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GEYSERS RESERVOIR PERFORMANCE - AN UPDATE

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ABSTRACT

The Geysers geothermal project operated by Union Oil Company of California remains the world's largest single supplier of geothermal electricity, despite having passed its peak output. The Union-NEC-Thermal (U-N-T) project supplies an installed capacity of around 900 MW, and peak output exceeds 600 MW. In the past decade the project has evolved in response to both resource and market changes. This paper reviews some of those changes and notes their effects on resource performance and management.

In 1987, the U-N-T project was base-loaded and at the peak of its capacity, providing steam to a fully regulated electric power generator at a fixed price well below the electric market's average. In 1997, the project sells steam into an increasingly competitive electricity market under a variable load contract, using a combination of fixed and variable prices to keep Geysers generation attractive. Daily and weekly load cycling are common.

Flow rate and pressure trends since 1987 show the influences of several developments. These include major power plant modifications, the change from base to variable plant loading and increased injection of surface water. Traditional decline analysis can lead to potentially misleading conclusions when applied to Geysers production data, especially those reported since 1991. The behavior of the reservoir corresponds well to Union's forecasts based on previously described simulation methods. These methods have been validated, and used successfully in selecting power plant and facilities investments.

INTRODUCTION

The Geysers geothermal field is well known as the U.S. geothermal industry's longest-running success story, and it continues to be one of the world's premier geothermal electric developments. Installed capacity at The Geysers represents about 25% of the world geothermal total, following closure of several old or underutilized plants (Huttrer, 1995). In 1989 the Geothermal Resources Council (GRC) held its annual meeting in Santa Rosa, California and focused its attention on The Geysers. That meeting was followed by the publication of a landmark monograph which has been widely used.

Many dramatic changes have occurred at The Geysers since 1989, some of which are not well known even within the geothermal community. These range from new external market forces to major internal contractual changes. Some field operations are now routine which were impractical a decade ago.

The retirement and sale of equipment from several power plants at The Geysers has encouraged public speculation about conditions at The Geysers and the field's future. We are happy to report that forecasts of a long useful life, which were made at the GRC meeting in 1989 (e.g., Barker, et *al.*, 1992), are being borne out. As we shall discuss, changing reservoir conditions and smaller economic margins require more sophistication than was once needed, but the technology is available for successful resource management.

