RESULTS FROM A FIELD-WIDE NUMERICAL MODEL OF THE GEYSERS GEOTHERMAL FIELD, CALIFORNIA

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ABSTRACT

A numerical simulation model of The Geysers geothermal field, California, has been developed using reservoir and production data provided by UNOCAL, Calpine, NCPA and CCPA. The model was originally developed by UNOCAL and was based primarily on data from the Unocal-NEC-Thermal (U-N-T) lease areas; the purpose of this study was to extend the model by incorporating data from other field operators and to use the re-calibrated model to forecast future production trends.

The model was successfully calibrated against pressure data from individual observation wells and field-wide isobaric maps. Forecast runs were then made for two production scenarios:

- wellhead pressures will reduce by 40 psi over the next five years and then remain constant;
- wellhead pressures will remain constant at their present levels.

The results show that the reduction in wellhead pressure allows an additional 1 million lbs/hr to be produced over the next ten years; equivalent to 55 MW(net) additional power production. However, the results also show the field production will continue to decline from the present level of approximately 23 million lbs/hr to 8.5 million lbs/hr by the year 2014; equivalent to a reduction in overall power production from the present level of 1,250 MW (net) to 475 MW(net).

INTRODUCTION

A field-wide reservoir modeling study of The Geysers geothermal field, located in Lake, Sonoma and Mendocino Counties, California was undertaken during 1991-92 under the guidance of the Technical Advisory Committee (TAC) Industry Consortium with funding from Lake and Sonoma Counties, through a grant from the California Energy Commission (CEC), and from members of the Industry Consortium. The TAC was initially created by the CEC during 1989 to investigate the decline in generating capacity at The Geysers and the methods available to mitigate the decline; the field-wide modeling study was undertaken as a part of these investigations.

The TAC includes representatives from both regulatory agencies and industry while the Industry Consortium is a sub-committee

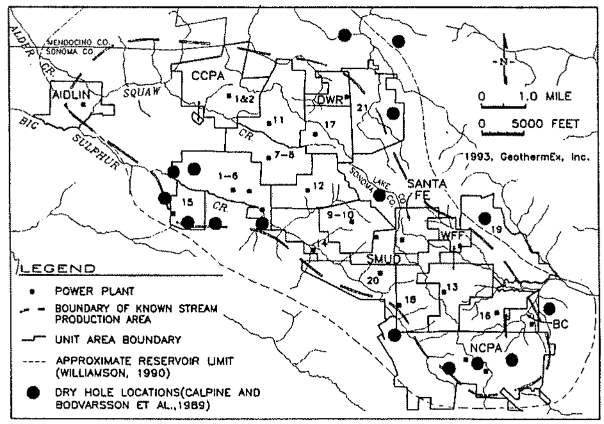

Figure 1: The Geysers geothermal field

of the TAC which includes representatives from steam field operators and utilities involved with The Geysers. The following groups are represented on the TAC Industry Consortium:

- Pacific Gas and Electric
- UNOCAL Geothermal
- Santa Rosa Geothermal Company (Calpine Corporation)
- Northern California Power Agency (NCPA)
- Sacramento Municipal Utility District (SMUD)
- Russian River Energy Company (as the service company for the Coldwater Creek steamfield, now owned and operated by Central California Power Agency No. 1)
- Wildhorse Ranch, Inc. (WHR)

BACKGROUND

The Geysers geothermal field is located approximately 75 miles north of San Francisco and is the largest identified and exploited geothermal reservoir in the world. The known productive field area, as defined by the distribution of successful wells, is approximately 30 square miles (figure 1).

First attempts to produce electricity from the resource came in the 1920's when steam from a few shallow wells was used to generate electricity for The Geysers Resort Hotel. However, it wasn't until 1955 when Magma Power Company obtained leases on the north side of Big Sulphur Creek that full scale commercial development began. Magma initiated a drilling program with Thermal Power Company and by 1958 sufficient wells had been drilled to supply steam to a small generating unit (Barker, *et al.*, 1991). Pacific Gas and Electric (PG&E) then signed a contract with Magma-Thermal to provide steam to Unit No. 1, a 12 MW power plant installed in 1960. Since 1960, an additional 28 generating units have been brought on-line, with capacities of between 23 and 137 MW (gross), to bring the total installed capacity to 2,056 MW.

