# THE ROLE OF DECLINE CURVE ANALYSIS AT THE GEYSERS

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## ABSTRACT

Recent increases in mass withdrawal rates as new power plants went on production at The Geysers have complicated standard decline curve analysis and associated reserve estimates. This paper demonstrates a method of calculating reserves using Fetkovich type curves to aid in proper application of harmonic and exponential decline equations where significant steepening in flowrate trends occurred between 1985 and 1988. However, extrapolation of production data during this transient decline condition may present conservative reserve estimates. Actual remaining reserves per well are thought to be between 2.7 billion (exponential) and 7.9 billion (harmonic) pounds of steam. The permeability-thickness product (kh) calculated from the Fetkovich type curve equations compare favorably with kh values calculated from long term pressure buildup analyses.

## INTRODUCTION

Decline curve analysis, a standard method of evaluating reserves and field life in the oil and gas industry (Arps, 1945; Fetkovich, 1980, 1984), is used extensively at The Geysers (Budd, 1972; Dykstra, 1981; Ramey, 1981; Enedy, 1987). Historically, Calpine Corporation has found this technique most valuable for short-term forecasting (1 to 3 years) to determine the number and timing of required infill wells for budgeting and planning purposes. Calpine recently conducted an extensive study of reserve estimation using a number of techniques including numerical simulation and P/z versus cumulative production on a well-by-well basis. The decline curve analysis was the preferred evaluation method because in addition to providing reasonable results, it can be implemented quickly, easily and cheaply.

The purpose of this paper is to demonstrate how the application of Fetkovich type curves can be used to monitor significant changes in reservoir response and to aid in correct application of harmonic and exponential decline curve methods. Production data from eight representative steam producing wells in the eastern Geysers (the Units 13 and 16 areas) are used in this study.

## BACKGROUND

Calpine supplies steam to Pacific Gas and Electric Company's Units 13 and 16, Sacramento Municipal Utility District's GEO #1, Bear Canyon plant and West Ford Flat plant for a total of 367 MW net (nominal) capacity or approximately 20 percent of the total Geysers installed capacity.

When Unit 13 (134.4 MW net) commenced operations in May 1980, there were no other plants in operation in the southeastern portion of The Geysers reservoir. Within a year, the start-up wells' normalized flowrate trend flattened to average slightly less than 10 percent exponential decline per year. Average static pressure, in the area of the producing Unit 13 wells, dropped approximately 8 psi per year.

During 1983 and early 1984, an additional 375 MW net came on line in this area. Therefore, the total steam withdrawal rate (in the eastern Geysers) increased from approximately 2.7 million lb/hr to 8.7 million lb/hr. Be-

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tween late 1985 and mid-1986 another 336 MW came on line which increased the total mass withdrawal to 14.7 million lb/hr. The plant start-ups in 1985-86 all directly offset the Units 13, 16 and SMUDGEO #1 areas. SMUDGEO #1 began operations in October, 1983 and in October, 1985, Unit 16 came on line. In late 1988 and early 1989 an additional 47 MW of generation began at West Ford Flat (27 MW) and Bear Canyon (20 MW).

The recent accelerated mass withdrawal of large steam quantities in the eastern Geysers has changed the apparent reservoir response. Annual average exponential flow rate decline in 1987 increased from approximately 10 percent to 30 percent for Unit 13 wells. Unit 16 producing wells, which had been in operation only 15 to 20 months exhibited an average exponential decline of 17 percent during 1987. Based on pressure buildup analysis of data collected during Units 13 and 16 plant overhauls (1986 and 1987), static pressure dropped an average of 35 psi during 1987. The increased decline rates led to an accelerated infill drilling schedule to maintain plant load in 1987. However, lower average initial deliverability of infill wells was observed in 1987. The resulting accelerated infill drilling schedule leads to tighter well spacing and often significant interwell interference which reduces the net increase in deliverability.

In the early production years of Unit 13 (1980-1986), decline curve analysis predicted a more or less constant drilling rate and recoverable reserve estimates. However, the reservoir response of the majority of Calpine wells seems to be in a transition period since 1987, for the reasons stated above. It is expected that the steepening flow rate and pressure declines will flatten after the reservoir has had time to adjust to the increased offset production as observed by Dee (1983).

## RESERVOIR AND WELL DESCRIPTION

Figure 1 is a plat showing midpoint of steam entry locations for the eight representative wells in the Units 13 and 16 areas.

