Numerical Reservoir-Modeling of Forty Years of Injectate Recovery at The Geysers Geothermal Field, California, USA

Steven L. Enedy[1] and Steven J. Butler[2]

[1]Northern California Power Agency
[2]GeothermEx, Inc., Richmond CA, USA
mw@geothermex.com • senedy@ncpageo.com

Keywords

The Geysers, numerical modeling, augmented injection, injection derived steam .

ABSTRACT

The Geysers geothermal field, located in Lake, Sonoma, and Mendocino Counties, California is the largest developed geothermal system in the world since 1973. Electric power generation started at The Geysers in 1960 with a 12 MW (gross) plant (PG&E's Unit 1). Injection of plant effluent, known as condensate, began in April 1969, into well Sulphur Bank 1, with the startup of PG&E's Unit 4. Condensate injection alone replaces ~ 22% of mass steam withdrawal from the reservoir. This net loss of mass is due to the fact that geothermal power plants at The Geysers typically lose between 70 to 80% of produced mass to evaporation in the cooling towers.

The total installed capacity in the field peaked in 1989 at 2,043 MW. As more and more power plants were built during the 1970s and 1980s and cumulative net mass withdrawals increased with time, reservoir pressures declined, eventually resulting in steam shortfalls and declining generation levels.

In response to this decline, field operators made modifications to augment injection and distribute water throughout the reservoir. Based on both internal studies by Operators and other Agencies (such as the California Energy Commission), it was determined that injection of water from outside sources was the most effective method of managing the long-term decline in the resource. There are three significant injection augmentation programs: 1) Capture and injection of excess rain water, especially from the Big Sulphur Creek starting the early 1980s, 2) Injection of treated effluent from Lake County into the Southeast Geysers, starting in late 1997, and 3) Injection of treated effluent from communities located in central Sonoma County starting in 2002. Between 1969 and 2008, injectate has been distributed into 137 wells across the field and has replaced 39.5% of the mass of steam produced. The mass replacement rate has increased to an annual rate of ~85% in 2008.

As this program of augmented injection has brought mass injected into near-parity with mass produced, the rate of reservoir pressure decline has been significantly reduced. Still, optimizing the distribution of augmented injection throughout the field and making 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 by the Northern California Power Agency (NCPA) that combines reservoir simulation with mathematical modeling of the wellbores, the pipelines, and the 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. This study goal was to determine the areal distribution and to quantify the recovery of injection derived steam over time. A two component option within the numerical model allows for the modeling of water as either in-situ or injection derived.

Numerical modeling results based on the two-component water option indicate that recovery of injection derived steam (IDS) started soon after injection began in 1969 and continues today. On average, ~ 61% of steam production was injection derived in 2008 and certain areas of the field are actually producing 100% IDS. Also, the rate of steam production for 2010 is 50 percent higher than predicted by previous modeling efforts without significant augmented injection indicating significant benefit from increased water injection.

Numerical modeling results also indicate that areal distribution of IDS recovery has gradually increased as injection has become more widespread. Injection recovery is highest within three distinct areas that, in general, correspond to the three low-pressure areas known as the Old Geysers' Area, the Central Area and the Southeast Geysers Area. Injection is quantified for these three areas of The Geysers.

1. Introduction

Electric power generation started at The Geysers in 1960 with a 12 MW (gross) plant. The first commercial test of injection into the deep reservoir occurred when condensate from Units 1 and 2 was injected into TH-12 from April 29, 1965 through May 3, 1965. The test was stopped when water production from TH-8 broke through to well TH-12, resulting in curtailment of Unit 2. Two wells (GDC 58I-11 and GDC 38I-11) were then drilled outside of the steam reservoir for condensate disposal, but neither had sufficient injectivity. Following the startup of Unit 3, successful injection was established into SB-1 by the steamfield operator Union Oil. SB-1 was chosen as an injector because it was relatively far from existing production and would not interfere with major steam producers. Tritium tracer into SB-1 later confirmed that flashed water was traveling to offset production wells. SB-1 was later plugged and abandoned in 1984. During the 1970s, injection grew but only as a result of the startup of additional power plants.

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 1991 the decline in generation at The Geysers had attracted the attention of the California Energy Commission (CEC), 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 injection, approximate, 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, make 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 CEC. 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.