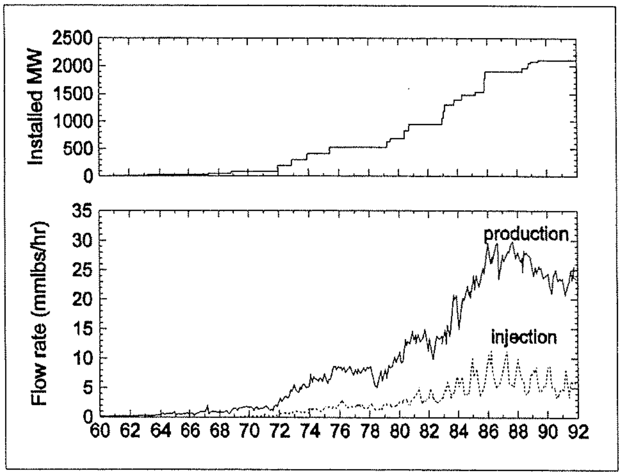

Figure 2: Development history at The Geysers

The growth of the generation capacity at The Geysers (figure 2) did not follow a predetermined schedule. During the 1960's growth was slow with installed capacity only rising to 82 MW (PG&E Units 1 to 4) by 1970. However, the growth rate accelerated during the 1970's when 610 MW was brought on-line and in the 1980's when an additional 1,364 MW of generating capacity was installed although the pace of development declined significantly after 1986. The last generating unit, the Aidlin 23 MW plant located in the NW Geysers area, was brought on-line in June 1989. At the present time, no new power plants are scheduled for construction at The Geysers due to a combination of increasing development cost and resource risk, decreasing availability of favorable steam or power sales agreements, and problems with the performance of the developed steamfield.

The field production flow rate peaked at approximately 30 million lbs/hr during 1986/1987 and has dropped steadily since that time to less than 23 million lbs/hr. The decline in overall production flow rate was caused by a significant increase in reservoir pressure decline associated with the accelerated development of the field in the early 1980's. Well LF-6 (figure 3), located in the Unit 9-10 area, is typical of many production wells in the field; prior to 1985, the production decline rate was 6% per year but this increased to 30% per year after 1985 due to increased offset production.

The significant drop in production flow rate has resulted in significant under-utilization of the installed facilities. In mid-

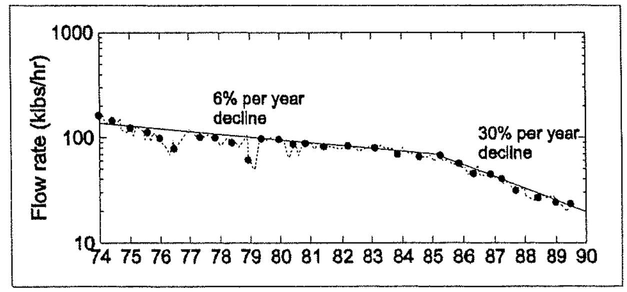

Figure 3: Well LF-6 monthly flow rate history

1991, it was estimated that the field-wide production was 1,300 to 1,500 MW compared to an installed capacity of over 2,000 MW. With this reduction in electrical generation, the ability of The Geysers to continue to provide significant electrical generation into the future has been questioned.

Since 1990, however, there is evidence that the production decline rate may be reducing, possibly due to:

- changes in generating strategy by moving from base load operation to load following in some areas of the field, notably NCPA;
- the reduction in overall production flow rate from the field, and;
- local changes in injection strategy.

MODEL DESCRIPTION

The field-wide model of The Geysers was originally developed by UNOCAL and a full description of the original model parameters is presented in Williamson (1990). The basic model was provided to the TAC Industry Consortium and modified to include data from other operators in the field, specifically NCPA, Calpine and CCPA. The model was then run to match historical data and to forecast field-wide reservoir behavior under different production scenarios.

The model is presently running on the TETRAD reservoir simulator and uses a "double porosity" formulation to account for the presence of fractures and low permeability matrix blocks in the reservoir. The wells are assumed to be completed within the fracture network while the matrix blocks provide the bulk of the reservoir storage capacity. The model does not include recharge but relies on storage in the matrix blocks to maintain production.

