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Numerical Reservoir-Wellbore-Pipeline Simulation Model of The Geysers Geothermal Field, California, USA

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ABSTRACT

The Geysers geothermal field, located in Lake, Sonoma, and Mendocino Counties, California is the largest developed geothermal system in the world. Electric power generation started at The Geysers in 1960 with a 12 MW (gross) plant. The total installed capacity in the field peaked in 1989 at 2,043 MW. As more and more power plants were built during the 1980s and net mass withdrawals increased, reservoir pressures at The Geysers declined, eventually resulting in steam shortfalls and declining generation levels. This net withdraw is due to the fact that geothermal power plants at The Geysers typically lose about 70 to 80% of produced mass to evaporation in cooling towers, with the balance of mass being returned to the reservoir through injection of steam condensate.

In response to this decline, field operators made modifications to the pipelines and turbines to be able to operate more efficiently at lower system pressures. Based on studies funded by the California Energy Commission that showed that injection of water from outside sources was the most effective method of managing the long-term decline in the resource, a program of augmented injection, using large volumes of treated sewage effluent, was started in the late 1990s.

This program of augmented injection has brought mass injected, more or less, into parity with mass produced, and the rate of reservoir pressure decline has been significantly reduced. Still, optimizing the distribution of augmented injection throughout the field and making corresponding adjustments to plant and pipeline facilities is a complicated process, with many interdependencies.

To aid in ongoing optimization of the field, an integrated model has been developed for the Northern California Power Agency (NCPA) that combines reservoir simulation with mathematical modeling of the wellbores, pipelines, and power plants. This integrated model, funded in part by the California Energy Commission, has proven very useful for evaluating the most cost-effective improvements to the combination of wells and surface facilities, and to study the benefit of increasing the volume of augmented injection.

1. INTRODUCTION

Electric power generation started at The Geysers in 1960 with a 12 MW (gross) plant. During the 1960s and 1970s, net generation grew slowly to about 500 MW, with only two operators active in either field development or power generation. Following the "energy crisis" of 1973, oil and natural gas prices skyrocketed, thus boosting the price of geothermal power which was based to a large extent on the price of fossil fuels. This caused a major spurt in the rate of growth in installed generation capacity at The Geysers (Sanyal, 2000). By 1989, the total installed capacity in the field peaked at 2,043 MW (GRC, 1992).

As more and more power plants were built and net mass withdrawals increased, reservoir pressures and corresponding well productivities began to decline at alarming rates. To maintain generation capacity in the face of rapid productivity decline, too many make-up wells were drilled in some parts of the field, which caused excessive interference between wells, further reducing well productivity. By 1989, drilling additional make-up wells became uneconomical and the net generation capacity was allowed to decline.

By 1992 the decline in generation at The Geysers had attracted the attention of the California Energy Commission, which funded an engineering study, including numerical simulation of the reservoir to investigate options to mitigate the generation decline. Reservoir modeling, conducted by GeothermEx in collaboration with the operators (Menzies and Pham, 1995), showed that injection of water from outside sources was the most effective method of managing the decline in the resource. At the same time, operators at The Geysers began making adjustments to the power plants and the surface pipeline network to optimize the use of the lower-pressure steam that was available.

Starting in the late 1990s, pipelines from Clear Lake and Santa Rosa were constructed to transport large volumes of treated sewage effluent to the field for injection (Enedy *et al.*, 2004). This program of augmented injection has brought mass injected, more or less, into parity with mass produced. The rate of reservoir pressure decline has been significantly reduced, and as of 2006 the decline in steam production from the previous year was only 0.5% (Johnson, 2007).

While reservoir simulation has been a valuable tool in geothermal developments since 1969 (Sanyal, 2003), the complexities of the surface pipeline networks, and distribution of augmented injection throughout the field, makes adjustments to plant and pipeline facilities a complicated process. Due to these interdependencies, an integrated model has been developed that combines the reservoir simulation with mathematical modeling of the wellbores, pipelines, and power plants within the NCPA area of the field. The location of NCPA's steam field within The Geysers geothermal field is shown in Figure 1.

