DRILLING ENGINEERING REVIEW OF THE 1973 - 74 DENVER UNIT INFILL PROGRAM WASSON SAN ANDRES FIELD

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INTRODUCTION

Prior to the 1973-74 Infill Program, the Shell-operated Denver Unit, Wasson San Andres Field, Gaines and Yoakum Counties, Texas (Fig. 1) included over 900 producing or injecting wells. Upon project completion in October 1974, the 1973-74 Denver Unit Infill Program added 120 wells (14 injectors, 3 replacement wells, and 103 new producers) to this total.

The 1973-74 program was sufficiently different from previous Denver Unit programs to require some changes in techniques and equipment. The most significant differences were cementing production casing to surface and drilling "in-town" and/or directional wells. These changes and the large number of wells necessitated the review of all drilling program facets to optimize performance and reduce costs. This paper presents the more significant points of this review and was prepared to document the cost reduction methods and the experience gained for use in future programs. The items discussed individually represent small cost reductions but collectively resulted in reducing 1973-74 Denver Unit Infill Program expenditures by $250,000.

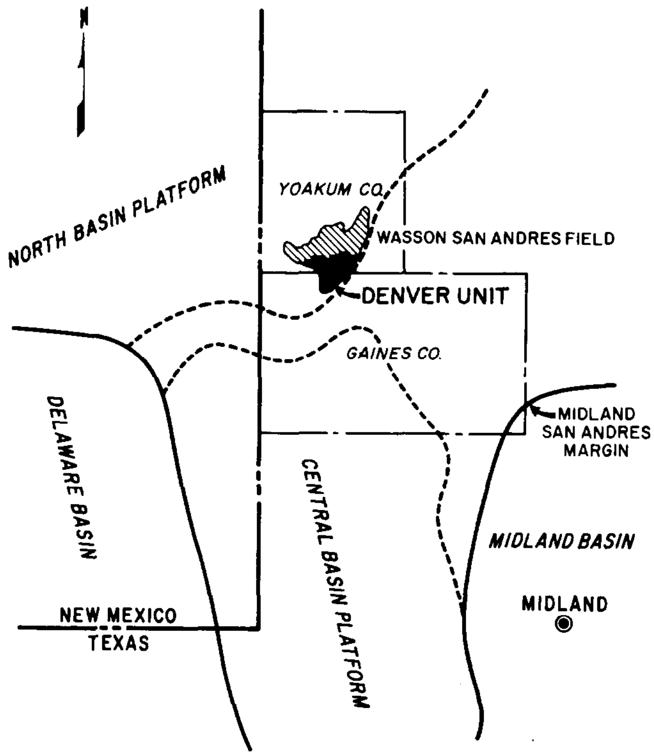

FIG. 1—LOCATION MAP DENVER UNIT WASSON SAN ANDRES FIELD

CASING PROGRAM AND CASINGHEAD EQUIPMENT

A review of Denver Unit casing histories showed that although no problems have been encountered with lightweight surface casing ($400\pm$ ft of 8-5/8 in., 24 lb/ft H-40 ST&C or 9-5/8 in., 32.2 lb/ft H-40 ST&C), the same was not true for production casing. Two wells drilled in 1971 containing 7-in. OD, 20 lb/ft K-55 ST&C production casing had collapsed within one year of placement. The failures occurred in the 3000-4000 ft interval and were presumably associated with the Yates formation, a high-pressure low-volume gas sand. Although the 20 lb/ft K-55 casing had adequate collapse resistance (2270 psi) by normal design criteria, the various casings (4-1/2 in., 5-1/2 in., and 7 in.) used prior to the 1971 wells had collapse resistances exceeding 2600 psi. Only two of these wells had experienced casing collapse in some 29 to 30 years and these were related to casing corrosion.

