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EVALUATION OF BRANCH AND HORIZONTAL BOREHOLES FOR IN SITU LEACH MINING

Prepared for

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF MINES

by
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16. Abstract (Limit: 200 words)

Multiple branch wellbores and horizontal holes, when applied to deep lying ore bodies, have the potential of significantly reducing well costs by reducing total footage drilled per acre of well pattern. In addition, horizontal holes may increase sweep efficiency. Several drilling and completion concepts are given and evaluated in this report. The evaluation shows that there is economic incentive to further develop these concepts for field application to ore bodies 1,500 ft deep.

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FOREWARD

This report was prepared by MAURER ENGINEERING INC., 2916 West T.C. Jester, Houston, Texas 77018 under USBM Contract Number J0199113. The contract was initiated under the Mineral Resources Technology Program. It was administered under the technical direction of U. S. BUREAU OF MINES with W. C. Larson acting as Technical Project Officer. Joyce Tillman was the contract administrator for the Bureau of Mines. This report is a summary of the work recently completed as a part of this contract during the period September 28, 1979, to July 28, 1980. This report was submitted by the authors in July, 1980.

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Maurer Engineering Inc. was prime contractor for this work. Completion Technology Company and Science Application, Inc. were subcontractors. Several individuals from each company made contributions throughout the study. Those who made direct input are:

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- William C. Maurer
- William A. Rehm
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Science Application, Inc.

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- Ralph Nelms

The application of multiple branch and horizontal drain holes to in situ leach mining was first proposed by Bill Larson (USBM). Bill was also Technical Project Officer for this project and made helpful input throughout the study. In addition, the project team acknowledges input from several mining operators who participated in various progress review meetings.

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I. SUMMARY

Uranium in situ leach mining is presently being conducted through conventional vertical boreholes which are, in general, about 200 to 500 feet deep. Injection and production well costs are low because they can be drilled and completed with water well type rigs.

Ore bodies that are low grade and deep lying may be uneconomical for commercial development, even by in situ leach mining, because drilling and completion costs increase with depth and are too high. Larger rigs must be used for drilling and completing deeper wellbores following more costly oil field practice.

Our study shows that multiple branched wellbores and horizontal holes (slant or drain hole drilling), when applied to deep lying ore bodies, significantly reduce well costs by reducing the total footage drilled per acre of well pattern.

Drilling and completion concepts were developed for multiple branched holes, slanted holes, and horizontal drain holes, and were costed for depths of 500, 2,000, and 5,000 feet. Cost estimates, when compared to those for conventional vertical single completions, are significantly less at depths greater than 1,500 feet.

Principal features of this report are technical descriptions of five new wellbore concepts to supplement or replace conventional, single well injectors and producers used to create a leaching sweep pattern within the ore body. The five new concepts are:

1. Triple Branch out of 13-3/8" Casing: Two directionally controlled holes and one straight hole drilled from a point downhole in a single 13-3/8-inch casing using a permanent bit and casing guide.

2. Triple Branch out of 9-5/8" Casing: A variation of Concept 1 using smaller, lower cost 9-5/8-inch casing and retrievable whipstocks.

3. Double Branch out of 9-5/8" Casing: One directionally drilled branch hole and one vertical hole completed with a special hydraulic pump system that simultaneously injects leachant to one branch and produces pregnant liquid from the other.

4. Horizontal Drain Hole out of 7" Casing: A long section of horizontal hole drilled through the ore body by making a short radius 90 degree turn with the bit from within a vertical, cased hole. A more involved scheme would utilize two horizontal holes drilled from the same vertical wellbore.

5. Horizontal Hole out of High Curvature Borehole: A long section of horizontal hole completed from the bottom of a long radius (5°/100 ft) directionally drilled section.

Multiple branched wellbores can be drilled using present oil field technology. However, casing these wells requires downhole templates for selectively reentering the branches. These templates can be simple, rugged, and a slight extension of oil field state-of-the-art. Template arrangement drawings are given in the report.

Our study shows that conventional vertical wells give the best overall balance between performance, risk, availability, and cost for both 500 feet and 2,000 feet ore body depths. However the multiple branch well concepts are competitive with conventional wells and, in each case, cost estimates are lower than the cost estimate for conventional wells. In addition, larger pumps can be installed in the 9-5/8" and 13-3/8" protective casings. The multiple branch wells suffer from high risk and lack of available equipment and experience and this is reflected in our evaluation. Based on their high score under cost and performance, there is incentive to further develop the multiple branch hole concept. The incentive is even greater when applied to ore bodies deeper than 2,000 feet.

We, therefore, recommend that the equipment concepts required to complete multiple branched holes, be designed, fabricated, and tested for future field tests.

II. INTRODUCTION

The process of in situ leaching (ISL) minerals provides an opportunity to develop resources that are currently uneconomical to mine using conventional surface or underground mining techniques. In the ISL process, metal values are recovered by moving fluids through rock instead of moving rock. This mining technique is best suited for recovering minerals that are located in deep lying, lower grade deposits that are water saturated.

An ISL operation consists of surface and subsurface facilities (see Figure 1), involving the following functions:

- Make-up of chemicals required to dissolve and maintain metal values solubilized in the subsurface
- Injection of solvent into the pores or fractures of the rock, using surface pumps to develop pressures in excess of the hydrostatic pressure of the deposit
- Utilization of well pattern layouts that provide sufficient time for the solvent to react with the mineral of interest and enrich metal values in the liquid phase to an acceptable level for surface processing
- Recovery of solutions in production wells, where a low pressure sump is created for collecting the injected solution and transporting the metal enriched solution to the surface
- Surface processing of production solutions where metal values are recovered from the solution and solvent is regenerated for additional trips through the pores of the rock.

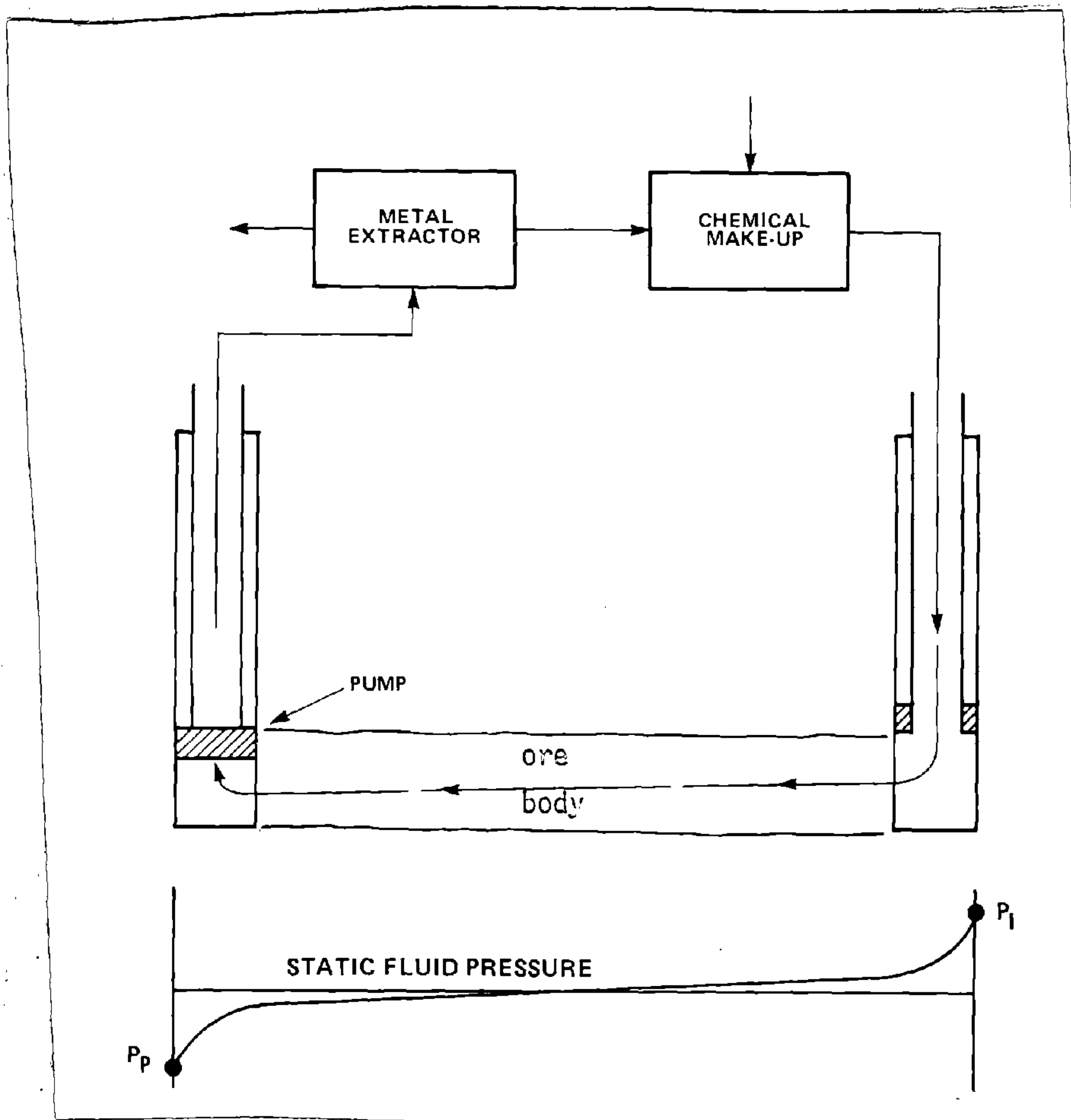

Figure 1. SCHEMATIC OF THE IN SITU LEACHING MINING PROCESS

In situ leaching is being commercially practiced in shallow (200-500 ft) uranium deposits. Mineral deposits of uranium, copper, nickel and molybdenum are known to exist at much greater depths and can be solution mined. However, recovery of these deep lying minerals by in situ leaching is dependent on having available low cost drilling and completion techniques.

In October 1979, the Bureau of Mines initiated a study to evaluate nontypical wellbore configurations, such as branch holes and horizontal holes, for in situ leach mining of deep ore bodies. Prior to this study, the Bureau developed several conceptual (Figure 2 and 3) designs for deep solution mining based on horizontal drain holes and branch holes. The Bureau showed that each have the potential of reducing unit subsurface costs by:

- Increasing efficiency of fluid sweep over a well pattern area

- Reducing the pressure gradient in the well pattern, thus achieving higher flow rates per well

- Reducing the total footage of overburden that must be drilled

It was necessary, however, to determine whether these nontypical wellbores can be drilled and completed economically and at a cost reduction when compared with conventional wellbores.

Conventional wellbores are usually placed in a five-spot pattern (Figure 4a) where the center well is a producer and the four-corner wells are injectors. This well pattern would sweep a given area, say 200 ft by 200 ft. In a broad field development program, each corner injector well would be shared with three other adjacent sweep areas so that the total well costs for a given sweep area is the cost of one producer and one injector.

Multiple branch holes can be arranged to penetrate the ore body in a five-spot pattern with fewer wellheads at the surface. One approach is three injectors out of one vertical wellbore and three producers out of a separate vertical wellbore as shown in Figure 4b; completion of these types of injectors and producers will be discussed later in the report. Fluid flow through the ore body would be the same for both conventional and multiple branch flow from cases. Well costs for one sweep area would be the cost of one-third the cost of a trip branch injector plus one-third the cost of a trip branch producer.

Horizontal holes would be arranged in the ore body to sweep across a given area as shown in Figure 4c. In this case, one horizontal hole would be an injector while the adjacent horizontal hole would be a producer. As flow from the injector would penetrate an adjacent sweep area and flow into the producer would come from another adjacent sweep area, the well cost for any sweep area would be the sum of one-half the cost of an injector well plus one-half the cost of a producer well. This assumes the length of the horizontal hole portion is the same as the well spacing (200 ft) in the conventional case.

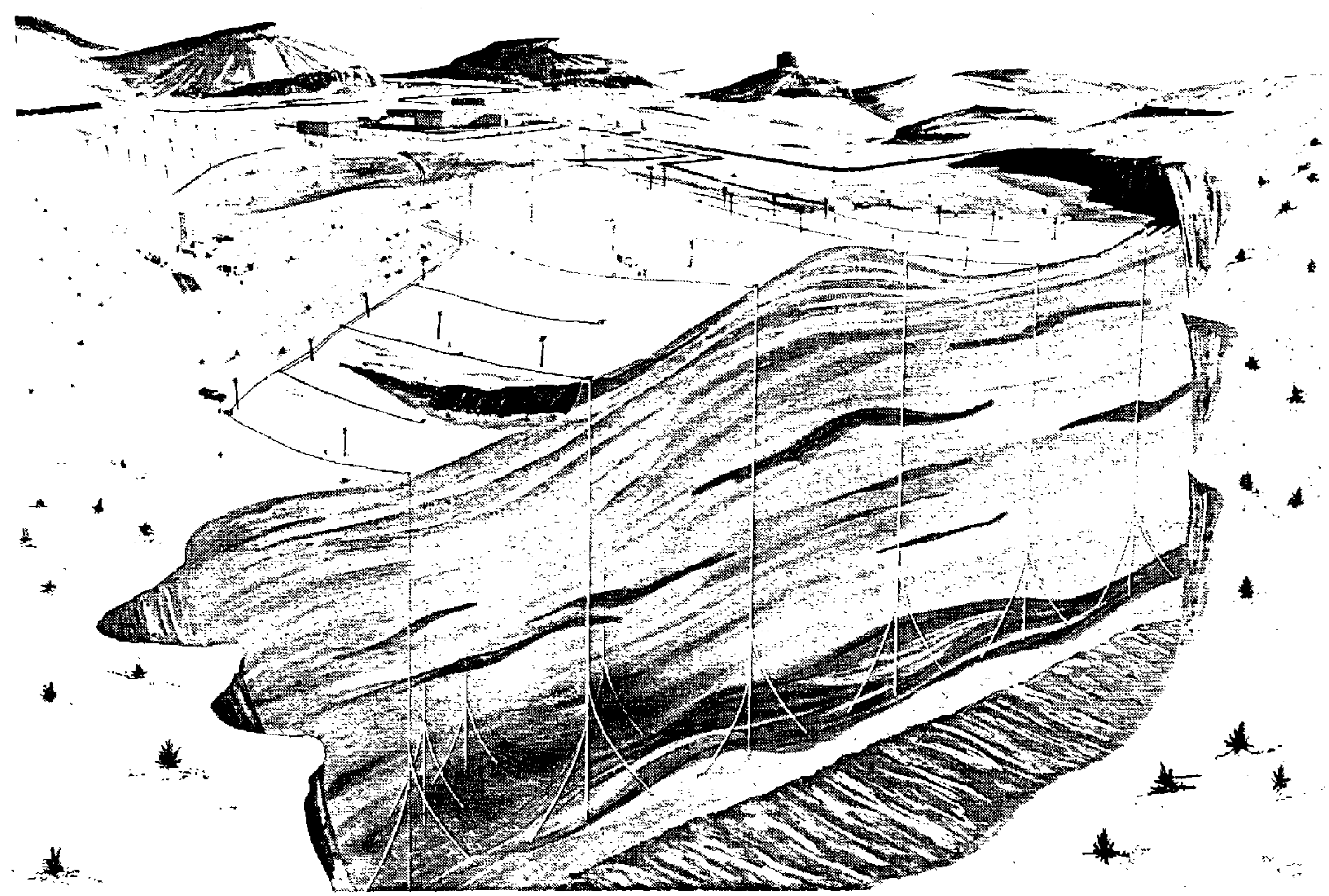

Figure 2. CONCEPTUAL PRODUCTION SCHEME USING BRANCHED BOREHOLES

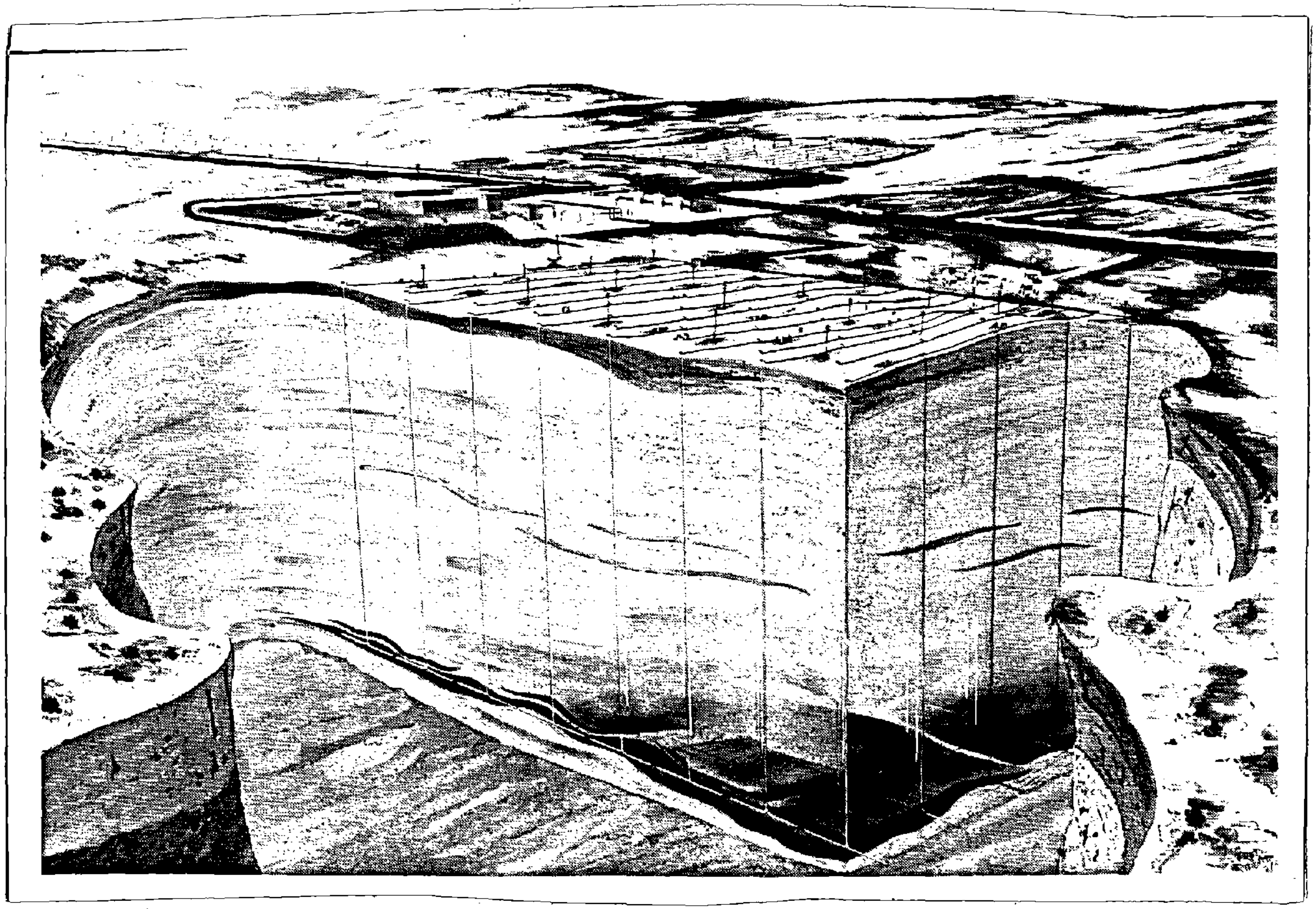

Figure 3. CONCEPTUAL PRODUCTION SCHEME USING HORIZONTAL DRAIN HOLES

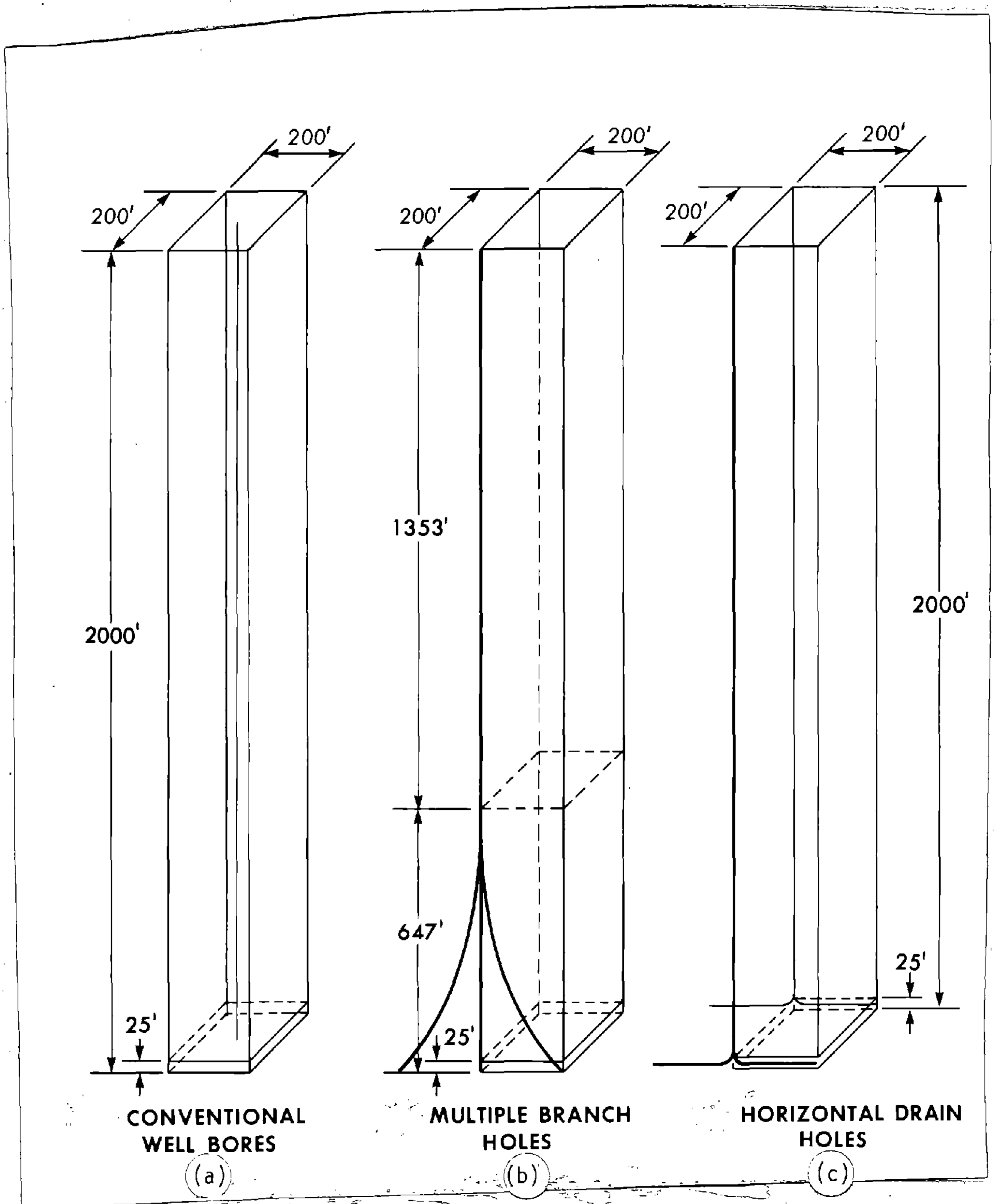

Figure 4. PLACEMENT OF WELLBORE TYPES IN SWEEP AREA

Our evaluation study followed engineering steps normally taken during the initial phases of project development (Figure 5).

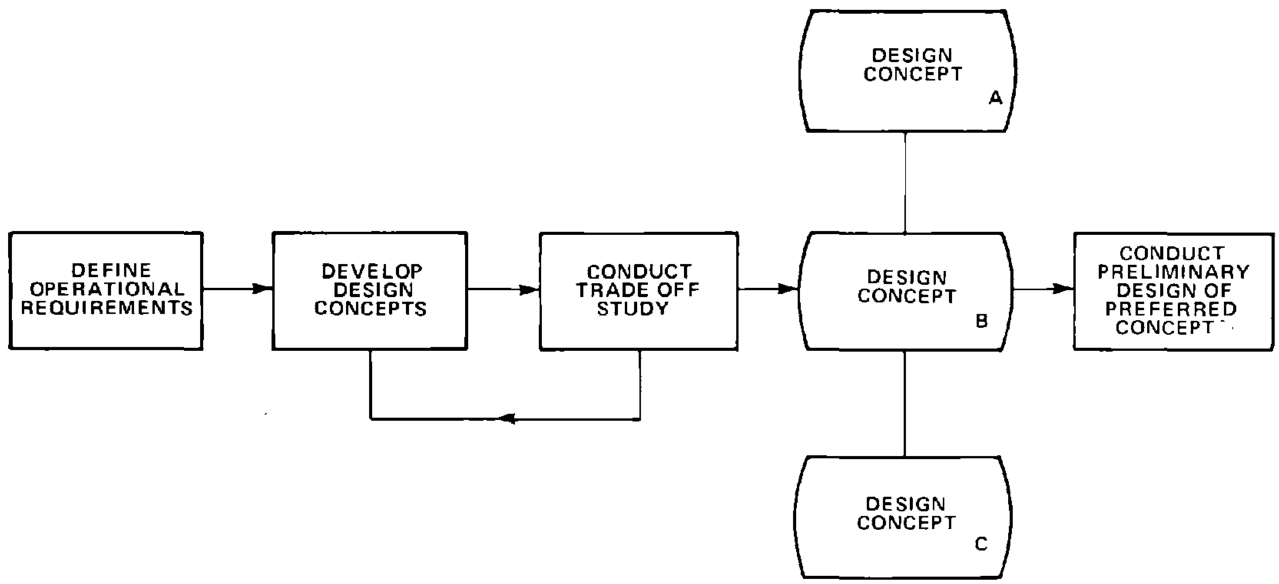

Figure 5. ENGINEERING DEVELOPMENT PROCESS

The evaluation steps in this case apply only to the wellbore and subsurface equipment.

We first defined operational requirements for a representative ore body. These requirements become the engineering baseline for the study.

The next step was to develop drilling and completion concepts for the branch and horizontal holes configurations. These concepts evolved from a state-of-the-art study and design extrapolations made by the project team. Trade off studies identified feasible design concepts and provide a basis for selecting a preferred concept.

III. OBJECTIVE OF STUDY

The objective of this study is to assess whether petroleum engineering technology related to drilling and completing branch and horizontal holes can be adapted for in situ leaching to either enhance mineral recovery or reduce capital and operating costs.

The incentive for evaluating this technology evolves from current interest in extending in situ leaching to depths of several thousand feet below the surface. Since the total allowable subsurface investment is fixed within a narrow range, the number of well patterns in operation at any time will have to decrease as mining depth increases, unless techniques are developed to reduce unit subsurface costs.

IV. IN SITU LEACH MINING

In Situ Leach Mining operations have been increasing significantly since 1960, when Utah Construction and Mining Company (now Utah International, Inc.) initiated work at the Shirley Basin, Wyoming. Since then a number of other ISL operations have developed in both uranium and copper deposits.

- Commercial uranium production in South Texas[1]
- Pilot uranium operations in Wyoming, Colorado and New Mexico[1]
- Kennecott's development project for copper sulphide leaching in Arizona[2]
- Occidental Minerals development of copper oxide leaching in Arizona[3]

Commercial implementation of ISL technology requires the integration of technical disciplines associated with petroleum and chemical engineering, geology, and hydrometallurgical processing. The following aspects of the ISL process impact the economic performance:

- Total flow rates of solution processed through the system
- Rates of fluid injection and production from wells
- The rate of mineral solubilization to the liquid phase
- The volume of rock swept by the fluid

Relating the above to site-specific capital investments and operating costs requires gathering, evaluating and integrating technical data on the deposit and solvent characteristics such as

- Deposit characterization
  - Depth
  - Ore grade
  - Total contained metal
  - Ore thickness
  - Flow conductivity (permeability)
  - Void space in rock (porosity)
  - Mineral distribution in rock
  - Natural groundwater flow

- Selection of solvent

  - Composition
  - Rate of metal solubilization
  - Interaction with gangue minerals
  - Impact on rock permeability
  - Impact on materials of construction used in wells and surface facilities
  - Trace metal solubilization and impact on surface processing and environmental requirements

A final design requires specification of the following subsurface parameters:

- Effluent metal concentration
- The number of wells
- The well spacing
- The frequency of future well pattern additions

Incentives for Horizontal Holes

Reservoir simulation studies carried out by the Bureau of Mines showed that horizontal holes or holes parallel with the plane of the aquifier give a more uniform fluid sweep of the rock over conventional vertical holes placed in a five-spot pattern.[4,5]

Flow rate through porous media, such as uranium sandstone deposits, depends directly on permeability (k) of the porous media and area through which fluid passes. Area is usually expressed in terms of area height (H) times a unit width. The product of permeability (k) and (H) indicates the amount of resistance to fluid flow through porous media. A large kH factor indicates a low resistance while a small kH factor indicates a high resistance. In other words, to maintain a given flow rate, a high kH condition requires less driving pressure than a low kH condition.

When well pattern separation distance is large compared to the thickness of mineralization, large flow rates at high pressure may be required. By placing horizontal injection and production wells in the ore body, not only is sweep efficiency improved but injection pressure requirements are reduced because the kH factor is greater. Horizontal holes are attractive for uranium sandstone deposits where well separations may be 10 to 20 times the thickness of mineralization. Other advantages of horizontal holes are:

- Reduce total wells by achieving higher flow rates per well. This can be used to:

  - Reduce investment, thus increase ROI or reduce price

- Increase flow rate per well

  - Develop property with low permeability
  - Work with lower effluent loading of metal
  - Reduce restoration time, more rapid turnover of pore-volumes

- Reduce injection pressure drop

  - Tolerate more impairment

    a. Clay swelling, substitute Na for NH_4 in alkaline carbonate or ionic preflush techniques

    b. Increase oxygen concentration, more concentration to achieve higher effluent metal values, even if free gas present

    c. Reduce pump investment costs and operating costs

- Reduce production pressure drop

  - Reduce tendency for impairment

    a. Gypsum loses solubility at lower wellbore pressure, associated with high drawdown

    b. CO_2 may come out of solution and cause scaling at high drawdowns

  - Reduce pump investment and operating cost

Incentives for Multiple Branch Holes

As the depth of mining increases the cost of drilling through non-mineralized rock increases.

Branch drilling reduces total footage required to penetrate in ore body in two or three locations on the five-spot pattern (Figure 4b). Savings in overburden drilling is offset somewhat by the cost of directional drilling the branches. This savings increases with depth because the kickoff point is deeper. Branch drilling is especially attractive in areas where overburden formations are composed of hard rock. The economic incentive for this technology is likely to be highest for uranium sandstone deposits where the interval of mineralization is small compared to the total depth of the well. Other advantages are:

- Reducing total footage to be drilled to attain given contact with mineralization. This will provide additional footage in mineralized zones to achieve higher well pattern flow rates, which will increase the possibility of working with a lower formation permeability or lower effluent metal concentration.

- For hard rock solution mining, where the length of mineralization may be several hundred or thousand feet, branch holes can serve two additional functions:

  - Provide expendable holes within the well pattern for use in explosive stimulation

  - Provide a means of completing a well such that the long interval of mineralization can be mined in segments, first the bottom, then the top or vice-versa.

V. DEFINITION OF OPERATING CONDITIONS

In the engineering development process, operating conditions or requirements are first established. These conditions become the engineering baseline from which concepts are developed and evaluations are made. Important operating conditions in our study are ore body geometry, well spacing (X, ft), and flow rate (Q, gpm) per well pattern.

The ore body geometry, selected for this study, is consistant with uranium sandstone deposits where the interval of mineralization is relatively thin. We chose an ore body thickness of 25 feet. The rationale for selecting uranium deposits is based on the following:

- Uranium is being commercially mined by in situ leaching.
- The probability of affecting a cost saving is highest for an operation where the leaching zone thickness is small compared to the total well depth, as is the case for uranium in sandstones.
- It is anticipated that the highest risk of implementing a new design will be related to the well completion, and that well completion concepts developed for uranium are likely to be applicable, with minor modifications, to other minerals.

Specific values of X and Q will be governed by: site-specific geology, metal commodity, effluent metal concentration, and economics. Since it is beyond the scope of this study to do a complete process design, some method is required of determining how X and Q vary with depth. This was obtained by plotting average values of X and Q versus depth for the South Texas commercial in situ uranium operations reported in Bureau of Mines Report IC-8777 (Reference 1).

For purposes of developing preliminary design concepts, we used conservative values of 200 feet and 150 gpm for a 2,000 foot operation. Values of X and Q of 100 feet and 50 gpm are used for a 500 foot deep operation. Design operating conditions are summarized in Table 1.

TABLE 1
OPERATING CONDITIONS

	500 ft	2,000 ft
Sweep Area	100 ft x 100 ft	200 ft x 200 ft
Ore Thickness	25 ft	25 ft
Casing	4" OD	5-1/2" OD
Production Rate	50 gpm	150 gpm
Geology	Unconsolidated to consolidated sandstones	Unconsolidated to consolidated sandstones

VI. DRILLING AND COMPLETION CONCEPTS

Branch wells and horizontal drain holes have been drilled in the past but none have been cased to allow leak proof and pressure tight communication throughout the well. These are major operational requirements for in situ leach mining. This section describes several concepts, generated by the project team, for drilling and completing these nontypical wellbores.

At the outset, we recognized that the incentive for applying new wellbore types to 500-foot ore production is marginal as conventional vertical hole can be drilled and completed at relatively low cost. Therefore, the concepts are directed primarily at ore bodies located at depths of 2,000 feet and beyond.

Our completion concepts indicate the use of fiberglass reinforced pipe (FRP). Experience shows that FRP delaminates on continual exposure to an oxidizing agent. This results in liberation of individual glass fibers which can plug perforations or small passages in pumps. Although aware of these potential problems, we are proceeding with FRP since it is presently being used. Our concepts, however, are not dependent on the use of FRP but can incorporate improved materials when they become available.

Wellbore concepts and their drilling and completion programs are covered under the following subheadings:

- Triple Branch out of 13-3/8"Casing
- Triple Branch out of 9-5/8" Casing
- Double Branch out of 9-5/8" Casing
- Horizontal Drain Hole out of 7" Casing
- Horizontal Hole out of High Curvature Borehole

TRIPLE BRANCH OUT OF 13-3/8" CASING

A triple branch well consists of a vertical protection casing with three branches extending into the ore body. A series of parallel rows of producers and injectors can be used to develop a five spot sweep area with less total footage drilled than with conventional wells. The concept uses directional drilling techniques that have been successfully used in offshore oil fields where geology is similar to that selected for this study.

One design consists of running 13-3/8-inch or larger, low grade steel protection casing, then drilling and completing three branch wells out through the bottom of the casing. The concept is particularly attractive at depths below 1,500 feet where significantly less drilled footage is required to develop a field. Factors such as slow surface drilling and difficult or expensive well site preparation provide additional incentive for branch well drilling. Estimated cost for drilling and completing a large diameter triple branch injection well in the 2,000-foot deep ore selected for study is $167,180 or $55,727 per well bottom. See Appendix D for cost detail.