The following description of the model has been summarized from Williamson (1990) and also includes details regarding changes that were made to the model for the present study.

Geometry

The basic layout of the model in terms of overall area and grid block layout was not changed from the original UNOCAL model. The overall area covered is 44,000 acres (12.1 miles by 5.7 miles), which includes all the presently developed areas of the field (figure 4). The model is split vertically into six 2,000 foot layers, with the top of the upper layer corresponding to mean sea level (msl). Each layer contains 32 by 15 square cells each 2000 feet on a side, giving a total number of grid blocks of 5,760; 2,880 matrix blocks and 2,880 fracture blocks. The long axis of the model is aligned northwest-southeast roughly parallel to the regional geologic strike.

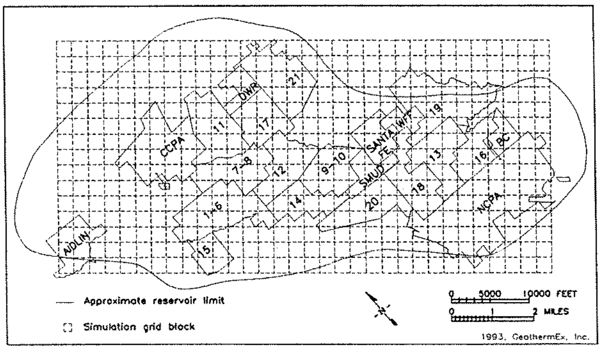

Figure 4: Simulation model grid block layout

The depth to the top of reservoir varies in elevation by as much as 6,000 feet throughout the field. The complex shape of the reservoir is reflected in the permeability structure in the model. The shape of the reservoir bottom is inferred from indirect observations and is poorly defined. Information used by UNOCAL to help define the bottom of the reservoir include:

- location of steam entries;
- hypocentral distribution of microearthquakes associated with injection;
- history-matching by comparing those areas of the model where liquid accumulated in the fracture domains of layers 5 and 6 (-8,000 to -12,000 feet msl) towards the end of the history-match period with areas where deuterium levels in the produced steam are high, indicating a contribution from injected condensate in the steam.

The extent of the productive reservoir in the original model was based on the approximate reservoir limits established by UNOCAL geologists (figure 1). However, additional information on reservoir extent is provided by the location of dry holes (Bodvarsson, Gaulke and Ripperda, 1989 and data provided by Calpine) and the area of known steam production (figure 1). Figure 1 shows that the productive boundary is not well defined in the SE of the field, where the West Ford Flat development and the East Ford Flat (Unit 19) areas are located.

In the original model, the West Ford Flat and East Ford Flat areas were assumed to have low permeability but the success of the West Ford Flat development indicates that the reservoir extends further to the east than was previously represented in the model. Hence, the reservoir geometry and matrix permeabilities were modified to include these areas for the present study.

Petrophysics

The important petrophysical properties required for the model include: matrix and fracture porosity, matrix and fracture permeability and fracture spacing. For the original UNOCAL model, these properties were derived mainly from the results of measurements on core taken from nine wells, on observations made while drilling, and on the interpretation of pressure-transient tests from within the UNOCAL-NEC-Thermal (U-N-T) lease areas.

Based on the above sources of data, the porosities used within the matrix domain of the model vary from 1.2 to 4.6% within the reservoir to 0.4% outside the reservoir. The UNOCAL data also suggested that the porosity decreases with depth from the surface and is strongly influenced by the proximity of the felsite, which underlies much of the field. Fracture porosity has not been well defined by available field data and is therefore used as a variable for matching the measured pressure data.

Matrix permeability values are also not well defined but are believed to be very low (in the micro-darcy range). For the fracture domain, permeability values were assigned based on observations during drilling and also on the interpretation of pressure transient data. The permeability values in the fractures range from 3 to 140 millidarcies for horizontal permeability and 4 to 200 millidarcies for vertical permeability.

Estimates of the fracture spacing were based primarily on the frequency of occurrence of steam entries, with typical values of between 160 and 600 feet. The fracture spacing, fracture permeability and matrix permeability are used by TETRAD to calculate the transmissivity between the matrix and fracture blocks.

