THE GEYSERS UNIT 18 STEAM FIELD DEVELOPMENT

J.J. Maney, R.C. Thompson and B.A. Koenig

Unocal Geothermal Division, P.O. Box 6854
Santa Rosa, California 95406

ABSTRACT

The Geysers Unit 18 is a 119 MW (gross) geothermal power plant operated by Pacific Gas and Electric (PG&E). The plant is powered by approximately 2 million lb/hr of dry steam at 115 psia and 368°F supplied by the Unocal-NEC-Thermal joint venture. In the last 7 years, Unit 18 has used just under 105 billion pounds of steam in the generation of about 6.5 million MWh of electricity. Unit 18 began commercial operations in February 1983 with steam from 15 start-up wells flowing through a steam gathering system typical of all Geysers power plants. This was the first unit in which production wells at The Geysers encountered felsite as a major reservoir rock. Felsite, an intrusion comparable to granite, has proven with time to be an adequate steam bearing formation. Make-up well requirements for the unit have been similar to other areas and a total of 25 production wells and one injector are presently in operation.

The production wells now powering the unit have been declining at a steady rate of 22 percent/year since 1986. In addition, a pressure sink has developed in the southeast corner of the unit area where original reservoir pressures of 510 psia have dropped to less than 200 psia. Efforts are now being concentrated in this area to study the effects of increased injection on production decline. In the absence of any major changes, the production decline will likely continue at a high rate.

INTRODUCTION

PG&E's Unit 18 is located at an elevation of approximately 2,695 feet in The Geysers KGRA at the eastern edge of Sonoma County in the northern half of Section 33, T11N, R8W, MDBM. The Unit 18 area is located in the southeast corner of The Geysers as shown in Figure 1, and contains 944 acres. It is bordered on the west by PG&E's Unit 20 and on the east by Unit 13. The 119 MW(gross) unit was placed in commercial operation on February 15, 1983. At that time The Geysers had an installed capacity of 1,172 MW with Units 1 through 15, 17 and NCPA-1. With Unit 18, PG&E's installed capacity was brought to 1,181 MW with an additional 238 MW under construction. Since Unit 18 began commercial production, over 104,864 million pounds of steam have been produced from 25 wells in the generation of 6,451,424 MWh of electricity with an average capacity factor of 88.9 percent. Figure 2 shows the trend in the average gross steam production from plant start-up through 1989.

This paper provides an in-depth look at the development of a Geysers geothermal project from inception through the first 7 years of commercial operation. The development of the Unit 18 area occurred in three phases spanning a 25-year period of exploration and development. The phases were: exploration and confirmation of reserves, production facilities, steam field development and the Unit 18 operation. The first drilling in the Unit 18 area consisted of two wildcat wells completed in 1964. These wells confirmed the presence of a high pressure steam reservoir essentially identical to that in the area of Units 1 through 6. Subsequent successful drilling of three additional widely spaced wells in the late 1960s to mid-1970s proved sufficient reserves for a 119 MW power

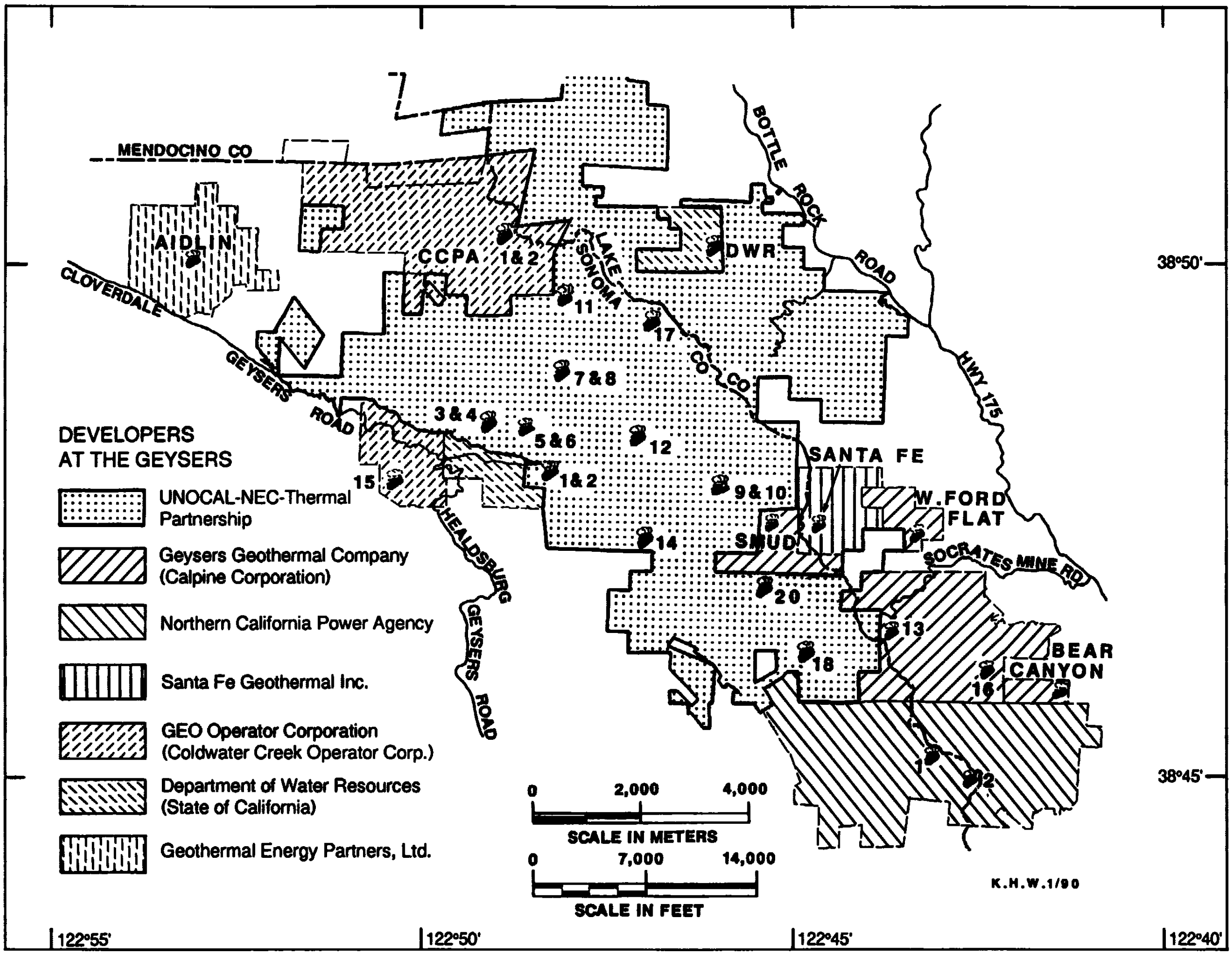

Figure 1. Geysers development map.

plant. Following these early exploration wells, development wells were drilled from 1980 to 1982 for the start-up of Unit 18. Wells have been drilled periodically since plant start-up to provide make-up steam.

