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FORKED WELLBORE COMPLETIONS IMPROVE DEVELOPMENT STRATEGY

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ABSTRACT

In recent years nearly half of the development wells drilled in the southeast Geysers were, at best, capable of only marginal steam production from their original producing interval. Traditionally, this original hole "leg" was plugged and abandoned and the well directionally redrilled, usually from the casing shoe, to an alternate bottomhole target. Often two or even three such redrills were required before an economically acceptable producer was realized. Northern California Power Agency (NCPA) has recently developed an innovative drilling technique whereby the producing interval of a subcommercial original hole is retained and its production is then combined with that obtained from the redrilled leg, resulting in a "forked" completion. Six such two-legged well completions have been attempted in the past 2 years, all of which were successful. This technique has permitted the profitable exploitation of heretofore economically unattractive or marginal areas of the reservoir.

INTRODUCTION

In 1974 Shell Oil drilled a well that extended The Geysers dry steam reservoir 1-1/2 miles in a southeasterly direction. This discovery resulted in additional drilling and the construction of a 110 MW power plant by Northern California Power Agency (NCPA), which went on line in early 1983. In September of that year the field was sold by Shell to Grace Geothermal, which operated it for 2 years. NCPA purchased the steam field from Grace in August 1985, at which time there were 20 production wells with a total steam potential of 2,128 thousand pounds per hour (M lb/hr) (142 MW). The primary reason for the purchase was that, with a second 110 MW plant nearing completion, it had become obvious that there would be insufficient available steam due to the manner in which Grace was conducting the development drilling program. NCPA immediately launched an accelerated three rig drilling campaign which resulted in the full capacity operation of Plant #2 when it was completed in May, 1986. Since that time drilling has been gradually scaled down until now there are 60 producing wells with a steam surplus of 25 percent based on 220 MW plant capacity. NCPA presently operates one agency-owned drilling rig which is engaged in maintaining this surplus by continued drilling and workover operations.

BASIC DRILLING PROGRAM

As in most areas of The Geysers, dry steam is produced from what are considered to be randomly oriented fractures in a graywacke-greenstone section underlain by a felsite intrusive, which is also occasionally productive. In the NCPA portion of the field the producing interval is competent to the extent that, even though producing from fractures, protective casing or liners are not required, and following initial cleanup, fill or bridging is not a consideration.

A typical producing well is directionally drilled from a multi-well site in accordance with the following basic program:

- 20 in. casing is cemented in 26 in. mud-drilled hole at 300 feet.

- 13-3/8 in. casing is cemented in 17-1/2 in. mud drilled hole at 2,200 to 3,700 feet, depending on the location of the well.
- The producing interval is air-drilled with 12-1/4 in. hole to a total depth that varies from 6,000 feet to a maximum of 10,000 feet.

NOTE: Occasionally for geologic or mechanical reasons (primarily lost circulation) a 9-5/8 in. liner of up to 1,400 feet in length may be required. In this case the producing interval is air drilled with 8-3/4 in. hole.

PREVIOUS DEVELOPMENT PHILOSOPHY

Although several dry holes were drilled by Shell, Grace and NCPA in attempting to define the productive limits of the reservoir, the early producing wells were completed with rig test flow potentials ranging from 90 to 300 M lb/hr. The general philosophy during the period of accelerated development was that if a well was not capable of at least 90 M lb/hr at 160 psig back pressure, that particular leg would be plugged and abandoned, usually to the 13-3/8 in. casing shoe. This was done with the thought in mind that the well could then be directionally redrilled relatively inexpensively (i.e. $500,000), with the expectation that the new producing leg could reasonably be anticipated to produce at an "acceptable" rate. Based on this criteria, occasionally two and even three redrilled legs were required before a rig test of greater than 90 M lb/hr was realized.

CURRENT DEVELOPMENT PHILOSOPHY

As development has progressed over the past 2 years and mass withdrawal from the reservoir has increased, the average flow potentials from new wells have gradually decreased to the point that an "acceptable" rig test flow rate is now considered to be in the 70 to 75 M lb/hr range. Additionally, an increased number of higher risk stepout or "edge" wells are now being drilled, with a corresponding increase in the number of producing legs that test in the 20 to 70 M lb/hr range. Further, the likelihood of abandoning these legs and redrilling with the expectation of encountering substantially increased steam flow in the second leg has also been reduced.

