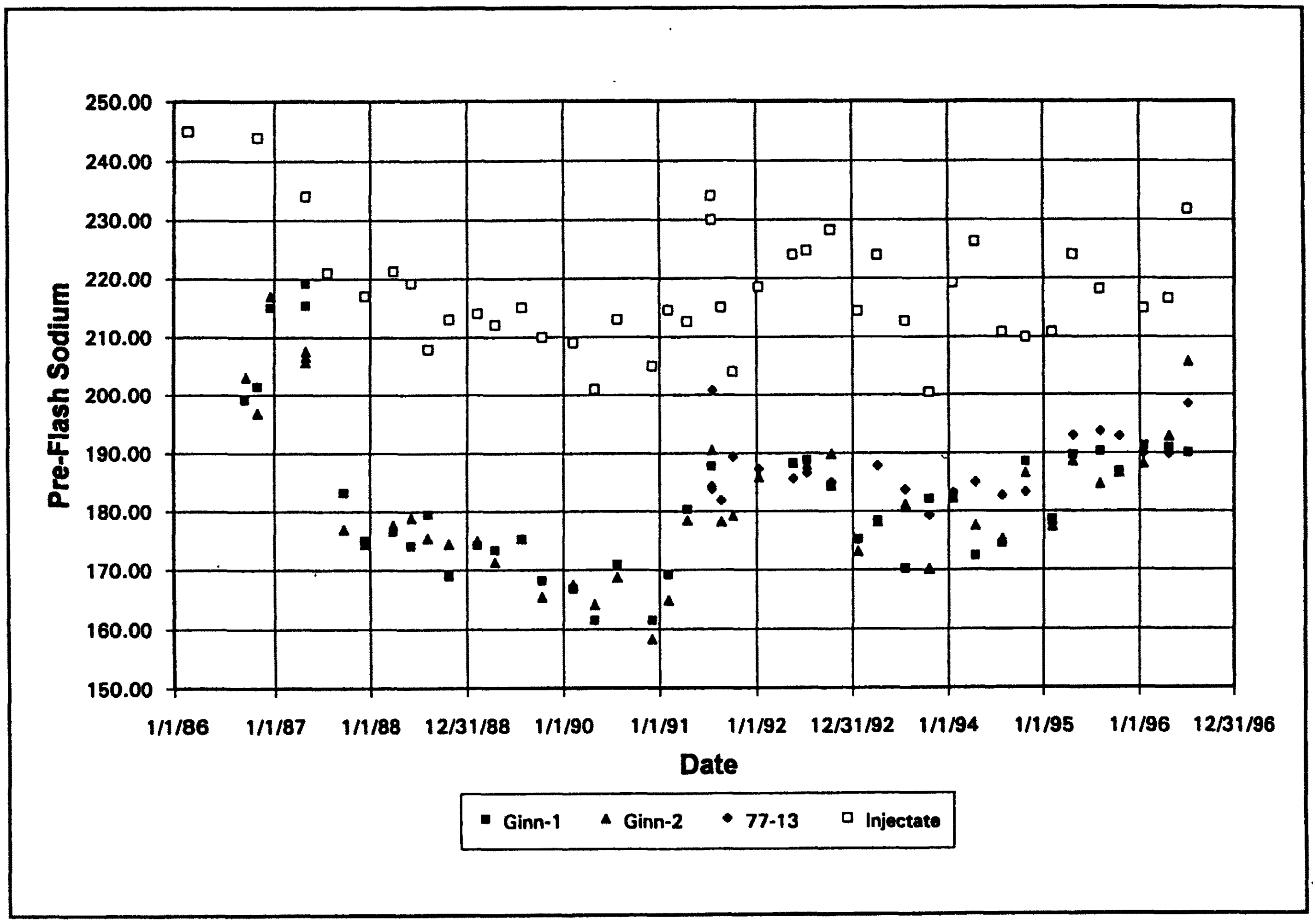

Figure 5. Plot of pre-flash sodium against date.

quickly boosted well flows and plant output. After a period of two years the reservoir temperature and pressure in one of the production wells is essentially stable and the rate of cooling in the other two wells has greatly diminished.

This case history confirms the importance of injection as by far the most important reservoir management tool in extending the productive life of geothermal reservoirs. To develop the most beneficial injection strategy it is absolutely necessary that the geothermal reservoir be viewed in its regional context, not simply as a closed self-contained entity. Much of the needed information about a reservoir and its relationship with the regional hydrology may not be available when a field commences operation but every effort should be made to obtain all possible information in a timely manner in case a change in reservoir management is required.

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