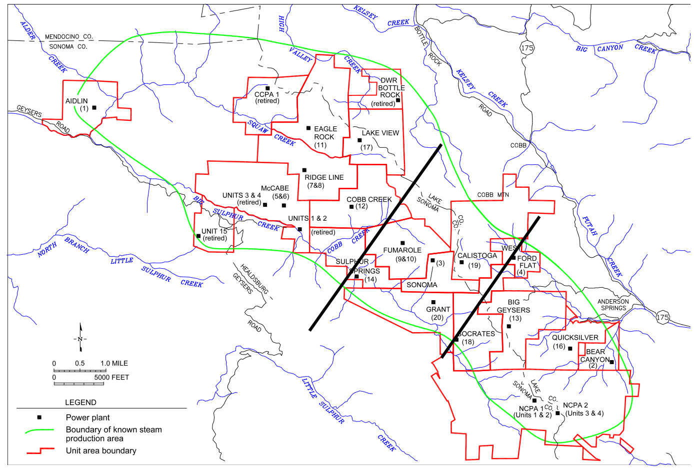

Figure 1. The Geysers Geothermal Field showing power plants, dedicated plant areas, and the location of Old Geysers (Northwest), Central and Southeast Geysers Areas for Injection Comparisons. NCPA's steam lease is located within the Southeast Geysers Area, and has been on-line since 1983.

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.

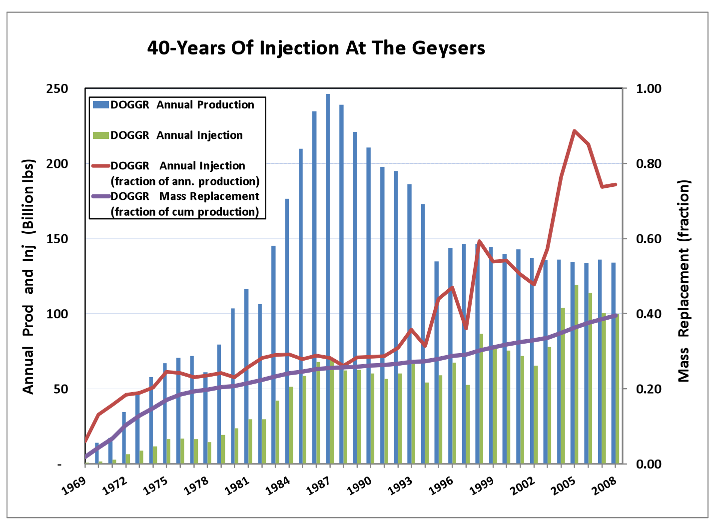

Figure 2. Annual production and injection data as reported by California Division of Oil, Gas and Geothermal Resources. Note the increase in the annual mass replacement percentage (red line) in 1998 with the startup of the Southeast Geysers Effluent Pipeline Project and again in 2002 with the startup of the Santa Rosa Recharge Project.

Previous numerically efforts began in 1988 for NCPA with the development of a 60-grid-block model of the Southeast Geysers Area using the numerical code TOUGH. It was found that due to the high permeability's throughout the field, development of a reservoir model covering only a small area of the field was not necessarily representative of reservoir performance. A generalized three-dimensional, dual-porosity, field-wide model was later developed by NCPA, based on published and publicly available data. The field-wide model was calibrated to represent the overall field response, and 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 could 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 were 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 Public Interest Energy Research (PIER) program of the CEC (PIER Grant PIR-04-001).

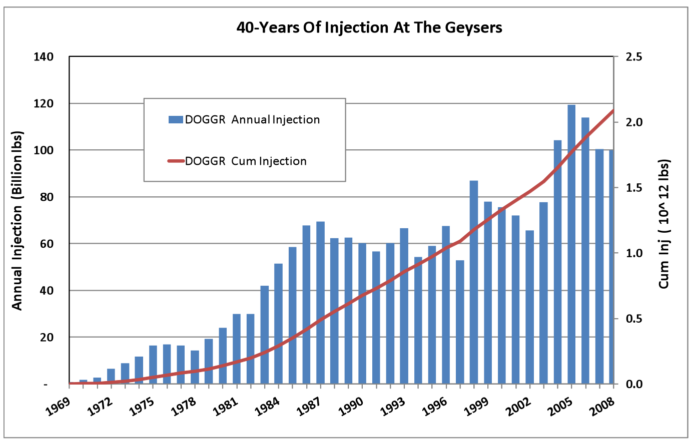

Figure 3. Annual injection data and cumulative injection. Note that ~ 2.1 trillion pounds of water has been re-injected into The Geysers between 1969 and 2008.