Drilling and Completion Techniques

Conventional oil field drilling techniques are used in branch well drilling. However, branch wells have not been cased in a manner suitable for in situ leaching mining. In following discussions, a concept is proposed to complete three branches below 13-3/8-inch or larger casing.

This completion scheme consists of running large diameter, low grade steel protection casing containing a drilling template (Figure 6), then drilling and completing three branch wells out through the bottom of the casing as illustrated in Figure 7. The bottom joint of casing contains the drilling guide and an internal indexing dog to allow for positive entry into the three branch whipstock.

A guide for the vertical branch contains a float collar and seal bore to accomodate an inner tubing string for cementing purposes. Once the protection casing is cemented in place, the three branches are drilled starting with the vertical hole. In each case, an indexing collar is run on the bit, Figure 7. The collar is keyed to orient itself in the internal indexing dog in the drilling guide. As the indexing collar lands on the dog, the bit is released and enters the appropriate branch. After the hole is drilled, the guide collar is retrieved by pulling the bit out of the hole.

The indexing collar then is re-keyed to index the drilling assembly into the second hole. Since the second and third branches are directionally drilled, the conventional drilling assembly is replaced with a downhole directional drilling assembly, such as bent sub and downhole motor. The drilling assembly then is run in the hole and rotated to locate the indexing collar on the internal indexing dog. As the collar lands on the indexing dog, the bit and drilling assembly are released into the appropriate whipstock. After drilling the first directional hole, the bit and guide collar are retrieved, as in the vertical branch. The third branch is drilled in the same manner as the second, i.e., the indexing collar is keyed to guide the directional drilling assembly into the proper whipstock.

Triple strings of fiberglass pipe with a triple tubing hanger are simultaneously run in the hole, Figure 8. Cement baskets are attached to the shoe of each casing string to prevent the fiberglass pipe from floating as heavy cement is circulated into the annulus. The three tubing strings are oriented into the branches by the top of the drilling guide. Once in place, the three casing strings are simultaneously cemented. The triple tubing hanger is set, cement is reversed out above the hanger and the three branches are perforated.

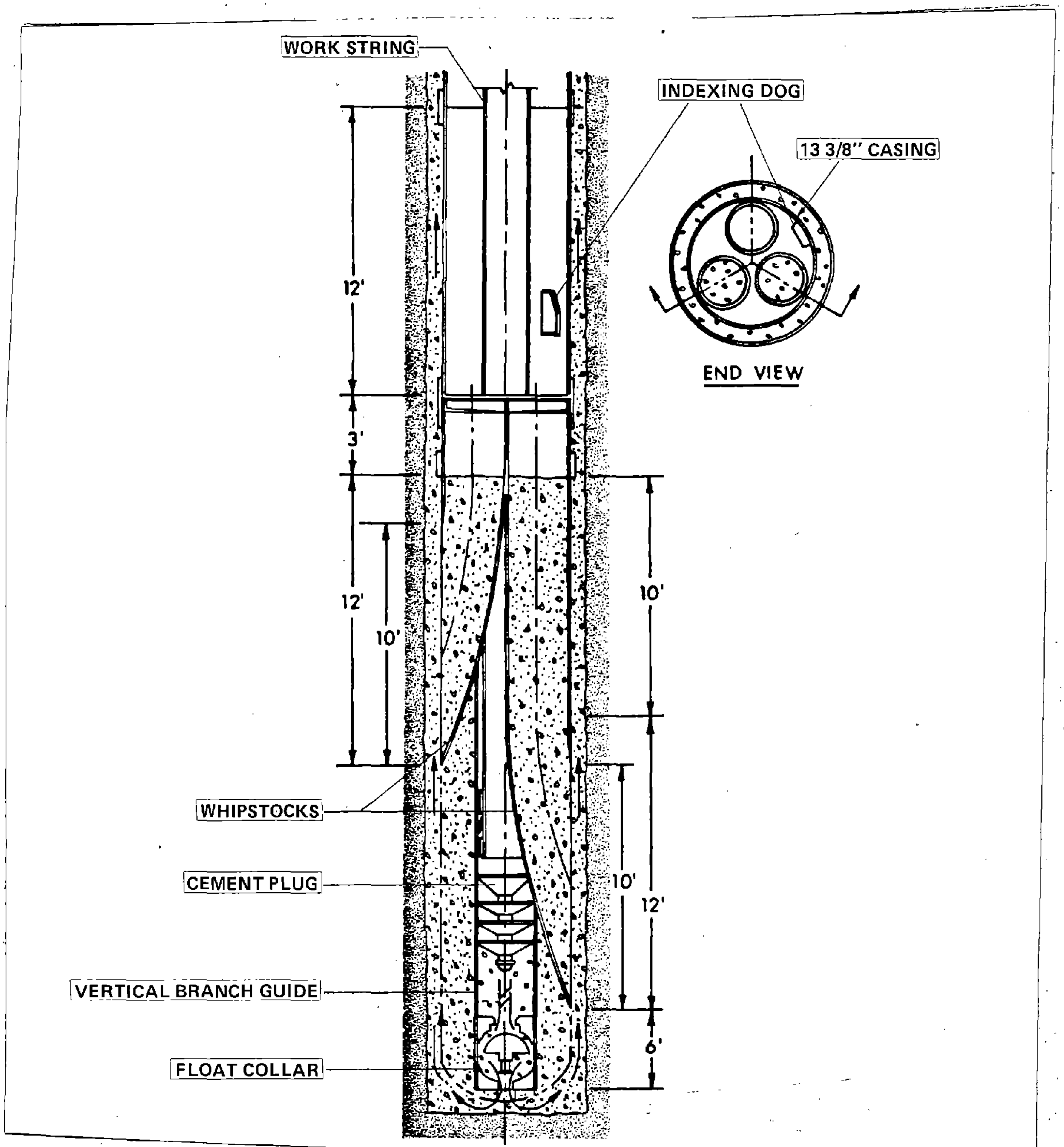

Figure 6. CEMENTING 13-3/8-INCH CASING WITH DRILLING GUIDE

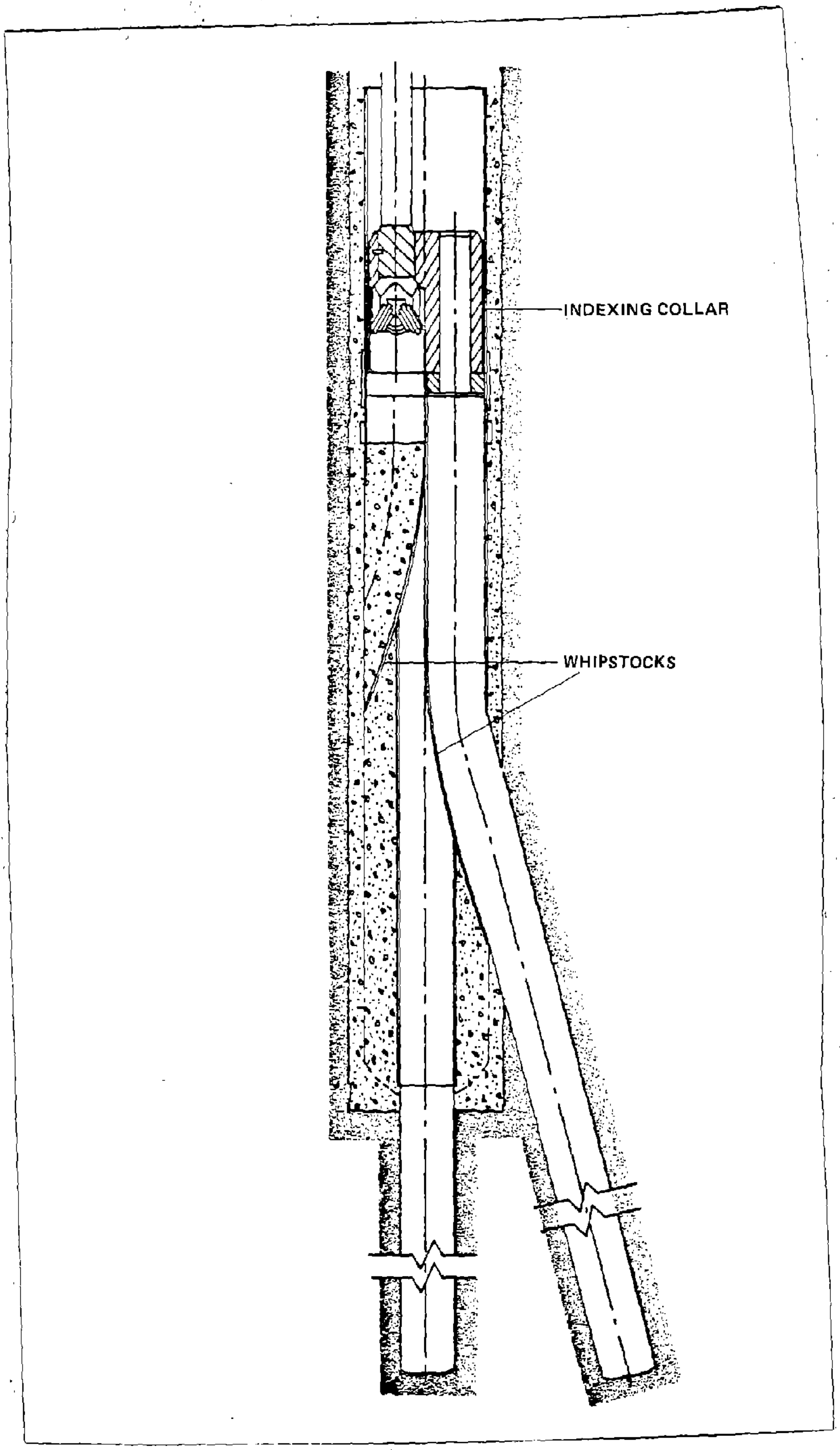

Figure 7. DRILLING THROUGH BRANCHING TEMPLATE

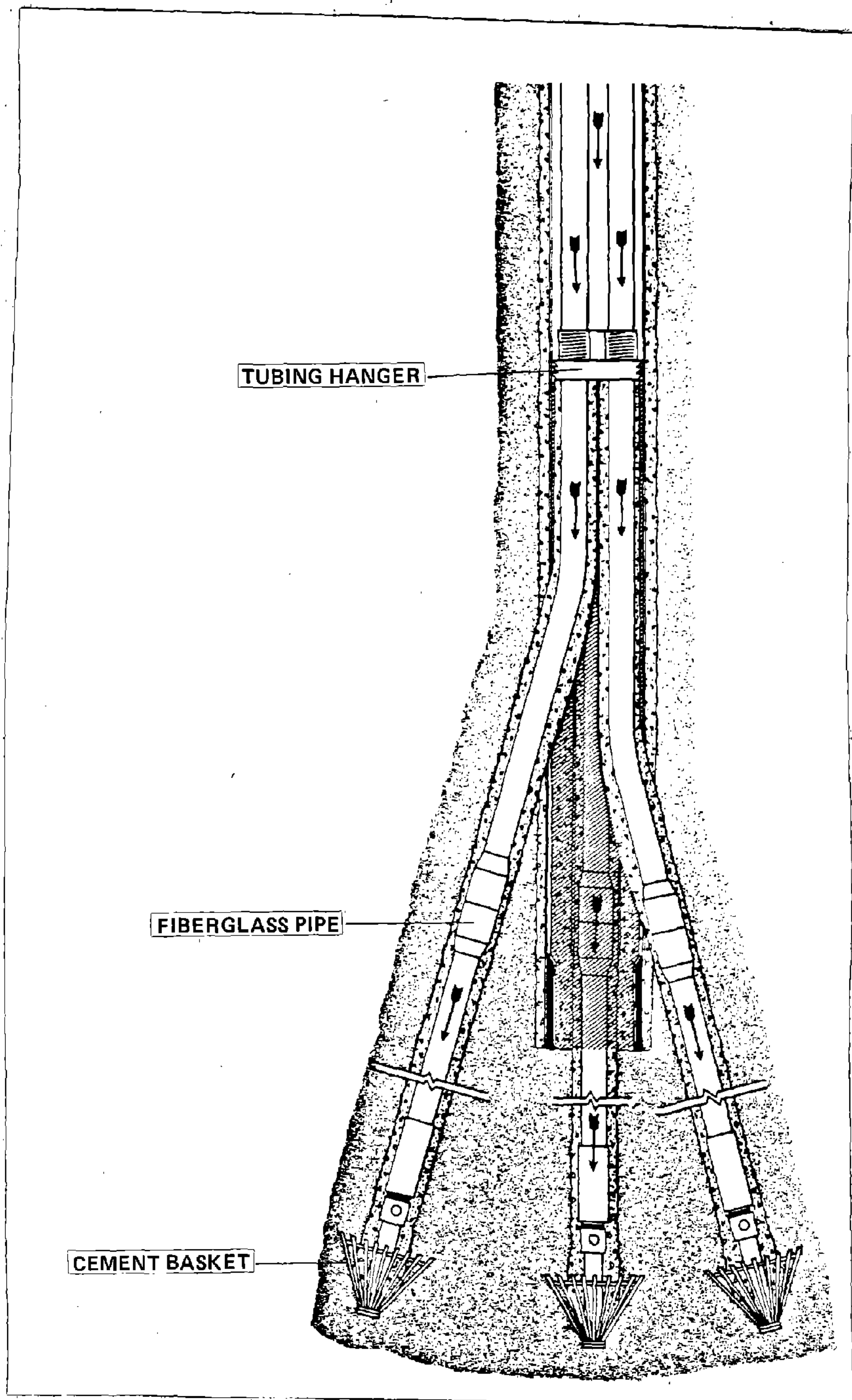

Figure 8. CEMENTING BRANCHES

System Limitations and Risks

Setting 13-3/8-inch casing at relatively shallow depths utilizes standard oil field drilling and cementing techniques. However, as the technique is applied to deeper objectives, care must be taken not to exceed collapse resistance of the casing. As a rule of thumb, the collapse strength should be greater than external hydrostatic forces acting on evacuated casing. For example, 13-3/8-inch, 54.5 lb/ft casing has a collapse resistance of 1,130 psi (API BUL 5C2). Assuming a formation pressure gradient of 0.5 psi per foot, 13-3/8, J-55 grade casing could be safely set at 2,260 feet. For applications below this depth, stronger casing must be used, i.e., 72 lb/ft, N-80 grade casing with a collapse resistance of 2,670 psi could extend safe setting depths to below 5,000 feet.

Use of 16-inch casing is limited to shallower depths. The strongest standard 16-inch casing is 84 lb/ft, K-55 grade casing with a collapse resistance of 1,410 psi. This would limit its recommended use to 2,820 feet. Some designers also apply "safety" factors to casing strength ratings. This would further limit depth capabilities.

The drilling guide proposed as a means for selective re-entry into each branch is a conceptual design that was generated as part of this study. Actual field tests are needed to accurately determine its effectiveness. However, the simplicity of the concept suggests that risks are reasonably low.

Techniques for drilling branch boreholes are low risk and widely used. A conventional drilling assembly would be used for the vertical branch and a downhole motor with a bent sub for the directional branches. The rate of deviation (5°/100 ft) is within limits of conventional directional drilling.

There is not sufficient oil field experience with triple fiberglass tubing strings set at shallow depths to accurately assess related risks. Actual field tests in shallow wells are needed to determine failure rate from tangled or kinked tubing. Triple completion equipment such as packers and tubing hangers are available from oil field service companies but in less variety than dual completion hardware.

A review of relative risk related to the proposed branch design suggests that formation integrity is critical. Branch wells should not be attempted in areas where caving and washouts are a serious drilling problem. Application of branch wells should be limited to well patterns with smaller (50 or 100 feet) spacings. The same 5°/100 ft deviation rate would allow the protective casing to be set closer to the ore body resulting in shorter branches that are less likely to cave in prior to casing.

Experience with triple oil well completions suggests that a dual branch completion would entail significantly less risk than a triple. Techniques used in completing triple branch wells can easily be adapted to a dual design.

TRIPLE BRANCH OUT OF 9-5/8" CASING

Directional drilling techniques can also be applied to triple branch wells with smaller protection casing. The completion scheme consists of running 9-5/8-inch casing with an internal indexing dog to orient whipstocks toward windows in the protection casing. Branches are drilled and a tubing guide is installed to direct fiberglass casing into the branches. A series of five spot patterns is developed by alternate parallel rows of producers and injectors. In deep wells, the concept could develop a field with significantly less total footage drilled than with conventional approaches.

Slow surface drilling or difficult and expensive well site preparation provide additional incentives for developing the concept. Estimated cost for drilling and completing a 9-5/8-inch triple branch injection well in the 2,000-foot ore selected for study is $172,160 or $57,387 per well bottom. See Appendix D for cost detail. The proposed completion scheme is described in this section with discussions of limitations.

Drilling and Completion Techniques

Branch wells with smaller protection casing offer several advantages over the 13-3/8-inch concept. Small drilling rigs can be used to drill 12-1/4-inch holes and set 9-5/8-inch casing. Less pump volume is needed to circulate cuttings and less rig power is needed to set casing. Potential for extending applications to greater depths is also greater with small casing, effectively increasing the value of experience gained at shallow depths.

For completion of branch wells with smaller protection casing (9-5/8-inch) the following approach is suggested. Protection casing is set an appropriate distance above the ore body. The bottom joint contains a prefabricated float assembly and seal bore for inner string or stab in cementing, and an internal indexing dog to positively locate each branch, Figure 9. Fiberglass-filled (or other material) windows are provided as easily-penetrated exit points for the two directional branches.

After the protection casing is cemented in place, the vertical 6-inch branch is drilled, Figure 10. A whipstock assembly then is run in the protection casing and rotated to seat on the internal indexing dog. When in place, the whipstock guides a directional drilling assembly through the pre-milled fiberglass window in the bottom joint of the protection casing, Figure 11. After the directional branch is drilled to the appropriate depth, the drilling assembly is pulled and the whipstock is retrieved with a whipstock pulling assembly.

The whipstock assembly then is modified to guide the directional drilling assembly into the upper window in the protection casing. The whipstock is run in the hole with a running assembly and rotated to land on the internal indexing dog with the whipstock facing the second pre-milled window, Figure 12. The upper branch is drilled directionally to the appropriate depth.

A triple tubing guide then is installed using the internal indexing dog for proper orientation, Figure 13. Once in position, it will guide the three branch casing strings into appropriate holes.

A triple string of fiberglass pipe and a triple tubing hanger then are simultaneously run in the hole. Cement baskets are attached to the shoe of each casing string to prevent the fiberglass from floating as heavy cement is circulated into the annulus. The top of the tubing guide orients the three strings into the branches. Once in place, the three casings are simultaneously cemented and the tubing hanger is set. Cement is reversed out above the hanger; the three branches are perforated and the well is ready for injection.

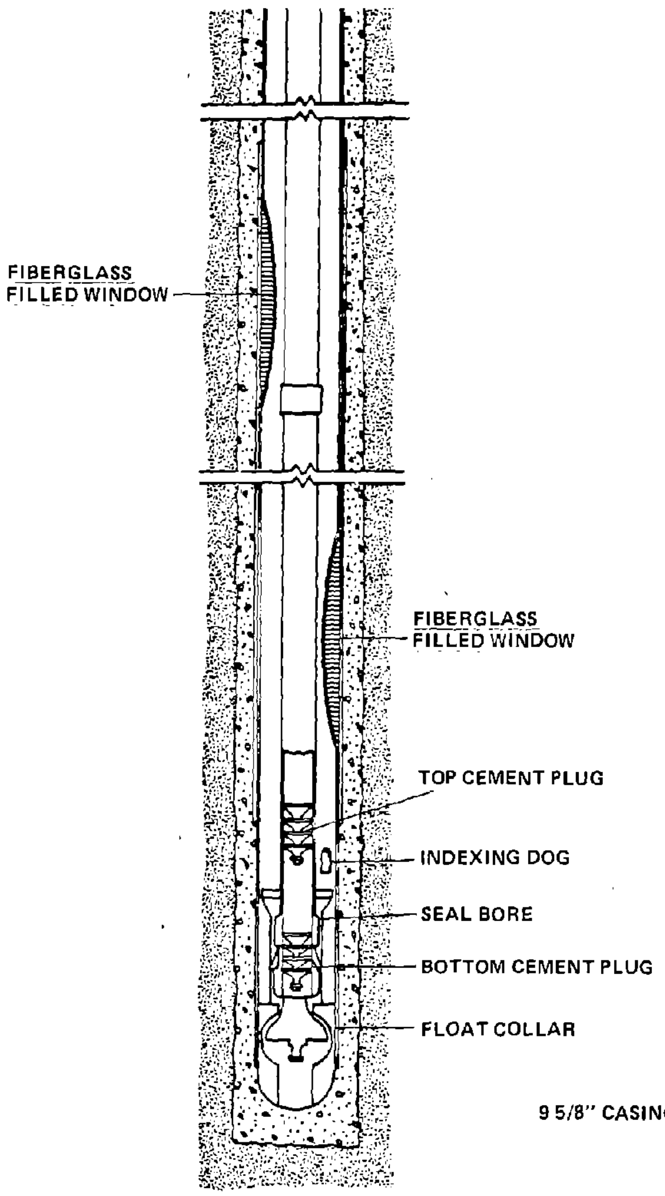

Figure 9. CEMENTING 9-5/8-INCH CASING

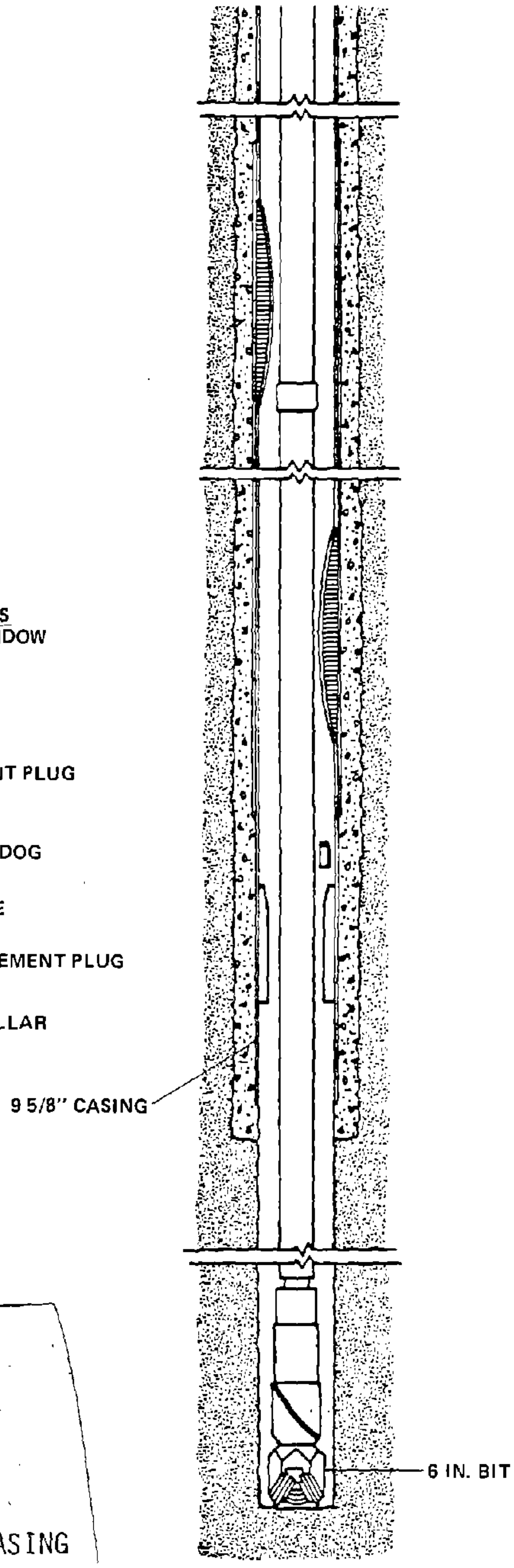

Figure 10. DRILLING VERTICAL HOLE

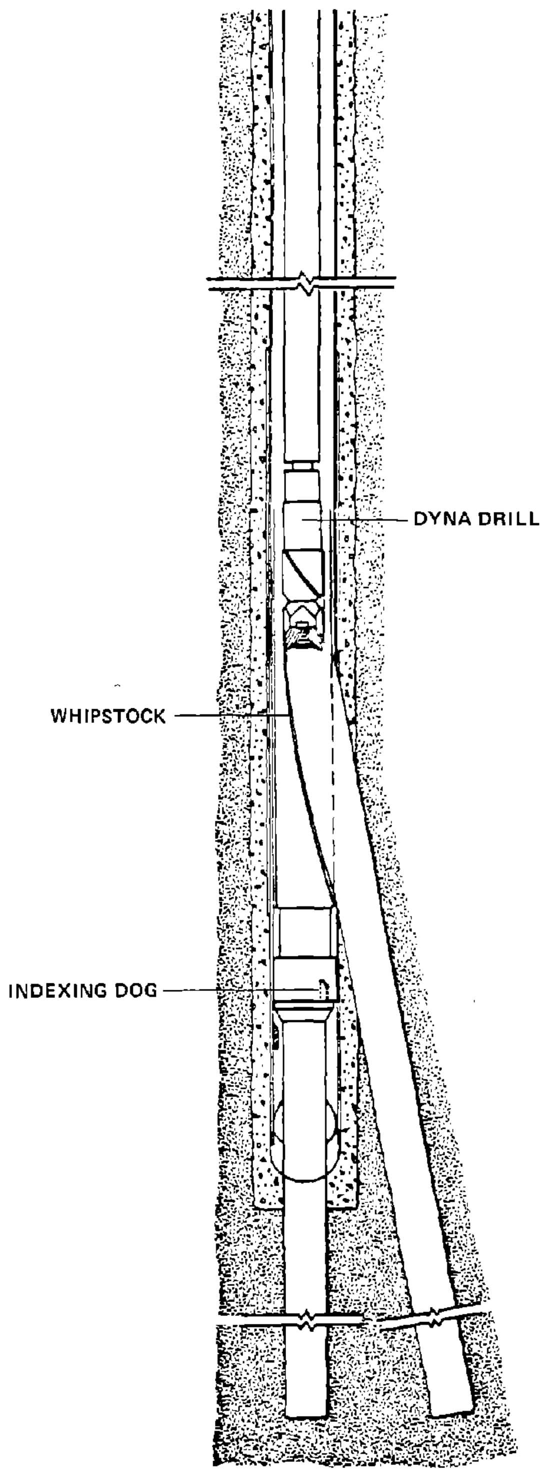

Figure 11. DRILLING SECOND BRANCH

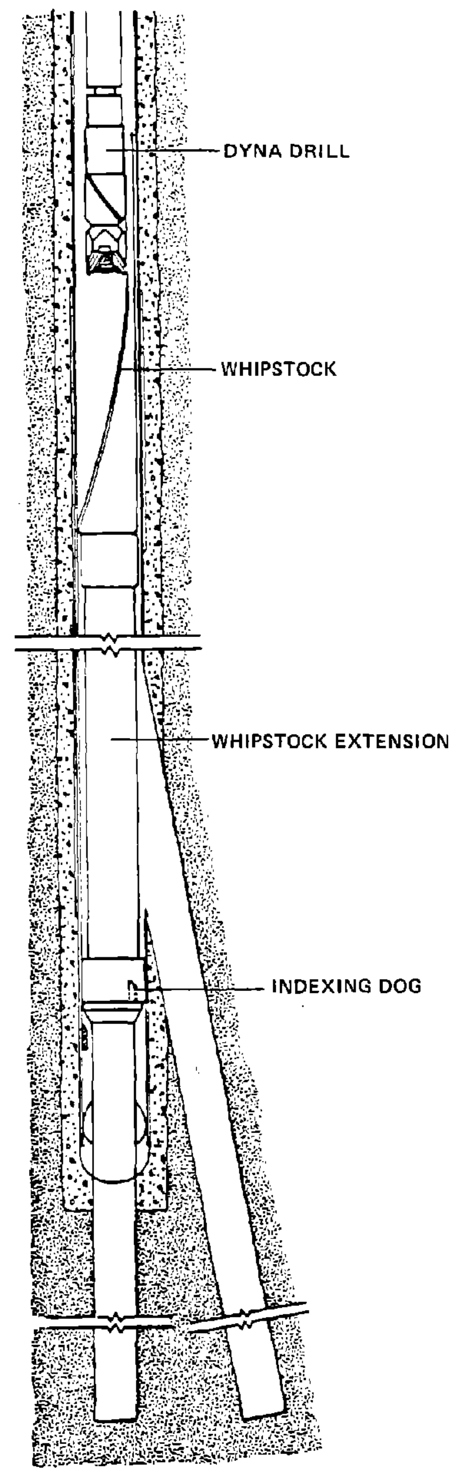

Figure 12. DRILLING THIRD BRANCH

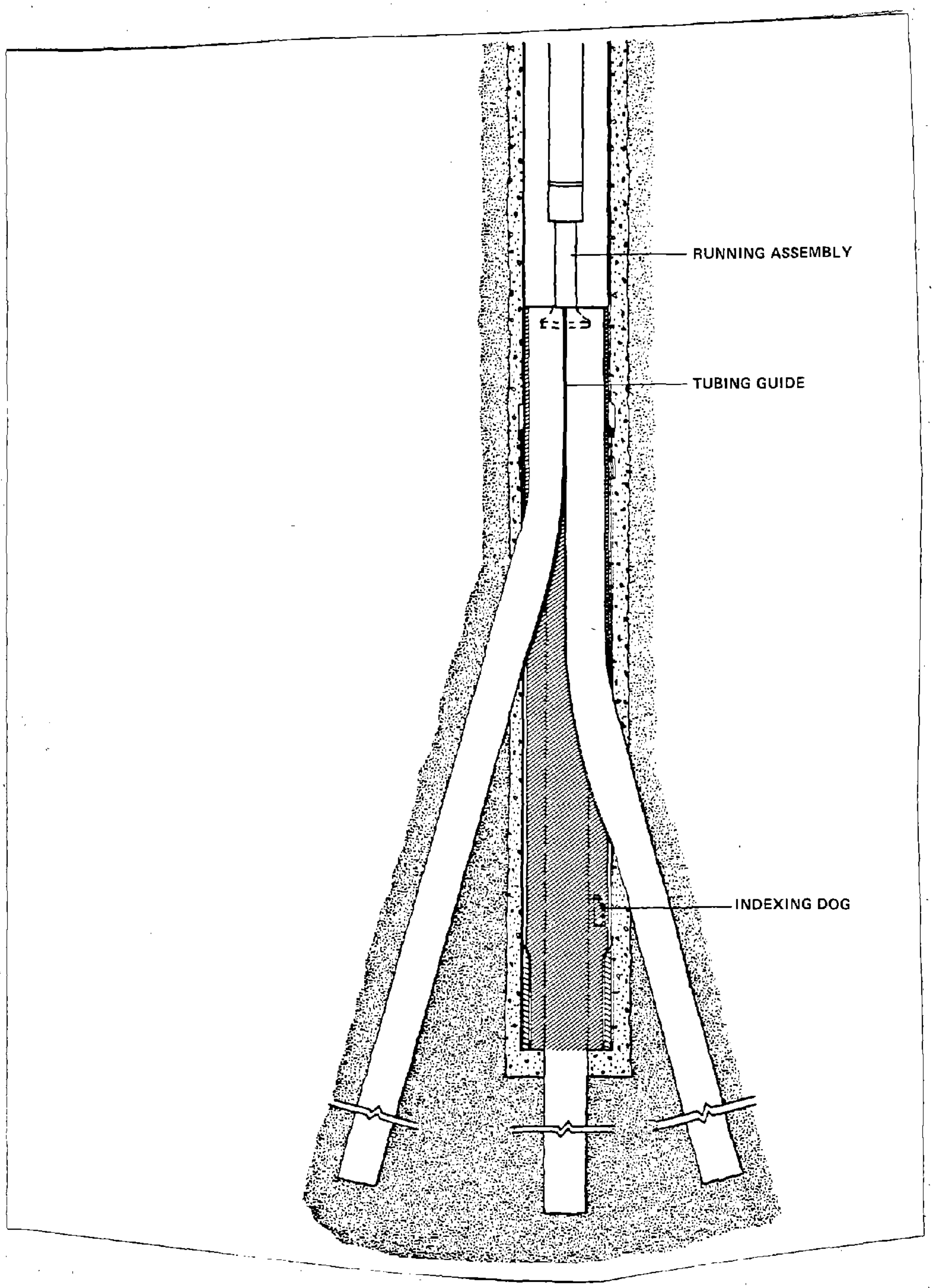

Figure 13. INSTALLING TUBING GUIDE

System Limitations and Risk

Setting 9-5/8-inch casing utilizes standard oil field drilling and cementing techniques, and higher grade casing is available for applications down to 5,000 feet and deeper.

The drilling guide proposed as a means for orienting the whipstock is a conceptual design generated in this study. Actual field tests would be required to establish a risk factor. However, the concept utilizes techniques that are successful in other applications. Whipstocks are commonly used to deviate above damage or collapsed casing, and both vertical and directional branches can be drilled with standard drilling equipment and procedures.

At greater depths, the pre-cut windows should be eliminated from the drilling guide to reduce risk of collapse during primary cementing. The drilling procedures then would be modified to include a mill to open windows in the casing. Additional rig time would be involved and well cost would go up accordingly.

The proposed tubing guide is essentially the same as was used in the 13-3/8-inch concept. However, it must be installed after the casing is set and the branches drilled. The 9-5/8-inch casing must be in good condition to allow the guide to be installed because the outside diameter of the guide utilizes the full I.D. of the casing, allowing only minimum clearance.

Once the tubing guide is installed, the three strings of fiberglass are run as in the 13-3/8-inch concept. This is the most critical phase of the branch completion. The open hole section of each of the three branches must have sufficient integrity not to cave or collapse while subsequent branches are drilled.

At this stage of completion, remaining risks are essentially the same as in the final stages of the 13-3/8-inch concept. The triple tubing hanger, cement baskets and cementing procedures are identical to those used with the 13-3/8-inch.

As discussed earlier, oil field experience suggests that a dual branch well would have considerably less completion problems than the triple. Additional risk reduction would be attained by reducing well spacing to 50 or 100 feet. This would move the protection casing closer to the ore body and reduce length of individual branches.

DOUBLE BRANCH OUT OF 9-5/8" CASING

A dual branch well consists of a vertical protection casing with two branches extending into the ore body. Either triple branch design can be simplified into a dual. Five spot leach patterns are developed by alternating rows of production and injection wells or by completing one branch as a producer and one as an injector. Risks associated with dual branch wells are considered to be less than a triple but cost incentives are also less. Estimated cost of a dual branch well with one branch producing and one branch injecting at 2,000 feet is $172,159, or $86,080 per well bottom. See Appendix D for cost detail.

The proposed procedures for drilling and completing dual branch wells are essentially the same as was described for triple branch wells with small diameter casing. Therefore, this section is primarily devoted to designing a lift system to utilize injection fluid as the power source for a downhole positive displacement pump.