Faced with these conditions NCPA has developed an innovative drilling technique whereby production from a marginal or subcommercial leg can be combined with that from a second leg resulting in a "forked" completion. A schematic drawing of a typical forked well is shown in Figure 1. Within the past 2 years six such completions have been attempted by NCPA, all of which were successful. Five of these wells are classified as development wells and the sixth is an exploratory stepout.

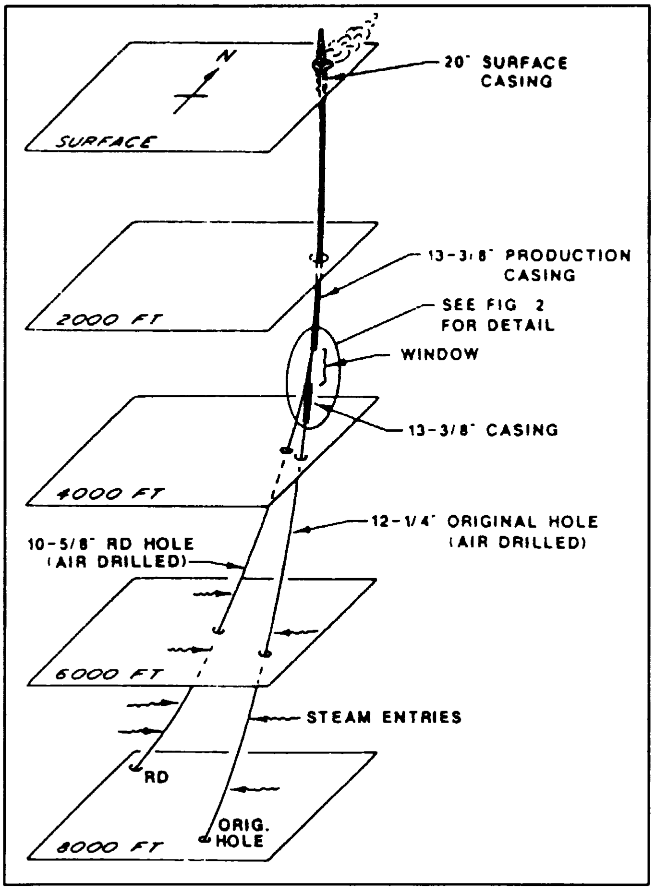

Figure 1. Schematic of a typical forked completion.

FORKED COMPLETION PROCEDURE

When the decision is made to fork a well, the following series of operations is undertaken in sequence:

1. The original producing interval is isolated by setting a drillable bridge plug 100 to 200 feet above the 13-3/8 in. casing shoe.
2. A section mill is then run and a "window" is cut in the 13-3/8 in. casing. The footage milled is critical, that is, it must be of sufficient length to allow sidetracking without an excessive dogleg, but as short as possible in order to ease reentry into the original hole. A 35 foot window has been found to be satisfactory from both standpoints. The location of this window should be as deep as possible and yet allow enough "hole" to establish the redrill well course using a mud motor prior to air drilling the production interval.
3. A cement kick-off plug is set in the interval from 60 to 75 feet below the window to 150 feet above it. After allowing adequate time for the cement to cure, it is drilled out to the top of the window.
4. The well is then sidetracked using a 12-1/4 in. bit, mud motor and 3 degree "kick-sub." It is important that the kick-sub be oriented such that the mud motor drills out

the top or "high side" of the hole. After time-drilling approximately 20 feet, the 3 degree kick-sub is replaced with a 2 degree kick-sub in order to reduce dogleg severity. A 12-1/4 in. hole is continued for an additional 100 to 200 feet, at which time hole size is reduced to 10-5/8 in.