ELECTRICITY MARKET EFFECTS

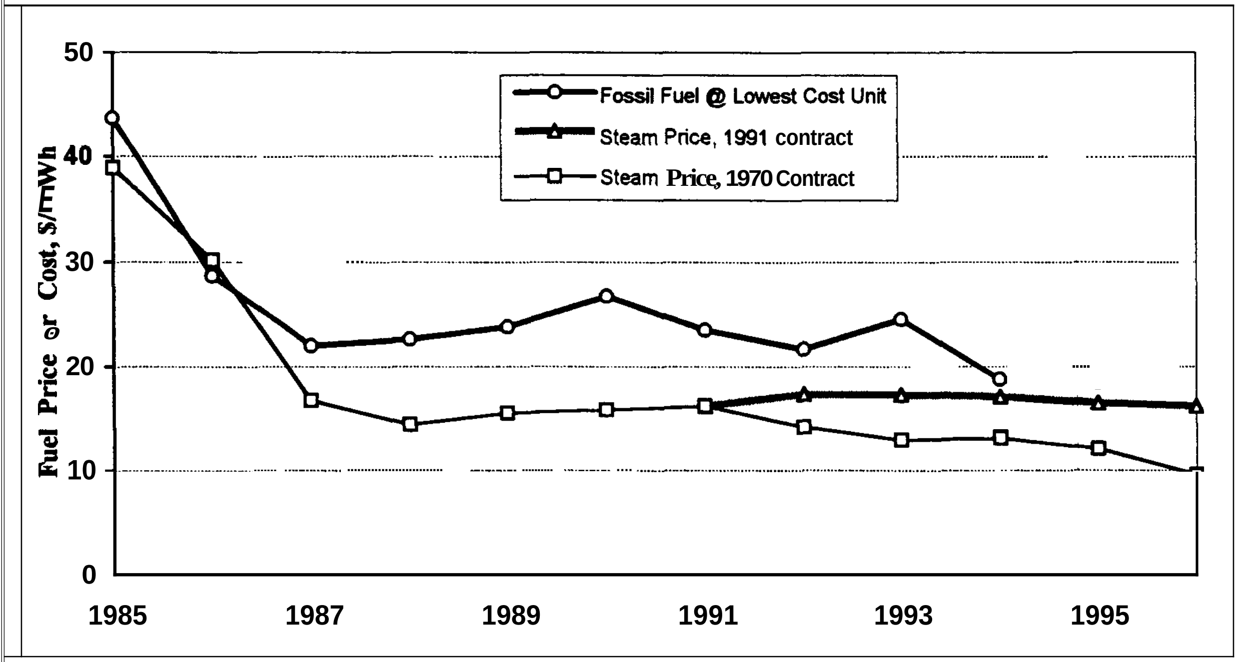
Much attention has been paid lately to California's move toward freer competition in the generation and marketing of electricity. However, the revolution in market forces began a decade ago at The Geysers ith the 1986 collapse of natural gas prices. From ›86 to 1988, Pacific Gas & Electric Company (PG&E) saw its average fossil fuel cost drop by half, from $5.09 to $2.58 per million Btu [per 1055 MJ], as shown in Table 1, below. The drop was so rapid that the fuel cost advantage over fossil plants enjoyed by PG&E's geothermal plants disappeared for a year. This was due to a one year lag in alternative fuel costs incorporated in the steam price formula in -N-T's 1970 sales contract with PG&E.

In 1989, U-N-T and PG&E agreed to settle long-standing disputes stemming from the 1970 contract. The experience of the 1980s provided both sides with asons to favor a new contract, which implemented new, more stable, price formula in 1991.

Figure 1 shows the relationship of the new "1991" formula price and the old, "1970," formula price, as ell as the hypothetical alternative fossil fuel cost at PG&E's "best" unit, at the Moss Landing plant.

Table 1: PG&E Steam and Fossil Fuel Price History

Year	Steam Price (1970 Contract) $/MWh	Avg. PG&E Fossil Fuel Cost $/MBtu	"Best" Avg. Fossil Unit Fuel Cost $/MWh	Geysers "Fuel *Cost* Advantage $/MWh
1983	36.54	5.69	48.53	11.99
1984	39.10	5.69	48.53	9.43
1985	38.91	5.09	43.67	4.76
1986	30.11	3.35	28.68	-1.43
1987	16.76	2.58	21.93	5.17
1988	14.43	2.64	22.59	8.16
1989	15.54	2.82	23.72	8.18
1990	15.84	3.15	26.68	10.84
1991	16.22	2.79	23.41	7.19
1992	14.15	2.56	21.63	7.48
1993	12.97	2.90	24.45	11.48
1994	13.13	2.23	18.75	5.62
1995	12.07	2.18	18.45	6.38
1996	9.55	N/A	N/A	N/A
		13-Year Mean:		7.33



igure 1: Fuel costs at The Geysers and at PG&E's most efficient fossil-fired plant.