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. (Figures 2, 3, and 4). 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 records are included in this study. 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. There are more than 15,000 monthly records on injection alone.

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 (Figure 10) . 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 was being returned to the reservoir

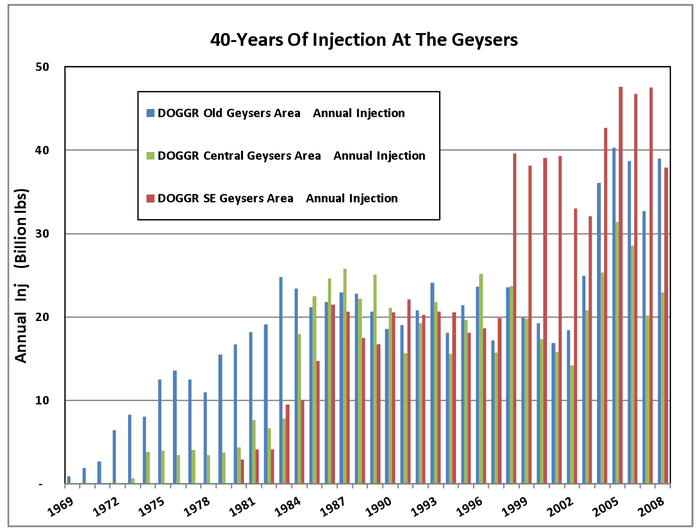

Figure 4. Annual injection for each of the three major injection areas. Note the concentration of injection into the Old Geysers Area in the 1970s and the increase of injection into the Southeast Geysers Area following the startup of the Southeast Geysers Effluent Pipeline in 1998.

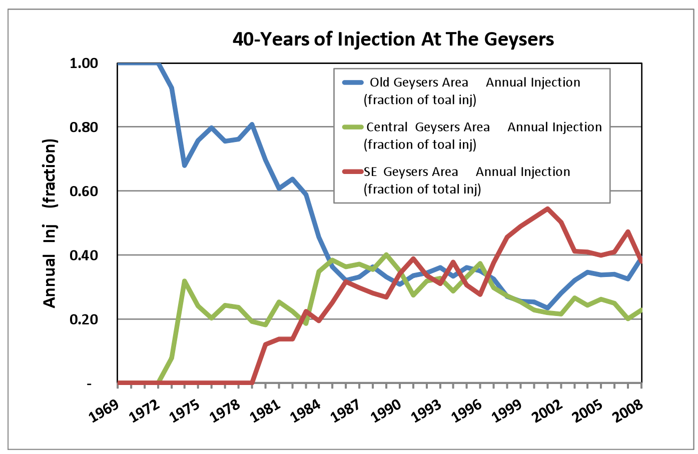

Figure 5. Fraction of Annual injection for each of the areas of The Geysers: Old Geysers, Central Geysers and Southeast Geysers. Note that injection was once concentrated into the Old Geysers Area but is now much more evenly distributed.

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 6), with the long-axis parallel to the regional geologic strike. The rectangular outline of the base grid is approximately 5.7 miles long in the SW-NE direction and 12.1 miles long in the NW-SE direction, and it covers the entire active area of the field. The grid area is 68.8 square miles by 2.3 miles in depth or 156.5 cubic miles. 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 6, the grid blocks are 667 feet in the x and y directions and 1,000 feet thick. The incorporation of a refined grid increases the number of grid blocks (matrix and fracture) in the integrated model to 14,400. Areas outside of reservoir are assigned fracture permeability two or three orders of magnitude below typical reservoir values. A more detailed presentation of the conceptual model of the reservoir is described in detail in previous reports (Butler, 2010)

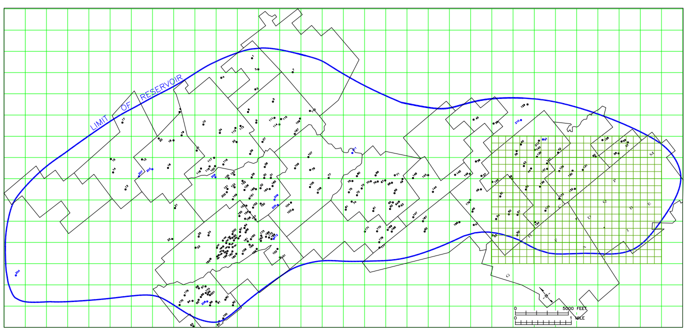

Figure 6. Grid system used in the integrated reservoir-wellbore-pipeline model.