Although the Yates pressure varies, 2800 psi was considered a maximum by Donnelly.[1] Since the Red Beds (see Fig. 2) above the Yates can form a seal around the casing, this maximum formation pressure can be applied to the casing. Rather than increase the footage of 7-in., 23 lb/ft K-55 casing (3270 psi collapse resistance) used in Denver Unit wells at a cost of $63,000 for the project, an alternative was sought.

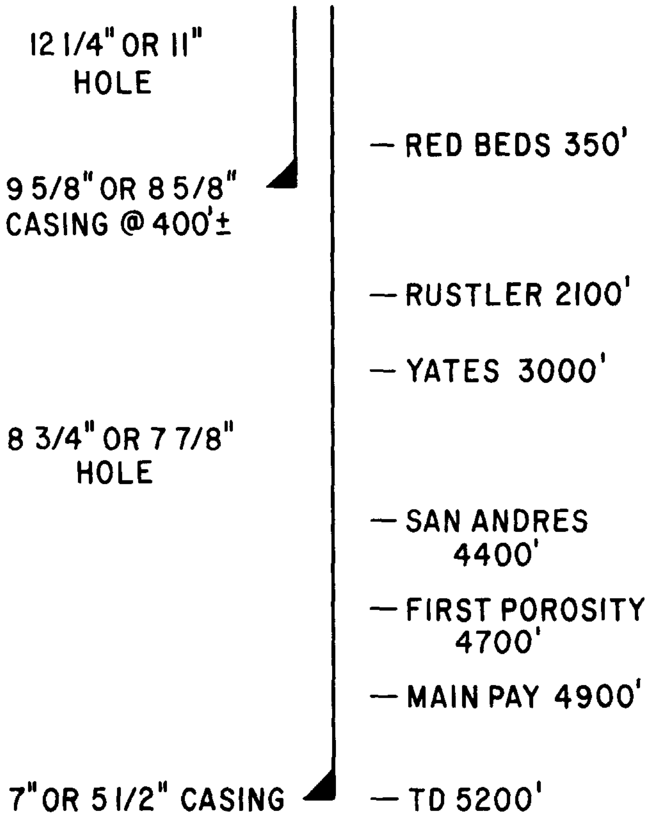

FIG. 2—GENERALIZED FORMATION TOPS AND CASING PROGRAM

The 1973-74 program required production casing be cemented to surface to minimize casing corrosion. Thus, if additional collapse resistance could be obtained from the cement, the additional cost of the heavier casing for collapse resistance could be avoided. Evans and Harriman have shown that a full cement sheath may improve hydraulic collapse strength of tubulars up to 23%.[2] The increase in strength decreases to 0 with increasing voidage of the cement sheath in either the longitudinal or radial directions. In order to obtain a 2600 psi collapse resistance from the 20 lb/ft K-55 casing, a 15% increase would be required from the cement. Since the 2600 psi was considered a maximum resistance needed, the use of cement and 20 lb/ft K-55 casing was considered adequate. Statistically, it was possible to lose four 1973 wells due to casing collapse if resistance was not higher than 2270 psi. The lighter casing was used in the 1973-74 program and no failures have occurred in an average of one year's service.

Fiberglass casing in combination with 5-1/2 in. OD steel casing was planned for the 14 injection wells. The fiberglass casing (5.6 in. OD, 4.5 lb/ft, LT&C) is placed from the top of the First Porosity (Fig. 2) to total depth for corrosion resistance, and the remainder of the string is conventional steel casing. The fiberglass casing was run in six injection wells, not run in two wells due to hole problems, and was lost in the hole on one well. An alternate casing program was used on the remaining five injection wells to facilitate open-hole logging. Steel casing (5-1/2 in.) was set at 4800± ft, and a completion rig later cleaned out to 5200 ± ft, obtained open-hole logs, and ran a 3-1/2 in. OD fiberglass liner. This alternate, which was used when open-hole logs could not be obtained prior to setting casing, permitted open-hole logs and resulted in saving approximately $2000/well by not requiring logs on a substitute well.