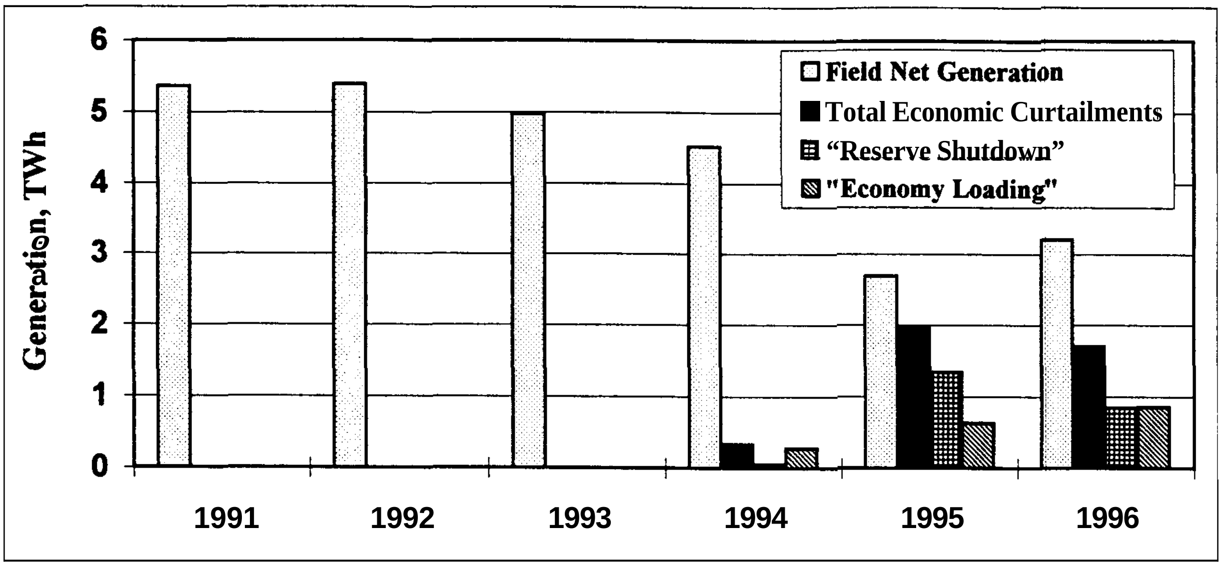


Figure 2: Field net generation for the years 1991 - 1996, with PG&E economic curtailments for comparison. Total Economic Curtailment is the sum of Reserve Shutdown and Economy Loading.

Continued erosion of the fossil fuel alternative price is apparent since 1990, further squeezing margins for operators of plants and steam fields alike. Not shown is the seasonal variation in electricity demand, and the supply of hydroelectric power which also affects The Geysers. In general, demand for Geysers electricity is lowest during Winter and Spring, and peaks in late Summer and Autumn.

The 1991 contract gives PG&E substantial flexibility to curtail generation, provided it purchases an annual 40% minimum of U-N-T's field capacity at the 1991 contract price. The Geysers fuel cost advantage was sufficient from 1991 - 1993 for U-N-T to sell all available steam at the 1991 contract price. This changed during the Spring runoff period of 1994, when the first economic curtailments were imposed by PG&E. Repeated heavy rainfall years and low gas prices produced major periods of curtailment in 1995 and 1996. U-N-T offers some steam which is not subject to PG&E's minimum purchase requirements for sale at variable market prices

Figure 2 shows the total net generation from U-N-T steam during 1991 - 1996, as well as the purchases PG&E did not make for economic reasons. 'Reserve Shutdown" designates non-generation by plants shut down for some period, while 'Economy Loading" indicates part-load operation of one or more units.

OPERATIONS

Plant Modifications

Although economic curtailments were not a factor in 1991 - 1993, economics did play a key role in facilities studies and modifications during the period. At the time the 1991 contract was being finalized, the California Energy Commission's Technical Advisory Committee Consortium (TACC) for The Geysers was evaluating several proposals to deal with declining fieldwide steam output through pipeline construction between steam field operations and subsequent plant consolidation. Union engineers were able to provide proprietary software enabling the pipeline analyses to be carried out with useful precision. The TACC (1992) concluded that long inter-operator pipelines between U-N-T and its neighbors were not economically attractive.

The TACC did note many other plant and field improvements which were recommended by its consultants. Many of these were provided for during the settlement of the suits between PG&E and U-N-T. Union and PG&E engineers have worked together since the 1991 contract was signed to match plant capacities and equipment to steam field characteristics. These power plant improvement studies have relied heavily on the reservoir-well-pipeline-plant integrated model developed by Union (Pingol, 1992).