EXPLORATION AND CONFIRMATION OF RESERVES

In June 1977, Unocal, as the operator for the Union Oil Company of California and Magma-Thermal joint ventures, proposed to PG&E a unit area containing 728 acres in the area depicted in Figure 3. Reservoir and mechanical data, including well schematics, flow test data, pressure build-up data and subsurface surveys were provided for five wells within this area to PG&E and their consultants for evaluation. The wells were DV-1, DV 73-33, GDC 65-28, LG-1 and LG-2. At this time, PG&E was already constructing Unit 13 on adjoining leases operated by Aminoil (now Calpine Corporation). Shell Oil had also drilled productive steam wells southeast of the proposed area, in what is now the Northern California Power Agency (NCPA) project (Smith and Cavote, 1988). These leases were the original federal KGRA offerings in 1974. Several of these competitor wells are included in Figure 3 for reference.

In April 1978, PG&E responded to Unocal's proposal with a concern that the 100 acre area in the southern portion of the unit area did not have any proven production. As a result, Unocal substituted a 100 acre area to the west with proven production for the 100 acre section to the south in May 1978, as shown in Figure 4. In July 1978, PG&E approved the unit area as having adequate steam reserves for a 119 MW unit with the understanding that the unit area boundaries might be adjusted as further exploration proved up reserves. On April 17, 1979, PG&E filed an Application for Certification (AFC) with the California State Energy Resources Conservation and Development Commission for The Geysers Unit 18. The AFC was filed pursuant to Public Resources Code Section 25540.2(a), which provides for an expedited certification process.

The original unit boundaries as proposed in 1978 were modified as adjacent acreage was secured by lease and

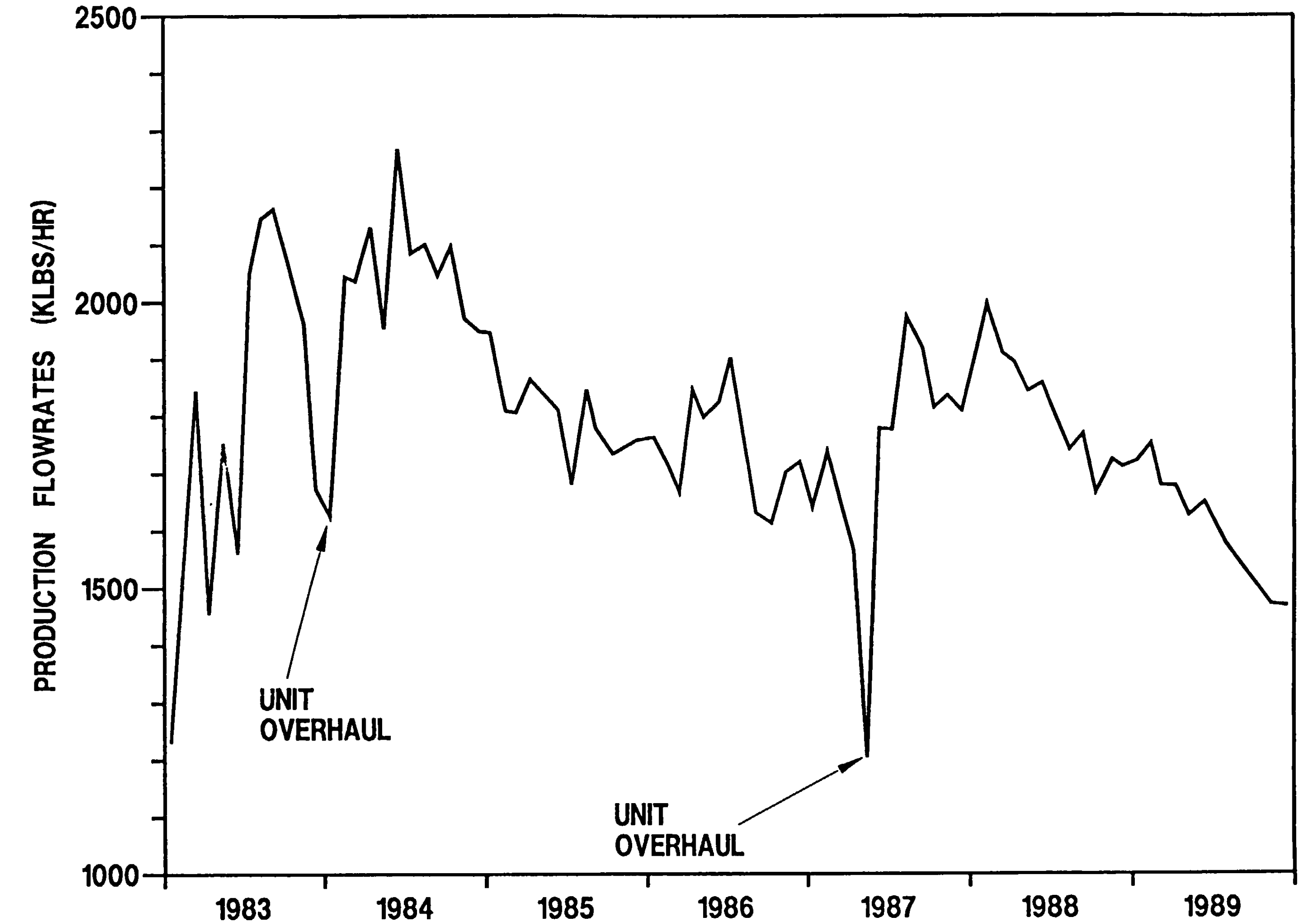

Figure 2. Unit 18 steam deliverability 1983-1989.