Group A wells have produced to Unit 13 since May 1980. These wells are drilled in a portion of the reservoir which exhibits low permeability (20-60 darcy-ft), low initial deliverability (100 to 200 k lb/hr at 140 psig) and low well density (50 acre). Well A-3 is adjacent to the two Unit 13 injectors (see Figure 1).

Group B wells, located in southern Unit 13 area, also have over 9 years of production history. However, these wells are completed in an area of the reservoir characterized by higher permeability (100 to 250 darcy-ft), higher initial deliverability (200-300 k lb/hr) and tighter well spacing (10 acre). The higher mass withdrawal rates and boiling off of the liquid fraction in this area have resulted in increased enthalpy and superheat in the wellbore (Enedy, 1989). At present, all Unit 13 condensate is reinjected

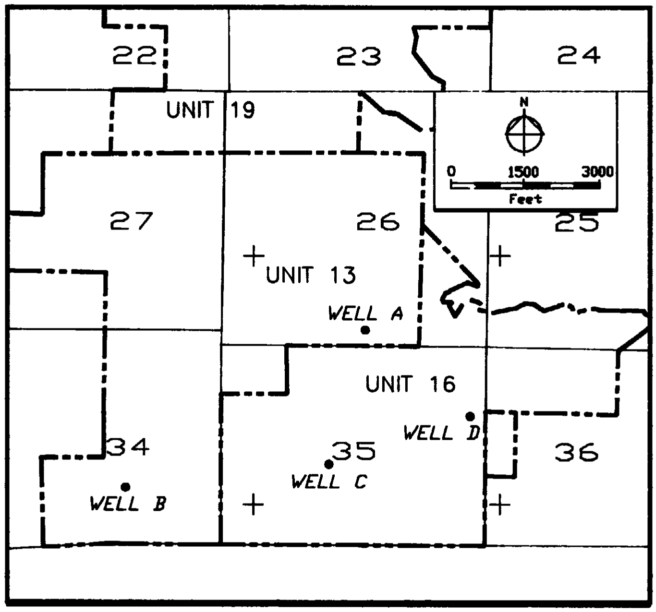


**Figure 1.** Well location map indicates midpoint of steam entries for subject wells in the Units 13 and 16 areas.

into the northern Unit 13 project area. However, plans are underway to direct most of that injection fluid into this portion of the reservoir to potentially realize an estimated 50 percent of injected condensate as produced steam. (Beall, Enedy and Box, this volume).

The two Group C wells are Unit 16 producers, each with over 3 years of production history. The reservoir in this area is almost identical to the southern Unit 13 portion (Group B wells) in terms of permeability, initial deliverability, and well spacing. Unit 16 condensate is reinjected into a well west of well C-2 (Figure 1).

## FETKOVICH TYPE CURVE METHOD

### Methodology

Flow rate data from the eight wells described above were normalized using Equation 1, often called the back-pressure equation:

$$W_n = \frac{(P_{ts}^2 - P_{tf}^2)^n \cdot W}{(P_{ts}^2 - P_{std}^2)^n} \qquad (1)$$

where:

$W_n$ = normalized flow rate, k lb/hr
$W$ = flow rate at $P_{tf}$, k lb/hr
$P_{ts}$ = surface shut-in pressure, psia
$P_{tf}$ = surface flowing pressure, psia
$P_{std}$ = standard flowing wellhead pressure, psia
$n$ = exponent of back-pressure equation, usually $0.5 \leq n \leq 1.0$

The flow rates normalized to 140 psig were plotted versus time (days on production) on log-log paper to the same scale as the Fetkovich composite analytical-empirical solution type curve. A match was obtained for each well. Figures 2, 3, and 4 are examples of these plots for wells A-2, B-2, and C-2, respectively. For all wells except C-2, the production data after about 1,000 to 2,500 days fell below the b=0 stem on the type curve (See Figures 2 and 3). The data were then reinitialized and again matched with the decline type curve as shown on Figures 2 and 3.