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 6. 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.

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 were 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 factors of 2 to 10.

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.

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 2008. Reservoir pressures calculated by the model were then compared with observed pressures. The matching focused on observation well data, chosen on the basis of location and availability of shut-in pressure data. As a check, a comparison was made to a field-wide isobaric map originally prepared by the CEC's Technical Advisory Committee (TAC) (Menzies 1992) and is shown in Figure 7. 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), parameters related to 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.

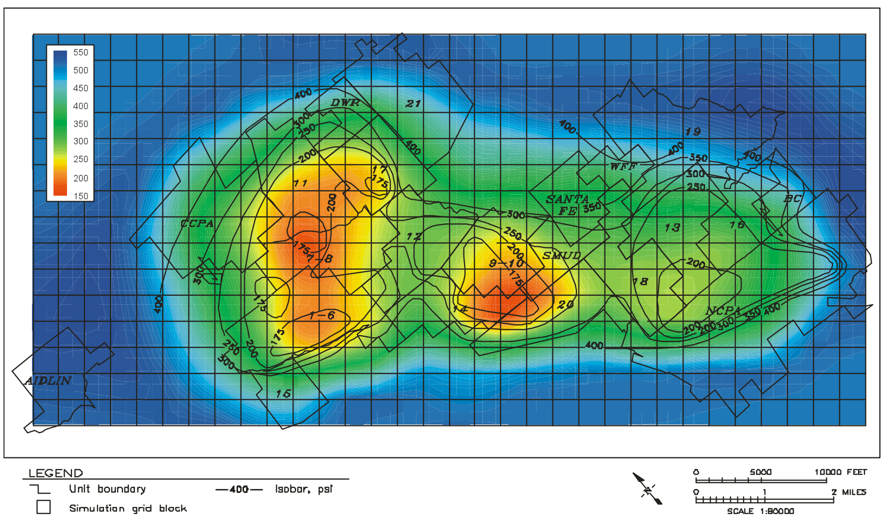

Figure 7. Numerical model calculated and actual (measured) isobaric contours at The Geysers for 1991. Note the three lower pressure areas (observed and calculated) in the Old Geysers, Central Geysers and Southeast Geysers Areas.

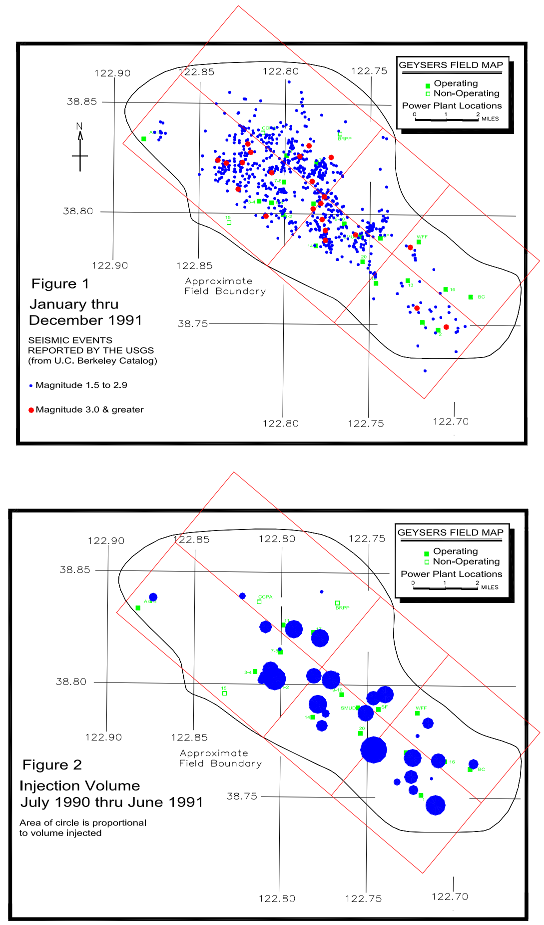

Figure 9. Location of 724 micro-seismic events (M>= 1.5) during CY 1991 and the location of 34 injection wells used between July 1990 and June 1991. The grid overlay is for comparison and show the three major pressure areas of The Geysers. Note the increased seismic activity in the Old Geysers and Central Geysers Area.