Completion, Artificial Lift Techniques

Either previously described branch completion technique could be applied to dual branch wells. A 9-5/8-inch scheme is proposed as an example of possible novel applications of dual branch wells. A dual branch well is less complex than a triple. In areas where caving or hole fill-up is a concern, the dual concept can significantly reduce risk of failure. Drilling and completion procedures are essentially the same as for the triple 9-5/8-inch concept described earlier. A vertical branch and one directional branch are drilled into the ore body as shown in the lower part of Figure 14. A dual tubing guide is installed and the dual branches are cased and cemented in place.

Dual branch wells can be used to develop five spot patterns by alternating parallel rows of injection wells and production wells. Flow rates are monitored throughout the field to insure uniform distribution of leachants and prevent fluid from migrating out of the mining field. Typically, overall production rate is maintained slightly higher than total injection to assure positive pressure differential into the leaching area and prevent leachant escape.

Another unique application of the dual branch concept is to use one branch for injection and one branch for production, as in Figure 14. The injection fluid is routed through a positive displacement downhole pump as the power fluid; it then is exhausted from the pump into the injection branch. Produced fluid is routed from the production branch into the pump and up the production string, as illustrated.

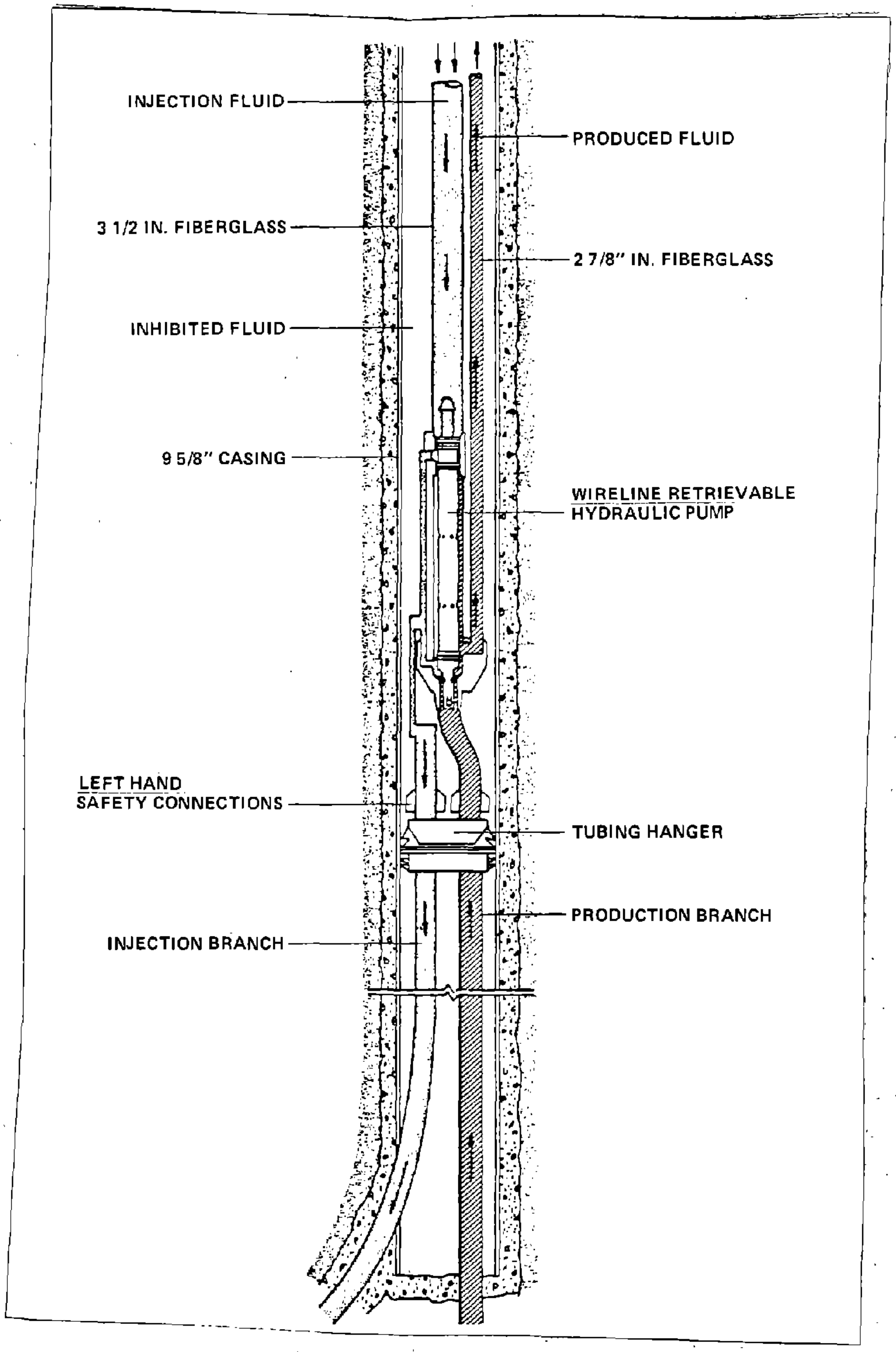

Figure 14. INJECTING AND PRODUCTION DUAL BRANCH WELL

The dual branch completion suggested in this section has several advantages over conventional production systems: 1) the downhole hydraulic pump is wireline retrievable for repair and 2) a dual branch production scheme requires less surface plumbing and requires no downhole electrical power. Also, the positive displacement pump maintains a constant ratio of produced fluid to injected fluid. For example, the system shown in Figure 14 utilizes a dual 9-5/8-inch branch well with 3-1/2-inch fiberglass injection tubing and 2-7/8-inch production tubing. A KOBE* Type E hydraulic bottom-hole piston pump modified to resist corrosion, and installed in the 3-1/2-inch tubing, will produce 2,400 bbl/day at 60% capacity with 2,100 bbl/day of injection fluid. Estimated pressure requirements for this system, 1) installed in a 2,000-foot branch well, 2) with 1,350 feet of head required to lift the production fluid, and 3) 120 psi over hydrostatic pressure required for injection are:

710 psi	-	to lift 1,350 feet of head plus friction loss in production string
460 psi	-	pressure loss in pump
10 psi	-	friction loss in injection tubing
120 psi	-	injection pressure into formation
1,300 psi		

The pump power required to inject 2,100 bbl/day at 1,300 psi is:

$$\text{Horsepower} = \Delta P\ (\text{psi}) \times Q\ (\text{bbl/day}) \times 1.7 \times 10^{-5}$$

$$\text{HP} = 1{,}300 \times 2{,}100 \times 1.7 \times 10^{-5} = 46.4 \text{ horsepower}$$

In reality, operating parameters of the dual branch system will be in a dynamic state. Injection and production pressures will vary with influence of adjacent wells and temporary changes in effective permeability. However, the critical ratio of produced fluid to injection fluid will remain constant. For example, the positive displacement pump in the example will produce 14% more fluid than it injects, i.e., total flow rate may vary but ratio of produced fluid to injection fluid will not change.

* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

System Limitations and Risk

Dual branch wells apply the same drilling and completion procedures as were proposed for triples. Setting 9-5/8-inch protection casing at 1,350 feet uses common low-risk drilling procedures. Speciality equipment such as the drilling guide, whipstock, and tubing guide are conceptually the same as proposed for triple branch wells. Risk associated with speciality drilling equipment for duals, therefore, is similar to those discussed for triples. However, a dual offers some significant risk reductions.

Less time is elapsed between drilling and casing of the first branch -- hence less chance of losing the hole. Dual completions are more common in oil wells. A wide variety of packers and tubing hangers are available with experienced people to install them.

Additional risk reductions can be gained by reducing well spacing to 50 or 100 feet, allowing the vertical protection casing to be set deeper, thus reducing arc lengths of the branches.

The pumping system in the dual branch example is novel. A standard positive displacement pump would require metallurgical modifications to utilize corrosive leachants as power fluids. However, advantages such as wireline retrieval, and fixed ratio of production and injection fluids warrant further study.

HORIZONTAL DRAIN HOLE OUT OF 7" CASING

Horizontal drain holes are drilled out of a vertical wellbore using an articulated bottom-hole drilling assembly. The rate of building angle from vertical to horizontal can be as high as 1-1/2 degree per foot of curved hole. After the 90° angle has been built, horizontal drilling follows. The horizontal portion has been drilled as far out as 200 feet.

A modified leach field could be developed by alternating parallel rows of injection and production horizontal holes. Each drain hole would replace two conventional wells and offer the advantage of more efficient linear flow through the ore body between injectors and producers.

The history of drain hole drilling goes back to the turn of the century. And it has been successful in improving oil and gas well productivity, particularly in California where geology is similar to that selected for this study. Drain hole drilling was a viable technique within the petroleum industry in the 1950s. Much of the technology is still available today.

Estimated cost for one 200-foot drain hole completed in an ore body at 2,000 feet is $138,850. If the drain hole is used to replace two conventional wells, the effective well cost is one-half the total. Detail cost data is included in the Appendix D. This section describes a proposed technique for completing drain holes and suggests limitations of the scheme.

Horizontal Drilling Techniques

Horizontal drain holes are drilled from below steel casing. Conventional 7-inch casing is set and cemented in place approximately 15 feet above the ore body. Special drilling procedures begin by drilling a 4-3/4-inch rathole vertically through the ore. Electric logs then are run to determine depth and thickness of the ore bed, and a single shot survey is used to determine deviation and direction of the rathole. Directional data combined with bed thickness data from logs is used to compute the proper whipstock orientation.

A special whipstock then is run to the appropriate depth in the rathole. Gyroscopic surveys are used to orient the whipstock in the proper direction. Once faced properly, the whipstock is planted or set and the setting tool is pulled.

Special angle building tools are used to drill the minimum available 3°/ft (19-foot radius) section of the hole. The special drilling assembly is guided into the proper direction by the whipstock. Once the angle is turned and the hole is essentially horizontal, a special 120 degree angle magnetic single shot unit is pumped around the turn to verify that a horizontal hole has been achieved. This very short radius allows maximum contact of thin ore bodies. However, longer radii curvatures would be easier to drill and such configurations would simplify subsequent completion procedures.

The horizontal section of the hole then is drilled with a stabilized drilling assembly. Every 50 to 80 feet, a directional survey is pumped down and retrieved to verify direction of the lateral hole. The process of drilling and surveying is repeated until the hole is drilled.

After drilling the lateral section of the hole, the mud is conditioned in preparation for casing. The whipstock is left in place to guide casing into the horizontal hole.

Special Casing/Cementing Techniques

Conventional steel or fiberglass casing cannot withstand stresses exerted by a 19-foot bending radius. An inexpensive, full-opening fiberglass coupling is needed. Figure 15 demonstrates the effect of hole diameter and radius of curvature on the maximum spacing of flexible joints. In this example, a 3-inch O.D. casing must be flexed every 2 feet to turn a 19-foot radius in a 4-inch hole. Figure 16 also suggests designs for flexible couplings that could be developed. Until inexpensive couplings are developed, it is necessary to use more complex and expensive flexible casing.

Coflexip* pipe is the only available tubular that apparently has the ability to turn a 19-foot radius and retain strength to resist collapse, and survive exposure to leachants, Figure 20. Typical applications of Coflexip have been offshore pipelines, control lines on subsea blowout preventers and high pressure lines for acidizing oil wells. As described in <u>Composite Catalog</u>, <u>1978-79 Edition</u>, complex tubulars of this type are made of three main components; an interlocked, spiraled steel carcass provides resistance to crushing and preserves pipe roundness even when subjected to short bending radius. Steel wire provides resistance to pulling and longitudinal stress produced by internal pressure. Thermoplastic internal tube and outersheaths make the pipe leakproof and corrosion resistant. Typical properties of 4-inch O.D. (2-inch ID), 16 lb/ft Coflexip pipe are 7,500 psi internal test pressure, bent around a curve with a minimum radius of 1-1/2 feet. Unique qualities of such pipe make it an excellent choice for casing short radius drain holes. However, it is expensive -- approximately 15 times the cost of similar-diameter fiberglass casing.

The recommended completion design for short radius drain holes uses flexible Coflexip* casing around the 90 degree turn and throughout the horizontal section below the turn, Figure 17. In the production interval, the flexible pipe is slotted or perforated. Conventional fiberglass pipe is used in the vertical interval between the top of the flexible pipe and the liner hanger. Additional fiberglass pipe is run from the liner hanger to surface. The liner assembly is pushed and washed into position using the whipstock to guide the flexible pipe around the turn. Special cementing procedures are used to cement the casing in place.

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* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement of the Bureau of Mines.

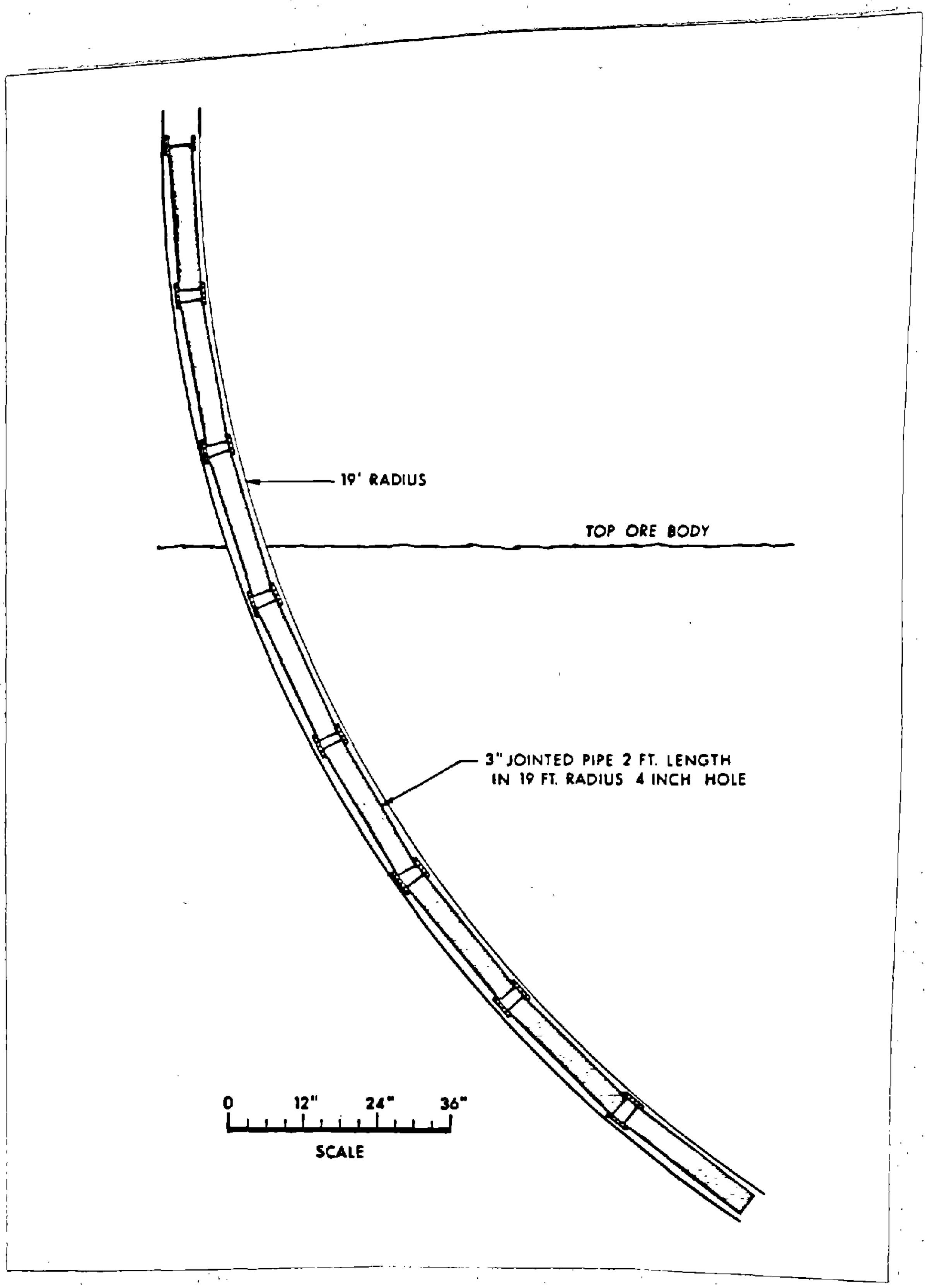

Figure 15. JOINTED CASING IN SHORT RADIUS DRAINHOLE

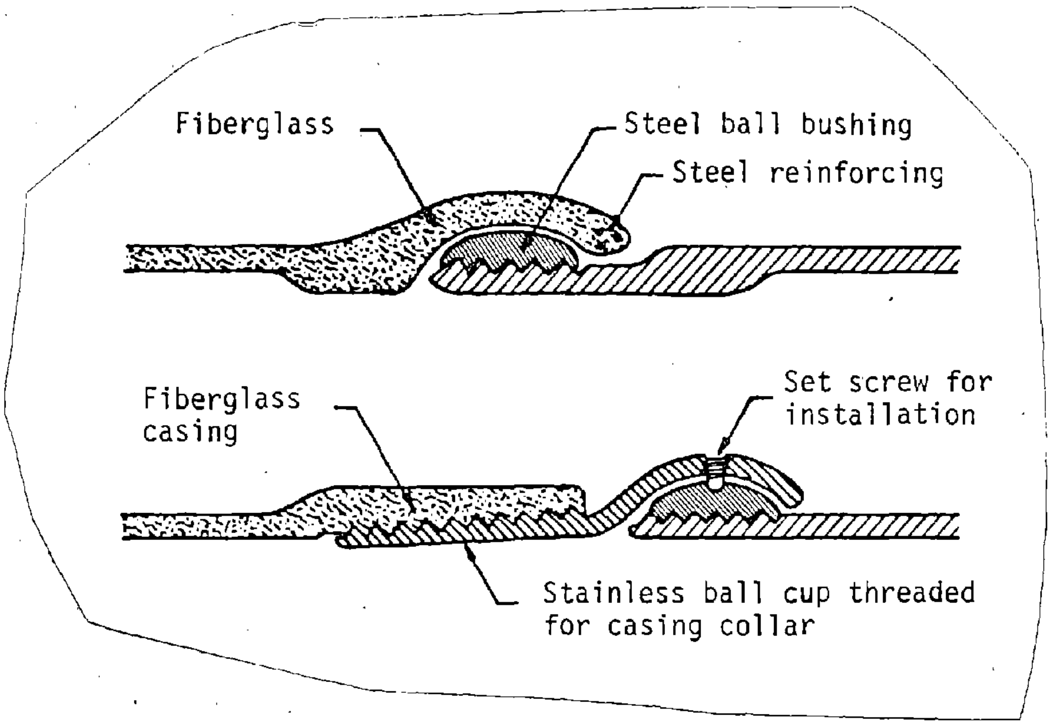

Figure 16. COUPLING CONCEPTS FOR ARTICULATED CASING

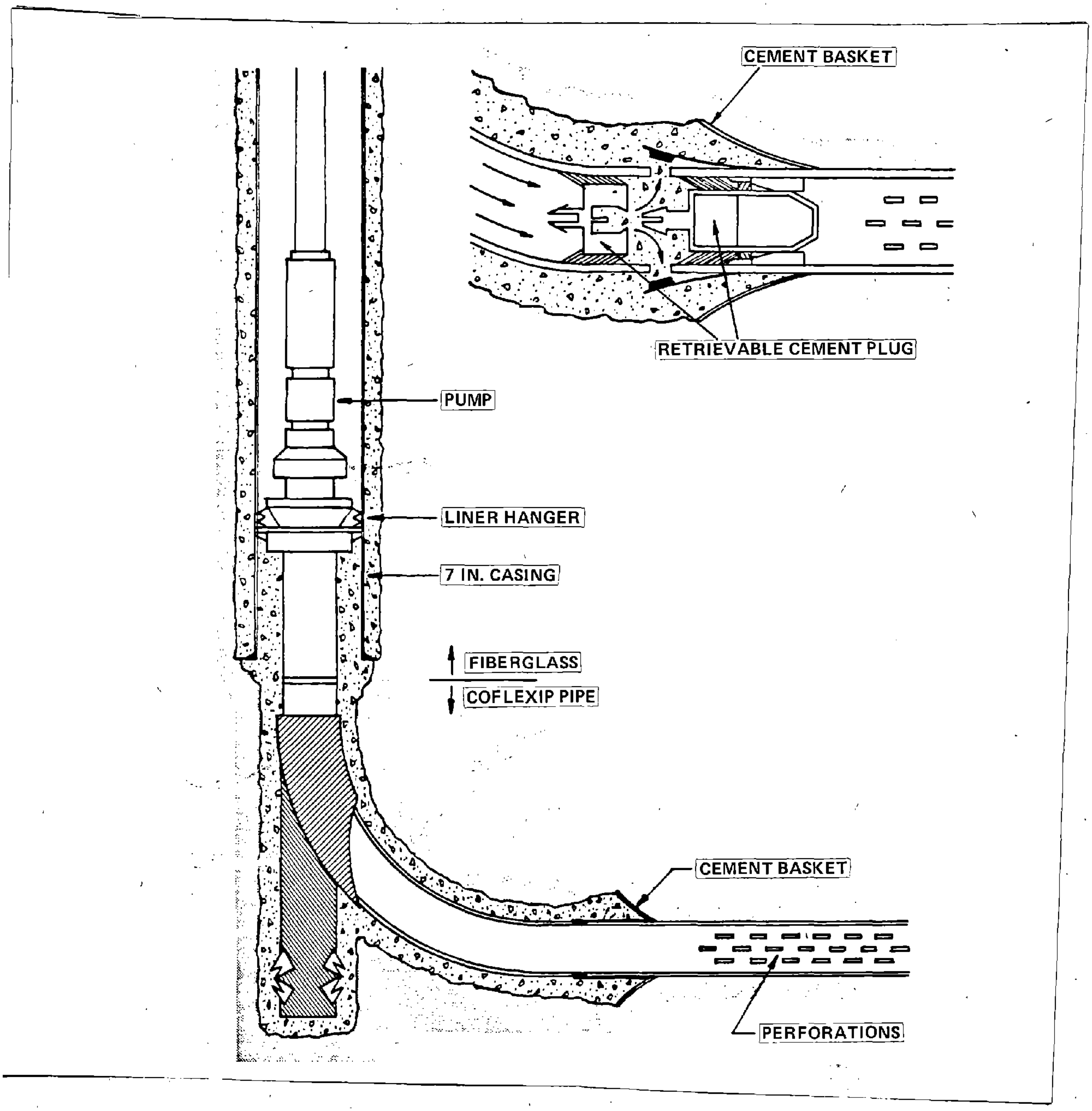

Figure 17. DRAIN HOLE COMPLETION SCHEMATIC

To efficiently cement the vertical section of casing and isolate the production interval from other formations, a special cement collar is needed, Figure 17. Conceptually, the collar consists of a short (two-foot) section of corrosion-resistant pipe with an internal upset or shoulder designed to retain the bottom cement plug. Cementing ports positioned upstream from the shoulder are opened as the bottom plug seats. Cement flowing through the ports opens the cement basket which forms a bridge against the formation, preventing cement from flowing into the production interval. After sufficient cement is pumped into the annulus above the cement basket, the ports are closed by the top cement plug.

The liner hanger is set after cement plugs are landed and cementing ports are closed. Cement is removed from above the hanger by releasing tubing from the safety connector and reversing out fluid.

To eliminate need for drillout after the cement job and to minimize cost, special wireline retrievable cement plugs are utilized. Figure 17 suggests a design where the top cement plug latches onto the preceding plug, leaving a fishing neck exposed for wireline retrieval. Conventional wireline fishing equipment consisting of a fishing grapple and knuckle-jointed weights are used to retrieve the plugs. As a safety factor, plugs are constructed of a material that is soluble in acid or leach fluid. Should wireline retrieval fail, plugs can be dissolved.

The drain hole is essentially ready for injection of leach fluid into the ore body as installed. To convert the well into a producer, the safety connection is released above the hanger and 2-7/8-inch tubing is removed and replaced by an electric pump and production tubing, as shown in Figure 17.

System Limitations and Risk

Historical experience with drain holes demonstrates that drilling techniques are available to turn the 90 degree angle and drill out horizontally. However, in areas with weak, unconsolidated sands that tend to be unstable or cave, the technique is likely to fail.

Care must be taken not to allow "porpoising" (poor vertical control) of the horizontal portion of the well during drilling. Irregularities such as this increase difficulty of pushing flexible casing into place. In thin ore beds, directional drilling accuracy is essential to prevent the horizontal hole from exiting into beds above or below the ore.

Increasing the radius of curvature will reduce critical bending stresses on casing and allow application of less expensive pipe with flexible joints similar to those suggested above.

HORIZONTAL HOLE OUT OF HIGH CURVATURE BOREHOLE

Slant hole drilling is another technique for drilling horizontally into ore bodies. For shallower objectives, a slant rig is used to initiate a directional hole. Directional techniques then are used to increase hole angle at 5°/100 ft (1,147-foot radius of curvature) until the well strikes the ore body in a horizontal plane, Figure 18. Deeper wells would have an upper, near-vertical section before starting the curved portion. Where depths are greater than the radius of curvature of the slant hole, a conventional rig using established directional drilling techniques can be utilized.

Slant wells have been drilled for various fossil fuel production operations. These types of wellbores may have merit for in situ leaching of uranium ore bodies, Figure 18. The advantage of the slanted hole is that several hundred feet of horizontal hole may be opened from a single wellbore. One slanted hole would be required for production while one adjacent slanted hole would be required for injection. This concept offers good sweep efficiency as it allows linear flow from the injection line to the production liner. Two, 400-foot lateral sections could be used to replace 8 conventional wells in adjacent 200-foot, five spot patterns.

Estimated cost for such a well drilled 400 feet horizontally into an ore body at a 2,000-foot depth is $273,676. If one slant hole is utilized to replace 4 conventional wells as noted above, effective cost is one-fourth of the total. Detailed cost data is included in Appendix D. For illustrative purposes, the more novel slant hole drilled at 500 feet with a slant rig is described in this section. Slant holes drilled at greater depth with conventional rigs would utilize similar drilling and completion techniques.

Drilling and Completion Techniques

The upper limit for building wellbore angle with a bent sub and drilling motor is about 5 degrees per 100 feet of hole. With this angle building rate, drilling would have to start at 35 degrees from the vertical in order to penetrate a 500-foot deep ore body horizontally. Slanted rigs are available which accommodate the 35 degree spud-in angle.

Total measured depth (TMD) of the curved hole is 1,099 feet and the radius of curvature is 1,147 feet, Figure 18. Casing bending stress in, say a 9-5/8-inch casing, is

$$\sigma_b = \frac{4.8125}{(12)\ (1,147)}\ 30 \times 10^6 = 10,500 \text{ psi}$$

which is within the strength capacity of casing.

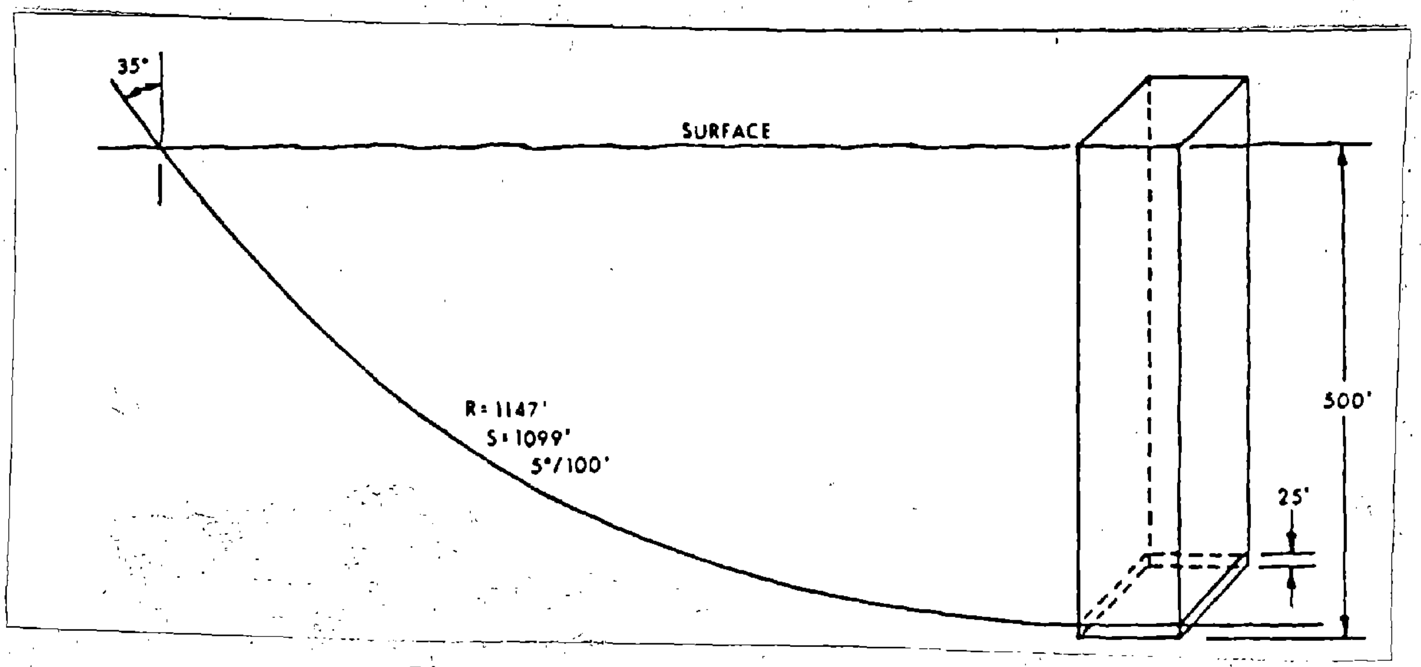

Figure 18. SLANTED WELL PARAMETERS

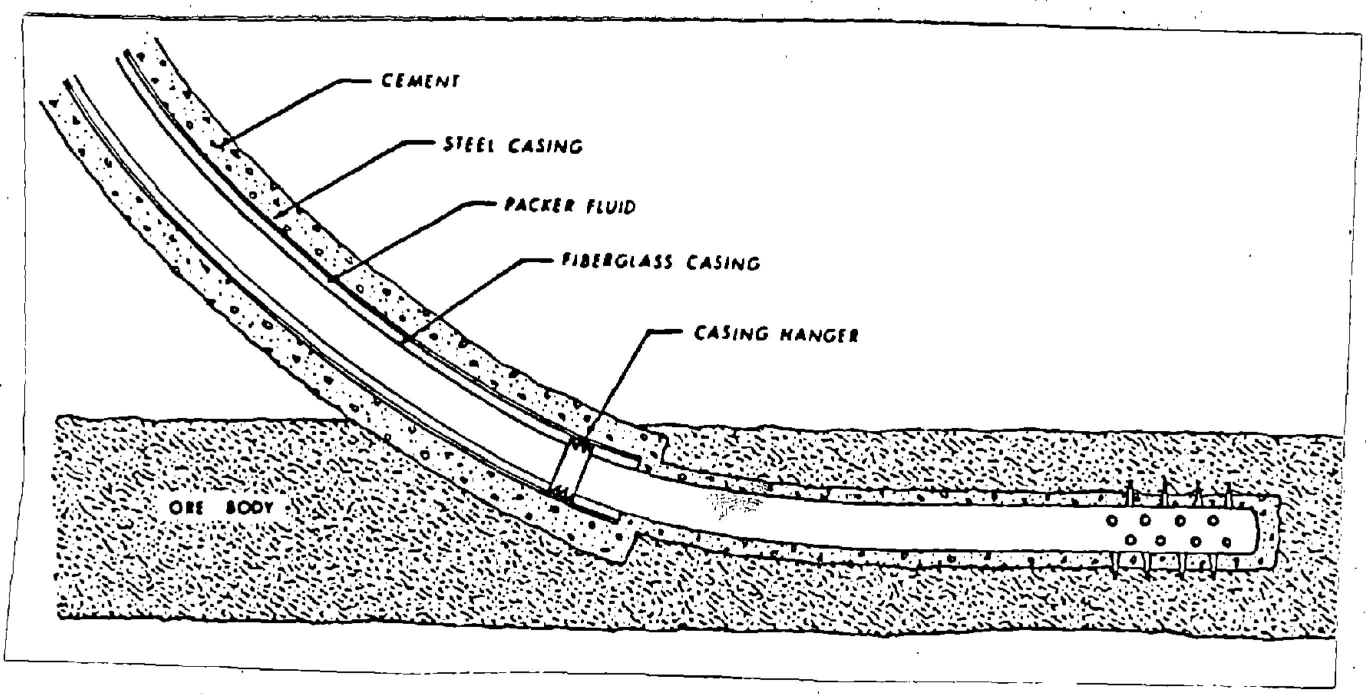

Figure 19. SLANTED WELL COMPLETION SCHEMATIC

A pilot hole should be drilled to establish wellbore configuration, then reamed to gage. Steel casing is set and cemented to the ore body. And the hole then is drilled horizontally out of the steel casing to accommodate the production (or injection) string, probably fiberglass.

The following completion program is suggested for the slant hole well starting at 35 degrees at the surface and utilizing a 400-foot horizontal hole through the ore body that would eventually service four-100 x 100-foot or two-200 x 200-foot patterns. Figure 19 illustrates the completion concept.

For large diameter completions required for producing wells, the upper 1,100 feet of hole required for angle building would be reamed to 12-1/2-inches, and 9-5/8-inch low grade steel casing would be cemented solidly in the hole using conventional practices. Steel is required to support further directional drilling -- the subsequent completion must be designed to isolate this string from corrosive fluids.

The horizontal hole then is drilled and reamed to 7-7/8-inch through 400 feet for the ore body using weighted fluids with special bridging and fluid loss properties, to support the hole. Casing for the horizontal hole would be conventional 5-1/2-inch fiberglass (FRP) casing. To avoid placing the string in compression while entering the hole, a string of light weight, flexible steel pipe would be used to push the string while fluid is circulated to wash out bridges and obstructions. A special casing hanger would be located on the FRP and within the bottom of the steel casing. This hanger would 1) seal the annulus for use of protective packer fluid and 2) anchor the upper FRP string so that it could be maintained in tension for longest operating life.

The horizontal FRP casing would be well-centralized. Conventional cementing practices would be used with emphasis on proper techniques to assure optimum mud removal. Cement would be circulated to above the hanger by use of conventional plugs and spacer fluids.

Perforating through the production interval would be done with USBM jet methods or conventional perforating tools pushed into the hole with a flexible steel string.

For injectors, the system can incorporate smaller, 4-1/2-inch, FRP casing in a 6-1/2-inch horizontal hole. Steel pipe could be 7-3/4-inch in a 9-5/8-inch hole. If larger production casing is needed for lift systems, FRP casing above the hanger could be 7-inch.

Slant holes at depths deeper than 1,147 feet can be drilled with conventional rigs and directional equipment, with a near-vertical section above the curved portion. Such a configuration would allow string weight to be used to push tubulars and completion/workover tools into the highly deviated section. Our cost estimate is included in Appendix D.