5. When the redrill well course is firmly established with regard to inclination and direction, the mud drilling fluid is "unloaded" and the hole is air drilled to total depth. Figure 2 schematically shows the configuration of both holes in the sidetrack area while air drilling the second leg.
6. The redrilled leg is then flow tested, at which time a Spinner-Pressure-Temperature (S/P/T) log is run. If a log of the redrilled leg is desired, it is imperative that it be run at this time. This is because, after the original leg has been reopened, hole configuration usually precludes additional wire line operations in the redrill.
7. Reentering the original hole is the crucial step in the entire operation. A 12-1/4 in. bit is run on a 10 in. drill collar below a 12-in. stabilizer. The drill collar is modified with three sets of spiral ribs providing an effective overall diameter of 12-in. Basically, this may be described as the most rigid drilling assembly that will pass through the 13-3/8 in. casing. Cement in the kick-off area is time-drilled to the top of the 13-3/8 in. casing stub. The remaining cement is drilled out of the casing and the bridge plug is drilled and/or pushed to bottom. If difficulty is encountered in reentering the 13-3/8 in. casing stub, a tapered mill has been used effectively to facilitate reentry. Figure 3 shows the drilling assembly and hole configuration immediately prior to reentry.

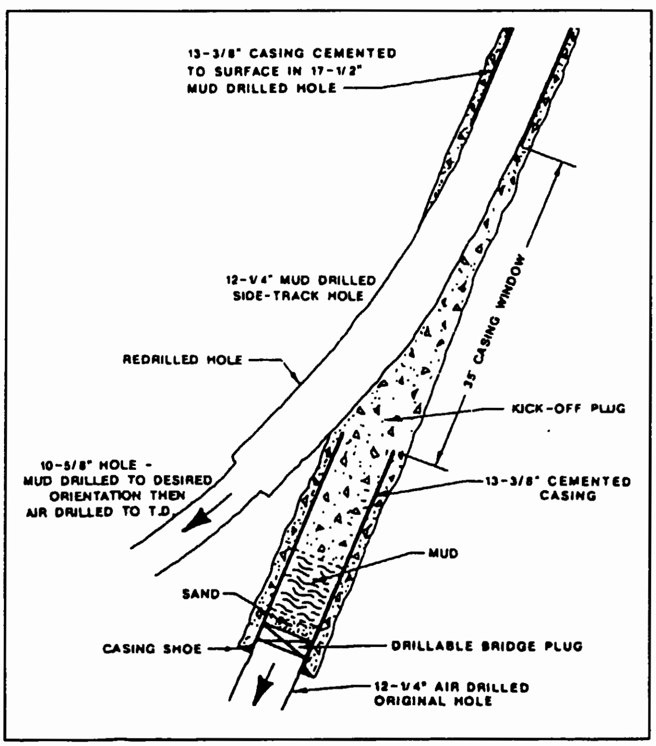

Figure 2. Detail of side track and casing stub area while redrilling.