Integrated model studies of the entire U-N-T pipeline network were carried out which identified Unit 12 in mid-1993 as benefiting from the removal of the blades from one of two turbine rotors, and directing all the steam to the remaining rotor. Generation was improved, and the model forecasts were proven correct within the weather-induced variance of power plant output data. Unit 17 was modified in 1994 with similarly good results. Equally important, the model studies led to choices which proved sound, but which were not the intuitive first choices of the personnel involved.

A less obvious but extremely significant effect of the 1991 contract was the removal of a fixed inlet pressure constraint at the power plants. Instead, PG&E and Union were committed to modifying plants and facilities for variable, *i.e.*, declining, inlet pressures. This changed the boundary condition on the producing reservoir, with pressure results which are apparent in Figure 3.

Flowing wellhead pressures were held within the range of 110 - 125 psig [758-862 kPa] by throttling at the plant inlets until late 1991. From late 1991 until late 1994, the flowing wellhead pressure steadily declined as plants were retrofitted with lower pressure gas ejectors and control valves were opened. Since late 1994, no long term stabilized operating condition is apparent in Figure 3. As will be discussed later, these changes in operation effectively nullify conventional decline curve analysis as an analysis or forecasting tool.

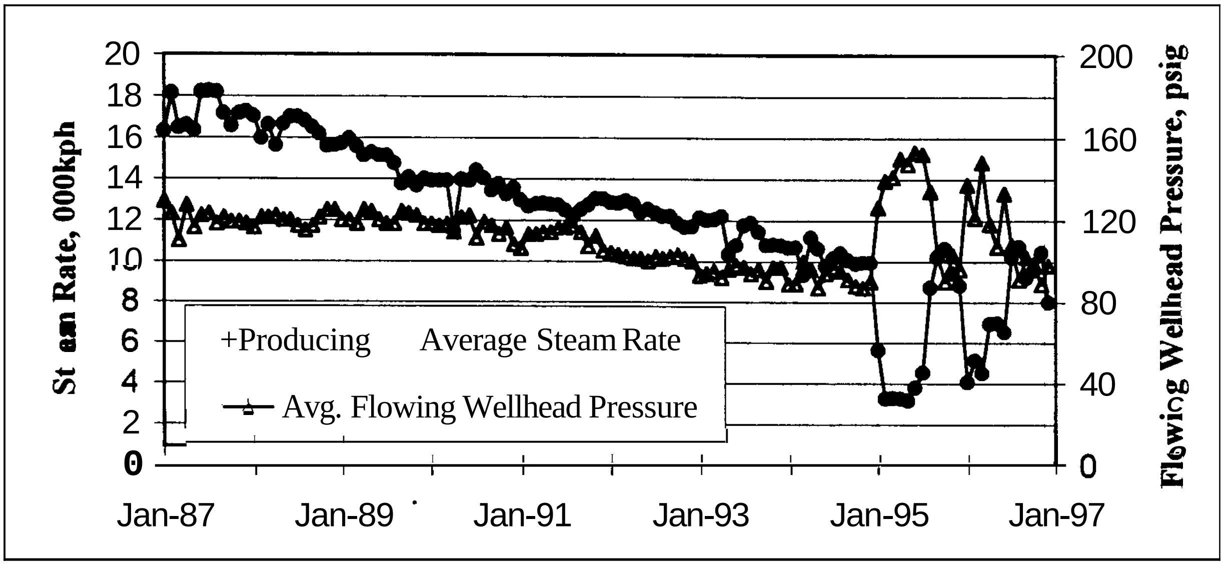


Figure 3:* *Field monthly average producing rate while on line, and averaged daily flowing wellhead pressure measurements.

Variable Loading

The TACC (1992) report had noted the lack of economic support for load cycling by PG&E, and stated PG&E's expectation that it would engage in seasonal base-load variation. It has since developed that daily and weekly cycling is desirable, and cycling is now a regular part of U-N-T's operations.