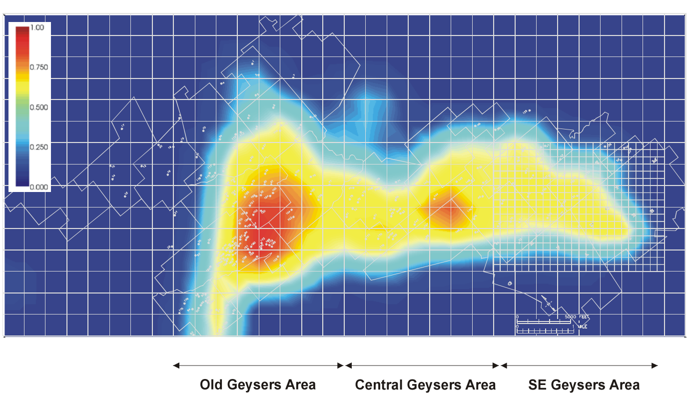

Figure 8. Fraction of Injected Water in the fracture system in 1991 at -5,000 ft. Note the concentration start of increased IDS in the Old Geysers and Central Geysers Areas.

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. Additionally, the model was adjusted for the two-water option that was defined as one water for the original water and steam in place in the reservoir ("in situ" water) and the second water as the injectate.

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 back-pressure properties determined the pressure constraint for each well.

After making these changes to the model, forecast runs were made and the productivity indices 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 indices, the model was used to make base case predictions of field performance through 2025. These results are shown in Figure 10, 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 through the Southeast Geysers Effluent Pipeline (SEGEP) drastically reduced the decline rate. With the addition of supplemental water from Santa Rosa, the steam rates began following an apparent 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.

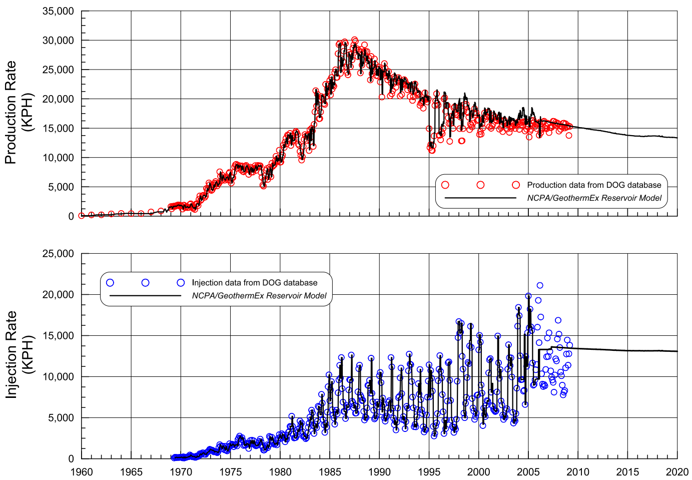

Figure 10. Historical and forecast Geysers field-wide production and injection including supplemental injection.

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 11, indicate that increasing the volume of water injected into the field could reduce the field-wide decline by about half in comparison to the base case scenario.

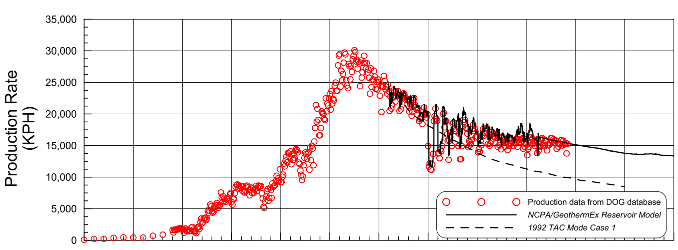

Figure 11. Projected field performance with 100% increase in the supplemental water from Clear Lake and Santa Rosa compared to TAC Model Forecast at 25% mass replacement.