System Limitations and Risk

Directional drilling and completion techniques proposed for slant holes are extensions of procedures that are common to directional drilling for offshore oil and gas production. However, to apply the technique to ore bodies as thin as 25 feet would require extremely accurate subsurface maps. Exact vertical depth and bed dip would have to be known prior to planning the well, and expert directional drilling techniques would be required to strike the ore body in a horizontal plane. The technique should not be attempted in unconsolidated areas where hole washout or cave-in are common.

COST ANALYSIS

This section gives our cost estimate of each drilling and completion scheme as applied to various ore body depths.

Drilling programs were first developed and then used as a guide to establish cost, according to the procedure listed below:

A. Determine Rig Rate

  1. Select and cost the smallest rig capable of safely handling the required casing (1,350 feet of 13-3/8-inch, 54.5 lb/ft casing weights 73,575 lb in air).

  2. Add cost of rig-related rental equipment.

     a. Additional rig pump capacity to circulate cuttings in large open holes (17 inch, 12-1/4-inch, etc.)

     b. Drill collars and stabilizers to prevent drift of the large vertical hole

B. Estimate Rig-up and Drilling Time

C. Estimate Cost of Special Services (Mud/Chemicals, Cement, Casing Crews, Logs, Perforating)

D. Estimate Directional Drilling Costs

  1. Time required to drill branch holes, etc.

  2. Day rate for directional driller and directional equipment

E. Determine Tangible Costs (F.O.B. Houston)

  1. Steel casing

  2. Fiberglass tubing and casing

  3. Packers

F. Specialty Items

  1. Drilling guide, completion templates, etc.

     a. Estimate cost of raw materials

     b. Estimate cost of fabrication

2. Pump and downhole assemblies

   a. Price standard high volume pumps

   b. Estimate additional cost to improve resistance to corrosive environmemt

Drilling costs are site specific and rig rates vary with demand. Also, distance relative to an active oil field significantly changes expense of services such as cementing, logging,and oil field type equipment rental. For comparative purposes each well scheme is priced as though it would be drilled in the Houston area.

The estimated cost for each well type is given in Table 2 with the supportive breakdown given in Appendix D. In each case, the cost is the cost for drilling and completing a given wellbore configuration. For example, the cost for drilling and completing a triple branch is the cost of vertical portion plus three branches. The cost for the conventional well is the cost for one hole. The downhole pump, a major cost item, is not included in cost figures in Table 2, but is included in the field development costs given in the next section.

TABLE 2

UNIT INVESTMENT FOR WELL SCHEMES

Completion Method	Ore Body Depth 500 ft	2,000 ft	5,000 ft
Conventional	$ 15,050	$ 80,850	$182,080
Triple Branch out of 13-3/8" Casing		167,180	341,226
Triple Branch out of 9-5/8" Casing		172,160	308,933
Double Branch out of 9-5/8" Casing		137,159	256,262
Horizontal Drain Hole out of 7" Casing (200 foot Drain Hole)	78,000	138,850	250,880
Horizontal Hole out of High Curvature Borehole (400 foot Horizontal Hole)	273,772	273,676	498,073

COMPARISON OF WELL COSTS PER SWEEP AREA

Total well costs for developing a mineral field by in situ leaching can be distributed among all sweep areas to arrive at well cost per sweep area or sweep area well costs. Sweep area well costs is a good parameter for comparing the economics of each wellbore type.

Consider that a broad mineral field is to be developed by a matrix of injector and producer wells drilled and completed in a five-spot pattern as shown in Figure 20. At present, the matrix of injectors and producers are conventional vertical wells and the well cost per sweep area is the total cost of one conventional injector well and one conventional producer well.

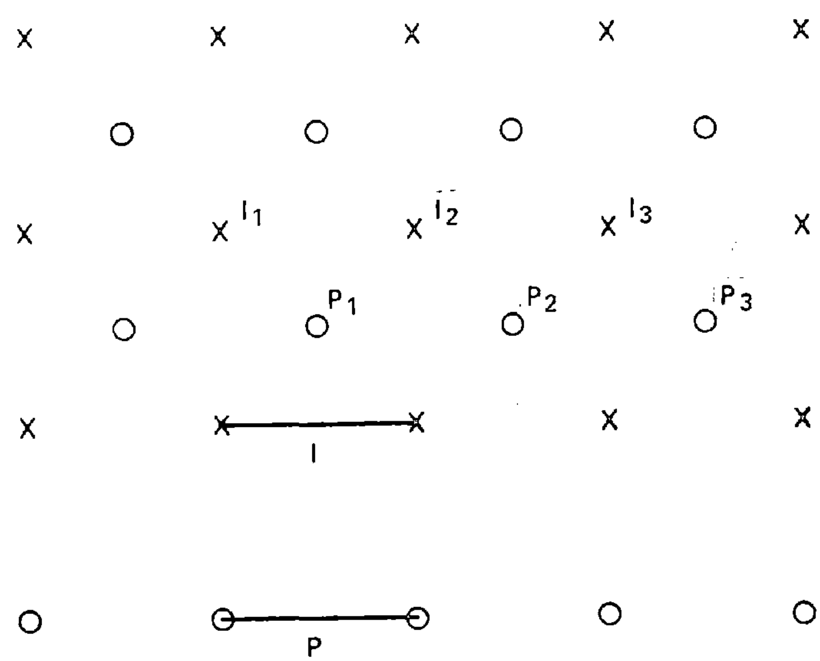

Figure 20. FIVE-SPOT FIELD DEVELOPMENT PATTERN

If the mineral field is to be developed using triple branch injector wells (I_1, I_2, I_3) and triple branch producer wells (P_1, P_2, P_3) the well costs per sweep area is the cost of one-third the cost of a triple branch injector well plus one-third the cost of a triple branch producer well. This formula was used to generate the sweep area cost for both triple branch cases (see Table 3).

The double branch well type is costed assuming one branch will be an injector and the other a producer. In this case, the cost of a double branch is the same as the well costs to sweep one area (200 ft by 200 ft area).

TABLE 3

WELL COST PER SWEEP AREA

Completion Method	Ore Body Depth* 500 ft	2,000 ft	5,000 ft
Conventional	$34,850	$181,700	$384,160
Triple Branch out of 13-3/8" Casing		122,603	235,634
Triple Branch out of 9-5/8" Casing		125,924	214,106
Double Branch out of 9-5/8" Casing		172,158	291,662
Horizontal Drain Hole out of 7" Casing (200 foot Drain Hole)	41,000	152,850	276,380
Horizontal Hole out of High Curvature Borehole (400 foot Horizontal Hole)	68,430	146,088	260,036

* Assumes a 100 ft spaced five spot pattern at 500 ft depth and 200 ft five spot pattern at 2,000 and 5,000 feet.

The sweep area cost of a horizontal drain hole is based on 200-foot long horizontal holes being placed in the ore body. For example, one horizontal hole would extend a distance of P (Figure 20). We assumed that adjacent horizontal holes would be separated by 200 feet for 2,000-foot and 5,000-foot ore body depths and by 100 feet for the 500-foot ore body depth. Thus, an injector is 200 feet away from a producer for the 2,000-foot and 5,000-foot ore body depths and an injector is 100 feet away from a producer for the 500-foot ore body depth case. The unit cost for 2,000-feet and 5,000-feet depths is the cost of one-half of a producer plus the cost of one-half of an injector. The unit cost for the 500-foot depth case is one-fourth the cost of an injector plus one-fourth the cost of a producer because the length of the 200-foot horizontal hole extends along two (100 feet x 100 feet) sweep area.

The same rationale was used to obtain the unit cost corresponding to 400-foot long horizontal holes drilled out of high-curvature boreholes. For example, the unit cost for the 500-foot depth case is one-eighth the cost of an injector plus the cost of one-eighth the cost of a producer; the length of the 400-foot horizontal hole extends along four (100 feet x 100 feet) sweep area.

The well cost per sweep area for each wellbore type is summarized in Table 3 and plotted in Figure 21 and Figure 22. This cost information shows there is potential cost savings with each wellbore type when applied to depths beyond 1,500 feet. Also, cost savings increase with depth. Other factors, however, enter into the overall evaluation as explained in the next section.

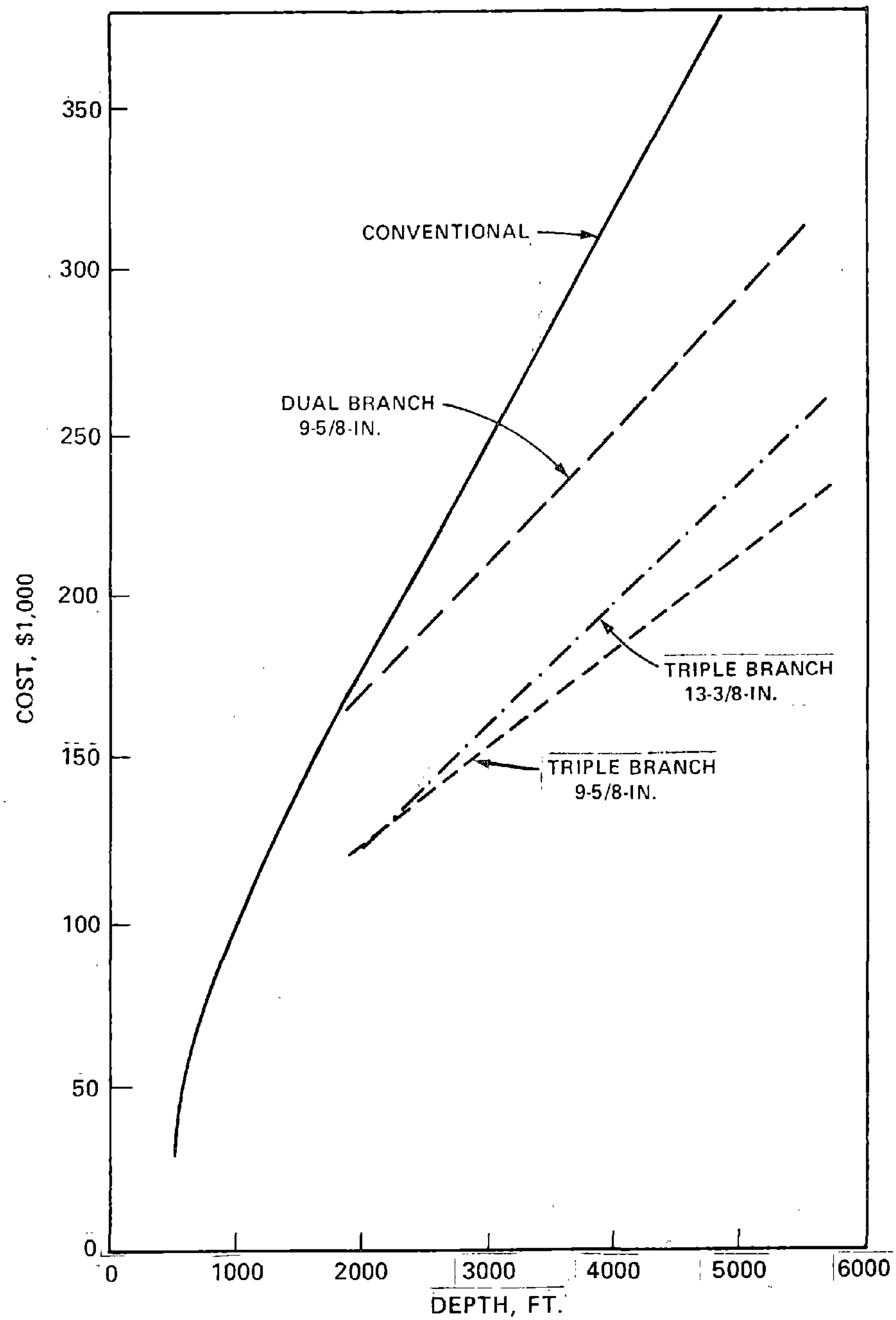

Figure 21. WELL COST PER SWEEP AREA USING BRANCH WELLS

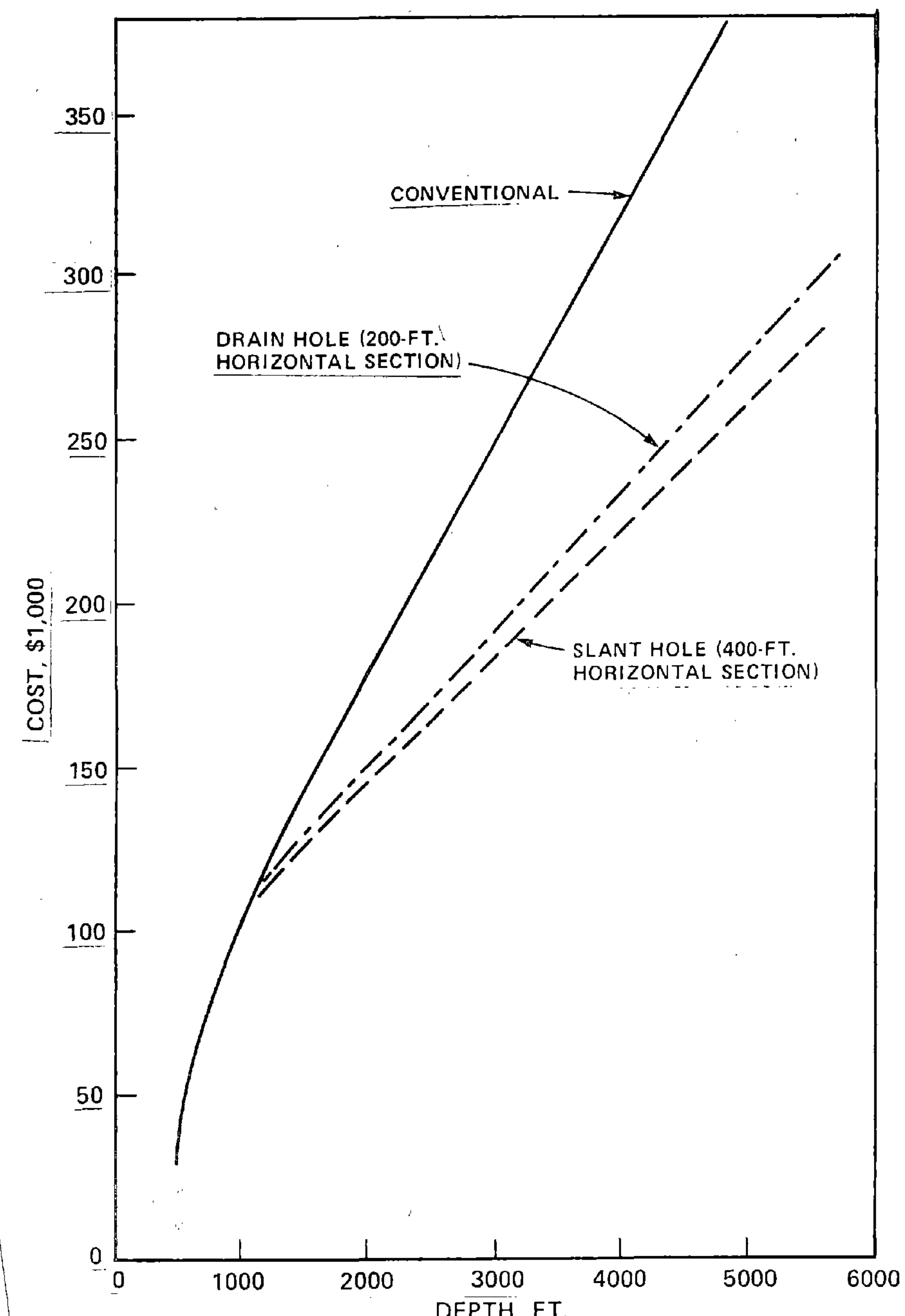

Figure 22. WELL COST PER SWEEP AREA USING HORIZONTAL BOREHOLES

VII. EVALUATION OF DRILLING & COMPLETION CONCEPTS

This section gives an evaluation scheme and ranks the various well concepts for in situ leach mining.

Specific drilling and completion concepts evaluated are given in Table 4. We did not evaluate these concepts for ore body depths greater than 2,000 ft because it was beyond the scope of the study.

Table 4

	500 ft	2,000 ft
Conventional	x	x
Triple Branch out of 13-3/8" Casing	Na	x
Triple Branch out of 9-5/8" Casing	Na	x
Double Branch out of 9-5/8" Casing	Na	x
Horizontal Drain Hole out of 7" Casing	x	x
Horizontal Hole out of High Curvature Borehole	x	x

Na - Not applicable since kick off point for branching is near the surface.

EVALUATION SCHEME

In our evaluation scheme we gave numerical values to engineering judgments and gave each concept a single score.

Evaluation criteria are defined under categories of performance, risk, cost, and schedule;

Performance - the capability to achieve needed operational characteristics, plus reliability.

Risk	-	the possibility that performance may not be met because of the design approach, absence of testing, or some specific technical consideration.
Schedule	-	the availability of a design depending upon the stage of development.
Cost	-	the estimated cost of the system including development and manufacturing costs.

Each category is weighted as follows (weighing was established jointly with the Bureau of Mines):

• Performance	30%
• Risk	30%
• Schedule	10%
• Cost	30%
	100%

Our approach was to break each category of evaluation criteria (performance, risk, etc.) into key evaluation elements and give each element an appropriate weight.

The numerical evaluation scheme had two key objectives. The first is to have a way to quantify our judgment against a fixed scale so that each wellbore concept will be rated in the same manner, thus showing their truest level of merit in comparison with each other.

The second objective was to give a way to examine the rationale of the final scores by looking at each element of the concept that was given a grade and see where the strong and weak points are in each. Since all design selections are the result of trade-offs, the scoring system aided in selecting a preferred concept.

Evaluation elements under each of the four categories (performance, risk, schedule, cost) are identified below.

EVALUATION CRITERIA

Performance

Technical Performance: The production scheme must satisfy performance requirements, as specified in an earlier section. The production scheme must be cost effective. It is, therefore, important that the production rates from the wells be great enough to make operations economical. Downhole equipment and tubing must be capable of handling high flow rates especially for the 2,000 ft case.

Sweep Efficiency: It is desirable to produce minerals at a high rate and with a high degree of recoverability. Wellbore schemes that allow linear flow between injection and production wells have better sweep efficiencies than wellbore schemes that allow line drive flow between injection and production wells.

Reliability: Downhole equipment and tubulars must be capable of operation in a corrosive environment as the leaching solution will be either alkaline or acidic. Produciton tubing or casing must therefore be made from appropriate materials of construction. Downhole equipment used for lifting the pregnant solution must not only be capable of delivering the necessary flow water but also operate in a corrosive environment for long periods of time without replacement.

Maintenance: The system should operate with minimum amount of maintenance. Workovers are costly and production is lost when downhole maintenance is required. Replaceable items should be accessible and easy to replace.

Risk

Stage of Equipment Development: The wellbore configurations and completion schemes considered in this study are nontypical and thus may require equipment and procedures that are not fully developed. Some of the proposed equipment is conceptual only while other equipment is fully developed and operational. Conceptual equipment has no track record and therefore carries with it a high risk level.

Drilling and Completion Experience: Drilling and completing these nontypical wellbores are key elements in economically developing each production scheme. Drilling and Completion are identified separately in our evaluation summary.

Materials of Construction: Tubulars must not only accommodate alkaline or acidic solutions but must also have adequate strength to withstand combined axial and bending stresses produced during installation and operation. Collapse resistance is also important. Schemes which minimize the quantity of special tubing would have lower risk.

Schedule

Equipment Availability: Equipment required to drill, complete, and produce from each scheme may or may not be readily available. Equipment may be conceptual, have a preliminary design, have a final design, been prototype tested, or fully developed and operational. Another aspect of availability is incentive for tool companies to invest in new products for in situ leach mining.

Personnel: The level of expertise and availability of trained personnel will impact job planning.

Cost

Comparison with Conventional: There must be economic incentives to replace conventional vertical five spot wellbore patterns with new production schemes. Therefore the cost of each scheme was compared with the cost of implementing production with conventional methods.

The cost evaluation numbers (Table 5) were determined by dividing the lowest cost estimate by the individual cost estimates (Table 3) and then multiplying by the cost weighting value (taken as 30%).

For example, the numerical value given in the cost of the conventional vertical well concept was determined as follows.

$$\frac{\$122,603}{\$181,700} \times 30 = 20.2$$

which was rounded off to 20.

EVALUATION RESULTS

Our evaluation is summarized in Tables 5 and 6.

TABLE 5

EVALUATION SUMMARY
(500 ft)

	WEIGHTING %	CONCEPT A	CONCEPT E	CONCEPT F
PERFORMANCE				
• Technical Performance	10	10	5	5
• Sweep Efficiency	10	5	10	10
• Reliability	5	5	2	2
• Maintenance	5	5	1	2
	30			
RISK				
• Stage of Equipment Development	10	10	7	8
• Drilling & Completion Experience	15	15	5	8
• Materials of Construction	5	4	2	2
	30			
SCHEDULE				
• Equipment Availability	5	5	1	3
• Personnel	5	5	1	2
	10			
COST				
• Comparison with Conventional	30	30	25	15
TOTAL SCORE	100%	94	59	57

A. Conventional
E. Horizontal Drain Hole out of 7" Casing
F. Horizontal Hole out of High Curvature Borehole

TABLE 6
EVALUATION SUMMARY
(2,000 ft)

	WEIGHTING	CONCEPT					
	%	A	B	C	D	E	F
PERFORMANCE							
• Technical Performance	10	5	10	10	10	5	5
• Sweep Efficiency	10	5	5	5	5	10	10
• Reliability	5	5	4	4	4	2	2
• Maintenance	5	5	2	2	2	1	2
	30						
RISK							
• Stage of Equipment Development	10	10	5	5	5	10	10
• Drilling & Completion Experience	15	15	10	10	10	5	5
• Materials of Construction	5	4	3	3	3	2	2
	30						
SCHEDULE							
• Equipment Availability	5	5	2	2	2	1	3
• Personnel Training	5	5	4	4	4	1	2
	10						
COST							
• Comparison with Conventional	30	20	30	29	21	24	25
TOTAL SCORE	100%	79	75	74	66	61	66

A. Conventional
B. Triple Branch out of 13-3/8" Casing
C. Triple Branch out of 9-5/8" Casing
D. Double Branch out of 9-5/8" Casing
E. Horizontal Drain Hole out of 7"Casing
F. Horizontal Hole out of High Curvature Borehole

VIII. PREFERRED CONCEPT

Based on the present state-of-the-art of drilling and completing wellbores, conventional vertical wells give the best overall balance between performance, risk, availability, and cost for both 500 foot and 2,000 foot ore body depths.

The nonconventional well concepts when applied to 500 foot ore body depths are poor competitors with convention wells, as anticipated.

However, the multiple branch well concepts are competitive with conventional wells and in each case cost estimates are lower than the cost estimate for conventional wells. In addition, performance is rated higher for the multiple branch wells primarily because larger pumps can be installed in the 9-5/8 and 13-3/8 protective casings. The multiple branch wells suffer from high risk and lack of available equipment and experience and this is reflected in our scoring (Table 6). Had equipment development and experience been rated higher, the total score for the triple branch concepts could easily be 85 as compared with 79 for conventional wells.

Based on their high score under cost and performance, there is incentive to further develop the multiple branch hole concept. The incentive is even greater when applied to ore bodies deeper than 2,000 ft as shown in Figure 21.

Horizontal drain holes and high curvature/horizontal holes are not as attractive as multiple branch holes because

- Little or no experience exists with respect to maintaining sand control in horizontal holes, whether drilled as a drain or a slant hole.
- Drain hole drilling is practiced at present by only one operator, and attaining horizontal lengths of up to 200 feet is risky.
- Although slant holes have been drilled over horizontal lengths of 2,000 feet, it is not known whether drilling of the horizontal portion can be maintained within a thin vertical zone of the dimensions of the typical uranium ore thickness, approximately 25 feet.

It is not our intention to rule out any of the nonconventional wellbore configurations for in situ leach mining. Each may have merit for other operating conditions and mining operators may want to evaluate them further paying particular attention to other types of ore bodies.

The triple branch out of a 9-5/8-inch casing can reduce well costs as much as 30% when applied to ore bodies 2,000 feet deep and as much as 44% when applied to ore bodies 5,000 feet deep. This particular concept can also be adapted for dual branched wells depending on company policy on multiple completions and requirements. We therefore select the triple branch out of a 9-5/8-inch casing as a concept worthy of further engineering study and development.

Its drilling follows oil field technology drilling practices and the subsurface tubing templates can be designed and fabricated from off-the-shelf tubulars. In addition, successful demonstration of the template design would enable this nonconventional hole completion to be applied to leaching of minerals other than uranium, especially in hard rock where hole stability is not as severe a problem as in sandstones.

The concept offers operational design flexibility, too. For example, the operator may elect to complete only two branches instead of three. One branch could go deeper than the other branch or branches allowing production from another zone. An interesting application is multiple branches at each leg of a five spot pattern. Multiple branches could also be drilled into selected points to monitor reservoir performance and boundary leakoff.

Our recommendation for developing the triple branch out of 9-5/8-inch casing is given in the following section.

IX. CONCLUSIONS AND RECOMMENDATIONS

Branch well drilling can reduce well costs when applied to ore bodies deeper than 1,500 feet. The practical limit for number of branches drilled and completed from one vertical wellbore is three. Two completion schemes could be developed to adequately case triple branch wells. However, both concepts require development of specialized completion templates and guides. The logical first-step in developing branch well completion equipment is to limit initial branch wells to include only two hole bottoms. Completion experience gained by developing templates and guides for dual branch wells could be readily extended to expertise needed to complete three hole bottoms. Further studies will be required to develop the specialized equipment proposed for branch well completions and to determine risks related to their use.

Horizontal drain holes utilize a short radius, 90 degree turn to penetrate ore bodies hroizontally. The concept is most adaptable to consolidated, thin ores with low to moderate permeability. Unconsolidated or soft ore bodies that tend to cave or wash during drilling are considered poor candidates for drain hole drilling.

Drain hole wells have been successfully drilled, and at least one contractor in Denver offers the directional drilling service. Equipment is available to drill drain holes with radii of curvature as short as 19 feet. The completion of such short radius drain holes for in-situ leach mining would require use of special flexible pipe that has not previously been utilized for casing; and the development of specialized cementing equipment is required to adequately isolate the ore body.

The drain hole offers apparent cost incentives at depths greater than 1,500 feet. One 200-foot drain hole effectively replaces two conventional wells. Drain holes with longer radii of curvature would simplify the completion design and improve chances of entering the horizontal hole with casing.

Slant hole completions can be designed with conventional oil well equipment. At depths greater than 1,500 feet, a slant hole penetrating 400 feet of ore could significantly reduce well costs by replaceing four conventional wells.

The primary limitation to utilizing slant holes is need to accurately know depth, thickness and dip of the ore body. The surface well location is typically displaced more than 1,000 feet from the down-hole entry point into the ore body. Inaccurate subsurface mapping or directional drilling error would result in missing the ore body or inadvertently exiting from the ore into adjacent formations. However, the technique is suited to deeper, relatively thin ore beds with thick, impermeable formations above and below. Slight directional drilling errors wherein a portion of the horizontal section penetrates adjacent impermeable formation would not be of critical concern.

Drilling and completing these nonconventional wells is technically feasible, and for ore body depths below 1,500 feet appear to be less expensive than single completion vertical wells currently used. Since the completion of both slant and drain holes at this time is rated as having a higher risk than the branch holes, we believe that the next step should be developmental work on downhole templates required to drill and complete multiple branch boreholes. Conceptual drawings of the drilling and completion templates for the 9-5/8-inch triple branch case were given earlier in Figures 9 through 13.

Major tasks recommended for developing the concept further are:

Task 1 - Design branching templates and casing housing and produce shop drawings needed to fabricate the reentry templates and the casing housing.

Task 2 - Fabricate templates and casing housing in accordance with the design developed in Task 1.

Task 3 - Prepare a checkout plan to assure that the special equipment can be readily inserted and accurately seated in a wellbore casing and to confirm that the templates will perform their purpose of allowing reentry into a predrilled directional hole. In general, the checkout will consist of inserting a modified whipstock into the specially designed wellbore casing and orienting the whipstock toward precut windows. A tubing template will be checked out in a similar fashion.

Task 4 - Conduct equipment checkout in accordance with the plan developed in Task 3.

Task 5 - Prepare instruction handbook with sketches and descriptions of unique characteristics that require crew knowledge for best operation and maintenance. The objective is to provide enough information that any mining operator can incorporate the equipment into a drilling program tailored to his own standard operating procedures.

Task 6 - Assist the Bureau of Mines to obtain mining operator participation in a full-scale application of the equipment.

Task 7 - Prepare final report which gives results of checkout at the fabricator's facility, and a set of drawings and specifications that will allow additional procurement of the equipment built and tested.

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APPENDIX A

NON-TYPICAL DIRECTIONAL DRILLING AND COMPLETION EXPERIENCE

Current directional drilling practices are based on years of experience in oil and gas drilling. In many instances, it is desirable to drill straight holes. In other cases, it is desirable to direct the hole toward a lateral target several thousand feet below the surface. Typical applications of directional drilling for oil and gas production are shown in Figure 23.

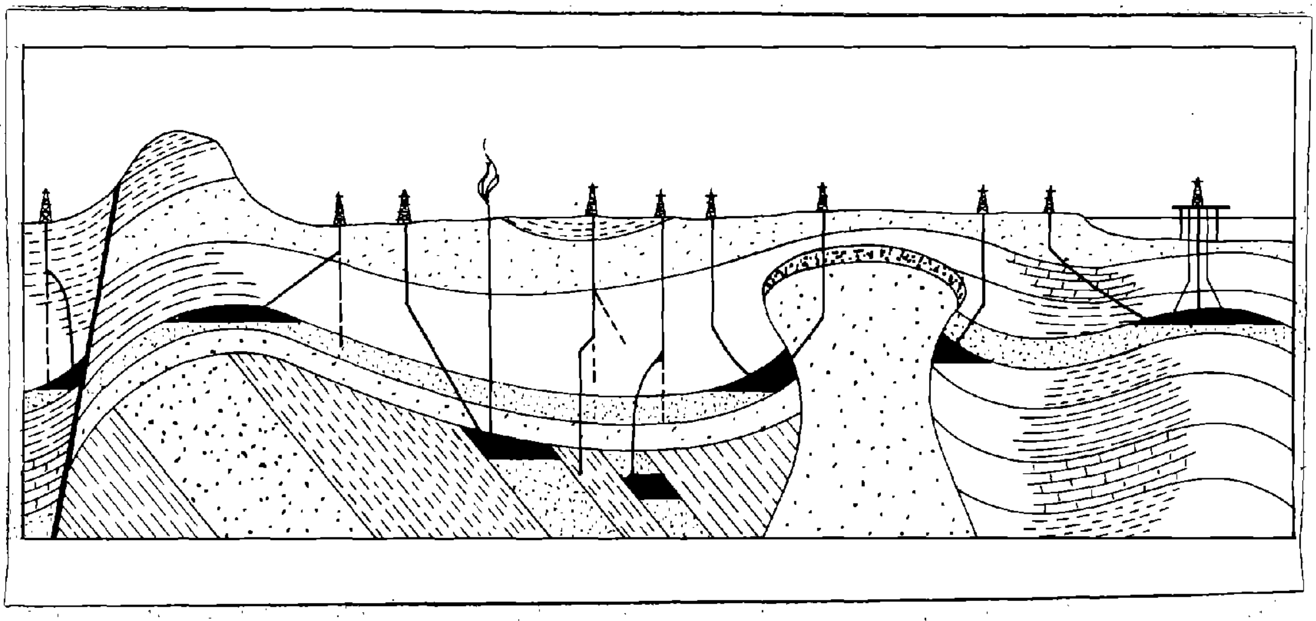


Figure 23. TYPICAL APPLICATIONS OF DIRECTIONAL DRILLING

Development of modern directional systems has been spurred by offshore petroleum developments where multiwells must be completed from a single platform. As many as 30 directional wells are drilled from one platform. Special hardware has been developed to control the path of wellbores to hit desired targets. Whipstocks and jets have previously been utilized to direct the bit. More recently, downhole motors with a bent sub or housing are used. Control of the borehole path requires frequent surveys and the reorientation of bottom-hole assembly.

Recently other applications for directional drilling have emerged. They are, for example, horizontal and slant hole drilling into coal seams for drainage and recovery of methane, vertical to horizontal drilling for in situ coal gasification processes and mineral leaching, drilling curved holes for utility lines, and geothermal applications. These and other directional drilling applications will require extension of present drilling technology and hardware.

In this section of the report, we give a brief summary of nontypical directional drilling experience. This background information was a useful reference throughout the study and is presented here under the following subsections:

- Branch Drilling and Completion
- Horizontal Drain Hole Drilling
- High Angle Buildup to a Shallow Formation
- High Angle Buildup Followed by a Long Lateral Hole
- Straight Horizontal Drilling

Branch Drilling and Completion

The Russians have been drilling and completing branched wells since the early 1940s to increase total production from oil and gas reservoirs.

"Multi-Bottom Hole" and "Branched Horizontal Well" drilling are names applied to a Russian drilling technology in which the lower end of a well is branched out into a number of sharply bent shafts, each having a horizontal or gently sloping orientation to its axis. The primary advantage of this technique is that a well of this design can cover a significantly larger area of a producing zone more completely than can a well of conventional design. Thus, a greater surface area for filtration purposes is exposed to the drainage zone.

This technique was first described in 1941 by N. S. Timofeyev in response to Russian demands for greater production of hydrocarbons in view of the depletion of the then known Russian natural reserves.[6] The technology involved was later developed and applied by Soviet Engineers: A. M. Grigoryan, V. A. Bragin, K. A. Tsarevich, K. I. Kovalenko and G. P. Ovanesov. As of 1976 more than fifty of these wells had been drilled in different producing regions of the Soviet Union. Each of these wells had 5 to 10 shafts ranging in lengths of 30 to 300 m each.[7] It is claimed by the Russians that for an ideal porous media, such an increase in both the length and the surface of the filtration area, would increase the oil flow by several times. Thus, a given level of production could be achieved using a smaller number of production wells. Considering these thoughts it may be stated that the general reasons for drilling holes of these configurations are as follows:[6]

1. To obtain wells having an increased flow level.

2. To increase the total oil recovery from a field.

3. To reduce the number of wells required for the development of some fields.

4. To permit the development of low flowing fields having low rock permeability or high viscosity oil where the flow rate would make the field uneconomical.

5. To significantly increase the profitability of developing fields with rapidly varying rock permeability.

6. To increase the absorbant property of relief wells used to bring under control another well that has gone out of control.

When considering the above, it is interesting to note a Russian drilling philosophy that has been stated as follows:[8] "During the planning of multi-shaft horizontal wells the main objective is to maximize the flow and the total production of oil under those conditions that provide for long term use of the well. Subordinate considerations are the rates of production and complexity of the operation. The economics involved should be considered not from the viewpoint of individual organizations, government groups, etc., but from the interests of the national economy as a whole."