Cycling, especially when carried out differently at several interconnected power plants, creates several practical reservoir engineering problems. Thermal cycling of wells and casing increases their failure rate, and variable load operation makes partial well failures difficult to detect. Variable loads also require instrumentation to gather and process more reservoir monitoring data than a base load operation. Methods of sieving and analyzing large quantities of highly variable data for detection of subtle problems are required for the project to maintain its full potential.

The record of monthly flow rate and pressure in Figure 3 shows how variable even monthly averaged data now is. The two sets of aggregate data graphed in Figure 3 do however display the expected inverse variation of rate with wellhead pressure.

The cycling response of individual wells is much less consistent than the aggregate behavior shown in Figure 3. For example, two adjacent wells on the same drill pad may have noticeably different characteristics, as in Figure 4. The production rates of wells DX 24 and DX 25 are shown on a semilog scale to highlight the consistency of their behavior throughout the base load period from 1987 through mid-1994.

DX 24 dropped nearly to zero flow in February and March 1995, and never regained its base load deliverability during that year. Because the well showed signs of dying on line, it was opened to production in April and May, with a very slow response. DX 25, on the other hand, dropped to about half rate for all four months. Then it came back in June at a higher rate than before curtailment, only to decline rapidly later in the year. The two wells were managed differently in 1996, with the result that both more closely approached their base load standards of performance.

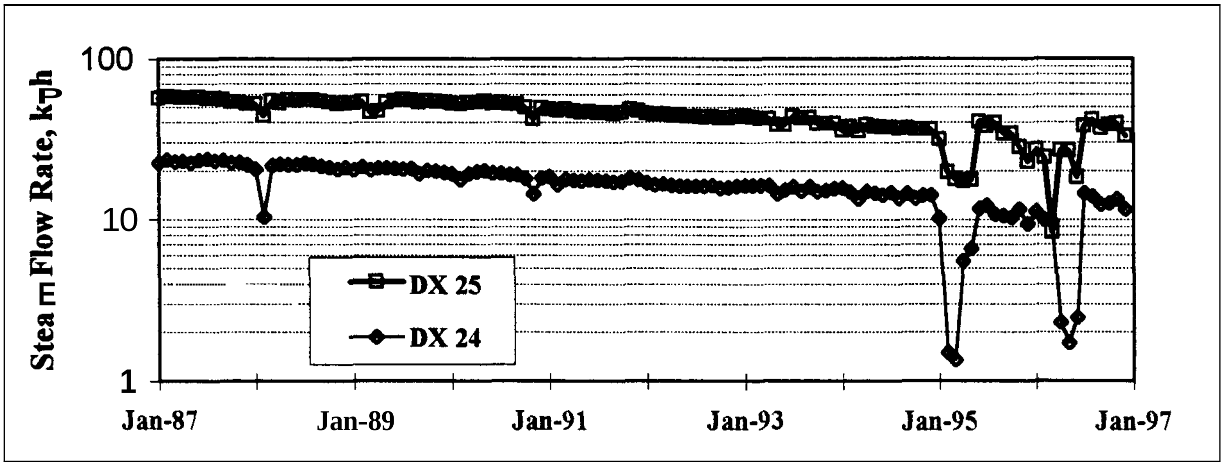


Figure 4: Monthly average flow rates for wells DX 24 and DX 25.

Water Injection

Condensate injection became a regulatory requirement in 1969. Supplemental fresh water injection has been used for augmented heat recovery in depleted areas since 1980, when Union built a pump station on Big Sulphur Creek near Units 1&2. A second pump station, near Unit 14, and a third near Unit 20 now operate throughout the rainy season. Together with numerous small stream catchments, these projects have increased fresh water injection to more than 18 billion pounds per year(8.2 Mt/a) during wet years. Figure 5 shows the resulting fieldwide total injection and mass replacement. Due to the curtailments in 1995 and 1996, mass replacement exceeded 57% in both years. The Southeast Geysers Effluent Pipeline project should be completed in the Summer of 1997. This line will bring a mixture of treated wastewater and Clear Lake water to The Geysers, to be shared by the U-N-T project, Northern California Power Agency and Calpine Corp. U-N-T's share will amount to 7.4 billion pounds per year (3.4 Mt/a). This will increase U-N-T injection fieldwide by 25%, rake the local mass replacement ratio in the southeast to or above unity, and keep the fieldwide ratio above 50% even in dry years.