The reservoir portion of this integrated model is a three-dimensional, dual-porosity numerical model which utilizes a highly refined grid within the NCPA area and a coarse grid in the rest of the field. The wellbores and pipelines are modeled with pressure-drop formulas, and the power plants are modeled with empirical curves relating flow rate to inlet pressure. The integration of the reservoir and wellbore-pipeline simulations was funded in part by the California Energy Commission. The integrated model has proven very useful for evaluating the most cost-effective improvements to the combination of wells and surface facilities at The Geysers.

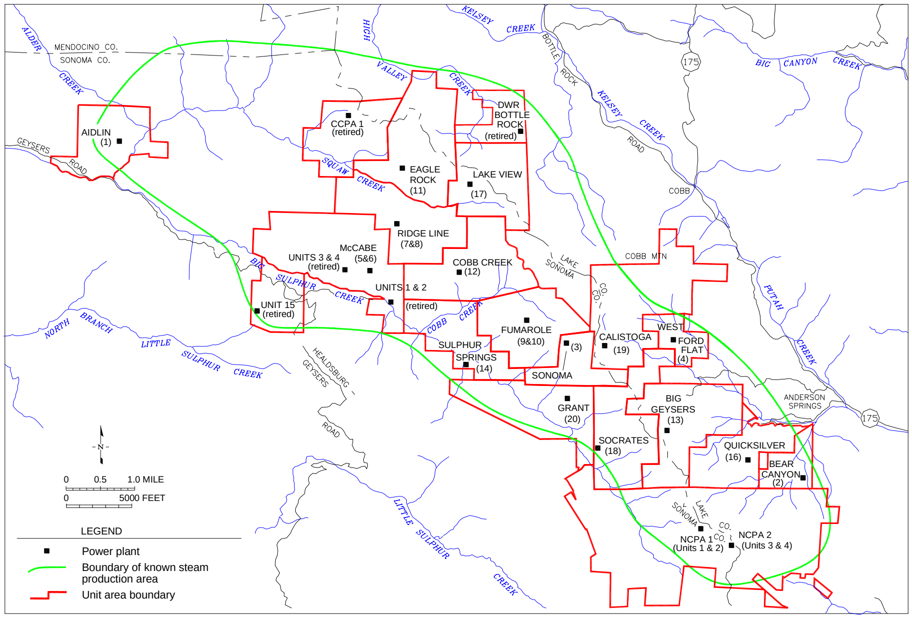

Figure 1: Location of NCPA's steam field within The Geysers geothermal field.

2. INTEGRATED RESERVOIR MODEL

The development of an integrated reservoir model began with the development of a reservoir model. This model used the commercially available geothermal simulator TETRAD (Vinsome and Shook, 1993). This program was chosen based on its use in past simulations of The Geysers. The final integrated reservoir-wellbore-pipeline model utilizes a simulation program called TAP. This program incorporates functionality from the PIPE simulation program (that has been used to model the pipeline network in the NCPA area) and the TETRAD reservoir simulator.

Due to the high permeabilities throughout the field, development of a reservoir model covering only the NCPA area of the field was ruled out. Instead, a generalized three-dimensional, dual-porosity field-wide model was developed based on published and publicly available data. Once this field-wide model was calibrated to represent the overall field response, a highly refined grid was added to the NCPA area to improve the model's ability to match local reservoir conditions. In this way, the field-wide model would be used to describe the pressure boundaries of the NCPA area over time.

In the integrated model, the wellbores and pipelines were modeled with standard pressure-drop formulas, and the power plants are modeled with empirical curves relating flow rate to inlet pressure. This integration of the reservoir and wellbore-pipeline simulators was funded in part by the California Energy Commission (PIER Grant PIR-04-001).