As of 1976, multi-bottom hole drilling technology could be divided into the following two general categories:

1. Drilling of wells into larger oil or gas fields in those areas having a thickness of 35 to 80 m or more, and at depths of 600 to 1,500 m (Figure 24). Formation pressures normally are at hydrostatic levels or less.

2. Drilling of wells into zones that are 50 or more meters thick and at least 2,500 meters in depth (Figure 25). These wells would generally have horizontal shafts of a 1,000 meters or more in length and a large number of branches. Such wells would normally be used in fairly resistant formations. The wells defined in the first category are the more prevelent in use. Alternate configurations of this design are noted in Figure 26. The wells defined in the second category were as of 1976, still fairly experimental in nature.

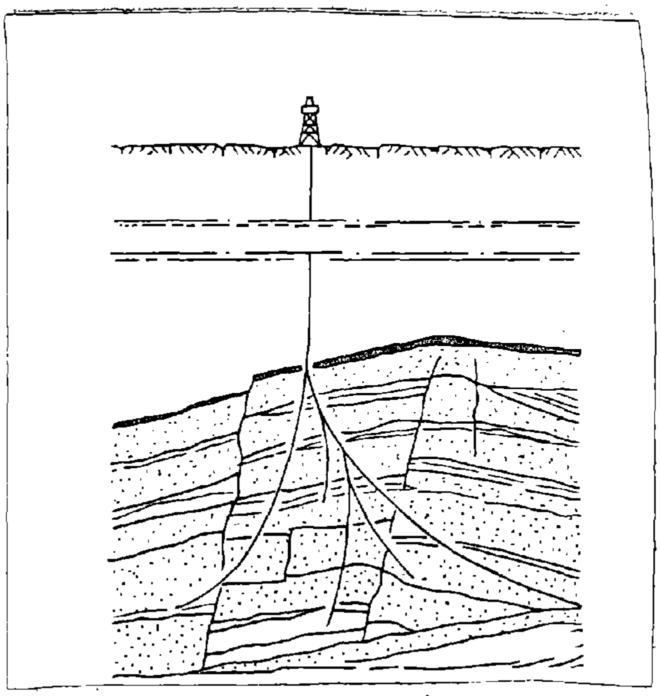


Figure 24. SHALLOW MULTIPLE BRANCH WELL CONFIGURATION (GRIGORYAN, 1976)

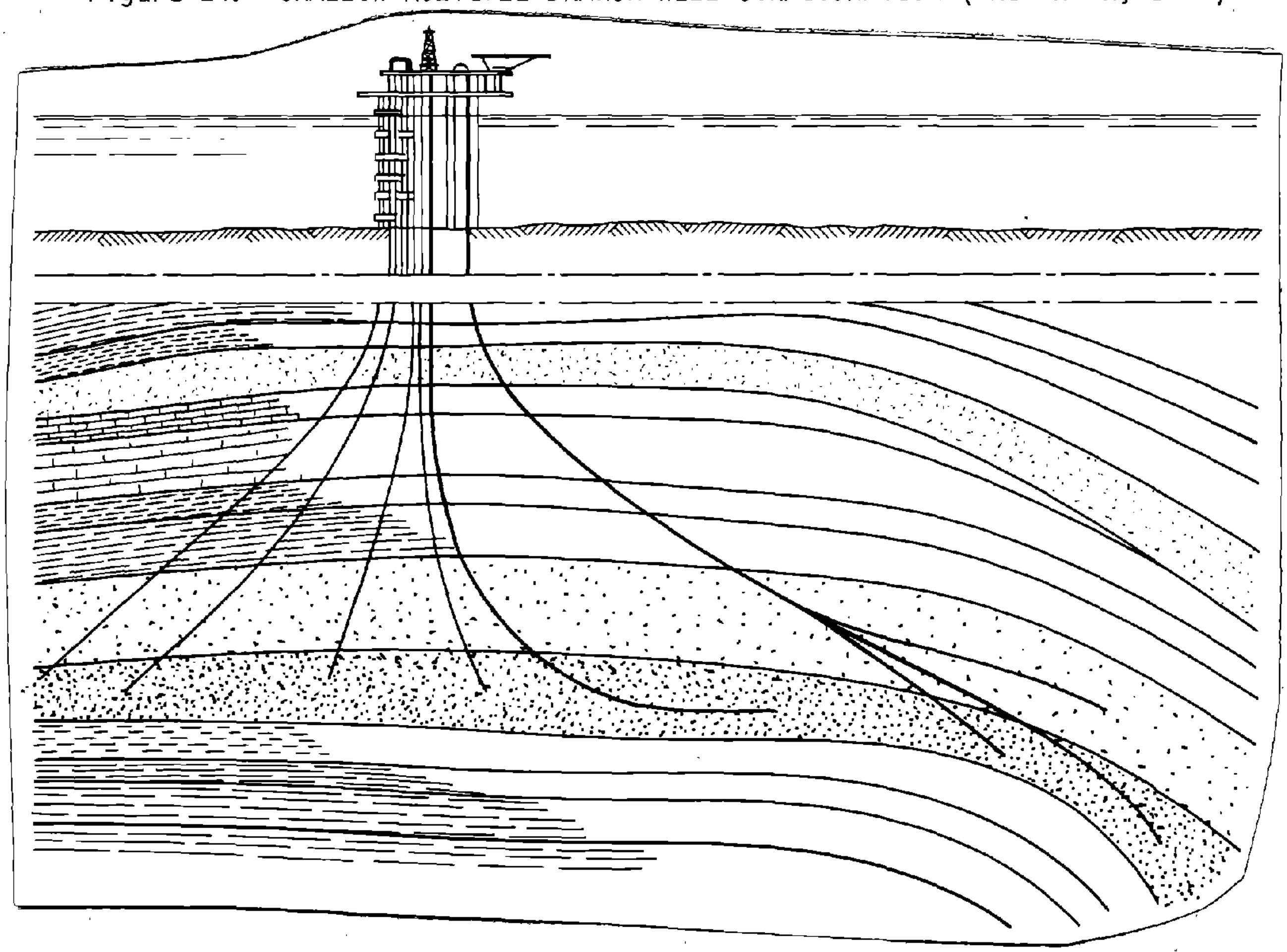
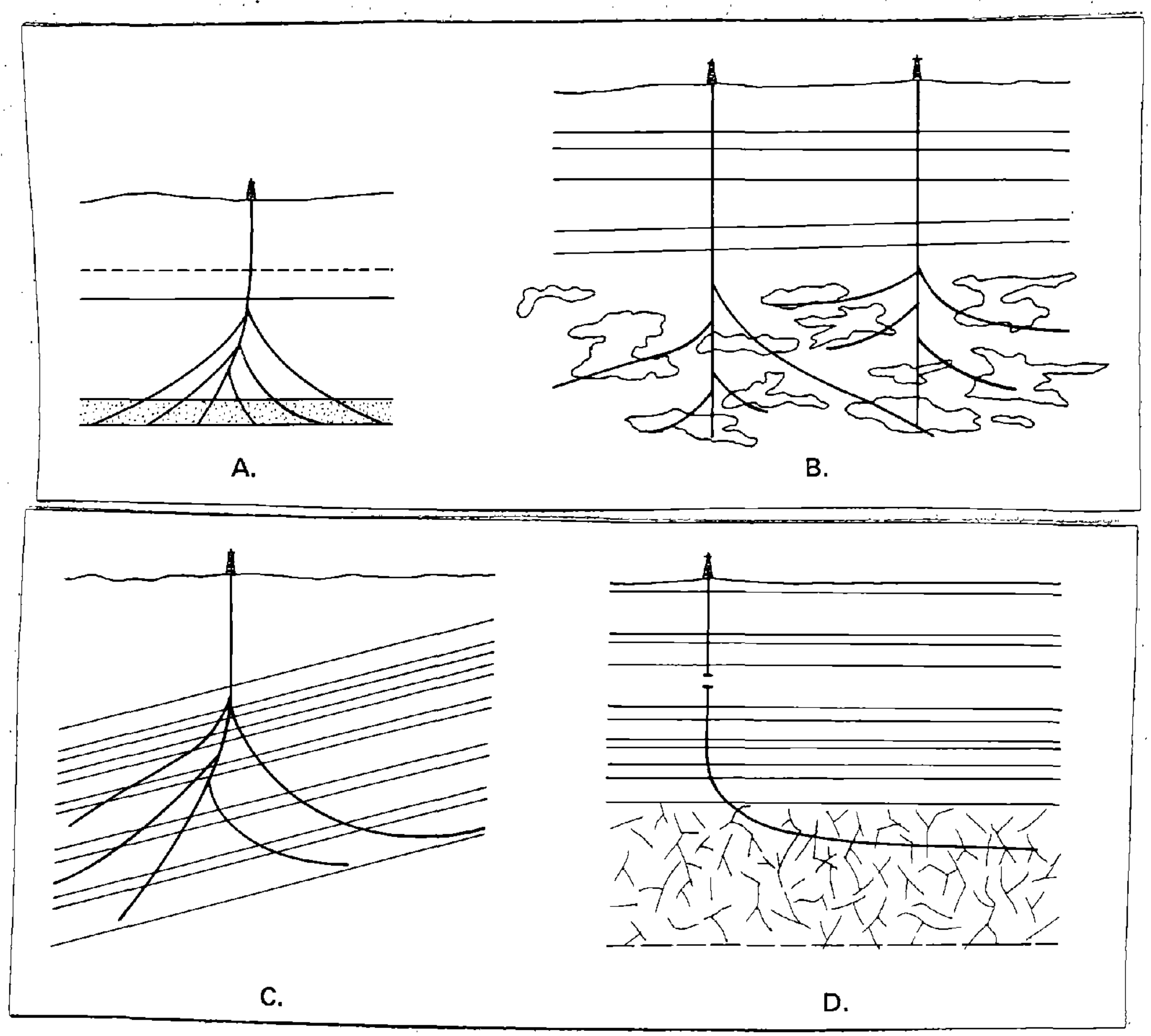


Figure 25. DEEP MULTIPLE BRANCH WELL CONFIGURATION (GRIGORYAN, 1976)



A. Thick formation underlying resistant rock

B. Producing formation is composed of a thick strata of limestone

C. Producing formation has interlayers of shale

Complex geological zones and formation pressures that must be maintained

Horizontal penetration of formation

D. Thick Limestone formation having a predominately vertical fracture pattern

Figure 26. ALTERNATE SHALLOW MULTIPLE BRANCH WELL CONFIGURATIONS (GRIGORYAN, 1976)

Analysis of the well configurations noted in Figures 24, 25, and 26 give credence to three additional advantages claimed for the use of this technology. These advantages are:

1. Improved Exploration Capability. Due to the vastly larger area that can be covered from a single well of this design, a number of cores can be obtained from different geological stratas or zones. Thus, a greatly improved and far more accurate understanding of the geology of the area and its potential value can be obtained.

2. Folded Geology Potential. In areas where the geology is characterized by a number of sharp folds, oil can often be trapped in a number of pockets that can not be economically produced by conventional drilling methods. A single multi-bottom well, however, can tap a number of these pockets and thereby improve the economic potential of the well to the point where it may be worth drilling.

3. Drainage Flow to Old Wells. In areas of low porosity multi-bottom wells can be used as drainage wells to convey oil to lower zones of higher porosity from which the oil could be produced more easily. In this case, gravitational forces are used to help produce areas not originally considered.

Significant production rates and cost advantages have been claimed by the Russians for this technique.[7] In one experiment, 4 multi-bottomed holes were drilled by Ngdu Borislavneft in a small thoroughly exhausted field of fractured sandstone that had been producing since 1914. The field had 30 conventional wells drilled into it spaced 30 to 80 m apart. Notwithstanding the dense arrangement of these wells, four multi-bottom hole wells were drilled. In the fifteen years they produced, they accounted for 47% of the total field production.

Initially, the four wells had flow rates 10 to 20 times greater than nearby wells. After several years of production, formation pressures stabilized and flows from the multi-bottom wells remained at level approximately proportional to the number of branches each individual wells had. Costs for the multi-bottom hole wells are claimed to be 30% to 80% higher than conventional wells drilled into similar geological areas.

Multi-bottom holes are usually cased from the surface to that point where the first branch hole is drilled. This casing is cemented into position with normal oil field procedures. The branches are also cased. This casing, however, acts as a hole stabilizing and strengthening mechanism more than anything else. It, too, is cemented into position. At the point where the main hole and the branch hole intersect,

Figure 27, no casing is used, nor has any mechanism been defined for sealing off this area. The Russians do state, however, that the entire well should be designed so that these intersections occur in very stable areas.[8] It would appear that such intersections could be cement lined in a way that would offer more protection. It should also be noted that the Russians continually state that this multi-bottom hole technique is used in low pressure areas or where the oil has a fairly low gravity.

Two operational wells are described below to complete the discussion of Russian activity on branch drilling.

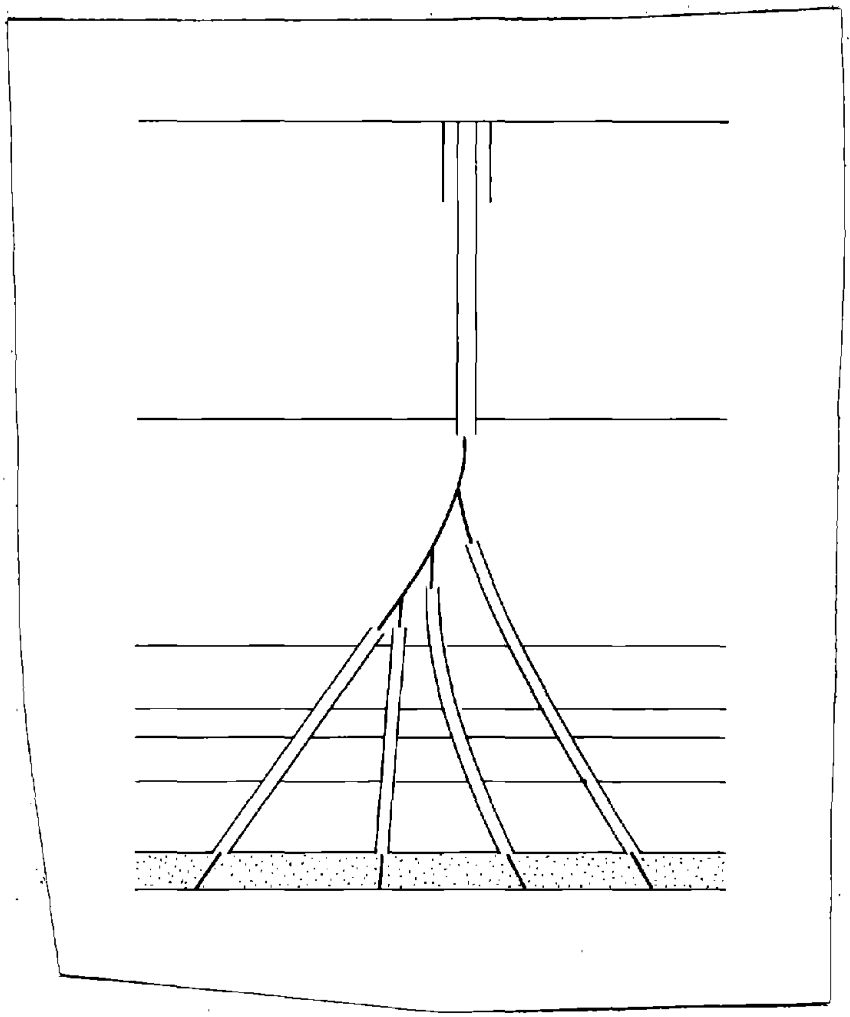


Figure 27. TYPICAL CASING PROFILE FOR MULTIPLE BRANCHES (GRIGORYAN, 1969)

Well No. 1543 - Borislav[9] This well was drilled in the Pol'miny section of the 9th district of Boreslav. The well, Figure 28, penetrated the Yamna producing zone at a depth of 420 m. The pay zone was 45 to 50 m thick and was composed of an alternating sequence of dense sandstone and shales. Five sharply angled shafts were drilled with a minimum radius of 10° per 10 m section of shaft. (Verification of this bend radius has not been obtained.) The maximum distance between the bottom of the different branches was originally less than 60 meters. Shafts I and II, however, were drilled deeper to locate the lower boundary of the Yamna formation and also to increase the drainage surface area. The branches were drilled with short turbodrills, 3.5 m in length.

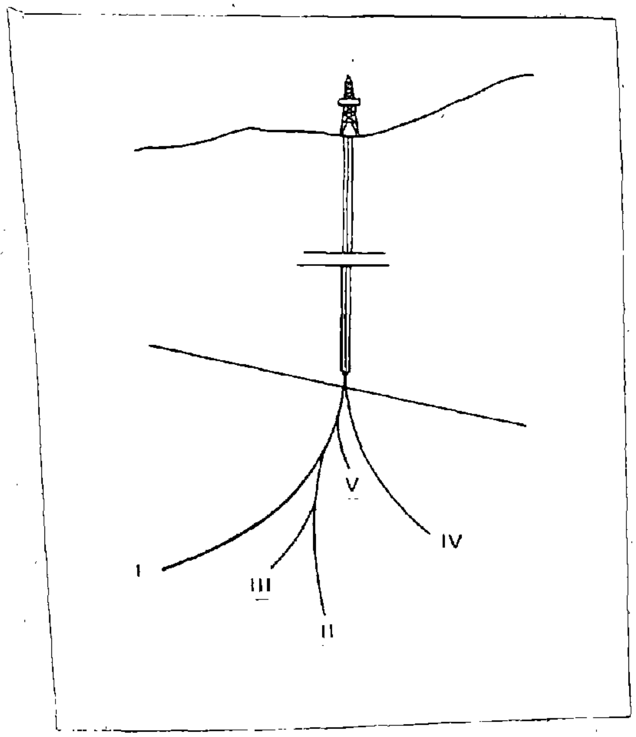


Figure 28. BORISLAV PRODUCION WELL (GRIGORYAN)

The main shaft is cased from the surface to the 385 meter level with a 14 inch liner (Figure 28). Branches II, III and IV are known to be cased. An interesting characteristic of this well design is that the oil produced from branches I, II, III and V is allowed to flow to the intersection of branch IV and then into branch IV. Branch IV contains a bottom-hole pump which then transfers the oil to the surface.

Well No. 801-D-Dolinskoe[10] Multi-bottom hole drilling technology was needed to drill into the Dolinskoe field. This field, composed of complex geologic traps, numerous tectonic disturbances, and considerable lithologic and reservoir hetrogenity of rock formations, appeared to be ideal for this drilling technique. An electric downhole motor was chosen for this application primarily because the power cable could also be used for down-hole telemetry during the drilling operation.

As noted in Figure 29, the vertical part of the hole was drilled to 1704 meters using a 295 mm bit. Whipstocks were used for angle build up of 2.7°-3.3° per 10 meters of penetration. At a depth of 1930 meters, the angle of wellbore inclination amounted to 63°. Drilling continued with 219 mm intermediate casing run to a depth of 2056 m. The hole was continued to a depth of 2242 m. At this point the angle of inclination of the borehole was 96°.

Four branch wells were drilled from the horizontal section of the well as noted in Figure 29. A production liner was placed in the second branch well and run back up to a depth of 2019 m. At this point, it was connected to a 146 mm production casing, run to the surface. Information is not available as to whether the other 3 branch wells were cased. It should be noted that certain incongrueties exist with regard to well depths and inclination angles.

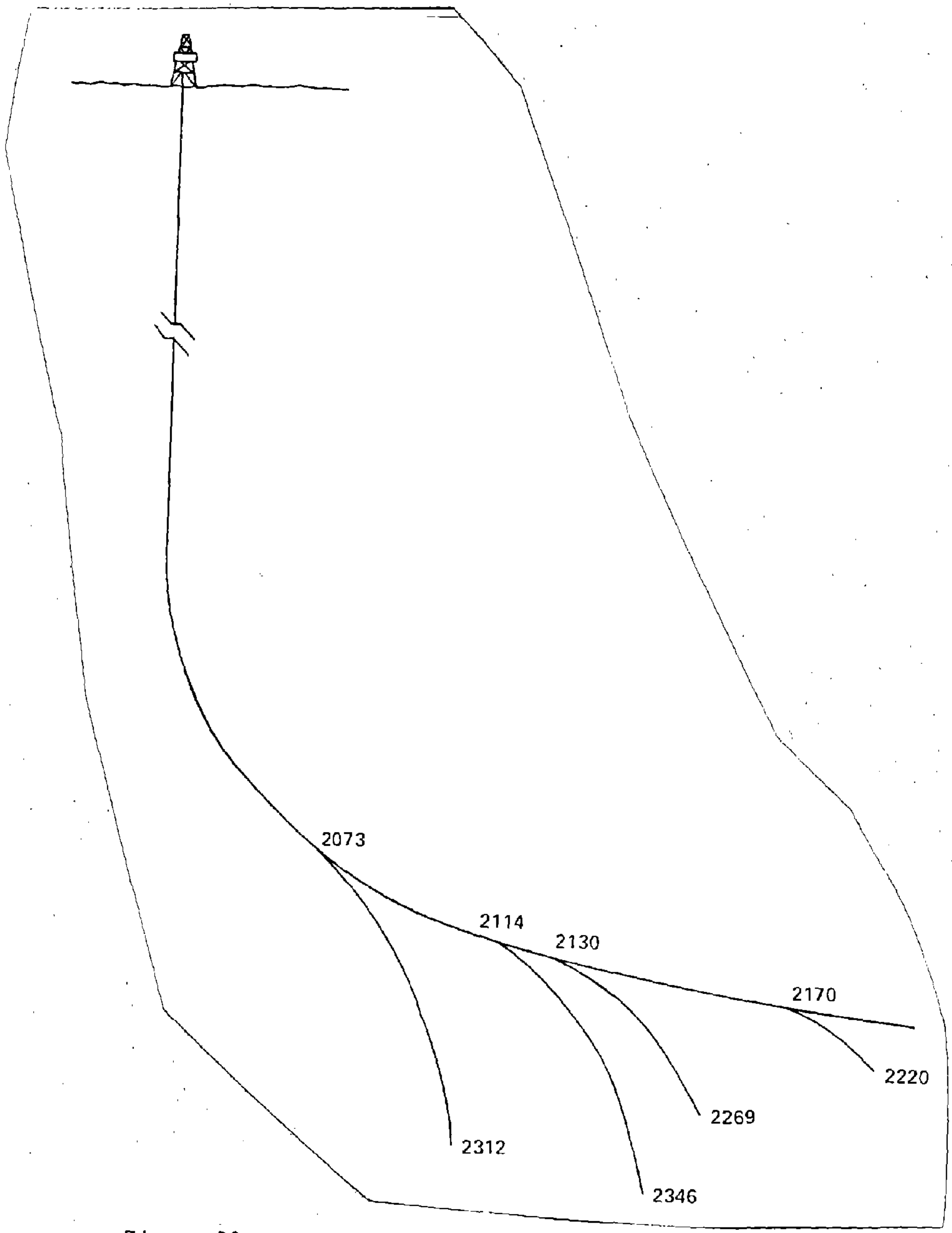


Figure 29. DOLINSKOE PRODUCTION WELL (DITCHUK, 1976)

Although the Russians have drilled numerous multi-bottom holes, the technology is not totally new to the U. S. In the early 1950s, technology was apparently tried in some of the lower central states. At that time it was called "Roots" drilling as the well configuration resembled the roots of a tree. The technology was apparently abandoned due to the lack of effective turbodrills and required accessory equipment.

Recently branch drilling is being applied to geothermal reservoirs and for methane drainage from coal in the U. S.

Branch wells such as the one shown in Figure 30 have been drilled at the Raft River (Idaho) geothermal site. The branch holes were drilled as follows:[11]

> "An 8-1/2-inch hole was next drilled to 4,342 feet or approximately 100 feet below the 9-5/8-inch liner shoe. Directional drilling with Eastman Whipstock services was initiated at this point. The hole drift angle was increased from 4-1/2° at 4,342 feet to 8-1/2° at 4,395 feet, using a Dyna-Drill downhole motor. Conventional drilling was resumed and the first directional leg, RRGE-3A, was completed at a total depth (TD) of 5,853 feet.
>
> "The second directional leg, RRGE-3B, was kicked off at 4,524 feet without setting a cement plug at the kick off point. The desired drift angle of approximately 8° was established after considerable difficulties. Conventional drilling was then used to complete the second 8-1/2-inch hole to a total depth of 5,532 feet. The horizontal separation between this leg (RRGE-3B) and the first directional leg (RRGE-3A) was 220 feet.
>
> "The final directional leg, RRGE-3C, was kicked off at 4,332 feet. A drift angle of approximately 12° was established before conventional drilling resumed and the 8-1/2-inch hole was completed at a total depth of 5,917 feet on May 24, 1976. See Figure 30 for the relationships between the three directional legs (3A, 3B, and 3C)."

In 1979, the Bureau of Mines successfully drilled multi-branched holes into a coal seam[12]. The branches were drilled from the surface out of the bottom of a high angle wellbore. Figure 31 shows the type of branches drilled into the coal seam. The purpose of the multi-branch holes was to drain methane from the coal seam in advance of underground mining.

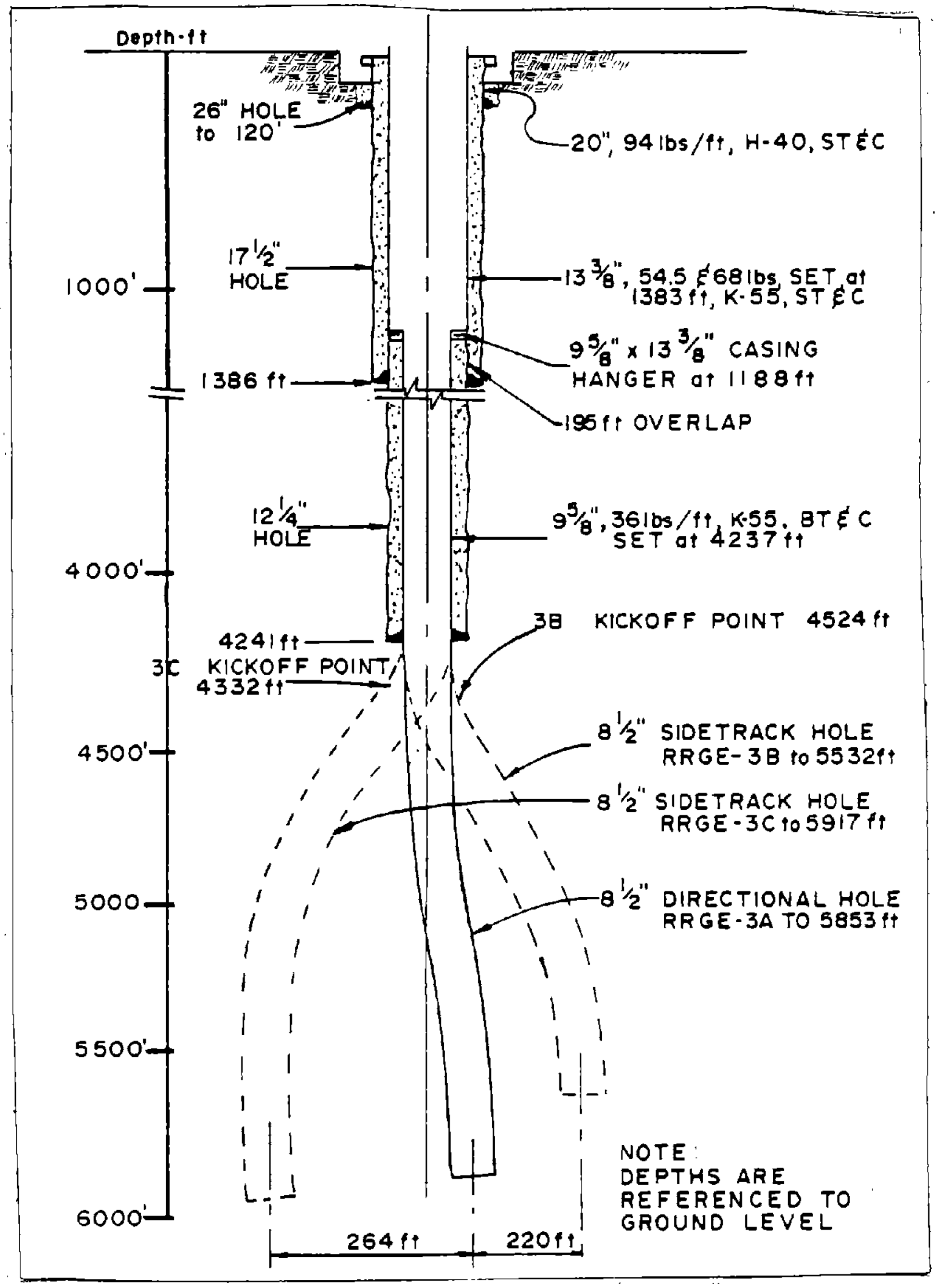


Figure 30. BRANCH HOLE CONFIGURATION IN GEOTHERMAL PRODUCTION AT RAFT RIVER

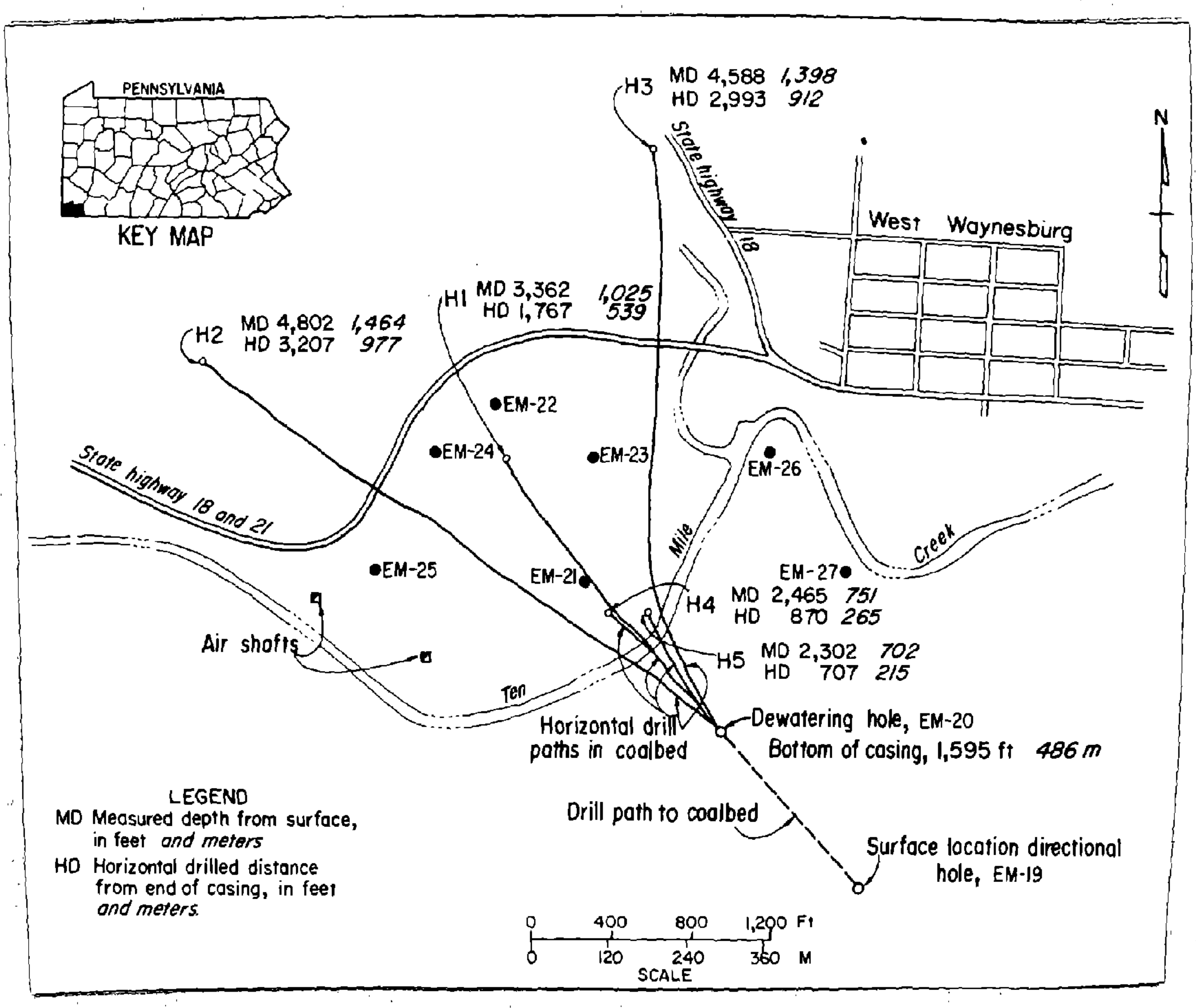


Figure 31. SCHEMATIC PLAN VIEW OF THEORETICAL MULTIPLE WELL DIRECTIONAL DEGASIFICATION SYSTEM (DIAMOND, OYLER, 1980)

In both examples, Raft River and Emerald Mine, previous branches were not re-entered or cased. Herein lies the main problem in applying branch drilling to in situ leaching operations (i.e., individual branches must be re-entered with casing). We overcame this problem by use of downhole templates as explained in another section of this report.

Horizontal Drain Hole Drilling

Horizontal drain holes are drilled from vertical wellbores with a special articulated bottom-hole drilling assembly. A drain hole is deflected from the vertical wellbore with a whipstock and may penetrate the formation laterally to around 200 feet (see Figure 32). The purpose of drain hole drilling in the petroleum industry is to increase productivity. Some of the claims attributed to drain holes are:

- Enhanced recovery flooding efficiency is improved.
- Natural fracture systems may be intersected.
- Tight or virtually impermeable formations may be producible.

Drain hole drilling reached its peak in the 1950s when it was gradually replaced by hydraulic fracturing as a well stimulation technique.

Drain hole drilling tools have been patented and built as far back as the turn of the century. In the early 1930s, about 120 wells in the Mid-Continent were provided with drain holes. In the early 1950s, drain holes were drilled in approximately 50 wells mostly in California.[13]

A patent granted to J. L. Addison in 1891 was titled "Groove Cutting Machine for Oil or Gas Wells." The stated object was to "renew or increase the flow by opening fresh fissures, channels, or cavities." In 1919, Bernard Granville patented an apparatus which could possibly drill horizontal holes "several hundred feet."

In 1930, Robert E. Lee of Coleman, Texas, patented an air-actuated percussion drill for forming laterals. He had observed experiments run by the Bureau of Mines in the late 20s and was convinced that a device which would form these channels could increase productivity. After some testing of this equipment, he concluded a rotary bit would be much better.