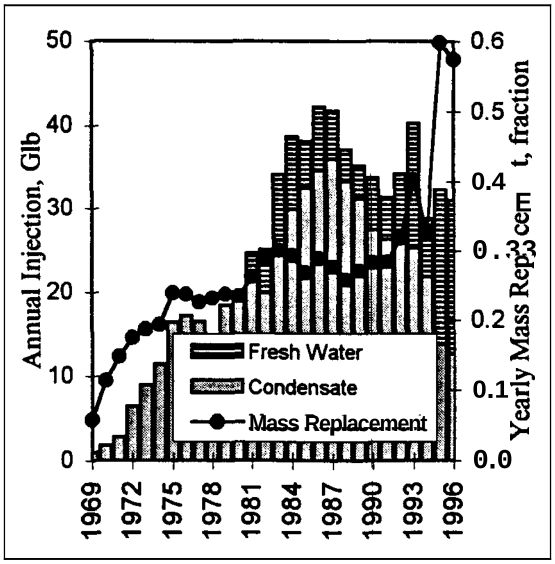


Figure 5: History of injection and mass replacement ratio at The Geysers.

FORECASTING

A principal challenge for reservoir engineering at The Geysers is to accurately forecast the benefits of many competing potential investments in plant and field improvements. It is ironic that after 36 years, operation of the field is changing so much that the relatively simple tools which are often applied to mature fields don't give particularly useful results. To illustrate the difficulty, consider the data and decline curve in Figure 6.

Ordinarily, seven and one half years of data would be ample for a decline curve fit. Earlier in the life of The Geysers, or in many other fields, it would serve nicely. However, even though the harmonic curve in Figure 6 has a correlation coefficient, R^2, of 0.89, it underpredicts the peak monthly production in 1996 by more than 1 billion pounds [454 kT]. This error is equivalent to continuous generation of about 75 MW for the month. This difficulty with transients is not surprising, since transient operations violate several assumptions underlying decline curve techniques. Unfortunately, this harmonic curve also appears to be unreliable in predicting the level to which the transient will decay.

Looking at 1995, the production trend for September and October rises steeply above the harmonic curve. The October-November trend drops equally steeply. (November's production would have been the same as September's, were it not depressed by a Thanksgiving weekend curtailment of 0.58 Glb. [264 kT]) The steep slope of the production data as it approaches the harmonic curve inspires little confidence that this decline curve indicates a level at which production would settle if base loading were to resume.

Selecting peak rates for decline curve analysis is sometimes used to filter data. This approach could be particularly misleading when applied to cycling or post-cycling data, as it tends to lead to a serious underestimate of the underlying reservoir decline rate under base load conditions.

More encouraging results come from comparing the field base load production history with two numerical simulation forecasts published in 1989. Barker, *et al.*(1992), showed two forecasts of base load operation in their Figure 15. One assumed a fixed inlet pressure of 100 psig and the other an infinitely variable inlet pressure. Those forecasts are