The noncritical nature of Denver Unit wells permitted the use of used casing whenever such casing was available. Casing recovered from wells plugged in the Shell-operated Elk City Field in Oklahoma has been the source of used casing (primarily 5-1/2 in. OD) for the 1972 and 1973-74 Denver Unit Infill Programs. This casing had been electromagnetically inspected (transverse and longitudinal defects, visual thread, and full length drifting) prior to usage at an approximate cost of $1600/well.

Although the Elk City Field casing was 25± years old, it was in good condition. Consequently, inspection results from 1972 and early 1973 were reviewed to determine if this inspection and cost could be eliminated. The inspection results are summarized in Table 1.

Thus, casing designs based on 70% remaining wall thickness are adequate for 91% of all used Elk City Field casing. It was found that the 9% of unusable casing could still be detected without electromagnetic inspection by following certain procedures. Since the bad boxes or pins were found visually, this procedure was continued by Shell personnel. The visual inspection plus full length drifting also located any crooked joints. Joints showing external corrosion pitting were visually rejected and if a sufficient number were found, would be electromagnetically inspected at a later date. The overlaps and seams (mill defects) are an

TABLE 1—USED ELK CITY FIELD CASING INSPECTION RESULTS — 1972 and 1973

USABLE CASING (Minimum 70% Remaining Wall)		UNUSABLE CASING (Less Than 80% Remaining Wall)	
Joints	(% of Total)	Joints	(% of Total)
3903	(91%)	380	(9%)

UNUSABLE CASING DETAIL

Type of Defect	% of Total Joints Inspected
Bad Boxes or Pins	5.4%
External Corrosion Pitting	3.3%
Overlaps and Seams	0.2%
Crooked Joints	0.1%
TOTAL	9.0%

(Overlap in remaining wall thickness due to varying instructions given to inspectors.)

inherent risk in all uninspected casing (new or used) but do not necessarily lead to failure. New casing for similar applications is not inspected by Shell.

By derating all used casing from the Elk City Field by 30%, visually inspecting, full length drifting, and rejecting joints with evidence of pitting, electromagnetic casing inspection was eliminated without increasing risk. This resulted in a cost reduction of approximately $1500/used casing string.

Drilling-related wellhead equipment for the 1973-74 program consisted of new and reconditioned used equipment. New casinghead equipment consisted of a 10-in. 2000 psi WP slip-on head with two 2-in. threaded outlets, a bull plug and a 2-in. nipple. Some used gate valves were used but predominantly a 2-in. to 1-in. swage and a 1-in. 2500 psi steam valve were used to further reduce costs. All casing slips used in the program were new. Premium slip and seal assemblies were used in previous programs but with annulus gas minimized or eliminated by cementing to surface, a less expensive assembly was considered acceptable. The premium slips were run as a precautionary measure on a few selected wells where Yates gas was severe. The use of the less expensive slip and seal assembly reduced costs by approximately $24,000 in the 1973-74 Infill Program.

CEMENTING

Surface casing cementing has been well-established over previous programs. Cement for 400±ft of surface casing consists of 200 sacks Class "C" with 4% gel and 2% CaCl and 100 sacks Class "C" with 2% $CaCl_2$. Prior to the 1973-74 program, production casing strings were not routinely cemented to surface. With concern over external casing corrosion, the decision to circulate cement to surface on production casing strings had been made. It was necessary then to completely revise cement slurries for this application.

With bottomhole pressures in the field estimated at only 1100 psi, one of the prime considerations in the design was to incorporate a lightweight cement. Further, to facilitate zonal isolation, a turbulent flow cementing regime was desirable. Various cementing tests were run, and the resulting initial cementing program for 7-in. production casing was as follows:

Lead Slurry — 1000 sacks, Class "C" with 2% "extender" and 0.5% friction reducer. Slurry weight - 11.4 ppg. Yield - 2.8 ft^3/sack.

Tail-In Slurry — 200 sacks Class "C" with 0.5% friction reducer. Slurry weight 15.0 ppg. Yield - 1.3 ft^3/sack.