Definition of the petrophysical properties in the areas outside the U-N-T area were based on data made available by the other operators for this study. Estimates of fracture spacing in individual blocks were provided by the operators, based on interpretation of drilling logs, while initial estimates of fracture permeability were provided based on results of pressure transient tests.

Thermodynamics

In general, over most of The Geysers field, an initial reservoir pressure of approximately 514 psia (corrected to mean sea level) was encountered and the vertical pressure gradients were vapor-static (Williamson, 1990). Temperatures did not vary significantly from saturation conditions (470°F), except in the NW section of the field where reservoir temperatures of greater than 500°F were encountered at depths of -6,000 to -8,000 feet msl; well above vapor-static saturation conditions. The conditions in the NW were not incorporated in the model; the upper four layers were set to saturation conditions corresponding to 514 psia while in layers 5 and 6, temperatures were set to boiling-point-depth conditions while pressures were increased according to a vapor static gradient. The pore space was therefore vapor-filled with superheated steam (liquid saturation = 0). It was not possible to create a stable initial state model of The Geysers field with boiling fluid below -8,000 feet msl (Williamson, 1990) and it was also necessary to set the vertical component of thermal conductivity to zero to inhibit heat transfer from the lower layers.

From simple mass balance considerations, it is known that The Geysers reservoir must contain liquid water in order to have maintained its productivity since 1960. The fracture domain liquid saturations in the original UNOCAL model varied from 1% in the NW Geysers up to 25% in the vicinity of Cobb Mountain, where initial pressure declines have been relatively low. There is a general decrease in liquid saturation from the SE to the NW. The matrix domain liquid saturation in layers 1 to 4 was initially set to a constant value of 83% in the original UNOCAL model.

The thermodynamic conditions from the original UNOCAL model were used as the initial conditions for the present study but it was found that it was necessary to make some changes in order to match the available observation well pressure histories and the overall field isobaric maps.

The relative permeability curves used in the model, which control the relative flows of steam and water between blocks, are based on UNOCAL's own experience but are similar to the Grant relative permeability curves which are commonly used in simulating fractured geothermal reservoirs. The residual water saturation is assumed to be 30% while the residual steam saturation is 0%.

HISTORY MATCHING

The UNOCAL model included detailed production data from the U-N-T lease areas and generalized production data from the Santa Fe lease area (figure 1) from the start of production in 1960 up to August 1991. Detailed production data, provided by NCPA, Calpine and CCPA for the individual wells in their lease areas, were also incorporated into the model.

The locations of production zones of individual wells were based on actual drilling profiles and discussions with each operator regarding production depths. For wells that produced from more than one layer of the model, it was assumed that the production blocks were stacked vertically. Due to the relatively large size of the grid blocks, this assumption is probably reasonable although the majority of the wells are deviated.

Specifying injection well locations was difficult due to the close proximity of production and injection wells in the field; this means that some production and injection wells would be located in the same grid block. To separate the production and injection wells, injection was located in layers 4 to 6 of the model even though the wells may be completed shallower. The justification for this approach is that the injected water is believed to sink toward the bottom of the reservoir due to gravitational effects.

Isobaric maps from 1987 to 1991 were provided by UNOCAL for use as the main parameter to calibrate the model; these maps were then modified based on data received from the other operators. For this study, the isobaric maps based on measured pressure data at October 1987, April 1989, and April 1991 were used for matching and compared with the simulated fracture pressure distributions in layers 1, 2 and 3 of the model, corrected to msl. The different layers were included as the production depth changes across the field; generally shallower to the SE and deeper towards the north although shallow steam is also found over a significant area along the NW/SE axis of the field.

Pressure data were also provided from a number of observation wells with relatively long pressure histories. The data from these wells were also matched to provide further calibration of the model.