Lee then developed rotary equipment which was used in 1929 to drill the first successful drain holes. These were located at Texon, Texas, and were drilled for Big Lake Oil Company. Two 5-1/4" laterals were completed around 3,000 feet. These extended about 23 to 24 ft into the pay formation. There was a significant increase in production, especially in the period just following recompletion.[14]

John Zublin patented drain hole drilling equipment in 1945. The main features of his first methods were flexible drill pipe and turbine-drive motor bit. The pipe obtained its flexibility through a spiral cut in the wall of the pipe. A high-pressure hose fixed in the inside of the pipe prevented leakage. A concurrent patent by Zublin covered a whipstock-like device which could be used for very hard formations.[15]

Several wells in California were reworked with Zublin drain hole drilling equipment. One well was down to producing about one barrel per day. After being shut down for 17 years, it was re-completed with 8 drain holes, averaging 53 feet each. Light weight mud operated the turbine bit with pump pressure running between 400 and 600 psi. Afterwards, production rose to a high of 25 barrels per day and averaged about 20 barrels per day. The same tools were used in more lateral drilling in subsequent wells in California.[14,15,16]

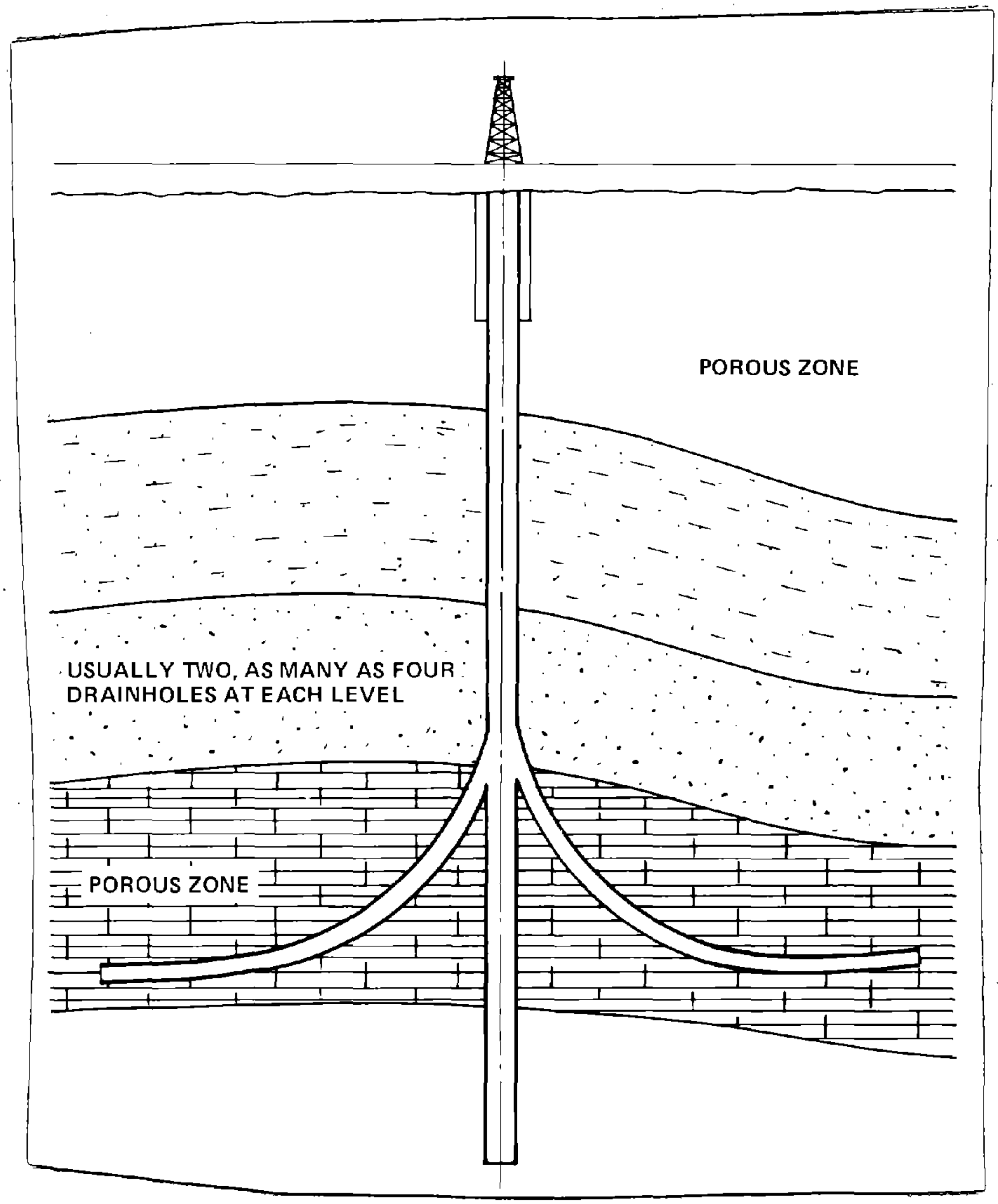


Figure 32. HORIZONTAL DRAIN HOLE

Later on, Zublin developed drain hole drilling based on rotating the entire drill string.[17] His equipment forms the basis of further developments.

By the early fifties, a workable technique for drilling drain holes evolved. Two main features of this technique are a whipstock assembly and a flexible rotary drill string.

The whipstock itself has a high face angle (8-14°) and has a sheath attached to it which extends for several joints. This length of sheath serves to stabilize and prevent damage which might be caused by the flexible drill string. Usually there is more sheath than length of flexible collars. This ensures the ability to pick up the whipstock assembly with a stiff drill string. The whipstock assembly can be hung from casing or fixed by the use of an anchor bit-tailpipe assembly. Pick up slots are provided so the whipstock can be used again at the same level, but in a different direction.

The drilling assembly itself consists of a centralizer, special-cut flexible drill collar, a universal (knuckle-type) joint, reamer sub, and conventional bit. The drill collars are made flexible with a cut similar to Zublin's toothed type. This has evolved in recent years to a special four-lobed nonspiraling cut. A universal joint-reamer-bit combination acts as a fulcrum and lever. The universal joint pushes on the upper end of the reamer. The reamer blades act as the fulcrum and force the bit to drill up, thereby building angle.

Although it is a well developed technique, several problems are inherent. Horizontal steering for example. Friction and reactive torque combine to cause the flexible collars and universal to "walk" up the side of the lateral bore and change hole direction. The solution to this problem is selection of a mud with adequate lubrication properties and finding the correct weight-on-bit.

There have been numerous examples of successful applications of horizontal drain holes. Many drain holes were drilled in the fifties in California. Success has been attributed to the softer sands of that region. Many of the failures there were attributed to the lack of a liner. In Texas and Louisiana, the success rate is somewhat lower. In Wyoming, several attempts were made and the success rate was very poor.

There appears to be a renewed interest in drain hole drilling because of the rise in oil prices. The method offers a way to rework old fields for additional oil recovery. Much of the drain hole drilling technology of the 1950s is dormant. One contractor, however, is still active. Tools marketed by Holbert drill with a radius of 38.2 feet and build angle at the rate of 1-1/2° per foot. Holbert's downhole equipment is shown in Figure 33. The flexible drill pipe is a key element. It is made from standard drill collars by torch cutting multiple four lobed universal joints. Drilling mud is pumped through a hose attached to fittings inside the box and pin connections.[18,19]

A special universal joint directly above the bit is designed to concentrate the force applied to the bit at a point below the center line of hole. Thus acting as a lever, with the blades of the reamer as a fulcrum, the bit is forced to dig to the high side of the hole. This causes a continual increase in angle as the hole is drilled.

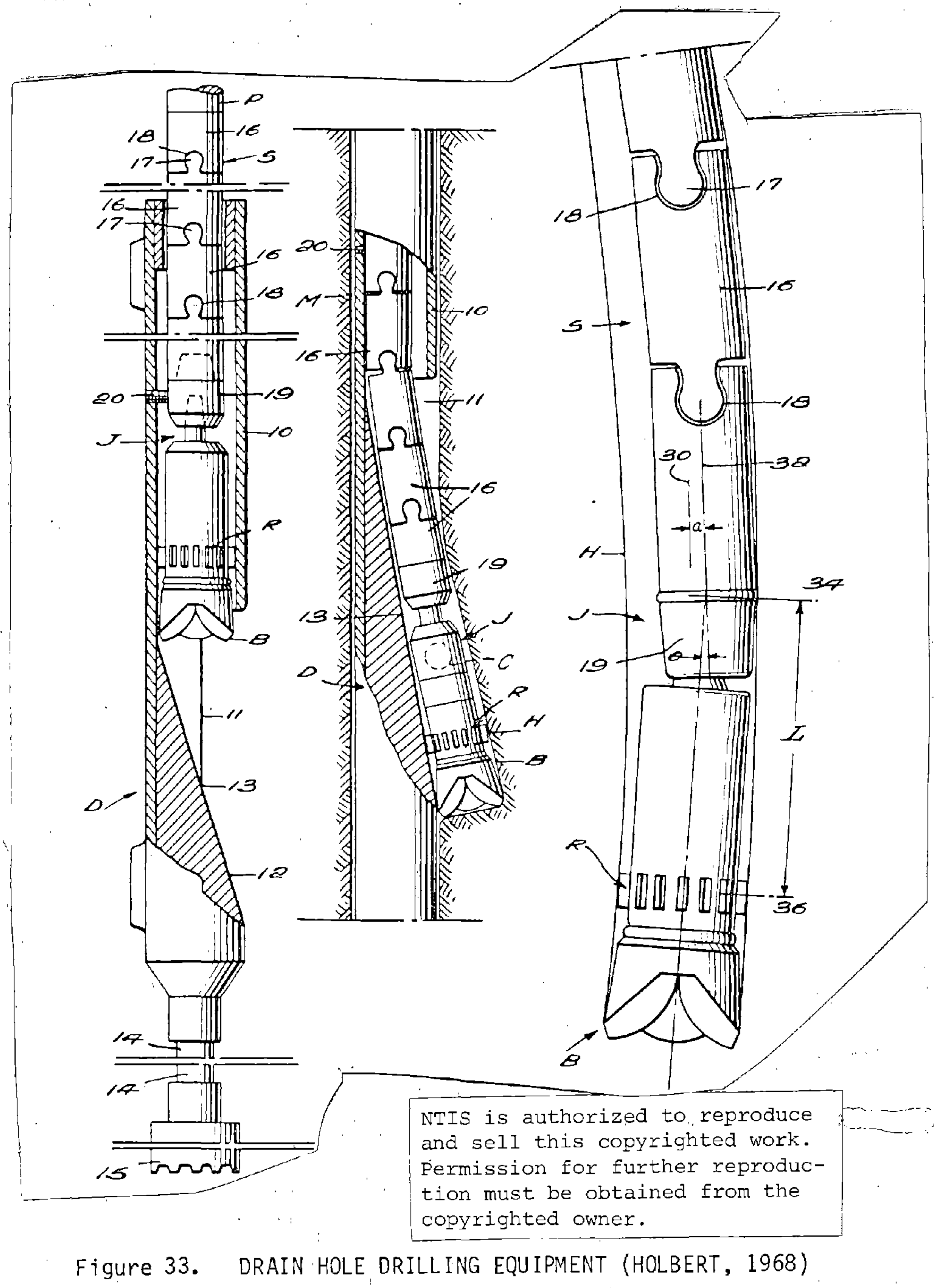


Figure 33. DRAIN HOLE DRILLING EQUIPMENT (HOLBERT, 1968)

High Angle Buildup to a Shallow Formation

High angle holes are also being drilled into fossil fuel bearing formation lying within a few hundred feet near ground level. Total angle for these holes is near 90°. The objective here is to penetrate the formation with a horizontal hole section after total angle is achieved. Horizontal holes allow better recovery rates and recovery levels than do vertical hole penetrating through the formation. Four wellbores of this type are discussed below.

Esso Resources Ltd. of Canada has successfully drilled and completed a 90° total angle wellbore and penetrated a 260 foot tar sand zone 1,452 feet deep.[20] Details of this wellbore are shown in Figure 34. It is the first well of this type and will be used in an in situ recovery pilot operation at Cold Lake (Canada). Other wells in this area have been deviated up to 35° from the vertical.

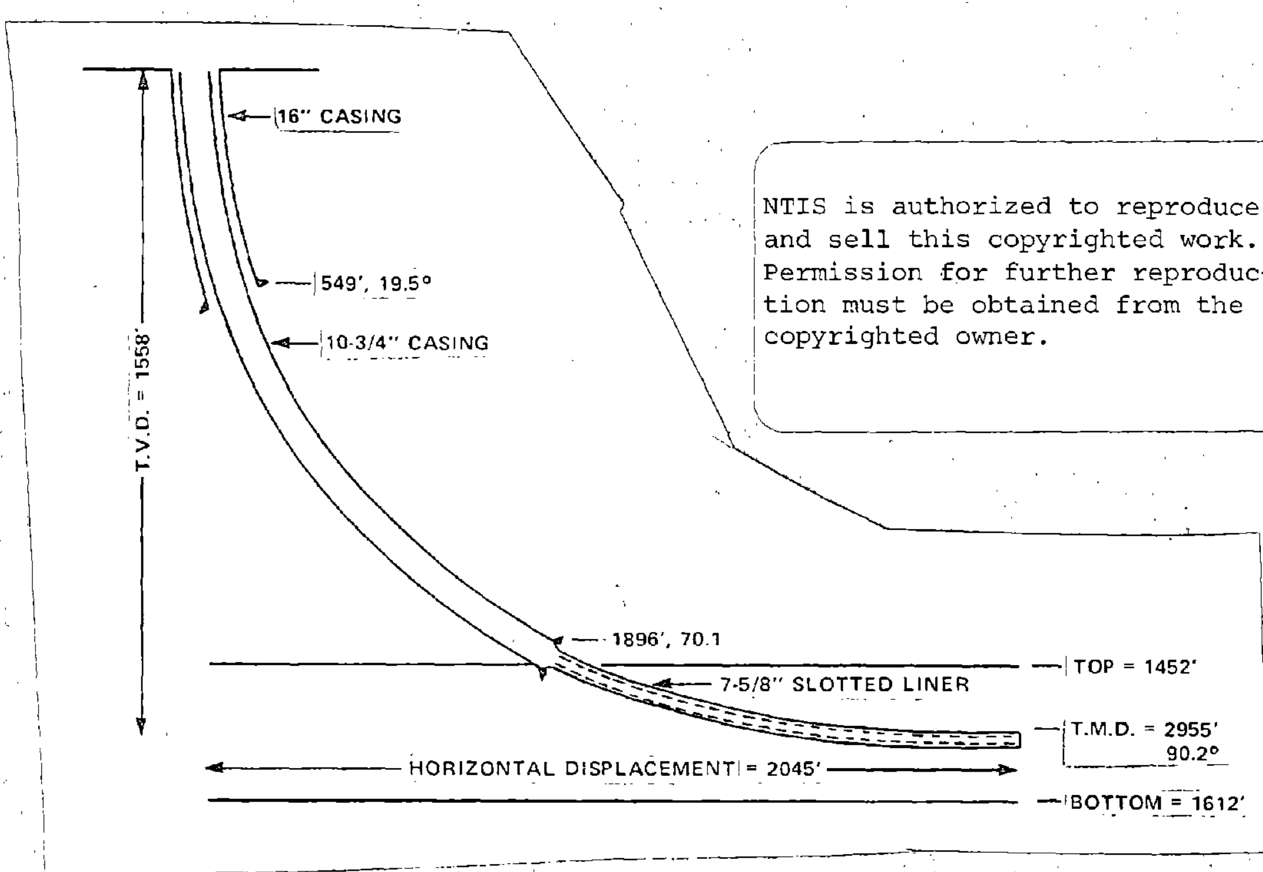


Figure 34. HIGH CURVATURE WELL INTO TAR SANDS (BEZAIRE, MARKIW, 1979)

Two general types of downhole assemblies were used in drilling the well, an angle building assembly and a hole opening assembly. The angle building assembly consisted of a mill tooth bit rotated by a Dyna-Drill.* A 6-1/2-inch Dyna-Drill was used in both the 12-1/4-inch and the 9-1/2-inch pilot holes. Angle building was accomplished using either a bent sub or a bent housing Dyna-Drill. The three bent subs were 1.5°, 2°, and 2.5°. Heavy weight drill pipe was run immediately behind monel collars so that steel drill collars could be placed further uphole in the more vertical section of the hole, providing weight on bit. This is contrary to current directional drilling practice but no pipe buckling problems were noted. This drill string assembly also reduced the chances of differential sticking. The hole opening assembly consisted of a pointed bullnose, a nonrotating stabilizer, followed by the reamer.

Directional surveys played a critical role in the success of the project. The horizontal portion of the hole was to be located near the bottom of the tar sand formation. The steering tool was used at all times in the pilot holes. Single shot magnetic surveys were run every 60 feet to provide a permanent survey record as the hole progresses. A telephone link from the drilling location to a computer in Edmonton was available and continuous computation of hole trajectory was maintained. A continuous surface readout appears to be indispensable for operational purposes.

As the hole inclination approached higher angles, the frictional drag on the drill string increased and satisfactory weight on bit became more difficult to maintain. Drill string drag during trips was usually about 10,000 to 15,000 pounds.

The most troublesome problem occurred in enlarging the 12-1/4-inch pilot surface hole. Initial efforts to ream the pilot hole with a 30-foot long bullnose was not successful. A short non-rotating stabilizer ahead of the hole opener was able to follow the pilot hole successfully. An angle buildup rate of 4-1/4° per 100 feet was maintained with 12-1/4-inch bits. All casing strings went in very smoothly.

In 1975, Morgantown Energy Research Center (MERC) contracted to have a high angle hole drilled into a coal seam near Pricetown as part of a program to study underground coal gasification.[21] The coal bed is 880 feet below ground level and is 6 feet thick at the test site (see Figure 35). The objective of the drilling program was to build hole angle until reaching the coal seam and then drill horizontally in the coal bed for a distance of 500 feet. It was necessary to tilt the derrick at an angle

* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

of 10° and build hole angle at a rate of 5-1/2° per 100 feet. Approximately, 60 feet of surface casing was set and then a 3-inch pilot hole drilled until the coal seam was penetrated. The hole was then reamed out to 7-7/8-inch and 5-1/2-inch casing set from the coal seam to the surface. Drilling continued horizontally with a 4-3/4-inch bit for approximately 500 feet. Drilling was accomplished with 2-3/8-inch Dyna-Drill downhole motors. Problems encountered during the 10-1/2 month drilling program can be classified into the following categories:

(1) Rig Trip Time
(2) Mechanical Failures
(3) Plugging and Sidetracking
(4) Hole Surveying and Tool Orientation
(5) Reaming
(6) Lost Circulation
(7) Pump Repairs

This drilling program showed that high angled directional wells can be drilled and inserted into coal seams for at least 500 feet. As this was an experimental drilling program, the costs were high. The cost of drilling this type of hole must be greatly reduced for in situ coal gasification to be commercially feasible.

Slant hole drilling from the surface using direction drilling techniques is being evaluated by the U. S. Bureau of Mines (USBM) as an alternate method for drilling horizontally into coal seams. Drilling is conducted from the ground surface instead of at the coal face and requires accurate directional surveying and bit control to hit the coal seam at a near horizontal slope (see Figure 36). Their project includes drilling into the Pittsburgh coal bed at the Emerald Mine near Waynesburg, Pennsylvania. A detailed description of the USBM project is given in Reference 12.

One goal of the USBM project is to drill a circular arc directional well having a planar radius of about 1,000 feet and then continue the drilling program with boreholes horizontally into a coal seam.

This wellbore was drilled with a truck mounted drilling rig using a 2-3/8 inch Dyna-Drill* having a bent housing. Accurate directional surveying, using Eastman Whipstock* magnetic singleshot equipment, was a key factor in the successful drilling of this hole.

* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

Bit force was generated by hydraulic cylinders pushing down on the drill pipe at the surface. Part of this push down load was absorbed by friction and confining forces along the drill pipe so the magnitude of the bit force was not exactly known during the drilling. The axial bit force component, however, can be monitored reasonably well from the known pump pressure. The Dyna-Drill* is a positive displacement motor so pressure drop across the motor is a good indicator of output torque and thus, bit thrust force.

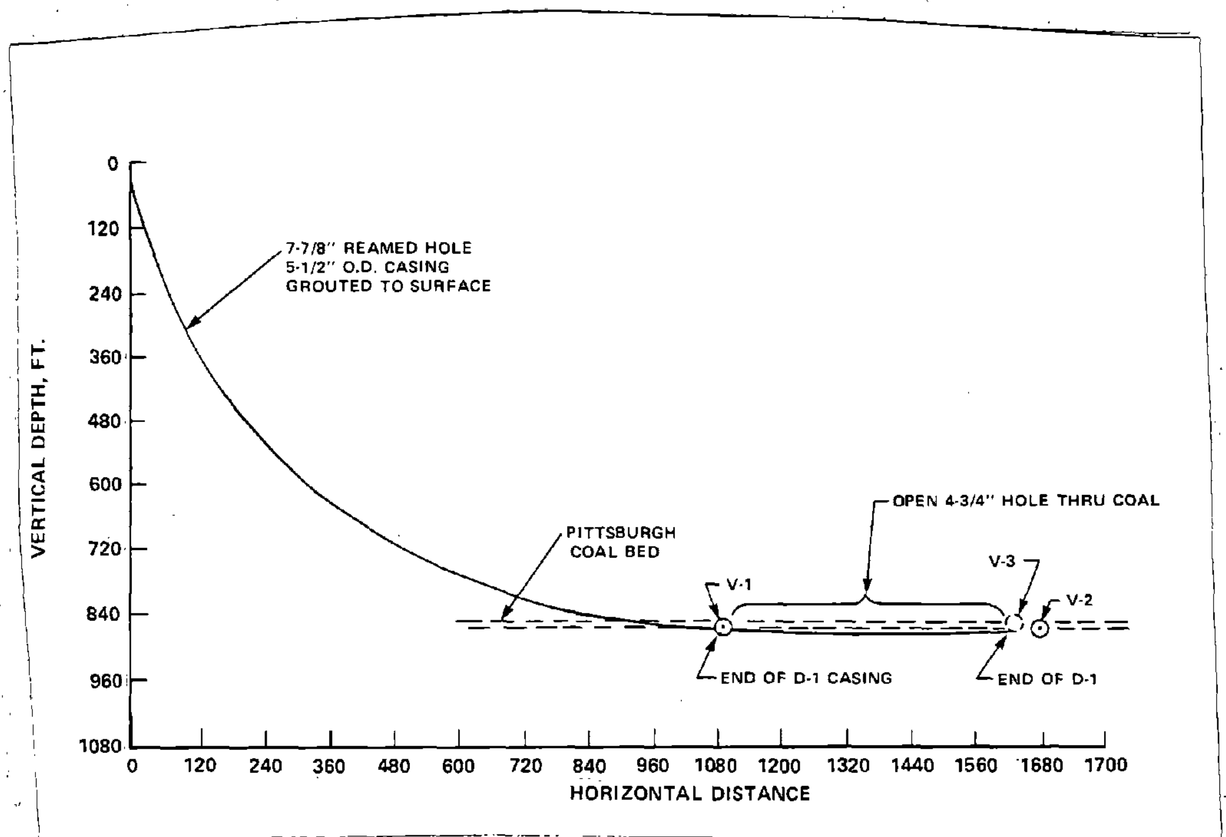


Figure 35. PRICETOWN SLANT HOLE (SHUCK, PASINI, MARTIN, BISSETT, 1976)

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* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

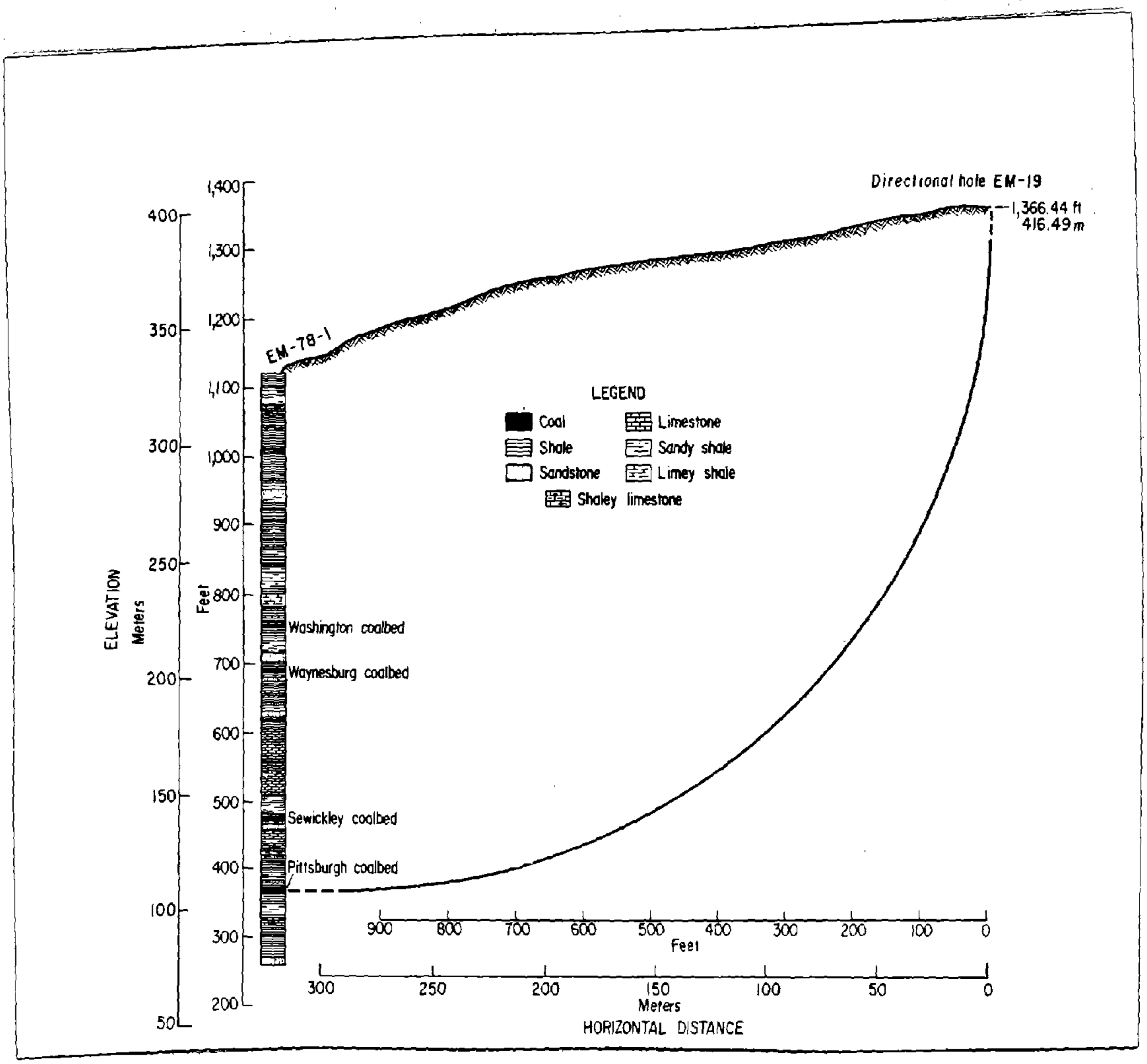

Figure 36. EMERALD MINE SLANT HOLE WELL PATH WITH GEOLOGIC COLUMN (DIAMOND, OYLER, 1980)

Lawrence Livermore Laboratory recently drilled a direction hole to penetrate a coal seam at Hoe Creek, Wyoming. The drilling rig was slanted about 30° and hole angle was developed at a rate of 5° per 100 feet in order to horizontally penetrate a coal seam about 150 feet below the surface. The coal seam is 25 feet thick. The horizontal portion of the hole in the coal seam was approximately 200 feet long.

Low penetration rate of 3 to 5 ft/hr was due to low bit force and the need to use diamond bits. Diamond bits were used because conventional roller bits cannot be used much beyond 150 RPM; the Dyna-Drill operated at 400 RPM. Low bit force was required to maintain directional control.

Since most of the costs are related to drilling the curved portion of the hole, it is important to be able to drill at least 500 feet in the coal.

High Angle Buildup Followed by Long Lateral Hole

Typical oil and gas hole configurations have target coordinates around 10,000 feet vertical distance and 12,000 feet lateral distance. The high cost of offshore installations, such as platforms, subsea wellheads, and flow lines, is giving impetus to drilling that results in a much greater lateral to vertical distance ratio.

In 1975, Tenneco Oil Company drilled three high angle holes (60°, 70°, and 80°) from a single platform.[22] By increasing the angle from 60° to 80°, the area that the well can investigate increased over sevenfold. Figure 37 shows how the hole angle was built at 4° per 100 feet to 80° and then a high angle straight hole drilled to the target.

Planning was a key factor in the success of these wells. Drilling rig selection and modifications were made to maximize drilling efficiency in order to prevent any downtime during drilling that might result in loss of the hole. An extensive review of high angle drilling in their area of drilling along with an action plan helped to provide a technically and economically sound basis for their high angle drilling program.

Angle buildup began after a 16-inch conductor pipe was cemented. The directional hole was kicked off at 1,350 feet with a Dyna-Drill* and a 9-7/8-inch bit, building about 4°/100 feet. This bit size was selected instead of a 15-nch bit to maintain closer directional control. The

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9-7/8-inch surface hole was opened to 15 inches with a bullnosed hole opener. A 10-3/4-inch surface casing was set after the angle buildup was completed allowing a relatively straight shot to TD. Thus, precluding possible key-seating problems.

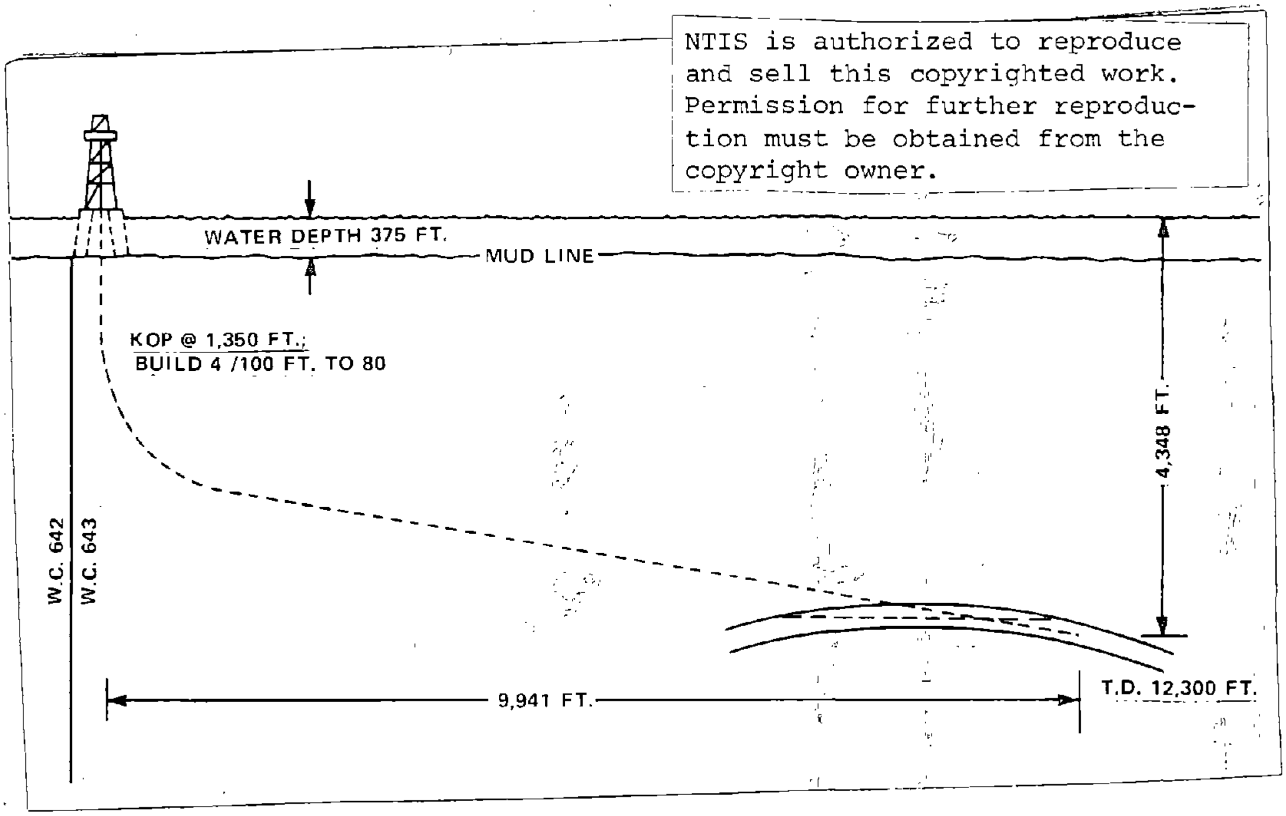

Figure 37. ULTRAHIGH-ANGLE HOLE (EBERTS, BARNETT, 1976)

There is little technology or experience for designing bottom-hole assemblies to lock in the required angle for high angle holes. The hole, therefore, had to be babied to prevent excessive porpoising. Single shot surveys were taken about every 180 to 240 feet and after each survey, drilling parameters had to be altered to keep the angle in check.

A possible discrepancy was found at high angles with the industry-recognized charts for nonmagnetic drill collar requirements. More nonmagnetic drill collars, than normally recommended, were required to give consistant survey readings.

Directional wells reaching maximum angles of 74° have been drilled by THUMS.[23] They report few stuck pipe and lost hole problems. Success is attributed to planning, optimum kickoff depths, using well plats, directional surveys, and good drilling techniques.

Their experience dictates that angle buildup must be limited to 6° per 100 feet and maximum hole angle held to 70°. Drop-off rate is limited by the ability or inability of drilling assemblies to deflect the hole downward. Experience indicates that even at slow drilling rates, angle reduction greater than 2-1/2° per 100 feet can rarely be attained.

Straight Horizontal Drilling

A review of the patents and discussions with mining engineers indicate that horizontal drilling into coal seams is relatively new. The first drilling of this type was first conducted in the United States in the early 1950s. In the early 1970s, Consolidation Coal Company began an intensive research effort to develop a drilling system which would drill into coal seams, monitor the location of the bit, and guide the drill bit within the coal seam. The technique for loading the drill bit was only one aspect of their total drilling research program. Continental Mining Research has stimulated much of the hardware development discussed below.

One innovative system for drilling horizontally into coal seams was developed by Drilco.* This system, sometimes called the "Kreepie-Krawler,"* is made up of a downhole Dyna-Drill* fluid motor and a downhole mechanical thruster. The thruster unit has the capability to

- Apply axial force to the drill bit
- Grip the walls of the hole
- Walk the downhole unit either forward or backwards
- Apply lateral force to the drill bit for directional hole control

The "Kreepie-Krawler" unit is powered and controlled hydraulically through a bundle of hoses which serves as an umbilical to a power source outside the hole (Figure 38).

* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by Bureau of Mines.