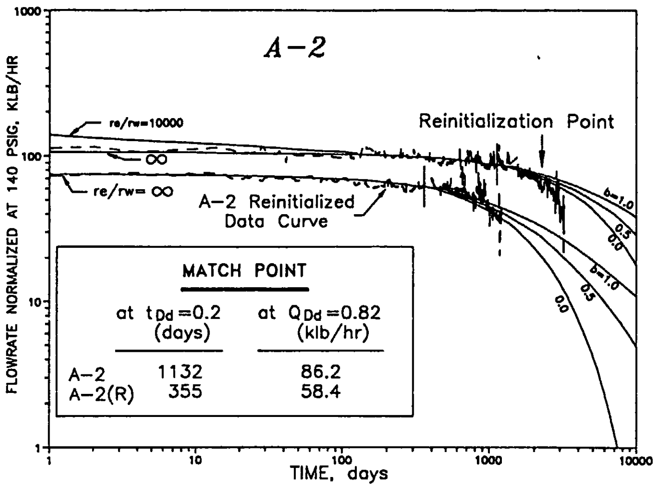


**Figure 2.** Fetkovich type curve match of well A-2 log rate vs. log time data. Data were reinitialized after 1,999 days on production.

## Results

Late reinitialized data fell between the b=1.0 and b=0 stems on the type curve (Figures 2 and 3). Note that well B-2 (Figure 4) required a second reinitialization after a total of 2,400 days on line. Table 1 shows the time of reinitialization for each well.

In early 1983, a new plant (NCPA #1 - 110 MW) came on line to the south of the B wells (see Figure 1). Wells B-1 and B-2 experienced effects of the additional offset production in third quarter 1984. However, since well B-3 has less offset production to the west, the increase in flow rate decline rate was not evident until late 1985. A second steepening of well B-2's decline rate occurred in November 1986, most likely due to two nearby infill wells drilled during this period which further decreased well spacing.

The Unit 16 plant commenced operations in October, 1985. Well C-1 and several other wells on the same pad were cross-tied and produced into the Unit 13 plant a few months prior to Unit 16's start-up. This impacted well A-2's flow performance almost immediately in October 1985 as shown in Figure 2. Pressure buildup analysis, using data collected during a 3 to 4 week plant outage, confirms communication between these two areas of the field. Wells A-1 and A-3, farther to the north, exhibit a response almost a year and a half later. The reason for this

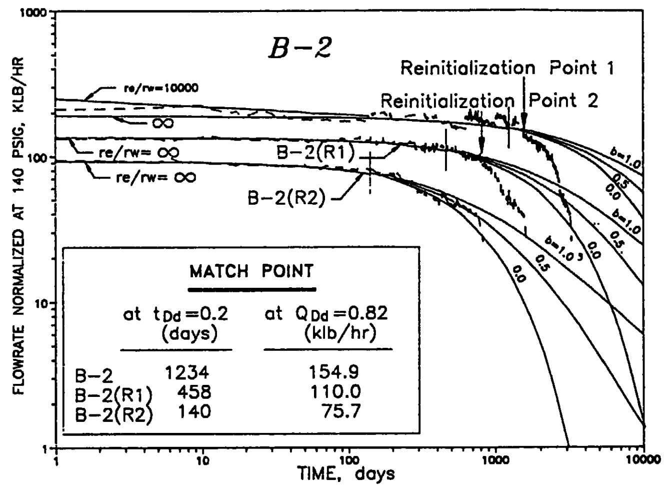


**Figure 3.** Fetkovich type curve match of well B-2 log rate vs. log time data. Two reinitializations occurred when flowrate data fell below b=0.0 stem at 1,599 days and again at 2,397 days on production.

delayed response is probably a combination of less dense well spacing, lower mass withdrawal rate, a lower kh area, and perhaps some support from the two nearby injection wells (Figure 1).

Well C-2, in the Unit 16 area, is the only well out of the eight presented whose late time flow rate data did not fall below the b=0 stem on the type curve (Figure 3). Its closer proximity to an injector (see Figure 1) may have delayed the response experienced by C-2 in April 1988. Both C-1 and C-2 have been on production approximately 4 years.