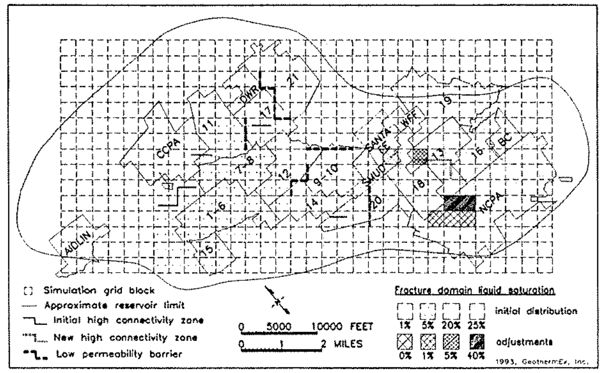

Figure 5: Model fracture domain saturations and zones of high and low conductivity

During the history matching, the main parameters that were modified included: fracture permeability, initial matrix water saturation and matrix permeability. Localized changes were also made to the initial fracture liquid saturation (figure 5) and some zones of high or low connectivity were added to the model in order to match the observation well pressure data.

Observation Well Pressure Data

Observation well pressure data from a number of wells were provided by the operators involved with this project and reasonable matches were obtained to the measured data from each well. The matches to two of the wells, 1862-1 (Calpine Unit 13) and F-4 (NCPA), are presented here.

Well 1862-1 is located in the northern corner of the Unit 13 area and the measured and simulated pressure responses are shown in figure 6. From 1982 to 1989 the simulated pressures closely follow the measured data in this well in terms of both the pressure decline rate and the overall change in pressure. In mid-1989, the measured pressure decline reduces and the pressures continue to decline at a lesser rate until the end of the measured history. The simulated pressure history shows similar characteristics but slightly overstates the current reservoir pressure in this well. This is probably due to the relative coarseness of the grid layout, although the overall match is considered to be very reasonable.

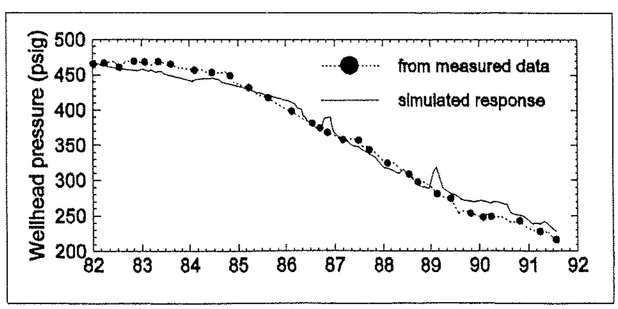

Figure 6: Well 1862-1 pressure history

The significant change in pressure decline rate that began at mid-1989 is probably due to the reduction in overall field production rate that began in 1988 (figure 2) combined with additional pressure support from the new injection strategy initiated in late 1989 by both Calpine and NCPA. In an attempt to alleviate the pressure decline in the low pressure area bordering the Unit 13, Unit 18 and NCPA areas (figure 1), injection was relocated to provide more direct pressure support. To obtain the change of slope in the simulated pressure curve, it was necessary to create a preferential path between well 1862-1 and the new injection area by increasing the transmissivity of blocks connecting the two areas fivefold (figure 5). The existence of a high permeability N-S path is consistent with the results from tracer tests conducted by Calpine and NCPA (Adams, *et al.*, 1991).

Well F-4 is located in the NCPA-1 area (figure 1) and the measured and simulated pressure responses are plotted in figure 7. The measured data show a steep decline in pressure from 1985 to 1988, followed by pressure stabilization. The pressure stabilization is associated with reduced load operation and the change in injection strategy that occurred in late 1989 when NCPA started injection to wells C-11 and F-1 (Enedy, *et al.*, 1991). The simulated pressures match the measured data to within 20 psi throughout the 10 years of pressure history. However, to obtain the match it was necessary to reduce the initial fracture water saturation for blocks in the vicinity of F-4 from 20% to 1% (figure 5).

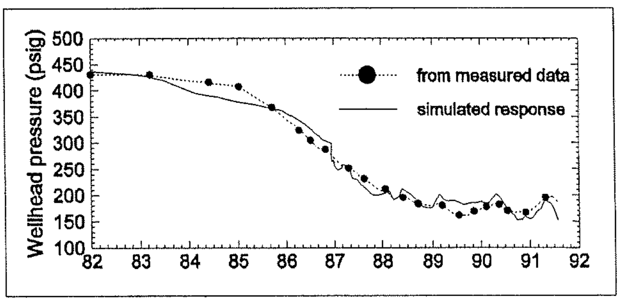

Figure 7: Well F-4 pressure history

April 1991 Field-wide Isobaric Maps

When the simulation model was first run to match the field-wide pressure data, it was found that in some areas the reservoir pressures recovered in response to the decline in overall production flow rate since 1987 (figure 2). However, the measured data show that in spite of the reduction in production, reservoir pressures have continued to decline or, in the best case, to stabilize (figures 6 and 7). Hence, in order to match the 1991 pressure contour data (figure 8), it was necessary to adjust the initial matrix water saturation which had been set to a constant value of 83% in the original UNOCAL model.