2.1 Production and Injection Database

The Geysers database of the California Division of Oil, Gas and Geothermal Resources ("CDOGGR") was the primary source of production and injection information used in this study. About 75% of the individual wells at The Geysers are publicly available. NCPA data from wells drilled on Federal land are not included in the publicly available database; however, NCPA allowed these records to be used in the development of the reservoir model. Combining the NCPA and the open record data yielded a database containing monthly production and injection data for essentially all of the active wells in the field. A plot of the total monthly production and injection data reported by CDOGGR is shown in Figure 2.

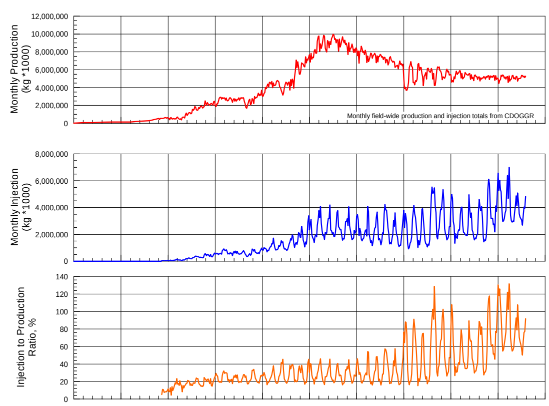

Figure 2: Monthly production and injection data as reported by California Division of Oil, Gas and Geothermal Resources field.

Until the late 1970s, only about 20% of the produced steam was returned to the reservoir through injection of steam condensate, with remainder of the produced mass being lost due to evaporation in cooling towers. Since this evaporation varies by season, the injection data contains a cyclic element. By the 1980s, operators started to supplement their injection with creek water, which further increased the winter injection rates. In the late 1990s, treated sewage effluent from Clear Lake and Santa Rosa raised the injection rate to the point that over 80% of the produced mass is returned to the reservoir.

2.2 Numerical Grid

The simulation grid for the integrated reservoir model covers an area of nearly 80 square miles and was oriented in the NW-SE direction (Figure 3), parallel to the main structural features of the field. The rectangular outline of the base grid is approximately 6 miles long in the SW-NE direction and 13 miles long in the NW-SE direction, and it covers the entire active area of the field. The base grid blocks are all of the same size, measuring 2,000 feet on each side.

The model has 6 layers and extends from sea level to 12,000 feet below sea level. Each layer is 2,000 feet thick, and has 15 blocks in the SW-NE direction and 32 blocks in the NW-SE direction, for a total of 2,880 blocks. Based on geological data and historical field response, the reservoir is modeled using double-porosity formulation based on the Warren and Root method (Warren and Root, 1963). This is a formulation commonly used to represent reservoirs in which fractures primarily control fluid flow, while storage is primarily contained within the rock matrix.

In the south eastern portion of the field, the grid system in layers 1 through 5 was refined to improve the model's ability to match individual well performance within the NCPA area. In this refined area, as shown in Figure 3, the grid blocks are 667 feet in the x and y directions and 1,000 feet thick. The incorporation of a refined grind increases the number of grid blocks (matrix and fracture) in the integrated model to 14,400.