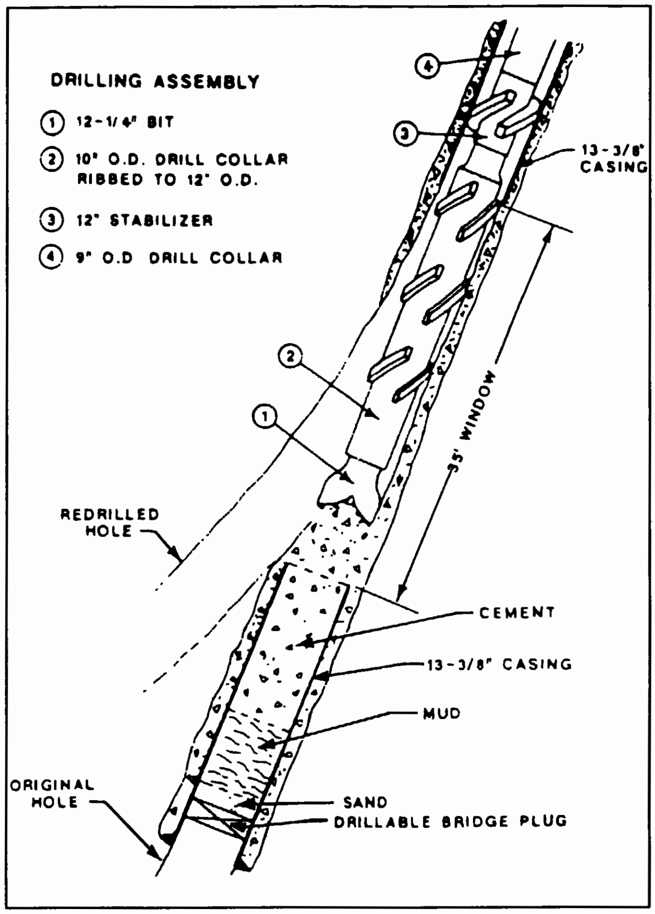

Figure 3. Reentering the original producing leg.

8. The combined flow from the two producing legs is then rig tested and an S/P/T log is rerun in order to finally determine the flow contribution from each leg. Since there is casing both above and below the entry point of the second leg steam, the flow contribution from each leg can be accurately determined from the spinner log (see Figure 4).

Pertinent data relative to the five forked-development wells completed prior to June 1, 1988 are shown in Table 1.

RISKS AND CONSIDERATIONS

While NCPA has been successful in all of the forked completions attempted to date, it is recognized that there is an element of risk associated with such an undertaking. To minimize this risk it is essential that, as the program is carried out, each step be given very close supervision and that onsite personnel are aware of both the importance and specific objective of each operation as well as potential problems and pitfalls.

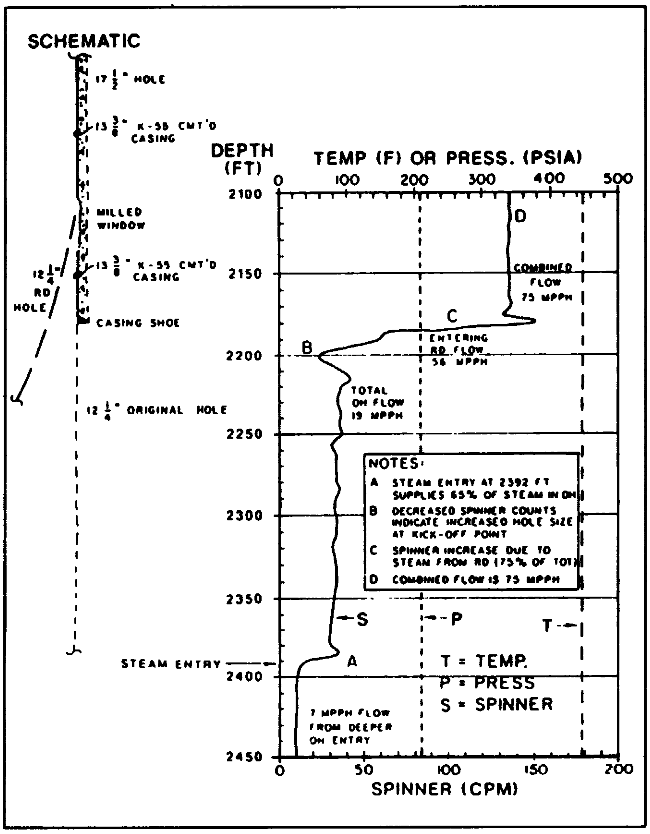

Figure 4. Forked hole S/P/T log.

An area which could easily prove to be a source of trouble is from the kick-off point through the mud drilled portion of the redrilled hole where, by necessity, drastic changes in inclination and direction occur. Particularly while air drilling, it is of the utmost importance to continually monitor the condition of the drill pipe in order to eliminate any joints showing excessive wear.

A second potential source of problems is the reentry into the 13-3/8 in. casing stub at the bottom of the window. Extreme care must be exercised in time-drilling the remaining cement in the window and reentering the stub in order to avoid an unintentional second side-track and/or damaging the top of the stub at the reentry point. Additionally, on trips subsequent to the initial reentry, rig personnel must be aware of the potential danger of damaging or deforming the casing stub.