In layer 1, the initial matrix water saturation was increased to between 86% and 95%, except for a small area in the vicinity of the SMUD lease (figure 1) where it was set to between 71% and 75%. In layers 2 and 3, the main production layers, it was necessary to modify the initial matrix water saturation distribution significantly and values between 55% and 90% were used in various parts of the field. In layer 4, the initial matrix water saturation was set to a constant value of 70%.

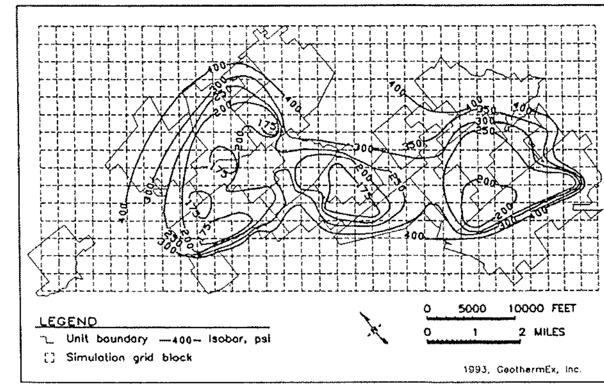

Figure 8: Measured pressure contours, April 1991

With these changes it was possible to obtain reasonable matches to the field-wide isobaric map for April 1991 (figure 8); the simulated isobaric maps for layers 1 to 3 are shown in figures 9 to 11.

Although a reasonable overall match to the measured data was obtained, the model calculated higher pressures than measured in the central UNOCAL area. This is possibly due to injection water recharge coming from deeper layers or too much recharge from the matrix blocks to the fractures.

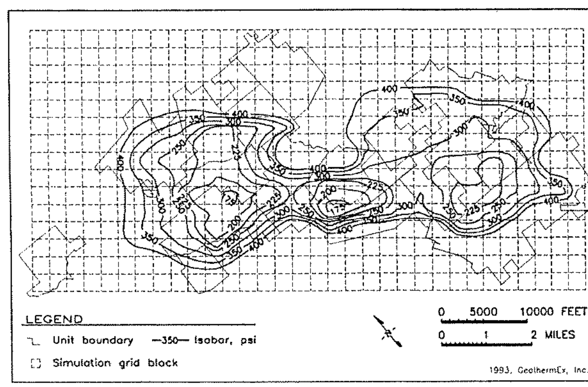

Figure 9: Calculated pressure contours (layer 1), April 1991

In the West Ford Flat area, the calculated pressures are lower than observed by approximately 25 to 50 psi. This is believed to be due to the proximity of the low permeability boundary blocks. Initial matrix water saturations of up to 90% were defined in this area to provide additional water reserves but this was not sufficient to maintain reservoir pressure. This may indicate that additional recharge is occurring in the SE Geysers area.

FORECAST RUN RESULTS

After the history matching was successfully completed, the field-wide model was used to forecast future field performance under two scenarios; both based on assumptions used in the PG&E ER-92 report. The first considered lowering well head pressures over the next five years by up to 40 psi (to a minimum wellhead pressure of 70 psia) while the second assumed that well head pressures would remain constant at present levels. The ability to drop well head pressure from the present levels will depend on

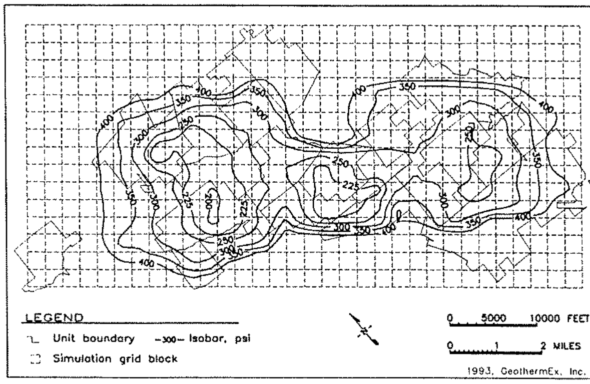

Figure 10: Calculated pressure contours (layer 2), April 1991

retrofitting of the present Geysers power plants to accept lower pressure steam to the gas ejectors. Modifications to the turbines may also be undertaken to improve efficiency at lower pressures.