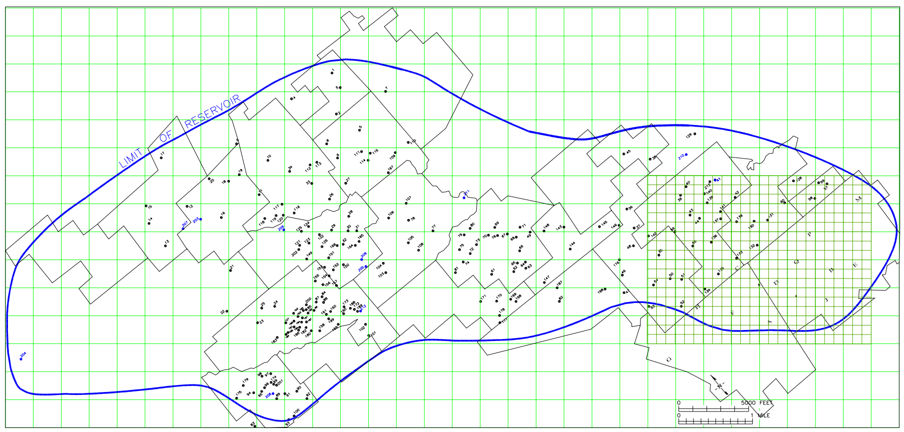

Figure 3: Grid system used in the integrated reservoir-wellbore-pipeline model.

2.3 Well System

The wells in the reservoir model are assumed to be completed in the fracture blocks, while the matrix blocks provide the bulk of the reservoir storage capacity. Considering the large number of wells drilled in the field (more than 700), and the limited well data outside of the NCPA area, production and injection wells were grouped by well pad. Locations of these pads were selected based on CDOGGR maps. In the base grid, production is derived from layers 1 and 2, and injection occurs in layers 2, 3 and 4. Within the refined grid, similar production and injection depths were utilized.

Within the NCPA area, production and injection wells were defined using observed steam entry data provided by NCPA. A rotation-translation program was developed to convert the location and depth of the steam entry zones to refined grid block locations.

Pad locations in the base grid are shown in Figure 3. In some areas of the field, injection and production wells are located on the same pad, which would result in having production and injection within the same grid block. This potential problem was resolved by specifying that injection occurs in a deeper layer, and production in a shallower layer. While some injection wells are completed at relatively shallow depths, it is generally accepted that the injection water sinks toward the bottom of the reservoir due to gravitational effects. In the refined grid, injection wells were able to be more accurately represented due to the smaller grid block dimensions.

2.4 Wellbore-Pipeline System

Using the x-y-z location of the first steam entry and casing data provided by NCPA, directional wellbore descriptions were developed for each production well within the NCPA area. The elevations used in the reservoir-to-wellbore pressure drop equations for the NCPA wells were then modified to match the depth of the first steam entry zone. In this way, the "end" of the reservoir inflow calculations and the start of the wellbore-pipeline calculations occur at the same physical location. For production wells (pads) outside of the NCPA area, elevations representing surface wellheads continue to be utilized.

The pipeline network was added to the integrated model based on the individual piping descriptions (diameter-length-elevation change) used in NCPA's pipeline model.

In total, the wellbore and pipeline network added approximately 300 additional nodes to the model. This may not be a large number, but inclusion of the wellbore-pipeline network significantly increases the complexity of the model. Since the frictional pressure drop in the wellbores and pipeline network are dependent on the square of the velocity, as opposed to the linear relationship present in the reservoir, the numerical complexity of solving the pressure equations increased. In addition, the volume contained within the pipeline sections is orders of magnitude smaller than within the reservoir grid blocks. This creates problems within the mass balance equations, resulting in shorter time steps being required for convergence. Overall, the coupled reservoir-wellbore-pipeline model could increase the computer run times by a factor of 2-10.

2.5 Power Plant Turbine-Pipeline System Interface

In the integrated model, the turbine boundary condition for each NCPA generating unit was described in general form by a turbine "inflow curve". The general form of this curve is that turbine inlet pressure is a linear or power function of turbine steam flow. The properties of each generating unit were further refined by the addition of a valve-wide-open pressure drop at the governor valve and a fixed steam rate requirement for non-condensable gas removal (ejector steam rate).

The variables used to describe each generating unit were derived from current operating data or calculated for plant optimization scenarios utilizing the THERMOFLEX power plant simulator used by NCPA. These variables provided a practical mechanism to couple the integrated reservoir/well/pipeline simulator to the THERMOFLEX power plant simulator.