## Permeability-Thickness Product (kh) Calculation

Equation 2 (described by Enedy, 1987) was used to calculate the permeability-thickness product or kh.

$$kh = \frac{1207(qt)(\bar{v})(\bar{\mu})(\bar{P})\ln[(re/rw) - \frac{1}{2}]}{(Pts^2 - Ptf^2)qDd_{(tDd)}} \quad (2)$$

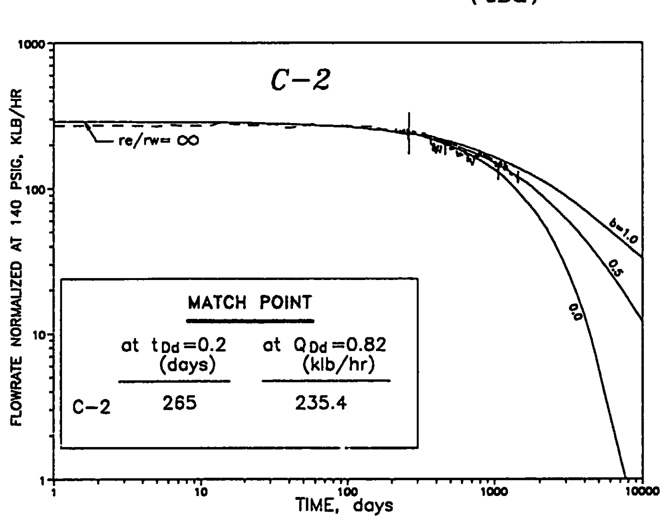


**Figure 4.** Fetkovich type curve match of well C-2 log rate vs. log time data. No reinitialization required, since data fall on b=0.5 stem.

**Table 1.** Reinitialization times.

| Well | Date | Comment |
|---|---|---|
| A-1 | February 1987 | |
| A-2 | October 1985 | New plant to E |
| A-3 | February 1987 | |
| B-1 | July 1984 | New plant to S |
| B-2 | September 1984 | New plant to S |
| B-2 | November 1986 | |
| B-3 | November 1985 | |
| C-1 | April 1988 | |
| C-2 | N/A | |

**Table 2.** kH comparison.

| Well | Pressure Buildup, kh, darcy-ft | Type Curve kh darcy-ft | Pd Term |
|---|---|---|---|
| A-1 | 64 | 68 | 9 |
| A-2 | 60 | 58 | 12 |
| A-3 | 21 | 35 | 6 |
| B-1 | 322 | 168 | 12 |
| B-2 | 139 | 109 | 12 |
| B-3 | 316 | 100 | 12 |
| C-1 | 464 | 233 | 12 |
| C-2 | 111 | 114 | 9 |

where:

$\bar{\mu}$ = viscosity at , cp

$\bar{P}$ = average reservoir pressure,psia

$P_{ts}$ = static pressure at the match point, psia

$P_{tf}$ = surface flowing pressure, psia

$q_t$ = mass flow at time t, lb/hr

$q_{Dd}(t_{Dd})$ = type curve dimensionless rate at type curve dimensionless time

$r_e$ = external boundary radius, ft

$r_w$ = effective wellbore radius, ft

$\bar{v}$ = specific volume at , lb/ft3

Table 2 compares the kh values calculated from Equation 2 with those estimated from recent pressure buildup (PBU) analysis conducted during plant outages averaging 4 weeks. Note that ($\ln[(r_e/r_w) - 1/2]$) or the $P_d$ term ranged between 6 and 12. The table lists the $P_d$ term that gave the best kh match to the values obtained by PBU analysis. A $P_d$ term of 12 provided the best match for the majority of the wells.

A good match resulted between the two methods especially for low and mid-kh values. The type curve method, however, yielded consistently lower kh values for high permeability wells (>200 darcy-ft). Also, kh values calculated from Equation 2 varied less than 5 percent after production data were reinitialized for wells A-1, A-2, A-3, B-1, B-2 and C-2. For wells B-3 and C-1 the estimated kh dropped about 10 percent after reinitialization.

As pointed out by Zais and Bodvarsson (1980), Fetkovich (1980) showed that decline curve analysis of production data can be made analogous to analyzing pressure data by using his log-log type curves. A log pressure versus log time plot is used in pressure transient work to select the proper straight line on a Horner semi-log plot (Earlougher, 1977). Similarly, Fetkovich type curves can be used to pinpoint where to begin exponential or harmonic decline analysis on the rate-time or rate-cumulative production curve. The changes in trend are often too subtle to discern on the rate-time or rate-production curve alone.

## RESERVE ESTIMATES EXPONENTIAL DECLINE CURVE METHOD

### Methodology

Most current decline curve analysis is based on Arps' work (1945, 1956).

Equation 3 is the general form of the Arps equation.

$$\frac{q(t)}{qi} = \frac{1}{[1+b(Di)(t)]^{1/b}} \qquad (3)$$

where:

b = reciprocal of decline curve exponent (1/b)

$D_i$ = initial decline rate, $t^{-1}$

$q_{(t)}$ = surface rate of flow at time t

$q_i$ = initial surface rate of flow at t=0

t = time

At The Geysers, production histories of steam wells can be modeled as having exponential (b=0), hyperbolic or harmonic (b=1) trends.