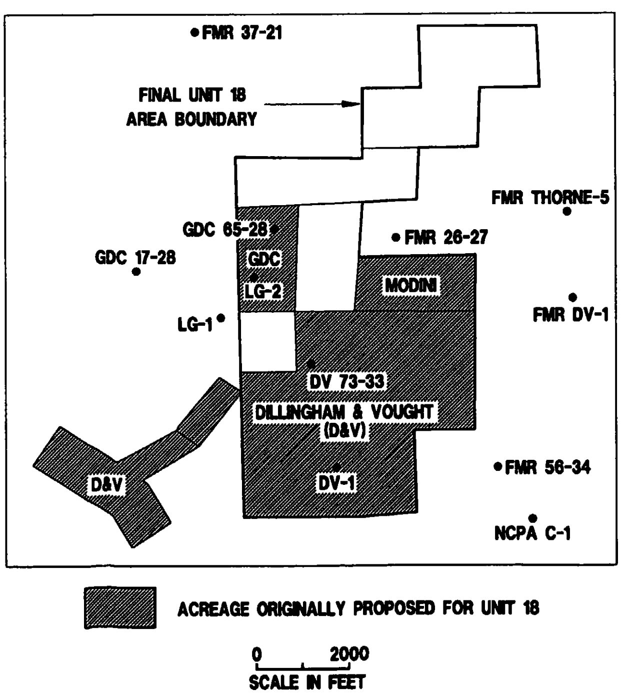

Figure 3. 728 acres proposed as Unit 18 to PG&E in June 1977.

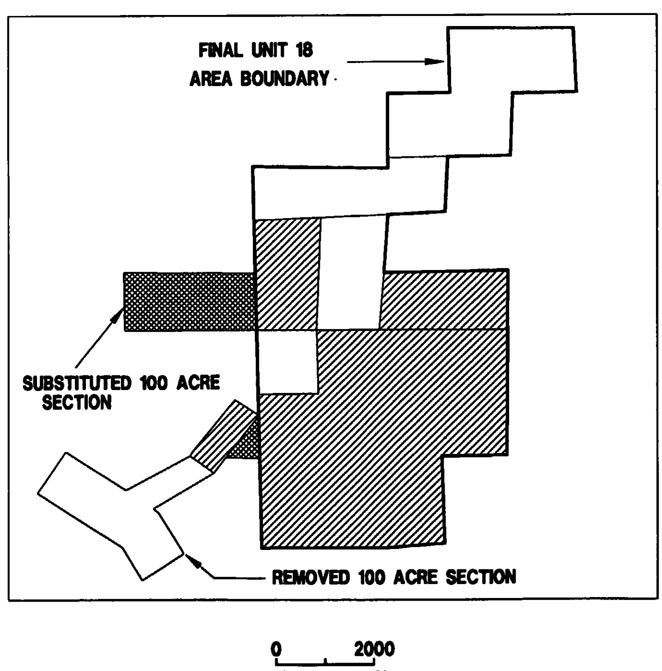

Figure 4. 732 acres approved for proposed Unit 18.

proven productive. The first major modification came after litigation between the U.S. Government and Unocal was resolved by the U.S. Court of Appeals in a decision which classified steam as a mineral right. As a result, Unocal secured mineral rights in November 1978, on the Beigel property. Then in March 1980, Tocher-1 was successfully completed on property to the north of the original unit area, which contributed an additional 160 acres. Finally, in March 1982, GDCF 14-27 was completed in the GDC lease just south of Tocher. These modifications are shown in Figure 5 along with the final unit area configuration indicated by the bold outline. The total acreage is presently 944 acres, a 212 acre increase from the original 732 acres approved by PG&E in 1978.

PRODUCTION FACILITIES

Power Plant Facilities

Unit 18 features a Toshiba turbine generator rated at 137,000 kilovoltA at 90 percent power factor utilizing a tandem compound, quadruple axial flow impulse turbine rated at 166,000 horsepower (hp). Primary H_2S abatement is through a Stretford system with a secondary abatement system employing a chelated iron and hydrogen peroxide process. The Transamerica DeLaval main surface condenser has a cooling surface area of 202,000 square feet and operates at 3.0 inches Hg back pressure with a circulating water flow rate of 140,000 gallons per minute (gpm). The Marley mechanically-induced draft, crossflow cooling tower has 11 cells. The air flow per cell is 1,357,000 cubic feet per minute (cfm) with an evaporation loss of 3,400 gpm. The cooling range is 105 to 80°F at 65°F ambient wet bulb.

Pipeline and Surface Facilities

The Unit 18 steam gathering system is very similar to other systems that were already in operation by Unocal and other operators at The Geysers. Its main components are: (1) well tie-in piping, (2) main steam line and separator, (3) injection system, (4) rock muffler, (5) a supervisory control system and (6) steam scrubbing system. A schematic of the Unit 18 steam gathering system depicting the location and current number of wells, pipeline routing and the location of the rock muffler and the power plant is shown in Figure 6. A brief description of each component is included below:

1. *Well Tie-In Piping* — The typical well tie-in piping consists of three main valves to safely open or shut-in the well. A rock catcher is incorporated to remove debris from the steam. A throttling valve controls the rate of steam flow from the well. An expansion loop ensures safe pipeline movement due to thermal changes. A root valve permits complete isolation of a well from the main steam line. The piping ranges from 10 to