Initially, fresh water was used to drill the salt section to avoid a drilling contractor price increase and the purchase of salt water. However, it was determined after five wells were drilled with fresh water that an additional 400± sacks of cement were required as compared to wells drilled with salt water. Salt water was used on subsequent wells at a savings of approximately $300/well. The inability to consistently circulate cement and obtain caliper logs, resulted in increasing lead slurry cement volume to a minimum of 1300 sacks. This volume is further increased by 100-200 sacks when severe gas is encountered, hole exposure time is excessive, or calipers indicate the need.

Cement circulation success was improved by the addition of 1/4 lb of a lost circulation material per sack of cement. However, with its use, the failure of float collars drastically increased, and the lost circulation material was subsequently limited to the first 650± sacks of the filler slurry. Cement circulation success through 120 wells was 78%. Although cement was not circulated on 22% of the wells, cement was raised above 1200 ft on all but five wells as verified by temperature surveys. If the corrosion of casing (predominantly in the 500-1500 ft interval) is associated with water flow from the Santa Rosa Sands as believed, primary cementing was 96% successful in eliminating or minimizing this corrosion.

As previously noted, friction reducer was used to induce turbulence at a lower pumping rate and reduce annular pressure loss since the formation frac pressure is very near the hydrostatic column of cement pressure. No loss of returns while cementing was noted on the first 18 wells which included friction reducer in all cement. This was removed from lead slurry cement, resulting in an $850/well cost reduction. This was considered practical since turbulence with one pump truck (10-12 BPM) is achievable if a Reynolds number of 2100 is used as the governing criterion. After eliminating the friction reducer, a partial loss of returns was experienced on 5 of 101 wells. One additional well had complete loss of returns due to apparent annular bridging. Of the six wells, cement was circulated on three.

Further cost reductions included removal of friction reducer from the 200 sacks of tail-in cement. The tail-in cement is not in turbulence without the friction reducer at the 10-12 BPM rate. It is not considered imperative, however, since the primary purpose of turbulence is to remove mud filter cake and effectively displace all mud; and these results are accomplished with the filler cement. Friction-reducer elimination reduced potential project costs by an estimated $87,000.

CEMENTING EQUIPMENT

Casing hardware for surface casing has consisted of an insert ball-type float, a Texas pattern guide shoe, and one centralizer 6± ft above the shoe. No failures of this equipment have been reported, and cost is essentially minimal.

In an attempt to improve zonal isolation, several different production casing and cementing techniques were used in the 1972 infill program. These included extensive use of scratchers, centralizers and resin-sand coating on casing across the pay interval. Zonal isolation was indeed improved from approximately 25% to 55% in the 1972 program, although the contributions made by each item were unknown. Since plans for the 1973-74 program included cementing to surface, it was assumed that zonal isolation would be improved by circulating approximately 10 times the cement volume past the pay section as previously used. Consequently, and because the relative merits of centralizing, scratching, and the frequency of their placement are somewhat opinionated, these items were critically reviewed.

Solid bar centralizers were used in the previous program to provide a positive standoff. By calculating casing loads at various points and using published centralizer strength charts, it was found that bow types give adequate standoff in Denver Unit wells. Further, these calculations indicate that the previously used one centralizer/joint frequency was probably unnecessary. One centralizer used every two joints (80-100 ft) appears more than adequate. Changing to the bow-type centralizer and increasing the spacing reduced project costs by $7000. Scratcher type and spacing were also changed. Use of a different type scratcher and a change in spacing to two scratchers per joint reduced project cost by $12,000. Zonal isolation testing of 1973-74 program wells was closely monitored in order to detect any detrimental effects produced by production casing cementing and hardware changes. As shown in Table 2, no detrimental effects from cementing or casing hardware changes were indicated. Conversely, no improvements in zonal isolation were noted by the increased cement volume.