A straight line on a log flow rate versus time plot represents an exponential trend. Equation 4 is used to estimate the exponential decline rate.

$$q(t) = qi \cdot e^{-at} \qquad (4)$$

where:

a = exponential decline factor

$q_{(t)}$ = production rate at t, lb/hr

$q_i$ = initial production rate, lb/hr

t = time, years

Early in the life of a well, or after a significant change in reservoir conditions, all three trends are essentially the same. Until a unique trend is defined, both exponential and harmonic methods are used to give a low and high end for reserve estimates.

In this paper, remaining reserve estimates are calculated for individual wells by extrapolating the current data trend to an assumed abandonment rate of 10 klbS/hr on either log rate versus time or log rate versus cumulative production plot. The Fetkovitch type curve match point (see Figures 5, 6, 7, 8, 9, and 10) aided in the determination

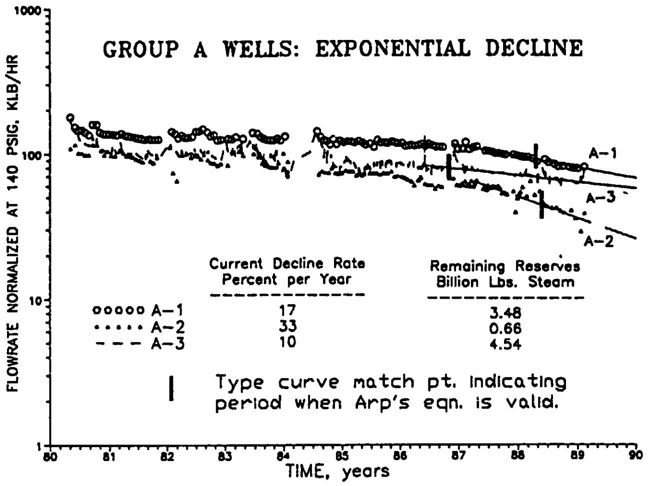


**Figure 5.** Group A wells: exponential decline. These three northern Unit 13 wells average the lowest decline rate (20 percent/yr) of the eight subject wells. The A wells produce from a low permeability, high reservoir pressure and and low well density portion of the reservoir.

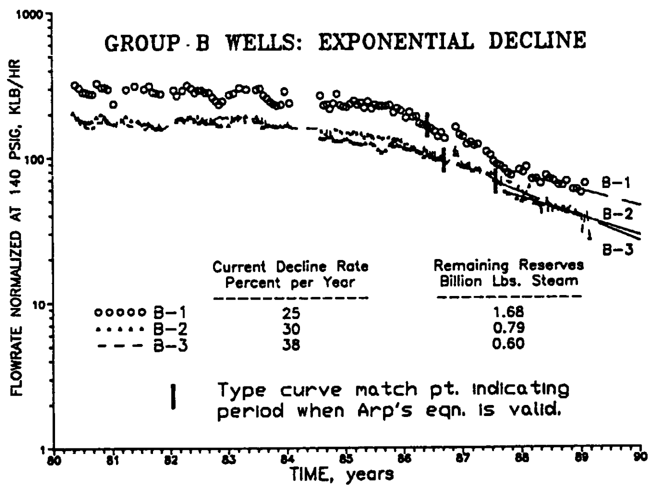


**Figure 6.** Group B wells: exponential decline. These three southern Unit 13 wells average the lowest remaining reserves per well (1.02 billion lbs steam) of the eight subject wells. The B wells produce from a high permeability, low reservoir pressure, and high density portion of the reservoir. Note steepening of decline rate from 1986-87 and subsequent decline curve flattening from 1988 on.

of the last stabilized decline period. Data prior to the match point should be considered as transient in nature. Once the individual well analysis is completed, wells with similar reservoir characteristics can be grouped together to evaluate areas of the wellfield.

Other economic (steam price) and operational constraints which impact the recovery of future reserves are beyond the scope of this paper. These parameters should be considered for a complete analysis.