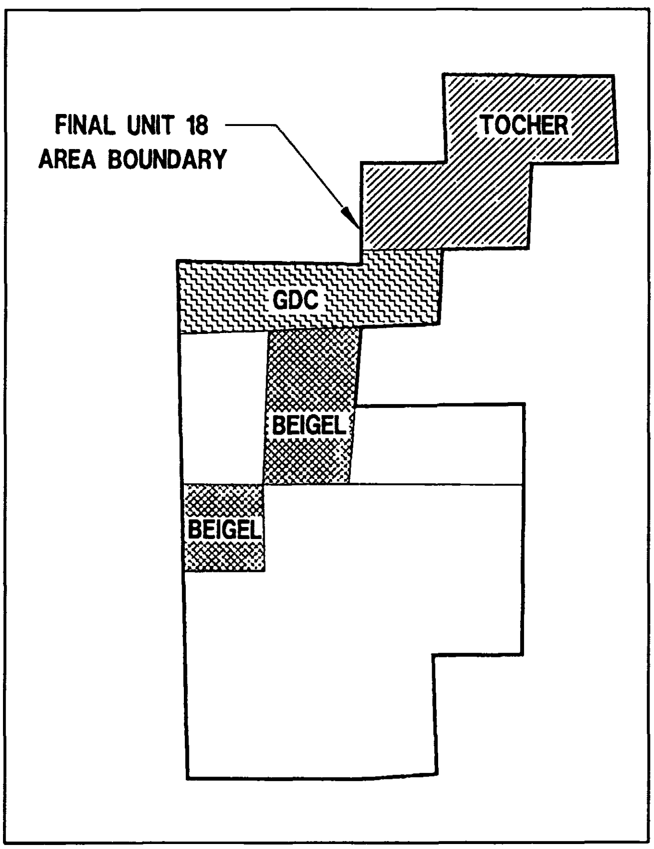

Figure 5 Final Unit 18 Area — 944 acres

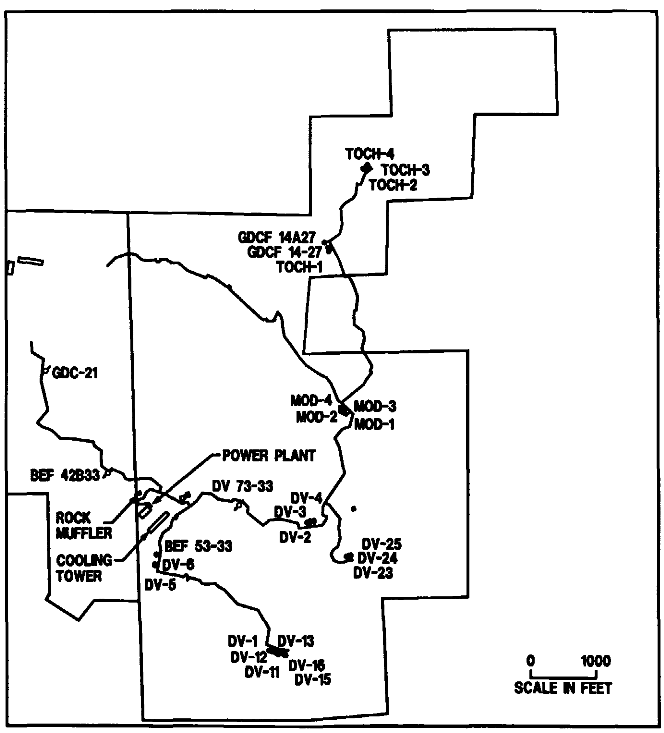

Figure 6 Unit 18 Steam gathering system.

18 inches in diameter and is insulated where possible to minimize heat losses.

2. ***Main Steam Line and Separator*** — The main steam line transports the steam from all the wells in the system to either the power plant or the rock muffler. The diameters of this line, which range from 16 to 48 inches, are determined by optimizing velocities, pressure drops and heat losses, on the bases of on anticipated steam production from the wells. The line is maintained a few feet above ground by pipe supports and anchors. It contains 1-1/2 inch condensate drain valves at low points, rupture discs (for safety relief) at key locations, and a number of thermal expansion bends. A vertical separator to ensure clean and dry steam to the turbine is also installed in the main steam line, just upstream of the power plant and rock muffler. The entire line and the separator are completely insulated to minimize heat losses.

   The design working pressure for the entire steam gathering system ranges from 475 psig near the wellhead to 180 psig at the power plant. All lines are installed in accordance with the applicable American Society of Mechnical Engineers (ASME) code.

   The main steam line right-of-ways were determined using the shortest distance to the power plant and topographic features as the primary considerations. Whenever practical, existing roadways were used to minimize the removal of vegetation. A minimum of cut-and-fill work was done, when necessary, to smooth the topography. In most cases the right-of-ways follow the natural contour of the ground.

3. ***Injection System*** — Cooling tower condensate constitutes the bulk of the fluid to be injected and is delivered into the Unocal pipeline from the weir box at Unit 18. Yard water is also an important source of volume during periods of rainfall. Unit 18 yard sumps are pumped to the cooling tower basin on level control. Cooling tower basin level is maintained by the weir position as long as the delivery pipeline is able to carry away the necessary volume. The excess fluid flows by gravity to the Unocal condensate surge pond. An automatic pond high-level shutoff valve is located at the inlet to the pond to serve as protection in the event a problem develops in the disposal system.

   The condensate surge pond, located downhill from the cooling tower, is a concrete structure having approximately 3 hours of surge time. A high-level shutoff valve affords spill protection under upset conditions. A backup level signal is provided to improve the reliability of the system. Pond level is monitored and alarmed via the Supervisory Control System.

   A positive displacement pump in the Unit 18 pumphouse is used to kill the injection well through the main 10 inch disposal line. To accomplish this, condensate is pumped down the wellbore until the wellhead pressure drops to zero and becomes a vacuum, at which time the kill pump is secured. Originally, the Unit 18 condensate was pumped from the pond to DV 73-33 by a vertical turbine pump on a variable speed level control. From May 1987 through February 1990, the Unit 20 injector, GDC-21, was being operated as the Unit 18 primary injector for reasons discussed later. In this mode, the Unit 18 condensate flowed by gravity to GDC-21 with pond level controlled by a pneumatic throttle valve. The present configuration utilizes the existing Unit 18 to Unit 20 injection crossover line to gravity flow condensate to the new Unit 18 injector, BEF 42B-33. BEF 42B-33 was placed in service as the primary Unit 18 injector on February 14, 1990.

4. ***Rock Muffler*** — A rock muffler is used to abate noise when stacking (venting) steam during power plant upsets. It is sized to accommodate the maximum steam flow rate to the unit. During use, the steam is routed from the main steam line through a steam manifold and four pre-set pressure control valves to a diffuser under the rock muffler. The steam is then passed through a bed of river rock which effectively reduces the steam noise as it exits to the atmosphere. The typical rock muffler dimensions are 40 x 50 x 18 feet.