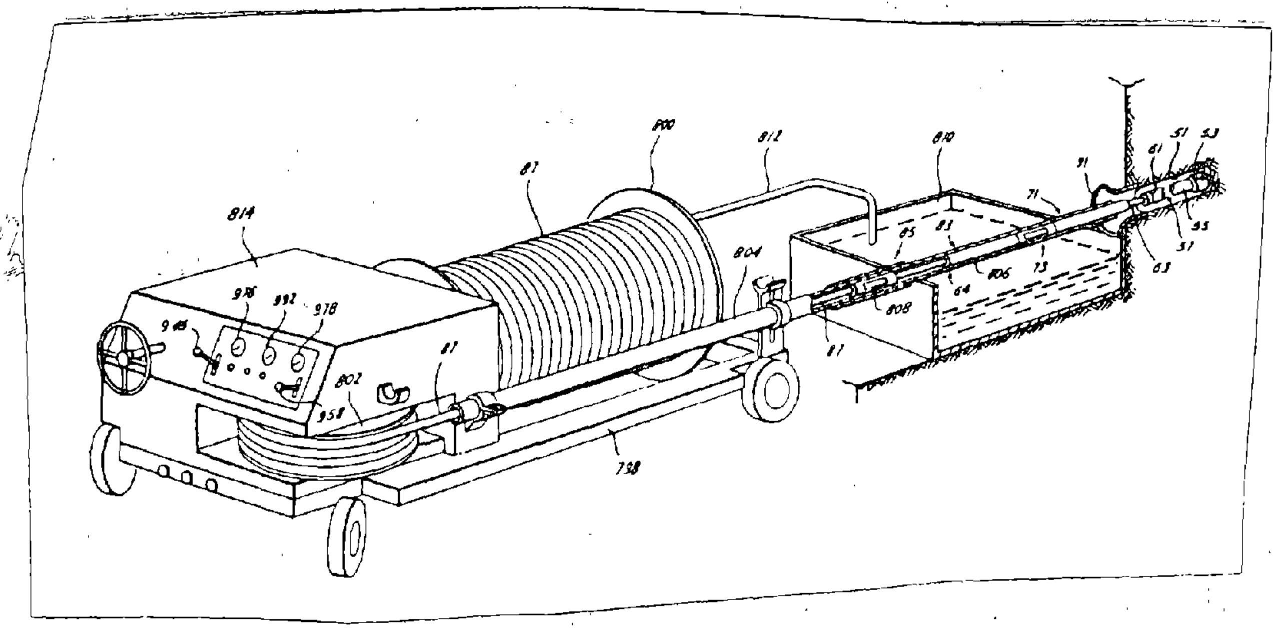

Figure 38. HORIZONTAL DRILLING MACHINE

The design philosophy behind the "Kreepie-Krawler" was an omni directional drilling system which would be compatable with automation. A hose bundle is more amenable to automation than drill pipe. Hydraulic thrusters near the bit give more direct control of the drill bit than do stabilizers or bent subs.

Drilco developed two different thruster size; a 5-3/4-inch O.D. tool and a 2-3/4-inch O.D. tool. Both have been used to drill several thousand feet into coal beds. The maximum length for a single hole (6-inch diameter) was in excess of 700 feet. Some of the characteristics of the 5-3/4-inch tool are:

Outside Diameter	5-3/4 in
Length	128 in
Stroke	30 in
Power Required	5 hp
Maximum Axial Thrust	7,000 - 8,000 lbs
Normal Drill Thrust	1,000 - 4,000 lbs
Normal Drilling Rate	200 ft/hr (occasionally 1,000 ft/hr)

Operational concerns with the "Kreepie-Krawler" are: the hose spool is cumbersome and there may not be enough room in a 5-foot coal seam for, say, 2,000-3,000 feet of 3-inch hose bundle.

Another drilling system for drilling horizontal hole at the coal face was developed by Acker Drill Company, Inc.* of Scranton, Pennsylvania. This system, which Acker labels "Big John," uses drill pipe to transmit rotation and axial thrust force to the drill bit. It has the capacity to drill horizontally to a depth of 3,000 to 5,000 feet. Downhole motors can be used in their drilling system, however, rotary power usually is delivered from outside the borehole.

Another underground mobile drilling rig was designed by Continental Oil Company and fabricated by J. H. Fletcher and Company* of Huntington, West Virginia. Thrust is developed outside the wellbore and transmitted to the bit by drill pipe.

Two of the first horizontal drilling machines built for coal mine operations were fabricated by the Longyear Company* of Minneapolis and Sprage and Henwood of Scranton, Pennsylvania. Both types are still in operation today.

Controlling hole direction is a major problem in drilling horizontally into coal seams. Coal is soft and side loads on the bit can easily build hole angle. When bit thrust is generated outside the borehole and transmitted through drill pipe, the entire drill pipe will buckle as a Euler column within the confines of the borehole. Stabilizers and drill collars are therefore required near the drill bit to eliminate pipe buckling near the drill bit and to control drilling direction.

There are two types of bottom-hole assemblies being used with underground mobile drilling rigs which use drill pipe to transmit axial force to drill bits. One is called the rotary borehole assembly. The other is called the nonrotary borehole assembly.

The rotary borehole assembly contains two stabilizers separated by a 20-foot drill collar section; the drill bit is adjacent to the bottom stabilizer. The entire assembly rotates with the drill pipe. The purpose of the two stabilizers and drill collar is to control hole direction. If a directional survey indicates the borehole needs to be turned up, the back stabilizer is removed and bit weight is increased to about 2,500 lbs. To turn the bit down, the back stabilizer is replaced, the

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front stabilizer removed, and bit weight is reduced to about 1,000 lbs. Normally both stabilizers are used with a bit weight of about 1,500 to 1,700 lbs applied through the drill pipe.

The nonrotary borehole assembly as proposed by Continental Oil Company includes a drill bit, deflection device or side thruster, downhole motor, and stabilizer.

> "The deflection device is a spring-loaded, eccentric sub which exerts a constant force on the side of the bit. The direction of this applied force depends on the orientation of the device and determines whether the bit will be deflected up, down, left, or right. The magnitude of this force and hence the rate of angle build is controlled by the size of the spring."[24]

The advantage of this assembly is it allows more directional control while drilling and provides nonrotating locations for downhole directional sensing instrumentation.

APPENDIX B

IN SITU LEACHING BACKGROUND

COMMODITY

The principal mineral commodities that will be discussed are uranium, copper oxides and sulfides. Of secondary interest at the present time are the molybdenum and nickel sulfides. Although these minerals may have suitable deposit characteristics to make in situ leach mining operations a favorable alternative of mineral extraction, no interest or activity has been identified to date.

The two most common uranium minerals which are extracted by leach mining operations are uraninite and coffinite. These minerals occur in two basic types of lithologies, i.e., in sedimentary sandstone and conglomerate deposits and in hard rock igneous and metamorphic rocks such as granites, syenities pegmatities, gneiss and schist. Over 96 percent of the uranium reserves in the U.S. occur in the former type of deposit. To date, most ISL production of uranium has been in sandstone and conglomerate deposits in South Texas, Wyoming, Colorado and New Mexico.

Both copper oxide and copper sulfide minerals can be mined by ISL methods. Copper oxides (including malachite and chrysocolla) and copper sulfides (such as chalcopyrite, bornite and chalcocite) occur in porphyry copper deposits, vein deposits, replacement deposits, etc. The bulk of this resource is located in the Southwestern U.S. in Arizona and New Mexico. Other copper deposits which may be suitable for leach mining occur in Colorado, Montana, Utah and Minnesota. To date, Kennecott Copper Corporation has done developmental work on the leaching of a copper sulfide deposit at Safford, Arizona, and Occidental Minerals is working on the development of a pilot leaching plant for copper oxides at Miami, Arizona.

In addition to the uranium and copper minerals discussed above, other commodities which may be candidates for leach mining in the future could include deposits of nickel and mobybdenum sulfides. A copper-nickel sulfide mixed deposit, such as the chalcopyrite-pyrrhotite mineralization associated with the Duluth Gabbro Complex in Northeastern Minnesota, could be an ISL target in the future. Similarly, the Climax Molybdenum Deposit of Colorado could represent a possible target site for leach mining techniques if this deposit is found to have the type of ore body characteristics that are suitable for ISL procedures.

GEOLOGY

Many mineral deposits in the United States are low grade and too deep to be commercially mined at a favorable rate of return by conventional mining methods. A survey of the geology of U.S. mineral resources has been made to determine the likelihood of finding deep lying low grade deposits.

There are two basic types of uranium deposits, sedimentary and hard rock. In situ uranium operations are currently being evaluated for sedimentary deposits at depths ranging from 100 feet to 2,000 feet. The mineralization is usually contained in intervals of several feet up to 40 feet in the sedimentary deposits. Hard rock uranium is likely to be contained at depths greater than several thousand feet, with the mineralization often being associated with faulting and fractures over lengths ranging from several feet to several hundred feet. Table 7, lists a number of uranium resources. From this list it is evident that a number of potential in situ candidates exist at depths of 1,000 to 5,000 feet, which is significantly deeper than present South Texas commercial operations.

The shallow uranium deposits of South Texas which are presently being commercially mined by in situ leaching methods generally have a thickness ranging between 3-30 feet. The uranium reserves of South Texas are contained over a range in depth between 120-575 feet. Most of the uranium recovered by in situ mining occurs in the roll-type mineralized deposits, which are associated with sedimentary sandstones, such as, tuffaceous and arkosic sandstones of Tertiary Age.[1] The primary uranium minerals are uraninite and coffinite. The sedimentary host rocks which contain the uranium ore have porosity values that range from 10-30 percent. The permeability of the shallow uranium deposits in South Texas can be as high as 20,000 md, with an average permeability of approximately 2,000 md. Operations are being carried out in a number of different types of sediments, some of which are:

- Oakville Formation, Miocene, consists of sandstones ranging between 50-250 feet deep
- Goliad Formation, Pliocene, consists of sandstones, 250-1,000 feet deep
- Catahoula Formation, Aligocene, consists of tuffs, clays, shales and lignitic silts
- Jackson Formation, Cocene, consisting of sandstone and lignite beds, ranging from 0-300 feet deep

The gangue minerals in these uranium deposits consists of clays, carbonate minerals, and sand.

TABLE 7. POSSIBLE TARGETS FOR IN-SITU URANIUM OPERATIONS

DISTRICT	LOCATION	DEPTH (Feet)	ORE MINERALS GRADE	ORE THICKNESS (Feet)	RECOVERY	ROCK TYPE	GANGUE MINERALS	COMMENTS
Alzada Uranium Deposit	Carter County, Montana	2000	Uraninite	2-20	Plan on sodium carbonate leach pilot plant	Sandstone, Shale	Sand, Gravel	Amoco Minerals Co. hopes to operate a pilot plant here soon.
Ambrosia Lake Uranium Field	McKinley County, New Mexico	0-2200	Coffinite, 0.15-0.25% U_3O_8	2-100	Room and pillar mine.	Sandstone	Feldspar, calcite, clay, pyrite.	
Austin District	Nevada		Uraninite 0.0X%			Quartz Monzonite	Quartz, orthoclase	
Bearpaw Mountain	North of Great Falls, Montana	0-1000 or more	Pyrochlore 100-150 ppm U.	Up to 300		Pegmatite		
Bruni Mine	Texas	120-160	Uraninite Coffinite	10	Am. carbonate-bicarbonate leach	Catahoula Sandstone		Operated by Wyoming Minerals Company
Burns Mine	Texas	575	Coffinite 0.15% U_3O_8	30	Am. carbonate-bicarbonate leach	Oakville Sandstone		Operated by U.S. Steel
Central City District	Gilpin County, Colorado	1000 ft. or more	Pitchblende 30-70 ppm U.			Schist, gneiss	Quartz, feldspar, calcite	No operating mines here. Similar geology to Schwarzwalder Mine
Clay West Mine	Texas	350	Coffinite 0.20% U_3O_8	10	Am. carbonate-bicarbonate leach	Oakville Sandstone		Operated by U.S. Steel
Conway Granite	New Hampshire	Variable	15-20 ppm U.	Variable	None	Granite	Quartz, feldspar, biotite	The uranium is disseminated throughout the granite rocks.
Crown Point	New Mexico	Up to 2000	Uraninite, Coffinite 0.3gt	20-40	Pilot leach plant.	Westwater Sandstone	Feldspar, calcite, clay, pyrite.	Pilot leach plant will be operated by Mobil. Permeability of ore is 500-2000 md.
Lamprecht Mine	Texas	230-275	Uraninite, Coffinite	10	Am. carbonate-leach solution	Oakville Sandstone		Operated by Wyoming Minerals

TABLE 7. POSSIBLE TARGETS FOR IN-SITU URANIUM OPERATIONS (Cont'd.)

DISTRICT	LOCATION	DEPTH (Feet)	ORE MINERALS GRADE	ORE THICKNESS (Feet)	RECOVERY	ROCK TYPE	GANGUE MINERALS	COMMENTS
Marysvale District	Utah	2500-5000	Uraninite 0.2%			Quartz monzonite & rhyolite	Quartz, plagioclase, chlorite, magnetite	Ore is vein and replacement deposit types.
Midnight Mine	NW of Spokane, Washington	Approx. 3000	Autunite, uranophane		Acid leach recovery from 1957-1965	Schist, granite	Calcite, quartz	Operated by Newmont Mining Company.
Mount Taylor Mine	Grants, New Mexico	Approx. 3000 ft.			Conventional mine			
Palangana Mine	Texas	260	Uraninite	3-5	Am. carbonate-bicarbonate solution	Goliad Sandstone		Operated by Union Carbide.
Pawnee Mine	Bee County, Texas	240-255	Uraninite 0.09%	5-6	Am. carbonate-bicarbonate leach	Oakville Fm. Tuffaceous Sandstone		Operated by IEC Comm.
Schwarzwalder Mine	Colorado	Approx. 3000	Pitchblende 0.1% U_3O_8			Gneiss	Feldspar, quartz, calcite	Operated by Cotter Corporation.

The deep-seated uranium deposits which may be candidates for future in situ uranium mining operations occur in Montana, New Mexico, Nevada, Colorado, New Hampshire, Utah, and Washington. These deposits have diverse geometries and geologic characteristics. In Colorado, there are two possible target uranium deposits, at the Schwarzwalder Mine and in the Central City District, both of which are hard rock. The Schwarzwalder deposit is a vein deposit, with the veins varying in thickness up to 10 feet. Both of these Colorado uranium bodies have depths exceeding 1,000 feet.

The Conway Granite of New Hampshire is a granitic pluton of variable thickness and depth which contains about 15-20 ppm uranium as an essential element in the granite. The outer 1,000 feet of the main Conway mass is estimated to contain 5-8 million tons of U_3O_8. This pluton has potential as a uranium leach target if the uranium could be extracted from the granite. Gangue mineralization consists of quartz, nicrocline, plagioclase,and biotite.

Several deep-seated sandstone uranium deposits are located in New Mexico at Crown Point, Ambrosia Lake, and Grants. The primary ore minerals at these ore deposits are uraninite and coffinite. Th uranium is found at depths up to 3,000 feet at Grants, up to 2,200 feet at Ambrosia Lake and up to 2,000 feet deep at Crown Point. The thickness of the uranium ore at these sites in New Mexico ranges from 2 to 100 feet, and the grade of the ore is approximately 0.15 to 0.25 percent U_3O_8. Gangue mineralizatin consists of feldspar, calcite, clay and pyrite. Mobil has begun a pilot leach uranium plant at Crown Point, New Mexico using a basic carbonate leach solution.

The Austin District in Nevada and the Marysvale District of Utah are potential uranium deposits for leach mining operations in hard rock. Uraninite is the primary uranium ore mineral of these districts, with a concentration which ranges from 0.02 to 0.2 percent. These uranium deposits occur within an igneous quartz monzonite host rock. The depth to the uranium ore at Marysvale ranges from 2,500 to 5,000 feet. The primary gangue minerals ore quartz-plagioclase, chlorite, magnetite, and orthoclase.

Table 8 summarizes a number of copper sulfide and oxide deposits that are deep lying and low grade. Most of these deposits are located in Arizona and New Mexico, with others in Montana, Utah, Maine, and Minnesota.

TABLE 8
POSSIBLE TARGETS FOR IN SITU COPPER, NICKEL AND MOLYBDENUM OPERATIONS

DISTRICT	LOCATION	DEPTH (FEET)	ORE MINDERALS GRADE	ORE THICKNESS (FEET)	RECOVERY	ROCK TYPE	GANGUE MINERALS	COMMENTS
Bagdad Coppler District	Yavapai County, Arizona	Up to 1950	Chalcopyrite, Chalcocite 0.6-4% Cu	Few feet to 180	Underground & open pit	Granodio-rite	Quartz, chlorite, calcite, sericite, magnetite	Ore type is a porphyry copper deposit
Banner Mining District	Gila County, Arizona	1600	Bornite, sphalerite, chalcopyrite, galena 0.9% Cu	10-80	Underground mine	Limestone	Quartz, garnet, marble, clays	Replacement type ore deposits.
Belt Services	Montana	Variable, to 1000 or more	0.25-0.7% Cu					Reserves is 100 million tons.
Bingham Canyon Copper District	Salt Lake County, Utah	Up to 5000	Chalcocite, Bornite 0.8% Cu		Open pit mine	Porphyritic granodlorite	Quartz, calcite clay	The pit is operated by the Kennecott Copper Corporation
Blue Hill Mine	Maine	Variable to 3000	Chalcopyrite, molybdenite 1.1% Cu			Schist	Quartz, feldspar	Kerramerican, Inc. suspended operations here in 1977.
Butte Copper	Butte, Montana	Nearly 5000	Chalcopyrite Up to 2% Cu	Veinlets 3-30 feet in length	Block cave mine and open pit mine	Boulder Batholith quartz Monzonite	Quartz, orthoclase plagioclase hornblende	Classical hydrothermal vein deposit.
Carr Fork Copper District	Tooele, Utah	Up to 2700	Chalcopyrite Ave. 0.5% Cu		Underground mine	Quartzite, skarn	Quartz, clay, garnet, opal	Developed by Anaconda Corp.
Central Mining District	Grant County, New Mexico	Surface to 3000	Chalcopyrite chalcocite 0.6% Cu	Up to 300 feet	Room and pillar mine and open pit mine	Limestone, skarn	Garnet, calcite, magnetite	UV Industries operates the Continental Mine in Hanover, N.M.
Climax Molybdenum Deposit	Lake County, Colorado	Surface to 1600	Molybdenite less than 0.4% MoS_2	Variable up to 700	Block caving mine and open pit mining	Igneass intrusives quartz monzonite granitic intrusives	Quartz, orthoclase, pyrite, fluorite, topaz	Mine operated by AMAX Deposit is similar to a copper porphyry deposit.
Duluth Gabbro Complex	Lake & St. Louis Counties, MN	0-5000	Chalcopyrite Pyrrhotite pentlandite	Variable		Gabbro	Plagioclase, olivine, phroxene	Similar to the Sudbury Canada deposit.

TABLE 8

POSSIBLE TARGEST FOR IN SITU COPPER, NICKEL AND MOLYBDENUM OPERATION

(Continued)

DISTRICT	LOCATION	DEPTH (FEET)	ORE MINDERALS GRADE	ORE THICKNESS (FEET)	RECOVERY	ROCK TYPE	GANGUE MINERALS	COMMENTS
Lordsburg Copper Area	New Mexico	1500-2000	Chalcopyrite 2.0% Cu	Veins, Averaging	Shrinking stope mine	Granodiorite stock	Quartz, feldspar	No longer in operation
Miami Copper District	Arizona	1000-2000	Chrysocolla[3] 0.5% Cu	200-400		Schist	Muscovite, Orthoclase, Magnetite, Clay	Occidental Minerals has a pilot leach mining plant at Miami
Safford Copper Deposit	Arizona	Variable to 3000 or more	Chrysocolla,[2,4] Chalcocite, Chalcopyrite 0.4% Cu	Variable to 1600	Pilot Solution Mining	Andesites, Dacites latites	----------	U.S. patent 3,951,458, states that a pilot leach plant was erected here by Kennecott Copper Co. Permeability of ore body averages 2 md.
San Manuel Ore Body	Pinal County, Arizona	To 2700	Chalcopyrite,[2,5] Chrysocolla 0.47-0.74% Cu	Variable, to 1500	Block cave mine	Quartz monozonite, diabase	Quartz, plagioclose	Reserves of 1000 million tons of sulfide ore.
Spar Lake Deposits	Troy, Montana	0-1100	Bornite, Chalcocite 0.74% Cu	Approx. 60	Room and pillar mine	Quartzite	Quartz, feldspar, clay	American Smelting and Refining of Spokane has plans to mine the deposit in the near future.
Warren Mining District	Cochise County Arizona	Variable, to 2000 feet or more	Chalcocite	50-400	----------	Limestone	Calcite, dolomite	

Occidental Minerals is currently operating an acid leach in situ operation at Miami, Arizona.[3] The Miami, Arizona copper oxide deposit occurs in a metamorphic type of host rock, with schist as the principle rock type. The gangue minerals include orthoclase, muscovite, magnetite and clay. The primary copper mineral at Miami is chrysocolla, averaging 0.5 percent copper. The copper oxide ore is found at depths of 1,000 feet to 2,000 feet, and a thickness of 200 feet to 400 feet. Estimates of the resource at Miami approximates 100 million tons of ore.

Most of the copper sulfide ore deposits listed in Table 8 are located in the Southwestern United States, principally Arizona and New Mexico. In Arizona, some of the copper sulfide deposits which may be exploited by ISL methods include the Red Mountain, Safford, Banner, and Warren Mining Districts. The latter two deposits occur in a limestone host rock, with gangue minerals which include calcite, dolomite, clays, garnet, and quartz.

The Banner Mining District has replacement type copper sulfide deposits which have been mined by conventional underground techniques. Most abundant minerals include; bornite, chalcopyrite, sphalerite, and gelena, with less abundant minerals; chalcocite, covellite and molybedenite. The grade of the ore at Banner is 0.9 percent copper. The copper mineralized replacement zone has a thickness of 10 to 80 feet and a depth of 1,600 feet below the surface. The primary copper ore mineral of the Warren Mining District in Arizona, which is also found within a limestone host rock is chalcocite. The depth of the copper ore is variable, possibly to depths of 2,000 feet or more. The thickness of the copper ore ranges between 50 to 400 feet thick.

The copper mineralization at the Bagdad District in Arizona, as well as the Bingham Canyon District in Utah, is porphyritic type of ore with a granodiorite host rock. The gangue minerals associated with these copper porphyries include quartz, calcite, chlorite, sericite, magnetite and clays. The principle copper mineralization incudes; chalcocite, chalcopyrite, and bornite, with grades ranging from 0.6 to 4% copper. The depth of the copper sulfide ore varies between 1,950 feet at Bagdad to 5,000 feet deep at the Bingham Canyon. Bagdad mineralization occurs over a thickness of several hundred feet.

Host rock at the San Mannel, Arizona, Lordsberg, New Mexico, and Butte, Montana copper districts is igneous intrusive, containing quartz monzonite, granodiorite, and the Boulder Batholith, respectively. The gangue minerals associated with these intrusives are quartz, orthodose, plagioclase and hornblende. The Lordsburg and the Butte Copper Areas are both vein types of ore deposits, with chalcopyrite in the veins, with up to 2 percent copper. The Butte Copper District is comprised of a zone of veinlets which range in length from 3 to 30 feet down to depths of nearly 5,000 feet. The Lordsburg Copper Area, has copper veins averaging 6 to 7 feet in width, at depths of 1,500 to 2,000 feet, and has been mined by a shrinking stope mining operation. The San Manuel ore body contains chalcopyrite and chrysocolla as primary mineralization with a grade of 0.47 to 0.74 percent copper. The depth of the ore zone extends down to 2,700 feet, with a variable ore thickness which approaches a maximum of 1,500 feet thick. The San Manuel ore body is being mined by a block caving, but with an estimated reserve of 1,000 million tons of sulfide ore, it is likely that in situ leach mining methods might be feasibly used at this site sometime in the future.

Kennecott operated a pilot in situ leaching test on copper sulphides at the Safford deposit. The Safford copper deposit with a host rock consisting of andesities, dacites and latites, has chalcopyrite and chyrsocolla as the primary copper ore minerals. The grade of the ore at Safford averages between 0.47 to 0.74 percent copper. The copper ore zone at Safford has variable depths, ranging down to 3,000 feet or more deep. The thickness of the ore is variable up to 1,600 feet thick.

The copper ore deposits of the Central Mining District in New Mexico are associated with a limestone/skarn host rock. The gangue mineralization includes calcite, quartz, sericite, clay, pyrite and magnetite.

Deep seated molybedenum sulfide and nickel sulfide ore deposits offer some potential for possible future opportunities for in situ leach mining operations. Two deposits of this type which may be suitable for solution mining extraction include the copper-nickel sulfides of the Duluth Gabbro Complex and the Climax Molybdenum Deposit. Table 8 describes the geologic properties of these two ore deposits.

The Duluth Gabbro Complex of Northeastern Minnesota consists of multiple intrusions of basic igneous rocks of two types, anorthositic gabbro and layered gabbro. The principal gangue minerals are plagioclase, olivine, and pyroxene. The copper/nickel mineralization, with concentrations of one percent in a ratio of 3:1 copper to nickel, consists of the sulfides chalcopyrite and pyrihotite, with lessor amounts of pentlandite and cubanite. The ore minerals are found at depths ranging from surface exposures to 5,000 feet deep, located primarily in the lower portion of the Gabbro Complex. Amax Exploration and International Nickel Company are interested in doing development work on the Duluth Gabbro copper nickel deposit.[27]

The Climax Molybdenum deposit is located in Lake County, Colorado, about 60 miles southwest of Denver. The deposit is characterized by a large mineralized intrusive granitic type of stock which is similar in form to a porphyry copper deposit. The grade of the ore is about 0.4 percent or less of MoS_2, with molybdenite as the principal ore mineral.[28] The host rock is a series of granitic quartz monzonite dikes and sills which have intruded the Idaho Springs Formation, resulting in at least four major hydrothermal events. The ore takes the primary form of finely crystalline molybdenite which is intergrown with quartz in fractures and irregular veinlets less than 0.25 inches thick.[29] The zone of mineralization is variable in thickness, up to 700 or more feet thick, and ranging in depth from surface exposures down to 1,600 feet deep. Gangue minerals consists primarily of quartz, with which the ore is intergrown. Other gangue includes orthoclase, fluorite, pyrite, and topaz.

The AMAX Corporation exploits the molybedenum at climax by means of a block caving underground mine and an open-pit mine to augment the underground operation. It is possible that one day in situ leach mining methods might be employed at Climax to extract molybdenite ore which cannot be economically mined by other means.

GEOCHEMISTRY

The selection of a suitable leach solution for ISL mining is related to metal type, the form of the mineral containing the metal, and the host rock. For example, factors such as the composition of the ore mineral, the rate of solubilization of the ore, the interaction of the solvent with the gangue minerals, the permeability of the host rock, and the interaction of the leaching solvent with the well equipment need to be considered prior to the determination of the type of solvent which will be used. The two basic varieties of leaching solvents used in ISL mining of copper and uranium include alkaline solutions and acidic solutions. The use of an oxidizing agent is usually required in conjunction with the solvent for leaching of uranium and sulfide ores. Because corrosive fluids are used in ISL mining, appropriate materials of construction need to be selected for the downhole and surface equipment used in the mining process.

Acid lixiviants which are used in ISL mining to extract copper and uranium minerals include sulfuric acid (H SO), hydrochloric acid (HCl), and nitric acid (HNO). The most common solvent is sulfuric acid.

Depending upon the nature of the gangue minerals associated with the uranium ore, an acid leach solution may be chosen as the type of solvent for the ISL process. Sulfuric acid is the principle type of acid solvent chosen for uranium, as seen in Table 9. The uranium is oxidized by an oxidizing agent, and then the sulfuric acid solution maintains the uranium in solution as a uranium sulfate complex. Once the uranium minerals are mobilized, the solution flows through the mineralized zone to a production well, where the pregnant solution is removed for processing. Should sulfate percipitate between wells uranium may also be lost from solution.

The acids which are available for use as leaching solutions in the extraction of copper include sulfuric acid, nitric acid and hydrochloric acid, with sulfuric acid being the most commonly used (see Table 10). A basic requirement in the acid leaching of copper is to maintain the pH of the solution at conditions below a pH of 3.0. Above a pH of 3.0, the copper solubilities are questionable with many varieties of other phases.

For copper sulphides, an oxidizing agent is required to solubilize the copper. These chemical agents are discussed in a subsequent section. Acid strengths are related to the desired level of copper enrichment and the amount of attach of acid on the gangue. For sulfuric acid leaching of oxides, a minimum of 1-1/2 lb of acid are required for each lb of copper oxide solubilized. Experience indicates that at least 5 lbs of acid per lb of copper is required to accommodate both gangue and copper dissolution. As an example, if it is desired that 3 gpl copper be produced, 15 gpl of H_2SO_4 should be injected at 5 lbs acid/lb copper acid consumption.

Typical alkaline leach solutions which are employed in uranium ISL operations include dilute concentrations of ammonium carbonate-bicarbonate and sodium carbonates.[1] An ammoniacal leach liquid used with an oxidizing agent can be utilized to leach copper sulphide minerals in a basic type of system. An ammoniacal leach is also possible for copper oxides, and might be considered if calcite content in an oxide is very high.

When uranium deposits occur in basic rocks such as limestones and carbonates, a sulfuric acid leach solution can be very expensive, because the acid is consumed by the gangue. In cases such as this, a basic leach solution such as ammonium carbonate or sodium carbonate would be more appropriate. Most in situ uranium leaching is performed with alkaline solutions.

The most common solvent for uranium recovery is ammonium carbonate-bicarbonate, which is used extensively in the South Texas and Wyoming in situ uranium operations. The pH of the lixiviant is in the range of 6-8.8. A disadvantage of the ammonium carbonate-bicarbonate solvent for uranium mineral deposits is that a saturation of the clays with ammonium ions in the ore body may result and thus may prolong the flushing treatment necessary for restoration.[3] Secondly, the ammonium carbonate-bicarbonate solvent may cause environmental pollution if the ammonia converts to nitrates. An alternate alkaline leach solution is sodium carbonate, which is usuable in uranium ore bodies that have a characteristically high sodium content. Studies have shown that sodium swells clays, thereby reducing the permeability of the ore body.[30] This problem would not occur in ore bodies which are high in sodium content. An oxidizing agent used in conjunction with an aequeous solution of sodium carbonate or ammonium carbonate-bicarbonate will mobilize the uranium as a soluble uranium carbonate complex, see Table 9. The soluble uranium is then carried in solution through the mineralized rock layer, and on to the production well.

In the basic copper leach system, a complexing agent such as NH_3 is needed to carry the metal in solution. The NH_3 reacts with copper to form a cupric amine complex $[Cu(NH_3)4]^{+2}$. This reaction requires 4M NH_3 per 1M Cu to maintain the complex in solution. Ammonium sulfate or ammonium nitrate is used for pH control.

An advantage in using the basic system over the acid solvent system can be seen in the case of a copper ore body associated with acid soluble gangue minerals such as clays and feldspar. These gangue minerals will not interact with the basic solvent and disrupt the pH control of the system, as happens with acidic types of solvents. A disadvantage of using a basic solvent system for copper leaching is due to the nature of the cation cupric amine complex, which can ion exchange with other cation exchange gangue minerals in the host rock, such as stilbite, montmorillonite, etc.

Site specific criteria relating to the type of mineral to be extracted, the host rock, the gangue mineralization, etc., will determine the leaching solvent chemistry which is employed in an ISL operation.

Oxidants must be used when reduced uranium minerals or copper, molybdenum or nickel sulfides are to be leached. The oxidizing agent acts to mobilize the metals in solution in order that the ore can be carried in solution to the surface and extracted.

Some uranium minerals occur in a native insoluble valance state (+4) and can only be recovered by in situ leaching if they are first oxidized to a more soluble form, i.e., the +6 valance state. An oxidizing agent must be employed with the leach solution to oxidize the plus-four valance state (UO_2) to the plus-six valance state (UO_3) in order for the uranium to be leached out.[31] Hydrogen peroxide and oxygen are the most commonly used oxidants for uranium solution mining.

Table 9

SOLVENTS FOR URANIUM LEACHING

Acidic	Uranium Mobilization Form
Sulfuric Acid H_2SO_4	Uranium Sulfate Complex $[UO_2(SO_4)3]^{-4}$
Alkaline	
Ammonium Carbonate - Bicarbonate $(NH_4)_2CO_3$ - NH_4HCO_3	Soluble Uranium Carbonate Complex $(NH_4)_4\ UO_2\ (CO_3)_3 + H_2)$
Sodium Carbonate Na_2CO_3	Soluble Uranium Carbonate Complex $Na_4UO_2(CO_3)3 + H_2O$

Table 10

SOLVENTS FOR COPPER LEACHING

Acidic	Sulfuric Acid	H_2SO_4
	Hydrochloric Acid	HCl
	Nitric Acid	HNO_3
Basic	Ammonium Sulfate	$(NH_4)_2\ SO_4$
	Ammonium Nitrate	$NH_4\ NO_3$

Peroxide is easier to inject than oxygen, but it is ten times more costly.[32] Both peroxide and oxygen may reduce liquid permeability, if the oxygen concentration exceeds the soluble level at the deposit pressure. Chlorate is a totally liquid soluble oxidant which is not used very often in solution mining because it is cost prohibitive. A disadvantage of using chlorate as an oxidizing agent is the formation of an end product of chlorate oxidation, Cl^-. The chloride ion may interfere with the extraction of uranium in the surface plant and also cause corrosion problems.

Copper oxide ores such as azurite, malachite and chrysocolla do not require oxidation prior to leaching. Only copper, nickel, and molybdenum sulfides need an oxidizing agent. The main purpose of the oxidizing agent in leaching chalcopyrite, for example, is to break the chemical bonds holding copper in the ore by oxidizing the sulfide and iron components. In the chalcopyrite mineral, the sulfide is in the -2 state. After oxidation, it may go to elemental sulfur (+0) or to sulfate, SO_4=, (+6 state). Once the mineral is oxidized, the leach solvent is able to dissolve the copper component.[32] The amount of oxidant required in copper leaching is dependent upon the final oxidation state of the sulfide.

Types of oxidizing agents used for copper sulfide leach mining include

- oxygen gas
- hydrogen peroxide
- metallic chlorates
- ferric chloride (soluble only in highly acid solutions)
- ferric sulfate (soluble only in highly acid solutions)

An important consideration to be made in the usage of oxidants is the impact of the oxidizing solutions upon the materials of construction of downhole and surface equipment. Oxide copper minerals and some uranium minerals which do not require an oxidant with the leaching solution permit a wider array of materials to be used than a system using an oxidizing agent. This will be dealt with more succinctly in the section on corrosion of materials.