A third operation requiring close supervision is that of disposing of the drillable bridge plug set in the lower portion of the 13-3/8 in. casing. This is normally accomplished by a combination of air drilling, blowing portions of the plug to the surface, and pushing the remaining debris to bottom.

Recognizing the risk that mechanical problems associated with any one of the above operations are a distinct possibility which could result in the complete loss of either or both producing legs, forked completions are never preprogrammed. Although provision is always made for the option should subcommercial production be realized, it is actually employed only under favorable geologic and mechanical wellbore conditions.

COST DATA AND ECONOMIC ANALYSIS

An economic analysis was undertaken on the basis of actual costs and rig flow test data for the five development well forked completions. The following represents averaged data for the wells:

a. Completed Well Costs

Original Hole Single Completion:	$1,090,000
Conventional Redrill Single Completion:	$1,522,000
Forked Completion:	$1,599,000

NOTE: Completed Cost = Total Drilling Cost + $110,000 allowance for installed surface production equipment.

b. Rig Flow Tests (corrected to 160 psig):

Original Hole	37.1 M lb/hr
Redrilled Leg	76.4 M lb/hr
Forked completion	102.6M lb/hr

Using these average values together with a "net" steam price adjusted for 12-1/2 percent landowners royalty, Operations and Maintenance costs, and property taxes) of $0.996/1,000 lb/hr and a production schedule consistent with NCPA experience in the southeast Geysers, profit indicators based on 1988 dollars with no escalation of either income or costs were calculated for the following cases:

Case I —Single original hole completion, (production schedule based on 37.1M lb/hr flow test).

Case II — Conventional redrill completion, (original hole plugged and abandoned with production schedule based on 76.4M lb/hr flow test).

Case III —Forked completion with production schedule based on 102.6M lb/hr flow test.

Case IV — Single original hole completion with production schedule based on 76.4M lb/hr.

The results of this analysis are shown in Table 2. Case I profit indicators show that a 37M lb/hr single completion is in fact unacceptable, (7-1/2 year payout and 3.4 percent rate of return). A 76 M lb/hr conventional redrill (Case II) shows marginally acceptable profit indicators (4 yrs and 14.9 percent). The forked completion (Case III), however, shows much more favorable profit indicators compared to the conventional redrill primarily because of an approximately 50 percent increase in production resulting from an increased investment of only 5 percent ($1,599,000-$1,522.000).

Table 1. Forked well data notes: MD = measured depth; VD = vertical depth; Incl = hole angle; Sep/O.H. = horizontal distance between redrill at total depth and original hole at a like vertical depth; Rig Test flow rates corrected to 160 psig.

DEV.	ORIGINAL HOLE					REDRILLED LEG							COMBINED	
WELL NO.	PROD CSG. DEPTH (FT.M.D.)	TOTAL DEPTH M.D. (FT)	TOTAL DEPTH V.D. (FT)	RIG TEST (M#/HR)	DRLG COST ($M)	KICK-OFF PT. M.D. (FT)	KICK-OFF PT. INCL. (DEG)	TOTAL DEPTH M.D. (FT)	TOTAL DEPTH V.D. (FT)	TOTAL DEPTH SEP/O.H. (FT)	RIG TEST (M#/HR)	DRLG COST ($M)	RIG TEST (M#/HR)	TOTAL COST ($M)
1	3900	7632	7327	20.2	969	3668	23	7086	6698	1136	30.2	602	50.4	1,681
2	2253	8930	8711	43.4	1,028	2177	12-1/4	6491	6321	684	112.9	482	127.6	1,620
3	2410	8335	8195	47.2	976	2115	13-1/2	7118	6879	690	97.4	557	129.4	1,643
4	2510	7944	7400	34.6	850	2348	31-3/4	7231	6833	574	55.1	466	82.9	1,435
5	3514	8167	7901	40.1	1,076	3225	14-3/4	7138	6648	957	86.4	432	122.6	1,618

Table 2. Economic comparison of single, conventional redrill, and forked well completions