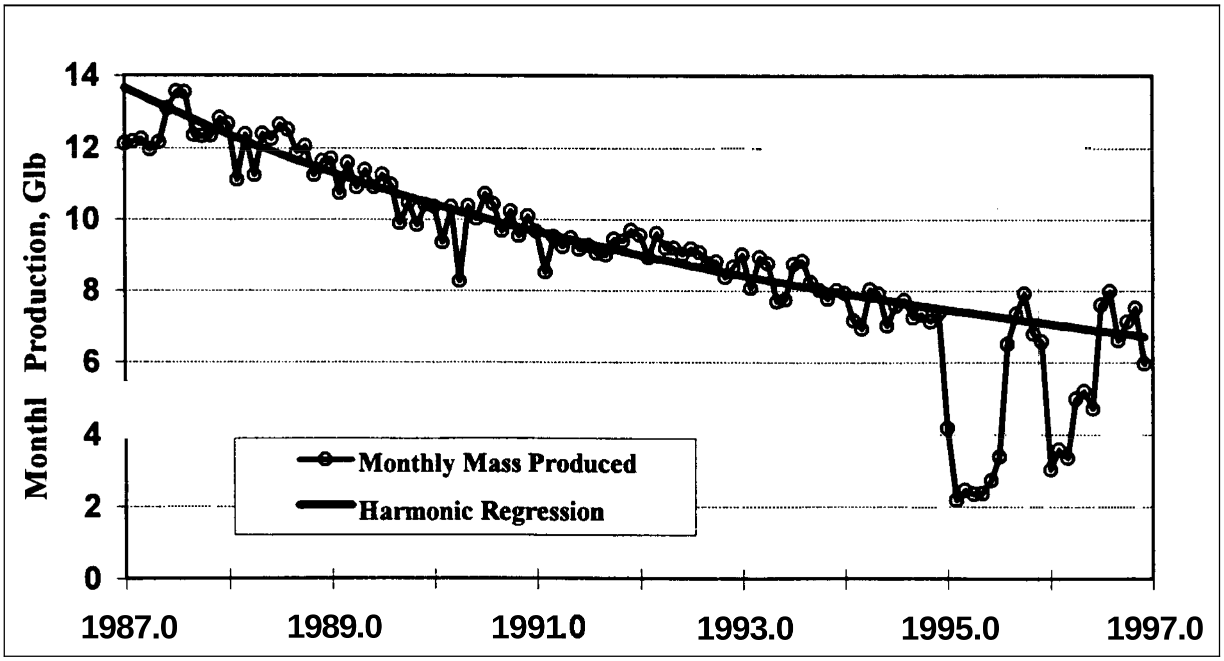


Figure 6: Field monthly production data, with a harmonic decline curve constructed by least-square regression of the rates from 1987 through mid-1994.

reproduced in Figure 7, below, with the measured steam rate from Figure 3 added for comparison. The simulator forecasts appear to do a good job of predicting base load performance. Operations are variable enough at The Geysers that conditions rarely correspond exactly to those assumed in simulations for more than a few weeks at a time. Nevertheless, we see good agreement between production and these forecasts when operating conditions do match. In particular, during the six months prior to the September 1991 contract signing, PG&E was quite careful to maintain inlet pressures close to 100 psig. The power plants then converted to valves-wide-open *(i.e.* variable pressure) operation over the next few months.

The production data in Figure7 follow the fixed pressure curve and then transition to the variable pressure curve in late 1991. The points which fall below the variable inlet pressure curve in 1992 and 1993 coincide with unit overhauls, the removal of half of Unit 12's turbine blades, and other curtailments

These forecasts were predicated on base load operation, and are therefore no more likely than the harmonic curve to predict the transient response after the 1995 and 1996 curtailments. The simulator *can,* however, unlike the decline curve, be set up to model the curtailed operation and the subsequent reservoir response. Others at this meeting will be discussing this technology.