### Results

Figures 5, 6, and 7 show production data versus time curves for the eight Calpine wells. Decline rates average

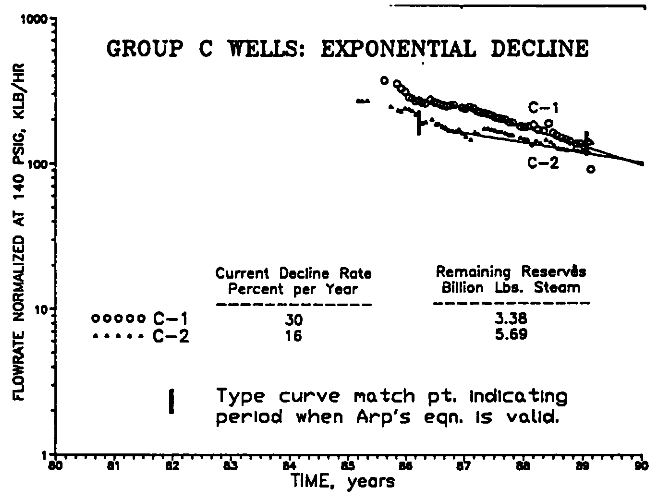


**Figure 7.** Group C wells: exponential decline. These two Unit 16 wells have similar decline rates and remaining reserves/well values as the Group A wells. The C wells produce from a portion of the reservoir similar to southern Unit 13 area (B wells) but with higher reserve pressure (Unit 16 has less production history than Unit 13) and more injection support.

(arithmetic average of the eight subject wells) 24.9 percent per year and remaining reserves average 2.6 billion pounds of steam per well. Group A wells, in northern Unit 13, have the lowest average decline rate (20 percent/yr) compared to Group B wells (31 percent/yr) and Group C wells (23 percent/yr). The northern Unit 13 segment of the field has larger well spacing, lower permeability, lower mass withdrawal rates, higher reservoir pressures and probable water-injection support which aid in maintaining flatter decline rates.

Group B wells, in southern Unit 13, have the lowest average remaining reserves per well (1.02 billion pounds of steam). The reservoir pressure is highly depleted in this portion of the field as the mass withdrawal rates have historically been almost twice that of northern Unit 13 wells. In addition, high downhole superheat and enthalpy values are observed as the liquid fraction of reserves boils away. Figure 6 shows that the Group B wells experience a dramatic steepening in flowrate decline between mid-1985 and 1988, then a subsequent flattening during 1988 through February 1989. Injection (800 gpm) is planned to begin in this area by late August 1989.

Group C wells, in the Unit 16 area, have the highest calculated average remaining reserves per well (4.54 billion pounds of steam) as this area is prolific but has been under production for only half as long as Unit 13 wells.

## HARMONIC DECLINE CURVE METHOD

### Methodology

A straight line on a log flow rate versus cumulative production plot represents a harmonic trend (Arps, 1956). Equation 5 is used to estimate the harmonic decline rate.

$$q(t) = \frac{qi}{1+ai \cdot t} \quad (5)$$

where:

$a_i$ = initial harmonic decline factor

$q_{(t)}$ = production rate at t, lb/hr

$q_i$ = initial production rate, lb/hr

t = time, years

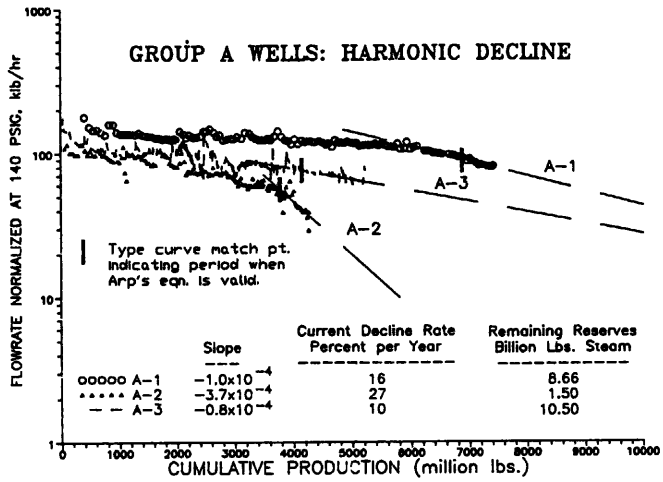


**Figure 8.** Group A wells: harmonic decline. Remaining reserves estimated for Group A wells using the harmonic decline equation is over twice that of remaining reserves calculated using the exponential method.