5. ***Supervisory Control System, SCS*** — The supervisory control system permits remote control of the wells from Unocal's field office at The Geysers, allowing automated ramping of throttling valves. Underground electrical cable connects the wells to two identical computers (an on-line computer and a standby computer) located in the field office. In addition to remote control of wells, connections are made to sense and record well flow rates, temperatures and pressures. Alarms are also incorporated to alert the computer operator of potential problems.

6. ***Steam Scrubbing System*** — Steam wells feeding Unit 18 typically produce superheated steam at the wellhead. In 1985, injection water broke through to steam wells near DV 73-33. Injection water can readily leach silica out of the reservoir rocks. This silica water when produced forms amorphous silica deposits when it mixes with superheated steam in the pipeline or upon pressure drops in the system. Evidence of silica plugging was observed in 1985 by increases in the turbine inlet pressure. Inspection of the pipeline also showed extensive silica scaling in the pipeline.

   A steam scrubbing system was installed at Unit 18 to improve silica removal from the steam and avoid curtailments caused by turbine deposits. Water is injected upstream of the main pipeline separator through a bank of atomizing spray nozzles. Unit 18 has a shell and tube surface condenser which provides an excellent source of injection water that has low total dissolved solids and is oxygen-free. With injection, the steam was brought from a superheated state down to saturation. The scrubbing system was originally operated intermittently; however, since late 1989 the system has been operated continuously with good results, as indicated by turbine inspection at overhaul.

STEAMFIELD DEVELOPMENT

Geology and Drilling

Several strategies were adopted during development and make-up drilling to maximize the effectiveness of the drilling programs. First, the Unit 18 development drilling program was designed to quickly identify the general distribution of permeability and focus subsequent drilling in the most productive areas. Early development drilling began in 1980 with wells from widely spaced pads. Following the initial drilling, new well pads were constructed and existing pads enlarged in order to target additional drilling in the most permeable zones. To avoid excessive interference, wells were directionally drilled to provide bottom hole spacings of at least 500 to 1,000 feet.

The start-up development wells indicated that the reservoir geology of Unit 18 is distinguished from other areas of The Geysers by a large proportion of a young intrusion informally called "felsite". Most, if not all of The Geysers is underlain by this 0.9 to 2.4 million year old silicic batholith (Thompson, this volume), which intrudes Franciscan-age greywacke (up to about 100 million years old), a type of sandstone. Greywacke is the primary host to the steam reservoir in most of the field because the felsite is usually present below typical drilled depths. The northwest-southeast trending felsite intrusion is shallowest beneath Unit 18, where it reaches sea level as shown in Figure 7. The southwest-northeast cross section shown in Figure 8 illustrates the distribution of felsite beneath the Unit 18 area and its general relation to the steam reservoir. Unit 18 was the first unit area drilled at The Geysers that encountered felsite as a major reservoir rock. Although fewer steam entries are encountered in felsite than greywacke, the entries appear to decline at comparable rates in both reservoir rocks.

Geologic models based on the position of the felsite intrusion were used to identify and predict the location of the productive zones during development drilling. The most permeable regions in the Unit 18 area were found to occur in zones parallel to, but slightly offset from the axis of the elongate intrusion, with less production along the crest. Productive exploration targets were successfully identified by using the known shape and location of the felsite body and extrapolating permeable flank zones into undrilled areas.

Unit 18 was brought on line with 15 steam wells providing approximately 2 million lb/hr of dry steam at 125 psia and 368°F with 24 degrees superheat. The 15 start-up wells are listed in Table 1 with their completion date, date of first production and rig test flow rates. The well locations are shown in the plan view of Unit 18 depicted in Figure 9. The majority of the development drilling took place in 1981-82 when 12 wells, representing 1.88 million lb/hr of steam, were completed.

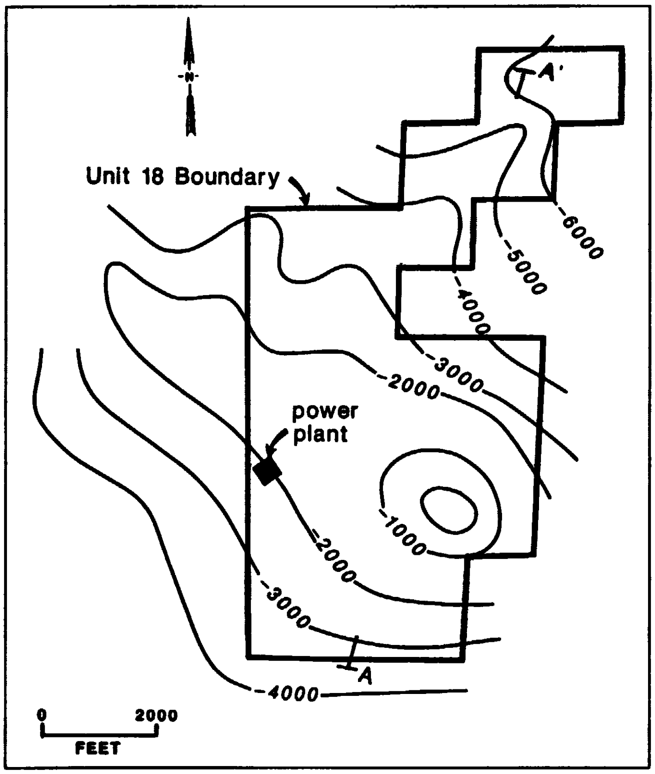

Figure 7. Elevation of felsite intrusion beneath Unit 18.

UNIT 18 OPERATION

Make-Up Drilling

Make-up drilling strategies used to optimize the results of the Unit 18 drilling program involved production from the distinctive fracture patterns in the greywacke and felsite reservoir rock types inferred from development drilling. Whereas productive horizons in greywacke exhibit a broad lateral extent, entries in felsite are encountered less frequently and are generally concentrated along narrow, steeply dipping northwest-southeast zones suggestive of near-vertical fractures (Thompson and Gunderson, this volume). In order to exploit an increased proportion of the more productive greywacke reservoir, and intersect more near-vertical fractures in felsite, wells were deviated at high angles from vertical. This technique proved quite successful in drilling wells with high productivity, often at relatively shallow depths.