The other main assumptions used in the forecast runs are:

- No infill-drilling in the UNOCAL, CCPA and NCPA leaseholds.
- Infill-drilling of new wells to maintain power production in the Calpine lease areas. The number of future wells drilled, their locations and expected production rates were provided by Calpine.
- No development of the East Ford Flat (Unit 19) area.

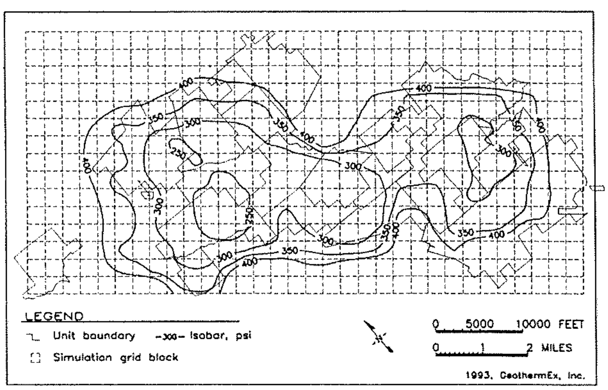

Figure 11: Calculated pressure contours (layer 3), April 1991

For the first run, the 40 psi pressure drop was specified differently for each operator. For UNOCAL, wellhead pressures were dropped by 20 psi at the beginning of October 1991 when they went to variable pressure operation (VPO) and the remaining 20 psi was dropped at a rate of 2 psi per six months over the next five years. In the Calpine and CCPA leaseholds, the 40 psi pressure drop was evenly distributed at 4 psi per six months starting from August 1991. NCPA wells required a different approach due to the current load-following operation. Present wellhead pressures vary from 90 to 130 psia, depending on plant operation, and a uniform initial wellhead pressure of 110 psia was therefore assumed at the start of the forecast run. The wellhead pressure was kept constant until the total production rate fell below the current average power plant steam requirement; after that time was reached the wellhead pressures were dropped at a rate of 4 psi per six months for five years. After the 40 psi pressure drop or when the minimum wellhead pressure of 70 psi was reached, wellhead pressures were kept constant through the remainder of the simulation run.

For the second run, wellhead pressures were maintained at the August 1991 level throughout the simulation. The primary purpose of this run was to see how much additional steam could be obtained by the 40 psia pressure drop. Constant wellhead pressures would be achieved by throttling the wells either with the wellhead or plant control valves.

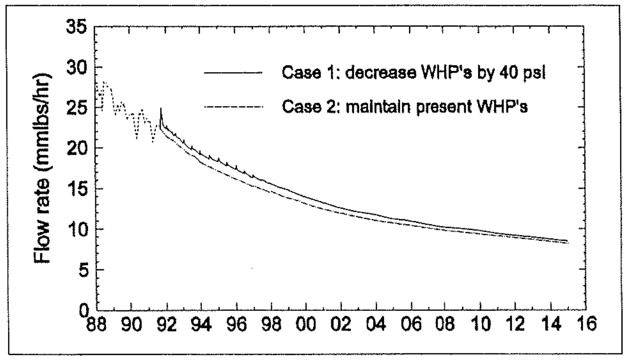

Figure 12: Fieldwide forecasts of steam production

For both forecast runs, the percentage of produced fluid that was injected was maintained constant at 25%; similar to the present injection percentage. The model did not consider the possibility that with declining production to a plant, the amount of injection water available from the cooling tower would drop below 25%. The possibility of enhanced injection was also not considered as the present model is not adequately detailed to provide information on the localized effects of injection. It is likely that the model will show improvement in overall reserve levels due to enhanced injection but would not be able to provide more detailed information on the effect of injection on nearby wells.

Due to the field-wide nature of the model and the overlap of grid blocks with area boundaries, only the steam forecasts for the entire Geysers field from the two scenarios are presented (figure 12). The increases in flow rate that occur during the period 1992 to 1999 are caused by the reductions in wellhead pressure.