PROFIT INDICATOR	CASE I (SINGLE)	CASE II (CONV. R.D.)	CASE III (FORKED)	CASE IV (SINGLE)
PAY OUT	7.5 yrs	4.0 yrs	2.9 yrs	2.7 yrs
RATE OF RETURN	3.4%	14.9%	24.1%	27.9%
COST OF STEAM	$29.38 LB/HR	$19.92 LB/HR	$15.52 LB/HR	$14.27 LB/HR

Table 3. Exploratory well

LEG	TOTAL DEPTH MD (FT)	TOTAL DEPTH VD (FT)	FEET DRL'D	KICK-OFF POINT MD (FT)	KICK-OFF POINT INCL. (DEG)	RESULTS
O.H.	8333	7645	8333			PLUG & ABD.
RD #1	8742	8392	5232	3510	14	PLUG & ABD.
RD #2	8960	8762	5248	3712	17-3/4	COMPL.
RD #3	9286	9103	6345	2941	15	COMPL.

Case IV shows profit indicators for an "acceptable" original hole single completion. For comparison purposes production from this hypothetical well was assumed to be the same as the averaged production from the redrilled legs of the five wells studied, 76.4 M lb/hr. If this rate were actually realized from the original hole, the well would be completed as is and no redrill would be undertaken. The purpose of this comparison is to show that Case III and Case IV profit indicators are virtually the same (payout - 2 years 11 months vs. 2 years 8 months and rate of return 24.1 vs 27.9 percent).

EXPLORATORY WELL

Table 3 and Figure 5 present data from an exploratory step-out well. Note that over 25,000 feet of hole were drilled in the four legs covering an arc in excess of 90 degrees. The initial two legs (Orig. Hole & Redrill #1) were not productive and were plugged and abandoned. The third leg (Redrill #2) proved to be a marginal producer in a southerly direction, so a cement plug was set, a window was milled in the 13-3/8 in casing, and the final leg (Redrill #3) was drilled in a westerly direction also encountering marginal production. Redrill #2 was then reentered and the well was completed as a 58,000 lb/hr forked producer with over 1,900 ft. horizontal displacement between the two producing legs at total depth.

CONCLUSIONS

As with many innovations in drilling technology and development strategy, the institution of the forked completion technique was dictated by operational and economic necessity. Because of present reservoir conditions, the extent of prior development, and on-going steam supply requirements, locations now being drilled are often of

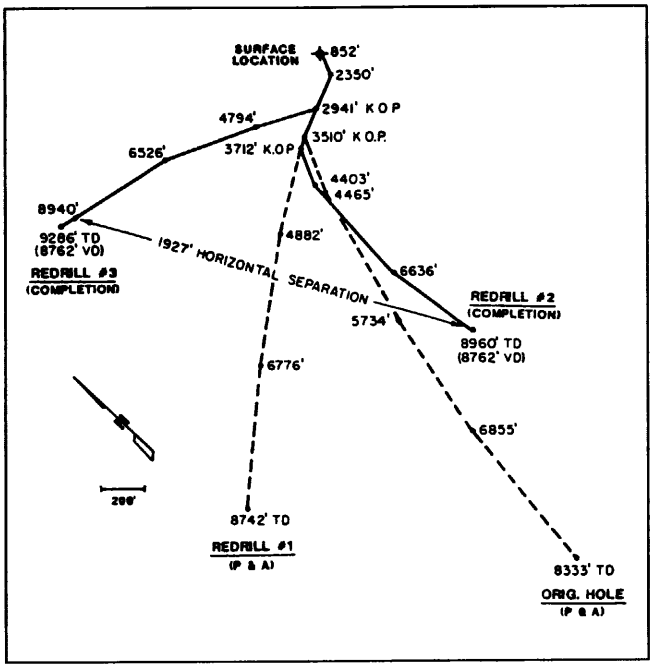

Figure 5. Plan of exploratory stepout forked completion.

inherently higher risk than in prior years. Thus, changes in methods were required if the resource is to be completely developed in an efficient cost-effective manner.

To date, given the geologic conditions of the southeast Geysers and, with careful planning and execution, the forked completion has proven to be a significant, reliable, routinely available alternative.