The strength and competency of the reservoir rocks in the Unit 18 area allowed a final drilling strategy to op-

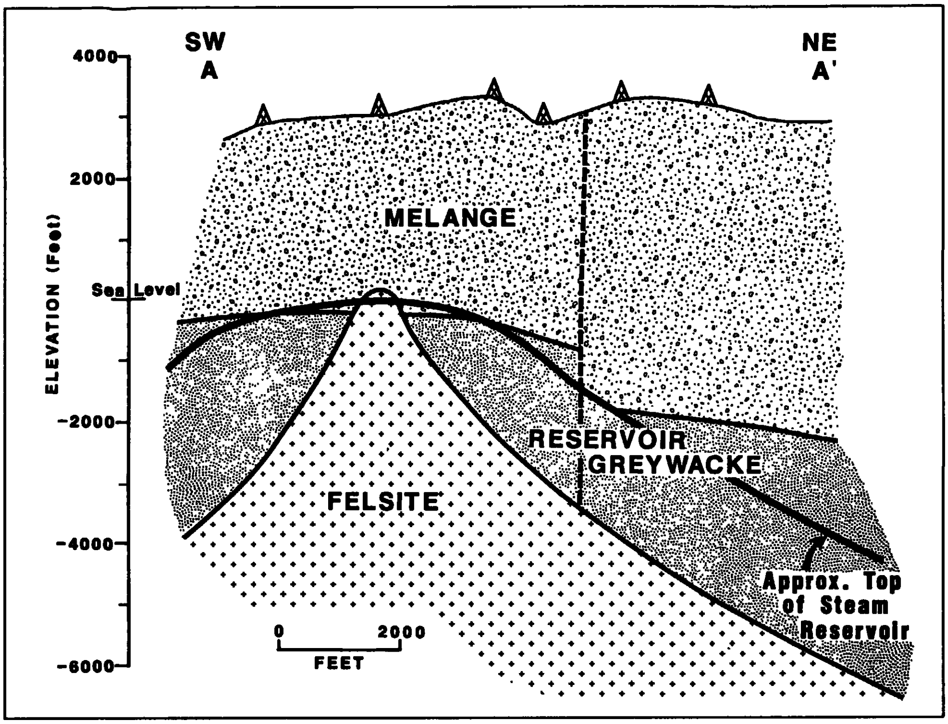

Figure 8.

Generalized southwest-northeast geologic cross section through Unit 18.

Table 1. Unit 18 start-up wells.

WELL NAME	COMPLETION DATE	DATE OF FIRST PRODUCTION	RIG FLOW TEST (LBS/HR)	DEC 1989 FLOWRATE (LBS/HR)
BEF 53-33	8/11/82	1/14/83	60,000	9,500
DV-1	3/25/77	1/14/83	145,000	61,000
DV-12	4/26/82	1/14/83	302,000	95,500
DV-13	6/11/82	1/14/83	137,000	44,500
DV-2	6/14/80	1/14/83	200,000	46,500
DV-3	7/24/82	1/14/83	82,000	20,000
DV-4	9/07/82	1/14/83	70,000	12,500
GDCF 14-27	3/03/82	1/15/83	103,000	REDRILL
MOD-1	1/12/81	1/14/83	180,000	67,500
MOD-2	3/11/81	2/15/83	141,000	40,000
MOD-3	4/05/82	1/14/83	233,000	71,500
MOD-4	5/14/82	1/21/83	290,000	109,000
TOCH-1	3/28/80	1/14/83	130,000	36,000
TOCH-2	4/24/82	1/14/83	130,000	41,500
TOCH-3	6/22/82	1/14/83	57,000	REDRILL

Table 2. Unit 18 make-up wells.

WELL NAME	COMPLETION DATE	DATE OF FIRST PRODUCTION	RIG FLOW TEST (LBS/HR)	FLOWRATE (LBS/HR)
DV-11	3/24/82	3/10/83	95,000	32,500
DV-15	1/12/83	7/06/83	320,000	91,000
DV-16	2/09/83	7/11/83	249,000	74,000
DV-23	10/26/87	11/11/87	137,000	82,500
DV-24	12/22/87	1/04/88	137,000	81,500
DV-25	2/19/88	2/29/88	126,000	85,500
DV-5	2/15/86	5/12/86	57,000	21,000
DV-6	3/24/86	4/12/86	206,000	39,000
GDCF 14A-27	8/18/87	8/25/87	287,000	168,000
GDCF 14-27 REDRILL	7/17/87	7/21/87	115,000	71,500
MOD-2 CLEANOUT	5/17/84	2/15/83	162,000	40,000
TOCH-3 REDRILL	6/22/86	6/24/86	186,000	67,000
TOCH-4	9/22/88	9/30/88	92,000	72,500

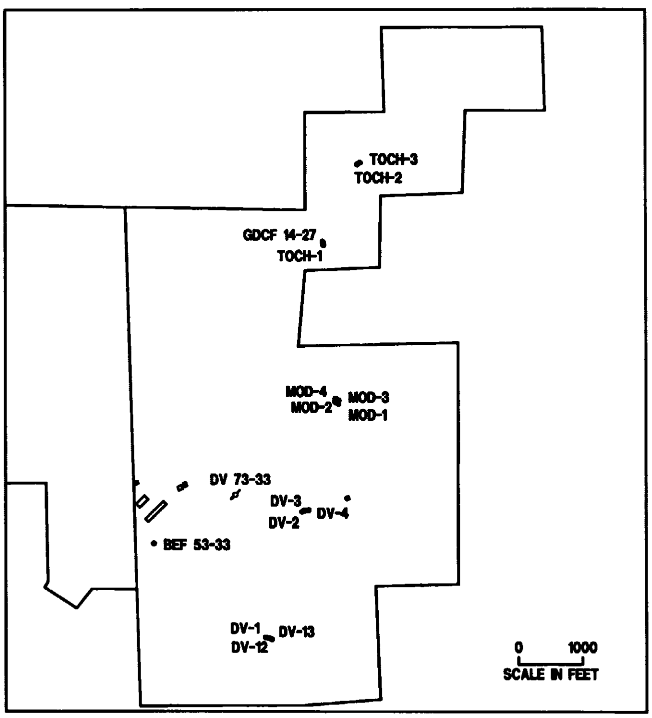

Figure 9. Unit 18 start-up wells.

timize the results of the drilling program. Forked-hole completions were employed for make-up wells drilled in the late 1980s. This technique involves connecting two separate penetrations that are drilled in open-hole below a production casing (Yarter, Cavote and Quinn, this volume). This drilling technique is risky because it is difficult to conduct remedials on forked holes and there is a danger of rocks collapsing at the point where the original hole is split into two penetrations. The areas of shallow felsite in Unit 18 are particularly well-suited to the forked-hole completion because felsite is an extremely competent reservoir rock and flow rates are often low enough to warrant the additional risk.