3. HISTORY MATCHING

Historical production and injection data as described earlier were inputs into the model, which was then allowed to run for the period from 1960 through the end of 2005. Reservoir pressures calculated by the model were then compared with observed pressures. The model was then "tuned" to match the observed pressure data as closely as possible. The important parameters that were adjusted during most of the history matching period were the fracture porosity, fracture and matrix permeabilities, and the fracture spacing. In the later phase of the history match (from about 1995 on), the amount of water-in-place (i.e., the matrix porosity and the initial water saturation) were varied to obtain a match to observed data. Numerous runs of the model were made, adjusting the above parameters on a trial-and-error basis, until a good match was obtained between observed and calculated pressures.

Static reservoir pressure data used for comparison with model results was derived from the CDOGGR database, which included a useful number of shut-in wells scattered throughout the field with relatively long wellhead pressure histories. A program was developed to convert these wellhead pressures, using information on wellhead elevation and steam density, to absolute pressures at mean sea level (the top of the reservoir). This enabled the model results (also interpolated to mean sea level by the simulation program) to be compared directly to the observed shut-in wellhead pressure data.

The location of these observation wells, chosen on the basis of location and availability of shut-in pressure data, are shown in Figure 4.

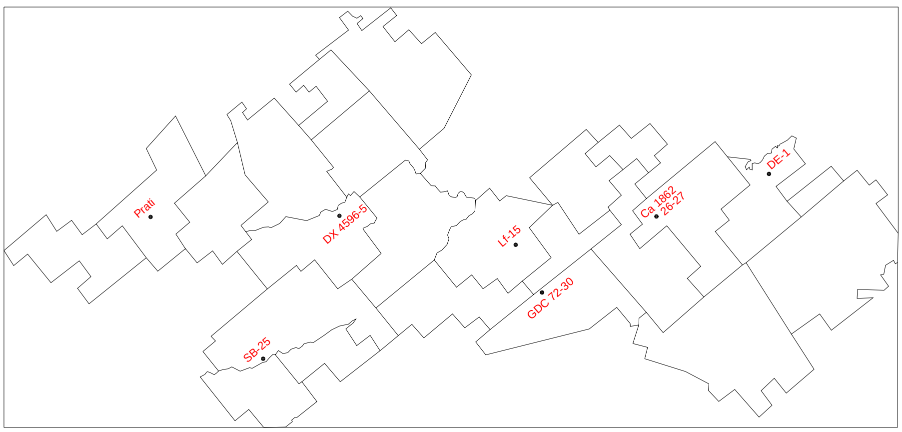

Figure 4: Location of the observation wells used in history matching the integrated model.

The match to observed pressures at well CA-1862 26-27, is shown in Figure 5. These results demonstrate that the model's ability to predict the sharp drop in reservoir pressure during the 1980s and the shallower pressure decline rates since the late 1990s.

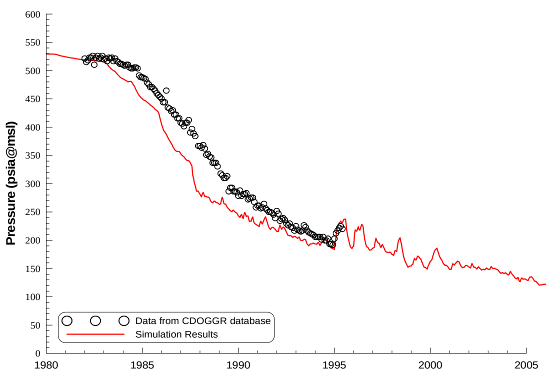

Figure 5: Observed and calculated reservoir pressures for well CA-1862 26-27.

4.1 Base Case Forecast

Before the integrated model could be used in forecasting field performance, it was necessary to change the way in which production was specified in the model. During the history-matching process, flow rates and injection rates were specified for each well or group of wells (pad), and the model calculated the resulting changes in reservoir pressure.