Comparing the results of the two scenarios (figure 12), the reduction in wellhead pressure provides a gain in flow rate of nearly 1 million lbs/hr, corresponding to additional generation of approximately 55 MW(net), over the next 10 years. Most of this gain occurs as a result of the UNOCAL leases moving to VPO during October 1991 but there are continued gains during the 1992 to 1999 period when additional declines in wellhead pressure occur. Beyond the year 2000, the improvement in steam flow rate is maintained at a lower though still significant level. By 2014, the steam field-wide steam production is 8.5 million lbs/hr compared with the present flow rate of approximately 23 million lbs/hr. The decline in flow rate calculated for case 1 can be fitted reasonably accurately by an average harmonic decline rate of 9% or by an average hyperbolic decline rate of 7.5% (Barker, pers. comm.).

The steam flow rate forecast for case 1 is plotted in terms of power output in figure 13 where it is compared with the ER-92 forecast. The ER-92 forecast has been modified to include the 146 MW generated by Qualifying Facilities (QF's) and to remove the expansion of the CCPA facility from 61 MW to 122 MW in 1994. These changes were required to be more compatible with the assumptions used in the model. The conversion to MW(net) was based on 18,000 lbs/hr per MW(net), which is believed to be a reasonable conversion factor based on data supplied by PG&E and Calpine. There is remarkably good agreement between the model results and the ER-92 forecast, particularly in terms of the rate of decline up to the year 2002. Beyond 2002, the model predicts a lower decline rate but the results are still very close. The results show that by the year 2000, the power output from the field will be approximately 800 MW(net) and by the year 2014, the end of the forecast runs, the output will have dropped further to 475 MW(net).

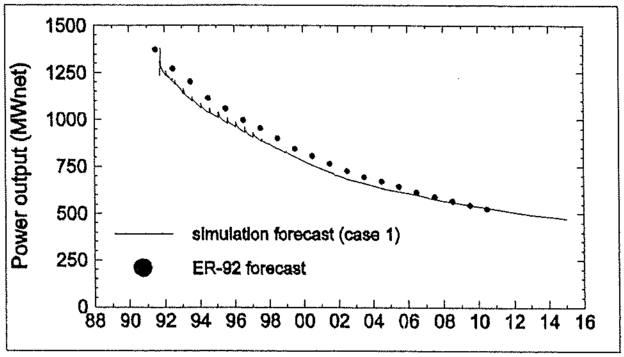

Figure 13: Fieldwide forecasts of power production

The calculated pressures as of 2007 indicate that pressures over the field will have declined by approximately 50 psi in the NW area of the field and by 75 to 125 psi in the central and SE areas of the field, respectively, when compared with the 1991 pressure contours. The higher pressure declines in the SE may be due in part to the impact of the low permeability boundaries in this area. If there is significant recharge in the West Ford Flat and East Ford Flat (Unit 19) areas, then the model results are probably conservative.

CONCLUSIONS

The field-wide model of The Geysers geothermal field was successfully calibrated against 30 years of available production and pressure data, with reasonable matches being obtained to pressure data measured in individual observation wells and to the overall field isobaric maps. The production data used in the calibration process were provided by four of the operators at The Geysers who control the majority of the productive area.

After calibrating the model, it was used to forecast future field behavior, assuming that wellhead pressures will reduce by 40 psi over the next five years. A further run was also made assuming that wellhead pressures will be maintained at their present levels. It was found that by reducing wellhead pressure, an additional one million pounds per hour could be produced over the next ten years; this is equivalent to 55 MW(net) additional production.

The forecast runs also indicated that over the next 15 years, pressures in the field will decline by between 50 and 125 psi, with the highest pressure drop occurring in the SE. It is felt, however, that the pressure drop in the SE may have been over-predicted due to the proximity of low permeability boundary blocks. There is some evidence that recharge may be occurring in this area and this is not included in the model. In terms of production flow rate, it is estimated that the total flow rate will decline from the present level of approximately 23 million lbs/hr to 8.5 million lbs/hr by 2014. This is equivalent to a reduction in overall field power potential from the present level of 1,250 MW (net) to 475 MW(net).

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