Well Histories

Between 1983 and 1988, nine additional wells were drilled to provide make-up steam and two of the original start-up wells, GDCF 14-27 and Tocher-3 were redrilled. This number compares well with other U-N-T unit areas at The Geysers. The well locations are shown in Figure 10 and listed in Table 2 with their completion date, date of first production and rig test flow rates.

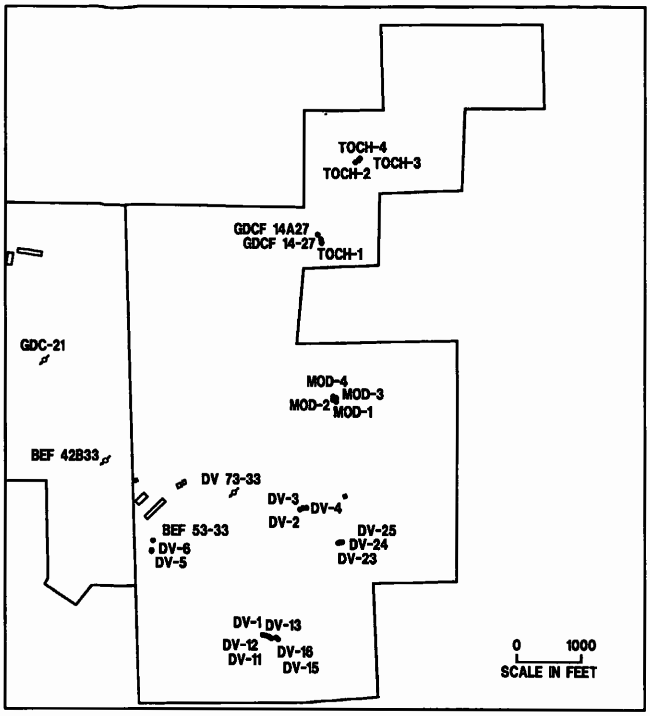

Figure 10. Present well configuration, 1991.

Initial flow rate declines in the Unit 18 wells were moderate but increased sharply in the mid-1980s in response to additional development in adjacent areas. Broad changes in deliverability since the power plant began operations can be seen from average monthly flow rate data compiled for the start-up wells, minus GDCF 14-27 and Tocher-3, from 1983 through 1989. It is important to note that these data, as shown in Figure 11, have not been corrected for decreases in wellhead pressure which have occurred over the time period; therefore, the following results can only be considered to be qualitative. Between plant start-up and early 1986 the wells declined at approximately 11 percent/year. Thereafter, the decline rate increased to, and held steady at, 22 percent/year through 1989. This increase can be related to the intense development occurring in the southeast Geysers area beginning in 1983 and continuing through 1988 as shown in Table 3 (Barker, and others, this volume). During that time period, 408 MW of generating capacity was brought on-line in unit areas directly adjacent to the Unit 18 area.

Increased production in the area has also resulted in dramatic pressure declines. This can be seen from changes in the static pressure distributions for Unit 18 for 1983,