In forecast mode, the production wells were switched to pressure control and allowed to flow at as high a rate as possible for the given pressure constraint. For the wells (pads) outside of the NCPA area this constraint was based on current average flowing wellhead pressure (CDOGGR database). For the NCPA wells, the wellbore-pipeline network and the turbine backpressure properties determined the pressure constraint for each well.

After making these changes to the model, forecast runs were made and the productivity indexes for each well or group of wells (pad) were adjusted in an iterative fashion. After many runs, a reasonable match was obtained between the flow rates predicted by the model and reported flow rates (CDOGGR database).

Using these calibrated productivity indexes, the model was used to make base case predictions of field performance through 2025. These results are shown in Figure 6, along with field-wide historical steam and injection flow rates. The historical steam rates from 1987 to 1995 appear to follow a harmonic decline trend, with an initial rate of 6% starting in January 1987. Starting in 1998, the combined effect of curtailments during 1995-1998 and the start of the injection of supplemental water from Clear Lake (SEGEP) drastically reduced the decline rate. With the addition of Santa Rosa water, the steam rates appear to be following a 1-2% harmonic decline trend starting in January 1998. Simulation results suggest that the decline rate over the next decade may be closer to 2% per year.

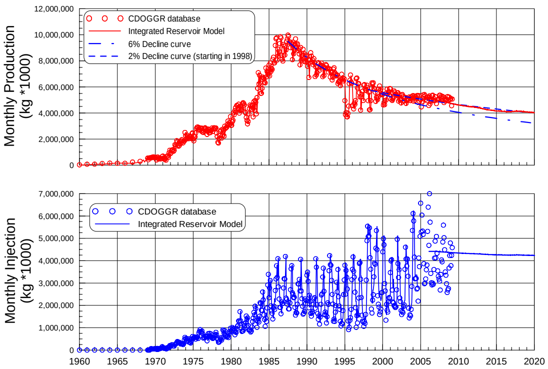

Figure 6: Historical and forecast Geysers field-wide production and injection,

4.2 Supplemental Injection

With the benefit that supplemental injection has shown in The Geysers field, it is reasonable to ask how much additional benefit could be realized if the supplemental injection rate were increased? To help answer this question, the integrated model was modified so that injection rates increase at the start of 2010 (using the same general distribution per well) based on a 100% increase in the supplemental water from Clear Lake and Santa Rosa. Field-wide simulation results, shown in Figure 7, indicate that increasing the volume of water injected into the field could reduce the field-wide decline by about half over the base case scenario.

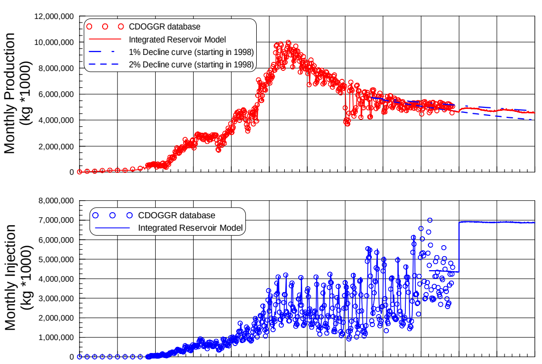

Figure 7: Projected field performance with 100% increase in the supplemental water from Clear Lake and Santa Rosa.

5. LONG-TERM FIELD OPTIMIZATION

In the model, not all of the injected water boils, and the remaining liquid accumulates in the bottom layers of the model. This accumulated water does provide pressure support, especially if injection into the shallower layers is reduced. Past tracer test results indicate that not all of the injected water is recovered over a short time period, so a similar process is apparently occurring in the reservoir. However, it is not known how deep this residual water travels and what fraction may ultimately be recovered.

These results bring to light the important effect that boiling of accumulated water in the deeper portions of the reservoir (*i.e.*, long-term recovery of injectate) has on long-term performance of the field. Research on how injected water boils within the reservoir combined with reservoir modeling to optimize the recovery of injected water as steam will be an important aspect of the long-term management of The Geysers.

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