Comparison to 1992 TAC Model Forecast

In 1992, a field wide reservoir model was developed by the TAC Industry Consortium in conjunction with a CEC study

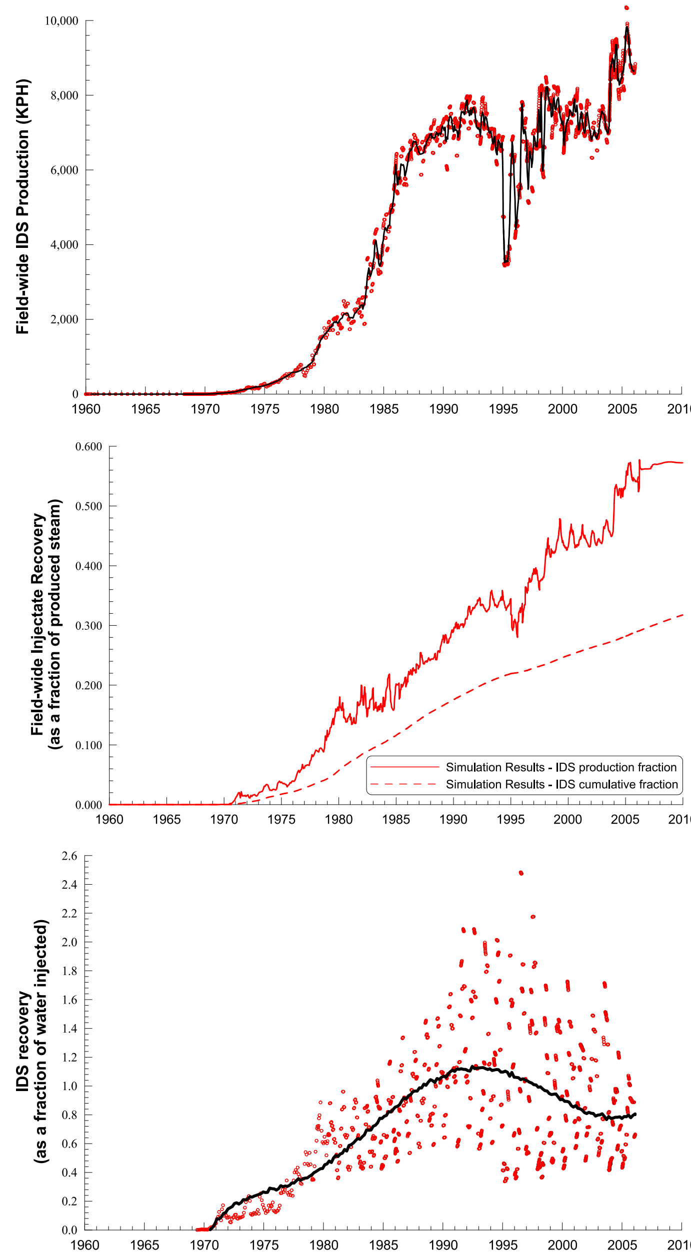

Figure 12. Recovery of injectate as steam as determined by the numerical model. (A top) pounds per hour, (B) fraction of steam production and cumulative fraction of produced steam and (C) fraction of injected water.

investigating increased decline at The Geysers. For example, in mid-1991, the field wide production was approximately 1,300 to 1,500 MW, compared to installed capacity of 2,106 MW.

For the 1992 forecast, the percentage of produced fluid that was injected was maintained constant at 25 percent. This is in contrast to the current mass replacement rate of near 100%. It was acknowledged in the 1992 report to the CEC, that “it is likely that the model will show improvement in overall reserves with enhanced injection”.

The 1992 forecast indicated that the expected flowrate would decline starting at a near harmonic rate at 9 percent. The forecast had a reasonable match to actual production until mass replacement increased in the late 1990s. The decline was significantly