TABLE 2—DENVER UNIT ZONAL ISOLATION TABLE

Category	Communicated	Not Communicated	% Success
All Wells	26	27	51%
Wells after centralizer and scratcher frequency changes	4	6	60%
Wells after removing friction reducer from lead slurry	12	14	54%
Test wells with sand-blasted casing	2	0	0%

Resin-sand coating was applied to the production casing strings from the top of the First Porosity to TD. This process has been used to improve casing-to-cement bond and zonal isolation. A six-well test program was established to determine if sandblasted casing would be as effective as resin-sand coated casing in isolating zones and was unsuccessful. Tests were invalidated on three wells, and one well was not tested. The two wells tested both had zonal communication, but this was not a large enough sample for any conclusions. A review of cement bond logs on three of the test wells and six control wells showed bond quality to be equally good for either technique.

Problems encountered in running fiberglass casing resulted in eliminating scratchers and reducing centralizer frequency. The fiberglass section of the casing string was lost on one Denver Unit well, and this further led to using a fiberglass shoe joint to facilitate drilling up if similar conditions were encountered. The fiberglass casing does not withstand much compression (maximum used is approximately 10,000 lb) and consequently, problems are encountered when using a full assortment of casing hardware.

As previously noted, problems with float collar failures (production casing) have occurred. In the 1972 program, approximately one-tenth of the current cement volume was used, and lost circulation material in the cement was unnecessary. Float failures were minimal or nonexistent. Flapper-type float collars were specified for the 1973-74 program as it was believed that this type equipment could function satisfactorily if lost circulation material were needed. With the addition of lost circulation material to the cement (to improve circulation success), float collar failures increased from 0 to 45%. Failure frequency was reduced to 14% by reducing the volume of cement containing the LCM, but the overall failure frequency of 18% (19 of 105) was still greater than expected. A float shoe at an additional expense of \$120/well was not justifiable in view of a failure cost averaging \$50/well.

Failure of the flapper-type float equipment may have been due to poor quality control and/or a weak return spring on the flapper mechanism. However, with the volumes of cement used (1500+ sacks) and the LCM requirements, some failures were expected. In many cases, extended circulation while washing to bottom may have eroded the sealing mechanism and resulted in the float failure. Reportedly, other operators in the Wasson Field have used the ball-orifice type float collars with comparable cementing programs with fewer failures than experienced by Shell. Float equipment other than the flapper type will be used in future programs.

DRILLING FLUIDS

The mud system used for Denver Unit wells is very simple and relatively inexpensive. The average mud material cost was \$1600, and the average total mud cost (including oil and water) was \$2215. Mud materials for a typical well cost approximately \$1400 which consisted of \$950 for starch, \$250 for paper, and \$200 for defoamer.

Earthen pits are used and a reserve pit is circulated until starch is added for fluid loss control at the top of the First Porosity. Fresh water is used to drill the Red Beds and paper is added for seepage. Oil (tank bottoms) is added after the Red Beds have been drilled to minimize problems associated with the thick native wall cake which is built up. Salt water is used immediately below the Red Beds and fresh water is discontinued to reduce erosion of the salt section (Rustler). Defoamer is normally required after starch is added.

Mud-mixing equipment found on the rigs usually consists of a hopper and/or a chemical barrel. Any mixing must normally be done by diverting fluid from the rig mud pump or by feeding directly into pump suction (as with starch mixed in oil). It has been determined in the field that the mixing of starch in oil (30±bbl) reduces the starch requirements sufficiently to be more economical than adding only starch. This is due to better dispersion of the starch with the limited rig facilities. Little control of mud properties is necessary (or practical with limited facilities) in drilling the wells. Fluid loss control of 20 cc or less is, however, required (from the First Porosity to TD) on wells to be logged. One change from the 1972 program was the use of 30 cc or less fluid loss control (rather than 20 cc) on wells not logged. This is estimated to have reduced mud costs by \$100±/well or \$6000 for the project.