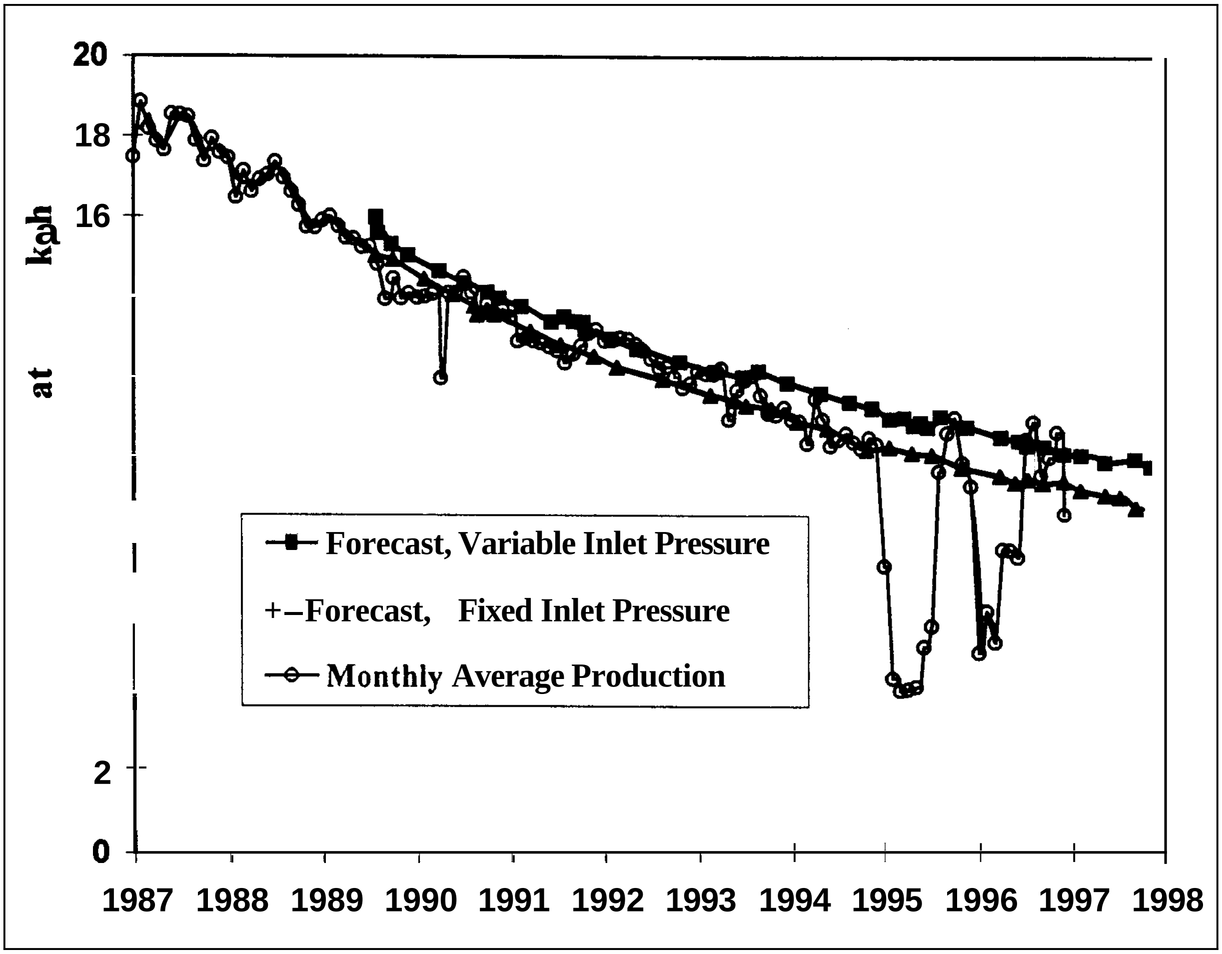


Figure 7: Comparison of field monthly production rate with two simulation forecasts first published in 1989 (adapted from Barker, et al., (I 992)).

CONCLUSIONS

Changes in the electric market and steam sales contracts have profoundly affected the operation of The Geysers by introducing extensive variable load operation..

A current generation geothermal reservoir simulation program gave good results in forecasting long term base load deliverability.

Widespread variable load operation requires the application of relatively sophisticated engineering for performance monitoring and forecasting.

Water injection will have an increasingly important effect on reservoir conditions. Union's surface water facilities have nearly doubled their collection rate in effectiveness in the past five years, and waste water injection is expected to start in 1997.

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