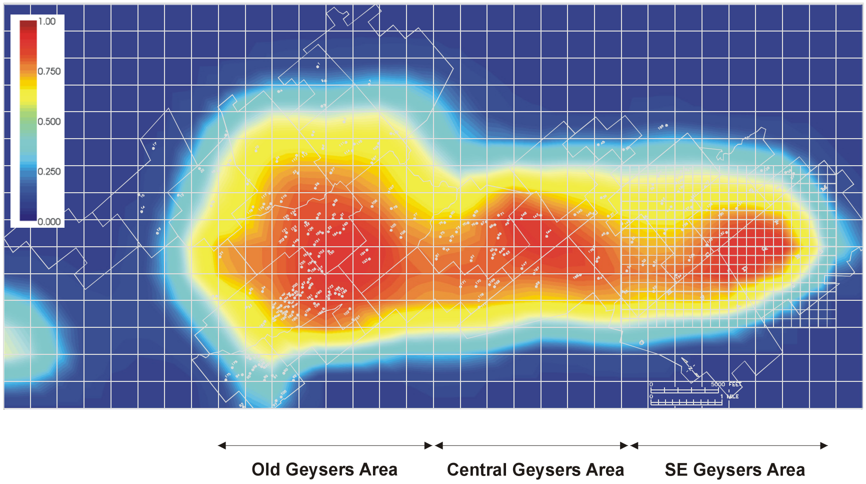

Figure 13. Fraction of injected water in the fracture system in CY 2010 at -5,000 msl. Note the three areas of influenced by injection.

decreased due to increased injection, such that by 2010, actual production was more than 50 percent higher than predicted by the 1992 field-wide model.

Recovery of Injected Water as Steam

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 when 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.

With increasing injection over time, the model indicates a corresponding increase in injection derived steam (Figure 13). In 2008, the numerical model indicates that 61 percent of produced steam is injection derived.

These results bring to light the important effect that boiling of both on-going injection and accumulated injected water in the deeper portions of the reservoir (*i.e.*, long-term recovery of injectate) has on long-term performance of the field. Continued studies of 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.

Acknowledgments

The authors wish to acknowledge the support of the staff at GeothermEx, Inc. and at Northern California Power Agency in preparing this paper. Additional acknowledgments go to the California Division of Oil, Gas and Geothermal Resources that helped in gathering the publicly available data, and to the California Energy Commission which helped fund this project.

References

Butler, S., 2010 Enedy, S. Sanyal, S.K. "Numerical Modeling of The Geysers Steam Field"; World Geothermal Conference, 2010.

Grande, M., S. Enedy, J. Smith, J. Counsil , and S. Jones. "NCPA at The Geysers", GRC Bulletin (July-August 2004), pp. 155-161.

GRC, 1992. "Monograph on The Geysers Geothermal Field," Special Report No. 17, Geothermal Resources Council.

NCPA Internal Report, 1989 "Assessment of Reservoir Conditions in the NCPA Leasehold at The Geysers," GeothemEx, Inc.

Johnson, E.A., 2007. "Summary of Geothermal Operations." In California Division of Oil, Gas, and Geothermal Resources, 2006 Annual Report, PR06 (9/07/OSP/1M), pp. 251-267.

Klein, C.W., S. Enedy, S. Butler. K and J. Morrow ,2009. "Injection Return and Evolution of Non-Condensable Gases at the NCPA Geysers Wellfield, California." Proc., GRC, Reno NV.

Menzies, A.J. and M. Pham, 1995. "A Field-Wide Numerical Simulation Model of The Geysers Geothermal Field, California, USA." Proc., World Geothermal Congress, Florence, pp. 1697-1702.

Sanyal, S.K., 2000. "Forty Years of Production History at The Geysers Geothermal Field, California – The Lessons Learned." Geothermal Resources Council Transactions, v. 24, pp. 317-323.

Sanyal, S.K., 2003. "One Discipline, Two Arenas – Reservoir Engineering In Geothermal and Petroleum Industries." Proc., Twenty-Eighth Workshop on Geothermal Reservoir Engineering, Stanford University, pp. 1697-1702.

Vinsome, P.K.W., and G.M. Shook, 1993. "Multi-purpose simulation," J. Petroleum and Engineering, v. 9, pp 29-38.

Warren, J. E., and Root, P. J., 1963. "The Behavior of Naturally Fractured Reservoirs," SPE J., v.3, pp. 245-255.

Warren, J. E., and Root, P. J., 1963. "The Behavior of Naturally Fractured Reservoirs," SPE J., 3, 245-255.

Williamson, K.H., 1992 "Development of a Reservoir Model for The Geysers," "Monograph on The Geysers Geothermal Field," Special Report No. 17, Geothermal Resources Council.