With the plan to circulate cement, and the consequent need to use salt water to reduce salt section erosion, the use of salt water through the Red Beds appeared to be a desirable procedure. Discussions with experienced personnel indicated that this was an undesirable practice and would lead to severe sloughing of the Red Beds. Inadvertently, this practice was tested when polymer content became low during two polymer-saturated NaCl mud tests. The saturated NaCl water resulted in severe hole sloughing. Although this phenomenon is not completely understood, the following is a possible explanation. When the Red Beds are drilled with fresh water, a considerable amount of shale dispersion and hydration occurs. The high (50±%) montmorillonite content of the shale results in a native mud which has some fluid loss control. Thus, at some point (after considerable erosion), the Red Beds become coated with a wall cake which serves to reduce further hydration.

When saturated salt water is used to drill the Red Beds, the shale dispersion is greatly reduced. A filter cake is not formed and the shale can become wet through capillary action, crystalline absorption, or along fractures or laminations. Further osmotic forces are in the direction of shale dehydration which can promote fracturing. Thus, when salt water is used, the wall cake is not formed and borehole instability is increased. Salt water should, therefore, not be used to drill the Red Beds, but can be used after drilling the Red Beds to reduce salt section wash-out.

Two tests were conducted with a "shale-inhibiting" polymer-saturated NaCl mud system in an attempt to insure obtaining open-hole logs without running additional surface casing. These tests both resulted in failures. This did not result, however, from failure of the system to inhibit the shale but rather from failure to maintain the proper system under the severe limitations of Denver Unit rig equipment. Although shale stabilization of the Red Beds with a polymer-saturated NaCl fluid is possible, it is not considered practical with present equipment limitations and current economic conditions in the Denver Unit.

OPEN-HOLE LOGGING

Obtaining open-hole logs in Denver Unit wells has been a problem in past drilling programs as well as the 1973-74 Infill Program. The Triassic Red Beds wash severely (4± in. over bit diameter) with fresh water drilling. Further, permeable sands (Santa Rosa) which probably accumulate a thick wall cake further aggravate the logging problem. The anhydrite section at 2100±ft is closer to gauge (1± in. over bit diameter) Consequently, hole shape resembles a funnel and hole cleaning problems could be contributing to the logging problems. However, bridges most frequently encountered with logging tools or casing are above this point in the 1200-1800 ft interval which includes the Santa Rosa Sands.

Logging problems have been most prevalent when Yates gas is encountered. The influx of gas results in high annular velocities through the Red Beds as the gas expands and increases the erosion. Further, some unloading of the hole occurs, and the hydrostatic pressure is removed from the Red Beds. Since Yates formation pressure could require up to 16± ppg mud, weighting the drilling fluid to prevent the gas influx is not practical. Hence, all problems normally associated with the Red Beds are magnified by Yates gas. Keeping the hole full during trips is one obvious means of minimizing (but not eliminating) this problem.

In general, logging problems in the Red Beds have been minimal unless further aggravated by water flows or Yates gas. Shell's success in logging wells without either of these extenuating problems was approximately 85% (35 of 41). With these problems, success was approximately 42% (5 of 12). The combined success ratio was approximately 75%. Failure cost on wells where logging was attempted but was unsuccessful averaged \$600/well. This does not economically permit drastic changes in the mud program or system. In order to reduce logging problems, several inexpensive procedures were attempted. Among these were: reducing fluid loss to approximately 5 cc, using sweeps of viscous mud or inorganic viscosifers to clean the hole, and increasing the viscosity of the entire mud system. These methods produced little or no improvement.

Logging success in the 1973-74 program was approximately 75% as compared to the 59% success of the 1972 program. There are three factors which may have influenced this improvement: (1) drilling contractors used in the 1973-74 program were, as a whole, better; and less time was spent on the wells; (2) the salt water used from the Rustler to TD rather than fresh water may have improved hole conditions by reducing washout in the salt section; and (3) repetitious attempts to log were increased because of previous program experience.