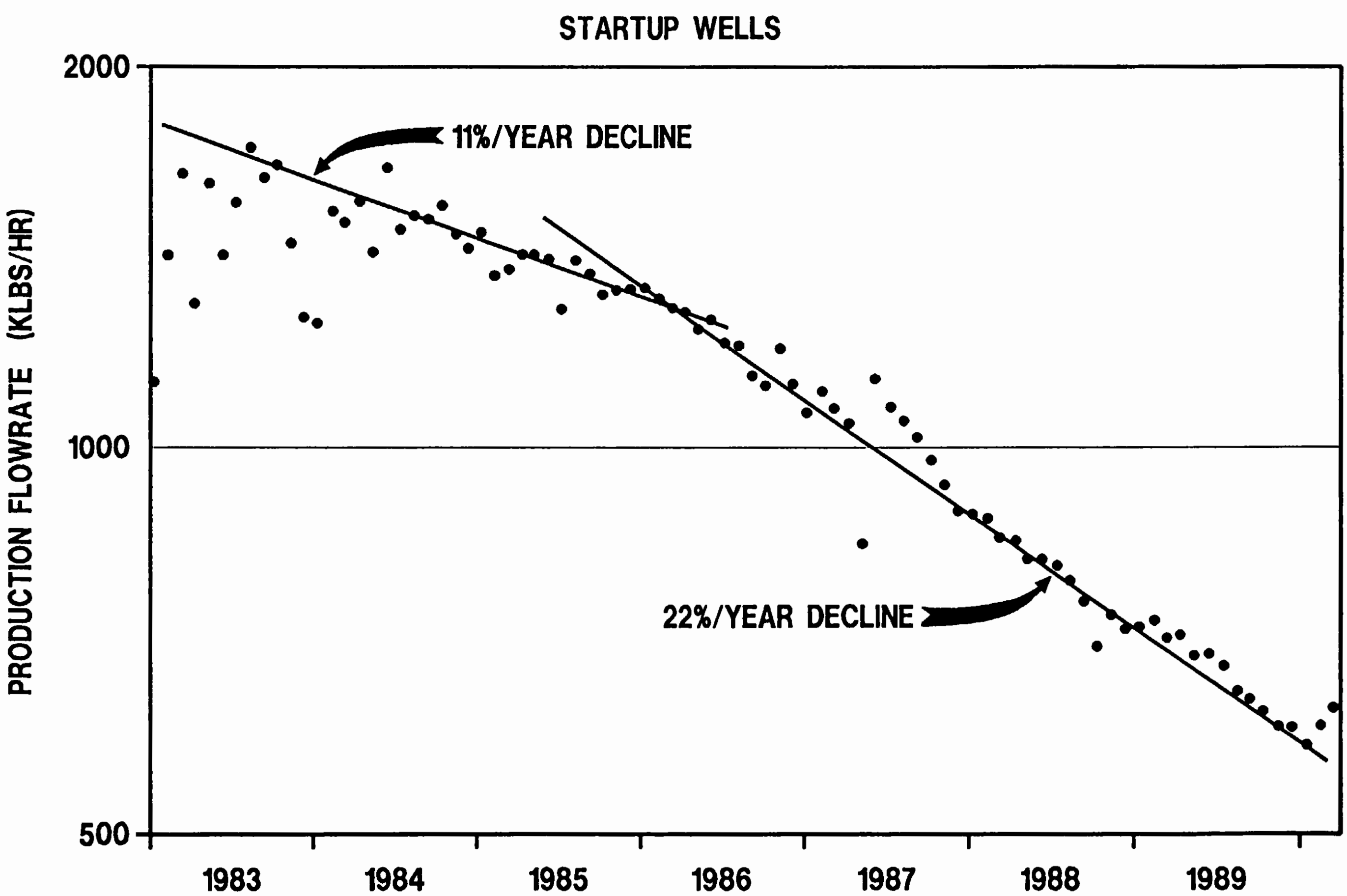

Figure 11. Unit 18 production flow rates.

1986, and 1989 in Figures 12, 13 and 14, respectively. These plots indicate a growing pressure sink in the southeast corner of the unit in an area of high well density. At present, this is one of the lowest pressure areas in The Geysers. A cooperative study is underway by the steam suppliers in this area (Unocal, NCPA, and Calpine) to determine the effects of increased injection into the sink area.

Noncondensible gas (NCG) levels in steam produced from the Unit 18 wells occupy a position near the low end of the fieldwide gas content spectrum. Gas contents during the power plant's initial operating year in 1983 varied from 54 ppmw to 1799 ppmw. Levels between 192 and 1697 ppmw were measured in 1989. Despite similar ranges over this 6 year period, NCG levels of most wells have slowly, but steadily increased with time. This is particularly evident in DV wells located in central and southern portions of the unit area. NCG contents of the Tocher and Modini leases are the highest supplied to Unit 18. These wells lie close to a margin of the productive reservoir. Field margins consistently produce steam with higher gas content. Steady and decreasing gas levels are observed in a few wells and can be related to water injection effects. The two major processes are diluting naturally occurring gases and inhibiting gas generation. Conversely, termination of DV73-33 injection in mid-1987 can be correlated with NCG increases and decreasing condensate production, in DV-1 and DV-12, as determined from isotopic composition.

Table 3. Geysers power plants.

UNIT	START-UP DATE	CAPACITY (GROSS MW)	CUMULATIVE CAPACITY (MW)
PG&E-1	9/60	12	12
PG&E-2	3/63	14	26
PG&E-3	4/67	28	54
PG&E-4	11/68	28	82
PG&E-5&6	12/71	110	192
PG&E-7&8	11/72	110	302
PG&E-9&10	11/73	110	412
PG&E-11	5/75	110	522
PG&E-12	3/79	110	632
PG&E-15	6/79	60	692
PG&E-13*	5/80	137	829
PG&E-14	9/80	114	943
PG&E-17	12/82	119	1062
NCPA-1*	1/83	110	1172
PG&E-18	2/83	119	1291
SMUDGEO-1*	10/83	72	1363
SANTA FE*	4/84	80	1443
DWR-BOTTLEROCK	3/85	55	1498
PG&E-16	10/85	119	1617
PG&E-20*	10/85	119	1736
NCPA-2	11/85	110	1846
CCPA-1	5/88	65	1911
CCPA-2	10/88	65	1976
BEAR CANYON CREEK	9/88	20	1996
WEST FORD FLAT*	12/88	27	2023
AIDLIN	6/89	20	2043

* DENOTES UNIT AREAS WHICH BORDER PG&E-18

Low general gas levels in Unit 18 wells are probably related to a lack of source materials in reservoir rocks. The felsite intrusive rocks lack gas source minerals and form a part of the producing reservoir. Intrusion of these rocks into overlying greywackes produced metamorphic changes that could have significantly reduced gas production from the sediments. Present or past influx of low gas meteoric water may also play a role in mitigating gas production in the Unit 18 reservoir.

Injection Strategy

The primary injector for Unit 18 at start-up was DV 73-33. This well was used exclusively for Unit 18 condensate disposal until mid-1987, when two make-up wells, DV-5 and DV-6, were drilled approximately 1,600 ft. southeast of the injector. Water entries were encountered during drilling of both wells at a depth of approximately 1,880 feet subsea. Isotope analysis of the water strongly suggests that its source was DV 73-33 injectate. In the absence of a good candidate for conversion to an injector, an injection crossover line to the Unit 20 injector, GDC-21, was constructed in late 1986 and early 1987. With the completion of this pipeline, GDC-21 became the primary injector for both Units 18 and 20. DV 73-33 was maintained as the back-up injector and used primarily in the winter months during storm conditions to prevent injection rates from exceeding 3,000 gpm in GDC-21.

In February 1990, BEF 42B-33 was placed in service as the Unit 18 injector to reduce the volume being injected into GDC-21. This configuration provides a dedicated injector for Unit 18 with sufficient pipe manifolding to permit the well to receive Unit 20 condensate also. This project is expected to benefit the reservoir by accessing more reservoir surface area in the fracture network through better distribution of injected fluids. This in turn increases the potential to boil more liquid to steam. In addition, the retirement of DV 73-33 as a back-up injector will eliminate the production breakthrough problems experienced at DV-5 and DV-6.

The injection histories for DV 73-33, GDC-21 and BEF 42B-33 are shown in Figure 15. Note the increase in injection at GDC-21 when Unit 18 condensate was transferred to the well in May 1987. The typical injection rate ranges between approximately 28 million gallons per month in summer to 54 million gallons per month in winter. These rates correspond to an average reservoir mass replacement of 29 percent.