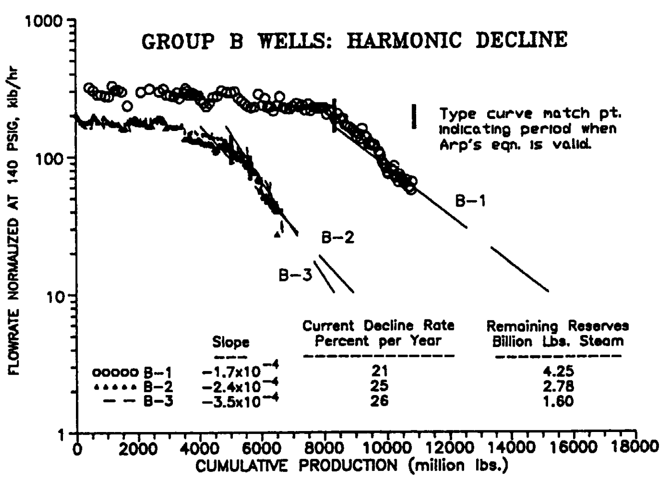


**Figure 9.** Group B wells: harmonic decline. Group B wells exhibit a steepening in recent data's decline trend. However, note that the three Group B wells have produced 30 percent more steam to date than the three Group A wells over an equivalent production period.

## Results

Figures 8, 9, and 10 show production data versus cumulative production curves for the eight Calpine wells. Current decline rates average 21.1 percent per year and remaining reserves average 7.0 billion pounds of steam

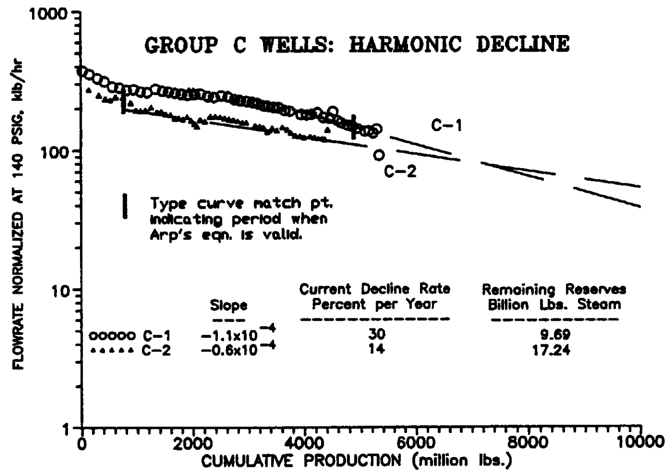


**Figure 10.** Group C wells: harmonic decline. Group C wells have higher average remaining reserves per well than Group A or Group B wells. However, the C wells have been on production for 3 years compared to A and B wells 9 year flowing history.

per well. Remaining reserves calculated assuming a harmonic trend are about 2.7 times greater than if an exponential trend is assumed. Actual remaining reserves are thought to be between the harmonic and exponential estimates as the production data usually lie between the b=1 and b=0 stems of the Fetkovich type curves (see Figures 3 and 4). As the reservoir response stabilizes and sufficient production data are collected, the b value becomes more unique and remaining reserves estimates are more certain.

Exponential trends are assumed for short-term planning and budgeting purposes (1 to 3 years) for the infill drilling program and overall field development. The rate versus time plot is easier to view than rate versus cumulative production for monitoring purposes (when wells need remedial work, interwell interference effects, effect of offset plant outages, etc.). In addition, for the near term, exponential and harmonic trends are essentially the same.

## CONCLUSIONS

1. The increase in total steam mass withdrawal rates (from 2.7 to 14.7 million lb/hr) due to the start-up of new power plants in the eastern portion of The Geysers between 1983 and 1986 resulted in a sudden steepening of reservoir pressure and flow rate decline rates.
2. Standard decline curve analyses are complicated by these significant changes in reservoir conditions.
3. Fetkovich type curves can be used to aid in the proper application of exponential and harmonic equations by reinitializing rate-time on log-log plots when it falls below the b=0 (or exponential) stem.
4. The dimensionless pressure term (Pd) was estimated using type curves and known permeability-thickness

products. The Pd term was higher in the more depleted areas of the field (southeast Unit 13 area) and lower near the injection wells.

5. Average remaining reserves per well, in the Units 13 and 16 areas, are expected to range between 2.7 and 7.9 billion pounds of steam using exponential and harmonic methods, respectively. Production data at this time are insufficient to uniquely define the exponent of Arps' equation.

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