In certain areas of the field, the Yates gas has precluded obtaining open-hole logs with normal procedures. For instance, in Section 55, it was necessary to run a long surface casing string (2200 ft) on Denver Unit 5507 to insure obtaining logs. Wells 5509 and 5508 both encountered sufficient gas to make open-hole logging attempts futile with the 400± ft surface casing string.

The most *economical* approach to obtaining open-hole logs appears to be continuation of the current approach. If conditioning runs are required and hole conditions do not appear too severe (judged by drag on trip out to log), short trip without circulation to 2200+ ft and attempt logging. Where the short trip is ineffective or hole conditions appear severe, trip to TD, circulate 3+ hours, and attempt logging. If logs are not obtained and hole conditions have not improved, terminate logging attempts. In cases where conditions have improved, a second conditioning run is made. If logs are not obtained in this manner, attempt to obtain them in a nearby well. If conditions do not permit substitution, run the long surface casing string on selected wells where logs are imperative. Where possible, use the alternative casing program on injectors to obtain logs.

DIRECTIONAL AND IN-TOWN WELLS

Six directional wells were drilled in the 1973-74 program. The directional wells were required due to bottomhole locations underlying various structures within the city limits of Denver City. Two of the six wells had long surface casing strings (2200± ft), and the other four utilized the normal (400± ft) surface casing point. The long surface casing string was used for two reasons: (1) the surface location of the wells was in town and for safety reasons, the longer casing was planned; (2) the displacement of these two wells was greatest (850±) and hole problems were minimized with the longer surface casing. Displacement of the other four directional wells was between 300 and 800 ft. Surface locations of these wells were on the outskirts of town, so somewhat normal drilling operations could be conducted.

A kick-off point of approximately 3100 ft (Yates sand) was used for most wells. Bottomhole targets were determined by striking 770-ft arcs from offset wells and applying other arbitrary or desirable boundaries. This resulted in some bottomhole targets with unique shapes but of sufficient size (equivalent to a circle with a 200± ft radius) to minimize directional problems. Maximum angle achieved was 31-1/2°. Angle-changing tendencies encountered were minor. Typically, after maximum angle was achieved, the angle dropped 5-10° over a 1500-ft length and right-hand walk was approximately 10°. All kicks were made with a downhole motor and only one well required a corrective run. All directional wells were drilled on daywork contracts. Although problems were minimal, cost of directional wells exceeded that of straight holes by approximately $20,000/well.

Wells which were within the city limits of Denver City or near homes close to the city required some special considerations There were eleven wells (including six directional wells) in this category. The following precautions were observed on all "in-town" wells: (1) daywork drilling contracts were used; (2) steel mud pits were used; (3) a gas buster system was installed to control any gas encountered; and (4) a 30± ft conductor string was set and a rotating head installed. For the five wells which were located in populated areas, the following additional precautions were observed: (1) surface casing was run to 2200± ft so that the Yates gas could be more completely controlled; and (2) reserve pits were minimized or not used to reduce clean-up requirements and disturbance.

The precautions noted, excluding the longer surface casing, added approximately $10,000/well to the project cost. This was predominantly due to the use of steel mud pits and limited reserve pits which required considerable hauling of waste mud and resulted in poorer drilling fluids and slower penetration rates. Insert bits were also used through the San Andres to reduce tripping and, thus, noise disturbance. By utilizing these techniques, the "in-town" wells were drilled without significant problems.

SUMMARY

The review of drilling-related cost items prior to and during the 1973-74 Denver Unit Infill Program resulted in reducing potential program costs by $250,000. This partially offset the severe increase in drilling costs encountered by all operators during this period. Although 900+ wells were drilled in this field prior to the program and techniques were well-established, there were and still are methods of reducing costs. The large number of wells associated with Shell's infill program magnified any cost reduction by a factor of 100+. The results derived from analyzing the value of a product, service, or technique may show small results on an individual basis but can collectively contribute significantly toward project cost reduction.

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