CORROSION OF EQUIPMENT

The use of conventional water well or oil field equipemnt in leach mining may create problems with corrosion of the materials of construction, and thus reduced usuable life of the hardware. Much of the oil well and water well down hole and surface equipment is not capable of functioning properly in the corrosive solutions which are characteristic of in situ leaching of copper or uranium minerals. For this reason, special materials of construction may be needed for the equipment used in leach mining, to withstand the corrosive downhole environmental which is associated with the in situ leaching of minerals. Some uranium minerals and copper oxide minerals, which can be leached with dilute acid and basic solutions, do not cause as much corrosion to the equipment as those uranium and copper sulfide minerals which require oxidizing leach solvents.[33]

Much of the surface equipment and downhole equipment employed in leach mining has special needs for their materials of construction, dependent upon the type of physical environment (temperatures and pressures) and chemical environment to which it is subjected. Surface pumps employed in the leach mining of copper and uranium minerals are readily available from many of the variety of surface centrifugal, rotary, or gear pumps applicable to acid or alkaline solutions. Types of metallics for surface pumps include various grades of bronze alloys, stainless steels, fiberglass, etc. Downhole pumps used in the production wells for leach mining generally need to operate at flows between 25-100 gpm, with 500-1000 feet of head. Typical materials of construction for copper and uranium leach operations include stainless steel and carbon steel.[33]

Shallow injection wells which operate at low injection pressure can be cased with casing strong made of PVC. FRP casing or a type of carbon steel and stainless steel or FRP combination casing is used in deep injection wells.

Injection tubing is normally constructed of RFP for in situ leach applications. Many uranium leaching operations in Wyoming and South Texas employ screens made of PVC when alkaline leach solutions such as ammonium carbonate-bicarbonate are employed.[1] Where dilute sulfuric acid solvents are used as leaching solvents for uranium minerals, as in parts of Wyoming, either stainless steel or PVC types of screens are utilized. Generally, a stainless steel screen would serve for copper or uranium leach operations.

A variety of API cements, Portland cements, and ASTM cements is available for downhole and surface applications. Type V ASTM cement, which has highly resistant properties, has been employed for construction of pits used in copper recovery from acid solutions. For highly corrosive environments, such as those employing sulfuric acid solutions, an epoxy cement appears to have the chemical properties which can withstand exposure to these leaching environments. Additives are available which can be used in conjunction with Portland cement to tailor a cement to the specific type of chemical and physical environment which exists in a leaching operation.

Packers for use in leach mining wells are available as specialty items in flatable, tension and hydraulic setting models.

Materials available for constuction of downhole and surface equipment for leaching of copper and uranium minerals need to be chosen carefully to minimize the occurrence of corrosion. Those materials which can withstand the acidic or alkaline solutions employed in leach mining include:

- Polyvinvlchloride (PVC)
- Fiberglass Reinforce Plastic (FRP)
- Elastomers
- Stainless Steels
- Carbon Steel

PVC is a type of plastic which is suitable for use as well as casing materials, and in piping, fittings, and valves. It has limited applications, and it is best suited for low-temperature and low-pressure environments. PVC plastic can be used in dilute acid, basic, or oxidizing solutions.

Fiberglass reinforced plastic is a type of reinforced epoxy material which has high-pressure uses. It can be used as material for tubing, casing and piping in either dilute acid or basic leaching solution applications.[33] In oxidizing solutions the RFP has only marginal to poor durability, which limits the use of FRP materials in certain uranium and copper sulfide minerals leaching.

Of the 300 series of stainless steels, 316 s.s. is probably the most resistant to corrosion. To be utilized in dilute acid leach solutions, the 316 s.s. must have a passive metal coating over the equipment to protect it from corrosion. In an oxidizing environment, the passivation will be maintained more readily than in a nonoxidizing environment. Variations in the flow rate of the solutions can cause damage to the life of passive metal coatings on the equipment. Once the passive surfaces which coat the 316 s.s. are removed, activated corrosion can take place more rapidly. Finally, 316 s.s. is more suitable for use as a material of construction for equipment subject to low temperatures and concentrations than for high temperatures, where corrosion rates for 316 s.s. are more rapid.

The use of carbon steel as a material of equipment construction for leach mining applications has very limited usage in the field for casing and piping. Carbon steel has a field life of only about six months for leach mining applications. Unless the oxygen can be completely removed from the system, the carbon steel equipment will rapidly corrode.

Thus, for longer term operations, carbon steel is too corrosive to be used. However, for very short term leach mining or pilot test operations on the order of one month duration, carbon steel equipment may be utilized readily due to its relatively inexpensive price and its availability.

The nature of the chemical environment of a leach mining operation will determine which materials of equipment construction can be selected for a specific operation. It has been shown here that certain materials are more resistant to corrosion in an oxidizing solution, for example, than in a nonoxidizing solution. Further, it was observed that certain elastomers have excellent acid resistance, and thus would be a good choice of material in a dilute acid leach environment.

In selecting the materials of construction for surface and downhole equipment in leach mining operations, the operator needs to analyze the site specific chemical conditions which exist at a given location. He needs to determine whether an alkaline or acidic leaching solution will be employed to extract the copper or uranium minerals. When reduced uranium minerals or copper sulfides are to be leached, it will be necessary for the operator to decide what type of oxidizing agent should be utilized. Looking at the nature of the aequeous fluids which are employed, the pH of the solvents, the needs to select materials for the downhole and surface equipment which will be capable of functioning adequately in that particular environment, without being destroyed by corrosion.

APPENDIX C

DRILLING AND COMPLETION PROCEDURES

Drilling and completion procedures are given for each wellbore type as applied to a 2,000 feet ore body depth.

PROCEDURE FOR DRILLING 2,000-FEET CONVENTIONAL WELL

1. Drive 9-5/8-inch pipe to ± 20 feet.
2. Drill 7-7/8-inch hole to 2000 feet.
3. Condition mud and pull out of hole.
4. Run appropriate logs.
5. Run 5-1/2-inch fiberglass CSG to TD ± 2000 feet.
   a. A cement basket should be on bottom joint to anchor the light weight fiberglass CSG.
6. Condition mud.
7. Pump prewash fluid.
8. Drop bottom cement plug.
9. Pump sufficient cement volume to fill annulus.
10. Drop top plug.
11. Displace cement with mud.
12. Wait on cement.

Completion of Injection Well

1. Perforate appropriate interval.
2. Run 2-7/8-inch tubing with Baker Model JJ retrievable packer (or equivalent packer designed for fiberglass CSG).
3. Set packer appropriately above injection interval.

Completion of Production Well

1. Same as per injection well except electric pump is run below packer.

PROCEDURE FOR DRILLING TRIPLE BRANCH WELL OUT OF 13-3/8" CASING

1. Drive 20-inch pipe 20 feet ±.
2. Drill 17-1/2-inch hole to 1,353 feet.
3. Run 13-3/8-inch casing to TD with a whipstock drilling guide as a bottom joint containing a wireline retrievable drilling guide known orientation relative to the guide.
4. Retrieve gyroscope with wireline to determine orientation and deviation of drilling guide.
5. Rotate casing to achieve proper orientation of whipstock assembly.
6. Go in hole with workstring and stab into seal receptacle above float collar.
7. Condition mud and drop preceding cement plug.
8. Pump appropriate cement volume to cement 13-3/8-inch casing to surface.
9. Drop top cement plug and displace with mud.
10. Pull work string.
11. Wait on cement.
12. Rig up 4-1/2-inch bit and drilling assembly with alignment collar keyed to guide drill assembly into vertical drilling guide.
13. Go in hole with drilling assembly and rotate to align guide collar with indexing dog.
14. Drill vertical hole to 2000 feet.
15. Run appropriate log through drill pipe.
16. Condition mud and pull out of hole with drilling assembly and guide collar.
17. Modify guide collar to index drilling assembly into bottom (first) branch whipstock.
18. Go in hole and rotate to align guide collar with indexing dog in whipstock assembly.

19. Directionally drill bottom branch building angle at 5°/100 feet (for a 200-foot well spacing). Drill to 2,040-feet measure depth which will yield 2,000-foot true vertical depth. Directional survey as needed.

20. Log through drill pipe to be sure bit penetrated entire ore body.

21. Condition mud and pull drilling assembly and alignment collar out of hole.

22. Modify alignment collar to index drilling assembly into top (second) branch whipstock.

23. Go in hole with 4-1/2-inch drilling assembly.

24. Rotate drill pipe to index alignment collar on internal alignment dog.

25. Drill directional hole building angle at 5°/100 feet to a measured depth of 2,040 feet (200-foot wellspacing) or a TVD of 2,000 feet.

26. Log through drill pipe.

27. Condition mud, pull drilling assembly and alignment collar out of hole.

Completion Procedure

1. Run a 760-foot triple string of 2-7/8-inch fiberglass with cement baskets on shoes to act as casing anchors and prevent fiberglass from floating during cementing operation.

2. Install triple tubing hanger with double acting slips in string with left-hand safety connections above hanger.

3. Run remainder of triple tubing string ± 1,240 feet.

4. Stab tubing into whipstock assembly and simultaneously run into the 3 open holes (mud can be circulated through individual strings if necessary to clean out fill.

5. Condition mud by simultaneously circulating down all string.

6. Simultaneously drop bottom cement plugs in all strings.

7. Pump cement simultaneously in triple string using special surface manifold or two cement trucks for sufficient volume to fill whipstock assembly with cement.

8. Set tubing hanger.

9. Release safety connection in one tubing string and reverse out any cement above hanger.

10. Screw tubing back in hanger.

11. Wait on cement.

12. Perforate appropriate intervals in each branch.

13. Rig up injection manifold and begin injecting.

For Producers

14. Back all tubing out of hanger and pull.

15. Rig up electric pump and retrievable packer on 4-1/2-inch tubing.

16. Run sufficient 4-1/2-inch tubing to set pump 10 feet above hanger.

17. Set packer and rig up surface production manifold.

18. Pump comingled fluid from the three branches.

Cost Estimate

The cost estimate for drilling a 13-3/8-inch branch well at 2,000 feet is broken down into four sections. The first section details rig up cost which includes all expected expenses required to move a rig on to location. Costs reflect a drilling contractor's estimate of time and expenses related to rigging up a small rig on a good site within 50 miles of Houston.

Intangible drilling costs consist primarily of rig expenses. It was estimated that three days would be required to set 13-3/8-inch casing at 1,353 feet. A small rig with additional pumps and drilling equipment sufficient to drill a 17-1/2-inch hole was priced at $6,000 per day. An additional 7 days of rig time were allotted to directionally drill the branch holes. Directional drilling costs reflect estimated charges for directional driller and equipment.

Tangible costs are those related to purchased items such as casing or tubing. Cost estimates reflect typical pricing in the Houston area during the last quarter of 1979.

Production wells typically cost more than injectors. The fourth pricing section reflects those expenses relating to production pumps and downhole assemblies.

The $122,603 total estimate per drain area is the cost of one producer plus the cost of one injection well. This total will be used in cost comparisons with other well schemes.

PROCEDURE FOR DRILLING TRIPLE BRANCH WELLS OUT OF 9-5/8" CASING

1. Drive 13-3/8-inch pipe ± 20 feet.

2. Drill 12-1/4-inch hole to ± 1,350 feet.

3. Run 9-5/8-inch casing to TD.

   a. The bottom joint contains branch drilling guide, precut windows for branch holes and cementing float collar. See Figure 8. A gyroscopic survey tool is positioned on the guide referenced to the indexing dog.

   b. Retrieve gyroscopic survey tool with wireline and determine orientation of drilling guide.

   c. Orient whipstock windows appropriately to achieve proper branch hole configuration.

4. Go in the hole with work string and cement casing through seals in float collar.

5. Pull work string out of hole and rig up 6-inch bit and drilling assembly.

6. Drill 6-inch vertical branch through the bottom of the drilling guide to total measured depth of 2,040'. Note each branch will be equal in measured length to simplify casing-installation.

7. Log open hole section through drill pipe to verify ore thickness.

8. Condition mud and pull out of hole.

9. Rig up whipstock assembly and go in hole.

10. Orient whipstock on internal indexing dog in the drilling guide and set.

11. Disengage running assembly from whipstock and pull.

12. Rig up 5-inch Dyna-Drill assembly and 6-inch bit.

13. Drill first directional branch using the whipstock as a guide to direct drilling assembly through window in casing. For a 200-foot well spacing build angle at 5°/100 feet. Take single shot directional surveys as needed - measure depth at TD 2,040 feet, TVD 2,000 feet.

14. Log open hole section through drill pipe to verify ore thickness.

15. Go in hole with whipstock pulling assembly and pull whipstock.

16. Modify assembly to orient whipstock toward second window in casing.

17. Run in hole with whipstock and orient on internal indexing dog to face upper window.

18. Set whipstock and pull installation assembly.

19. Rig up 5-inch Dyna-Drill* and 6-inch bit and go in hole.

20. Drill through upper branch window building angle at 5°/100 feet. Run directional survey as needed. Total measure depth should be 2,040 feet or 2,000 feet true vertical depth.

21. Run appropriate log through drill pipe to verify ore thickness.

22. Condition mud and pull out of hole.

23. Rig up whipstock assembly and go in hole.

24. Pull whipstock.

Casing Procedures

1. Rig up tubing guide assembly and run in hole.

2. Orient tubing guide on internal indexing dog, set guide, then pull running assembly.

3. Run 760 feet triple string of 2-7/8-inch fiberglass with cement baskets on bottom to prevent fiberglass from floating out of hole during cementing.

4. Install triple tubing hanger in string with left hand safety connections above hanger.

5. Run remainder of triple tubing string ± 1,240 feet.

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* Reference to specific brands, equipment, or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

6. Stab tubing into tubing guide and run into open holes. (Note mud can be circulated through individual strings if necessary to clean out fill.)

7. Rig up cement head.

8. Condition mud.

9. Simultaneously drop bottom cement plug in all three strings.

10. Pump cement simultaneously through three strings of tubing using special surface manifold or two cement trucks (sufficient volume to fill template with cement).

11. Simultaneously drop top cement plugs and displace with mud.

12. Set tubing hanger.

13. Release one tubing string above hanger and reverse out any cement above hanger.

14. Screw back into hanger.

15. Wait on cement.

16. Perforate each branch.

17. Rig up surface injection manifold.

For Producing Well

1. Release all 2-7/8-inch tubing from above hanger and pull.

2. Run 4-1/2-inch tubing with packer and electric pump.

3. Set packer above tubing hanger.

4. Rig up surface pumping manifold and begin pumping.

Cost

The 9-5/8-inch branch completion concept was priced in the same manner as the 13-3/8-inch. Costs were broken up into 1) set up expenses, 2) intangible drilling expenses, 3) tangible expenses, and 4) additional production costs for pump and downhole assemblies.

Essentially, the total well cost for one producer plus one injector are comparable for both the 9-5/8-inch branch concept ($125,924) and the 13-3/8-inch ($122,600). The rig rate per day for drilling a 12-1/4-inch hole and setting 9-5/8-inch casing is estimated to be less. Reduced-pump capacity is required to circulate cuttings and smaller drill collars are used to maintain the vertical hole direction. However, these savings are offset by additional rig time required to drill and complete branch wells in smaller casing.

PROCEDURE FOR DRILLING DRAIN HOLE WELLS OUT OF 7" CASING

1. Drive 9-5/8-inch drive pipe ± 20 feet.
2. Drill 8-1/2-inch hole to ± 25 feet above midpoint of pay with deviation less than 3° from verticle at TD.
3. Run and cement 7-inch CSG.
4. Go in hole with 4-3/4-inch bit and drill vertical rat hole through ore body (core if desired).
5. Run appropriate log.
6. Take single shot survey to determine deviation and direction of rat hole.
7. Compute anchor length and whipstock face orientation that will achieve the desired drain hole elevation and orientation.
8. Run whipstock assembly into hole.
9. Orient whipstock face with gyroscopic surveys into orienting sub above whipstock latch, surveying after every surface rotation.
10. Plant whipstock after properly faced and condition mud to incorporate extreme pressure lubrication properties.
11. Go into hole with angle building assembly and drill 3°/ft (19-foot radius) portion of drain hole. Drill approximately 30 feet.
12. Pull drilling assembly out of hole and survey with magnetic 120° angle unit single shot instruments to verify 90° turn achieved.
13. Go in hole with stabilized drilling assembly.
14. Drill 50 to 80 feet of lateral.
15. Pump down survey tool and pull out of hole.
16. Repeat Steps 13 through 15 until total drain hole is drilled (± 200 feet).
17. Condition mud.
18. Pump down final survey tool.
19. Pull drilling assembly out of hole. (Note: Leave whipstock assembly in rat hole as casing guide.)

Procedure for Casing 200-foot Drain Hole with 19-foot Radius of Curvature at 2,000 feet

1. Run ± 200-foot Coflexip 4-inch OD Flexible Pipe (production interval slotted or perforated prior to installation).
2. Install special casing anchoring cement basket above slotted Coflexip.
3. Run 30 feet of Coflexip (not perforated) above cement basket.
4. Run ± 20 feet of 2-7/8-inch fiberglass (sufficient to extend inside 7-inch casing).
5. Run tubing hanger assembly with left hand safety connection on top.
6. Run 2-7/8-inch fiberglass to surface.
7. Condition mud.
8. Drop special wireline retrievable - leachant soluble cement plug.
9. Pump appropriate cement volume to fill casing with cement below hanger.
10. Pump top cement plug.
11. Displace cement with mud.
12. Set tubing hanger.
13. Release tubing from above hanger and reverse out cement.
14. Screw tubing back into hanger and retrieve cement plugs with wireline retrieve tools consisting of a fishing grapple with 30 feet of flexible weights and 20 feet of solid weights.
15. Spot acid to dissolve plugs (if plugs not retrieved by wireline).
16. Wait on cement.
17. Put injection well on line.

If Producer

1. Release tubing from hanger and pull out of hole.

2. Install electric pump and go back in hole with 4-1/2-inch tubing.

3. Latch into hanger and begin production.

Cost Estimate

Cost estimates for drain hole drilling are based on the same parameters as the branch wells. Expenses are broken down into 1) set-up costs, 2) intangible costs, and 3) tangible costs and special costs associated with production.

The time required to drill a 200-foot drain hole and the $22,300 for directional driller are cost estimates furnished by Don Holbert.

For cost comparison with other completion schemes it is suggested that one 200-foot drain hole essentially replaces two conventional wells in a 200-foot, 5-spot pattern. The effective cost per drain area is one-half the cost of a producer plus one-half the cost on injector or $152,850, compared to $181,700 for conventional wells at 2,000 feet.

APPENDIX D

COST ESTIMATE DATA

This portion of the report gives a breakdown of cost estimates for the following wells.

Well Type 500' Conventional

Rig Up Cost			
1.	Site Prep	$ 1,000	
2.	Transport	1,000	
3.	Rig Up Charge	-	
4.	Day Work days @ $ /day	-	
	TOTAL RIG UP COST		$ 2,000
Intangible Drilling Cost			
1.	Drilling Days 1 @ $ 3,750/day	$ 3,750	
2.	Mud Chemicals	-	
3.	Cement (Conventional CSG)	1,000	
4.	Casing Crew and Equipment Rental	-	
5.	Transport	-	
6.	Rig Day Work 1/2 days @ $ 3,750/day	1,850	
7.	Directional Driller days @ $ /day	-	
8.	Supervision	500	
9.	Cementing (Branches, etc.)	-	
10.	Open Hole Logs	-	
11.	Perforating	-	
	TOTAL INTANGIBLE COSTS		$ 7,100
Tangible Costs			
1.	Drive Pipe	$ 500	
2.	Surface CSG in; ft @ $ /ft	-	
3.	Protection CSG in; ft @ $ /ft	-	
4.	Production CSG Type 5-1/2 ; 500 ft @ $ 10.90/ft	5,450	Fiberglass
5.	Conventional Packers	-	
6.	Completion Template(s) and Tubing Hangers	-	
7.	Drilling Template(s)	-	
8.	Tubing Type ; ft @ $ /ft	-	
9.	Tubing Type ; ft @ $ /ft	-	
	TOTAL TANGIBLE COSTS		$ 5,950
	TOTAL COST INJECTION WELL		$ 15,050
Additional Cost for Production Well			
1.	Tubing Type 2-3/8 ; 300 ft @ $ 2.46/ft	$ 750	
2.	Less Tubing Changes from Injection Well Type ; ft @ $ /ft		
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	4,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 4,750
	TOTAL COST PRODUCER(S)		$ 19,800

Effective Cost per Drain Area

1-Producer $ 19,800

+1-Injector $ 15,050

TOTAL $ 34,850

Well Type 2,000' Conventional

Rig Up Cost			
1.	Site Prep	$ 1,500	
2.	Transport	2,000	
3.	Rig Up Charge	3,000	
4.	Day Work 2 days @ $ 3,750/day	7,500	
	TOTAL RIG UP COST		$ 14,000
Intangible Drilling Cost			
1.	Drilling Days 3 @ $ 3,750/day	$ 11,250	
2.	Mud Chemicals	500	
3.	Cement (Conventional CSG)	4,000	
4.	Casing Crew and Equipment Rental	1,000	
5.	Transport	1,000	
6.	Rig Day Work 2 days @ $ 3,750/day	7,500	
7.	Directional Driller days @ $ /day	-	
8.	Supervision	1,500	
9.	Cementing (Branches, etc.)	-	
10.	Open Hole Logs	2,500	
11.	Perforating	2,800	
	TOTAL INTANGIBLE COSTS		$ 32,050
Tangible Costs			
1.	Drive Pipe	$ 2,000	
2.	Surface CSG in; ft @ $ /ft	-	
3.	Protection CSG in; ft @ $ /ft	-	
4.	Production CSG Type 5-1/2 ; 2,000 ft @ $ 10.90/ft	21,800	
5.	Conventional Packers	4,000	
6.	Completion Template(s) and Tubing Hangers	-	
7.	Drilling Template(s)	-	
8.	Tubing Type 2-7/8 ; 2,000 ft @ $ 3.50/ft	7,000	
9.	Tubing Type ; ft @ $ /ft	-	
	TOTAL TANGIBLE COSTS		$ 34,800
	TOTAL COST INJECTION WELL		$ 80,850
Additional Cost for Production Well			
1.	Tubing Type ; ft @ $ /ft	$ -	
2.	Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	20,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 20,000
	TOTAL COST PRODUCER(S)		$100,850

Effective Cost per Drain Area

1-Producer $ 100,850

+1-Injector $ 80,850

TOTAL $ 181,700

Well Type 5000' Conventional

Rig Up Cost		
1. Site Prep	$ 2,000	
2. Transport	3,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 17,100
Intangible Drilling Cost		
1. Drilling Days 7 @ $ 6,000/day	$ 42,000	
2. Mud Chemicals	5,000	
3. Cement (Conventional CSG)	1,000	
4. Casing Crew and Equipment Rental	3,500	
5. Transport	2,500	
6. Rig Day Work 2 days @ $ 6,000/day	12,000	
7. Directional Driller days @ $ /day	-	
8. Supervision	2,500	
9. Cementing (Branches, etc.)	7,000	
10. Open Hole Logs	3,000	
11. Perforating	5,000	
TOTAL INTANGIBLE COSTS		$ 83,500
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG 9-5/8 in; 300 ft @ $ 11.60/ft	3,480	
3. Protection CSG in; ft @ $ /ft	-	
4. Production CSG Type 5-1/2 ; 5,000 ft @ $ 10.90/ft	54,500	
5. Conventional Packers	4,000	
6. Completion Template(s) and Tubing Hangers	-	
7. Drilling Template(s)	-	
8. Tubing Type 2-7/8 ; 5,000 ft @ $ 3.50/ft	17,500	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$ 81,480
TOTAL COST INJECTION WELL		$182,080
Additional Cost for Production Well		
1. Tubing Type ; ft @ $ /ft	$ -	
2. Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3. Packer(s)	-	
4. Pump and Downhole Assembly	20,000	
5. Stainless Steel	-	
Producer(s) Net Additional Cost		$ 20,000
TOTAL COST PRODUCER(S)		$202,080

Effective Cost per Drain Area

1-Producer	$ 202,080
+1-Injector	$ 182,080
TOTAL	$ 384,160

Well Type 13-3/8" 2,000' Three Branch Well

Rig Up Cost		
1. Site Prep	$ 1,500	
2. Transport	2,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 15,600
Intangible Drilling Cost		
1. Drilling Days 3 @ $ 6,000/day	$ 18,000	
2. Mud Chemicals	500	
3. Cement (Conventional CSG)	5,000	
4. Casing Crew and Equipment Rental	4,500	
5. Transport	2,000	
6. Rig Day Work 7 days @ $ 5,500/day	39,200	
7. Directional Driller 6 days @ $ 2,000/day	12,000	
8. Supervision	2,000	
9. Cementing (Branches, etc.)	2,000	
10. Open Hole Logs	7,500	
11. Perforating	5,700	
TOTAL INTANGIBLE COSTS		$ 98,400
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG in; ft @ $ /ft	-	
3. Protection CSG 13-3/8 in; 1,350 ft @ $ 17.91/ft	24,180	
4. Production CSG Type 2-7/8 ; 1,950 ft @ $ 3.50/ft	6,825	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	4,000	
7. Drilling Template(s)	2,000	
8. Tubing Type 2-7/8 ; 4,050 ft @ $ 3.50/ft	14,175	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$ 53,180
TOTAL COST INJECTION WELL		$167,180
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 1,350 ft @ $ 7.50/ft	$ 10,125	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 4,050ft @ $ 3.50/ft	-(14,175)	
3. Packer(s)	4,000	
4. Pump and Downhole Assembly	31,000	
5. Stainless Steel	2,500	
Producer(s) Net Additional Cost		$ 33,450
TOTAL COST PRODUCER(S)		$200,630

Effective Cost per Drain Area

1-Producer	$ 66,876
+1-Injector	$ 55,727
TOTAL	$ 122,603

Well Type 13-3/8" 5,000' Three Branch Well

Rig Up Cost		
1. Site Prep	$ 2,000	
2. Transport	3,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 17,100
Intangible Drilling Cost		
1. Drilling Days 8 @ $ 7,000/day	$ 56,000	
2. Mud Chemicals	6,000	
3. Cement (Conventional CSG)	11,000	
4. Casing Crew and Equipment Rental	6,000	
5. Transport	3,000	
6. Rig Day Work 9 days @ $ 6,500/day	58,500	
7. Directional Driller 7 days @ $ 2,000/day	14,000	
8. Supervision	3,500	
9. Cementing (Branches, etc.)	2,000	
10. Open Hole Logs	9,000	
11. Perforating	6,000	
TOTAL INTANGIBLE COSTS		$175,000
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG 20 in; 300 ft @ $ 35.72/ft	10,716	
3. Protection CSG 13-3/8 in; 4,350 ft @ $ 17.91/ft	77,910	
4. Production CSG Type 2-7/8 in; 3 x 650 ft @ $ 3.50/ft	6,825	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	4,000	
7. Drilling Template(s)	2,000	
8. Tubing Type 2-7/8 in; 13,050 ft @ $ 3.50/ft	45,675	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$149,126
TOTAL COST INJECTION WELL		$341,226
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 4,350 ft @ $ 7.50/ft	$ 32,625	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 13,050ft @ $ 3.50/ft	-(45,675)	
3. Packer(s)	4,000	
4. Pump and Downhole Assembly	31,000	
5. Stainless Steel	2,500	
Producer(s) Net Additional Cost		$ 24,450
TOTAL COST PRODUCER(S)		$365,676

Effective Cost per Drain Area

1-Producer	$ 121,892
+1-Injector	$ 113,742
TOTAL	$ 235,634

Well Type 9-5/8" 2,000' Three Branch Well

Rig Up Cost		
1. Site Prep	$ 1,500	
2. Transport	2,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 15,600
Intangible Drilling Cost		
1. Drilling Days 3 @ $ 5,600/day	$ 16,800	
2. Mud Chemicals	500	
3. Cement (Conventional CSG)	4,500	
4. Casing Crew and Equipment Rental	2,500	
5. Transport	1,000	
6. Rig Day Work 9 days @ $ 5,600/day	50,400	
7. Directional Driller 7 days @ $ 2,000/day	14,000	
8. Supervision	3,000	
9. Cementing (Branches, etc.)	2,000	
10. Open Hole Logs	7,500	
11. Perforating	5,700	
TOTAL INTANGIBLE COSTS		$107,900
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG in; ft @ $ /ft	-	
3. Protection CSG 9-5/8 in; 1,350 ft @ $ 3.50/ft	15,660	
4. Production CSG Type 2-7/8 ; 1,950 ft @ $ 3.50/ft	6,825	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	6,000	
7. Drilling Template(s)	4,000	
8. Tubing Type 2-7/8 ; 4,050 ft @ $ 3.50/ft	14,175	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$ 48,660
TOTAL COST INJECTION WELL		$172,160
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 1,350 ft @ $ 7.50/ft	$ 10,125	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 4,050 ft @ $ 3.50/ft	-(14,175)	
3. Packer(s)	4,000	
4. Pump and Downhole Assembly	31,000	
5. Stainless Steel	2,500	
Producer(s) Net Additional Cost		$ 33,450
TOTAL COST PRODUCER(S)		$205,610

Effective Cost per Drain Area
1-Producer $ 68,537
+1-Injector $ 57,387
TOTAL $ 125,924

Well Type 9-5/8" 5,000' Three Branch Well

Rig Up Cost		
1. Site Prep	$ 2,000	
2. Transport	3,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 17,100
Intangible Drilling Cost		
1. Drilling Days 7 @ $ 7,000/day	$ 49,000	
2. Mud Chemicals	5,000	
3. Cement (Conventional CSG)	10,000	
4. Casing Crew and Equipment Rental	5,000	
5. Transport	3,000	
6. Rig Day Work 10 days @ $ 6,500/day	65,000	
7. Directional Driller 7 days @ $ 2,000/day	14,000	
8. Supervision	3,500	
9. Cementing (Branches, etc.)	2,000	
10. Open Hole Logs	9,000	
11. Perforating	6,000	
TOTAL INTANGIBLE COSTS		$171,500
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG 13-3/8 in; 300 ft @ $ 17.91/ft	5,373	
3. Protection CSG 9-5/8 in; 4,350 ft @ $ 11.60/ft	50,460	
4. Production CSG Type ; ft @ $ /ft	6,825	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	6,000	
7. Drilling Template(s)	4,000	
8. Tubing Type 2-7/8 ; 13,050 ft @ $ 3.50/ft	45,675	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$120,333
TOTAL COST INJECTION WELL		$308,933
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 4,350 ft @ $ 7.50/ft	$ 32,625	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 13,050 ft @ $ 3.50/ft	-(45,675)	
3. Packer(s)	4,000	
4. Pump and Downhole Assembly	31,000	
5. Stainless Steel	2,500	
Producer(s) Net Additional Cost		$ 24,500
TOTAL COST PRODUCER(S)		$333,383
Effective Cost per Drain Area 1-Producer $ 111,128 +1-Injector $ 102,978 TOTAL $ 214,106		

Well Type 9-5/8" 2,000' Branch Well One Injector One Producer

Rig Up Cost			
1.	Site Prep	$ 1,500	
2.	Transport	2,000	
3.	Rig Up Charge	3,000	
4.	Day Work days @ $ /day	9,100	
	TOTAL RIG UP COST		$ 15,600
Intangible Drilling Cost			
1.	Drilling Days @ $ /day	$ 16,800	
2.	Mud Chemicals	500	
3.	Cement (Conventional CSG)	4,500	
4.	Casing Crew and Equipment Rental	2,500	
5.	Transport	1,000	
6.	Rig Day Work 6 days @ $ 5,600/day	33,600	
7.	Directional Driller 4 days @ $ 2,000/day	8,000	
8.	Supervision	2,500	
9.	Cementing (Branches, etc.)	1,500	
10.	Open Hole Logs	5,000	
11.	Perforating	4,500	
	TOTAL INTANGIBLE COSTS		$ 80,400
Tangible Costs			
1.	Drive Pipe	$ 2,000	
2.	Surface CSG in; ft @ $ /ft	-	
3.	Protection CSG 9-5/8 in; 1,350 ft @ $ 11.60/ft	15,660	
4.	Production CSG Type 2-7/8 ; 1,300 ft @ $ 3.50/ft	4,550	
5.	Conventional Packers	-	
6.	Completion Template(s) and Tubing Hangers	4,000	
7.	Drilling Template(s)	4,000	
8.	Tubing Type 2-7/8 ; 1,350 ft @ $ 3.50/ft	4,725	
9.	Tubing Type 3-1/2 ; 1,350 ft @ $ 4.61/ft	6,224	
	TOTAL TANGIBLE COSTS		$ 41,159
	TOTAL COST INJECTION WELL		$ -
Additional Cost for Production Well			
1.	Tubing Type ; ft @ $ /ft	$ -	
2.	Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	35,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 35,000
	TOTAL COST PRODUCER(S)		$172,159

Effective Cost per Drain Area
1-Producer $ -
+1-Injector $ -
TOTAL $ 172,159

Well Type 9-5/8" 5,000' Branch Well One Injector One Producer

Rig Up Cost		
1. Site Prep	$ 2,000	
2. Transport	3,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 21,550/day	9,100	
TOTAL RIG UP COST		$ 17,100
Intangible Drilling Cost		
1. Drilling Days 7 @ $ 7,000/day	$ 49,000	
2. Mud Chemicals	5,000	
3. Cement (Conventional CSG)	10,000	
4. Casing Crew and Equipment Rental	5,000	
5. Transport	3,000	
6. Rig Day Work 6 days @ $ 6,500/day	39,000	
7. Directional Driller 4 days @ $ 2,000/day	8,000	
8. Supervision	3,000	
9. Cementing (Branches, etc.)	1,500	
10. Open Hole Logs	6,000	
11. Perforating	4,000	
TOTAL INTANGIBLE COSTS		$133,500
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG 13-3/8 in; 300 ft @ $ 17.91/ft	5,373	
3. Protection CSG 9-5/8 in; 4,350 ft @ $ 11.60/ft	50,460	
4. Production CSG Type 2-7/8 ; 1,300 ft @ $ 3.60/ft	4,550	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	4,000	
7. Drilling Template(s)	4,000	
8. Tubing Type 2-7/8 ; 4,350 ft @ $ 3.50/ft	15,225	
9. Tubing Type 3-1/2 ; 4,350 ft @ $ 4.61/ft	20,054	
TOTAL TANGIBLE COSTS		$105,662
TOTAL COST INJECTION WELL		$ NA
Additional Cost for Production Well		
1. Tubing Type ; ft @ $ /ft	$ -	
2. Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3. Packer(s)	-	
4. Pump and Downhole Assembly	35,000	
5. Stainless Steel	-	
Producer(s) Net Additional Cost		$ 35,000
TOTAL COST PRODUCER(S)		$291,262

Effective Cost per Drain Area
1-Producer $ NA
+1-Injector $ NA
TOTAL $ 291,262

Well Type 500' Drain Hole

Rig Up Cost		
1. Site Prep	$ 1,000	
2. Transport	1,000	
3. Rig Up Charge	-	
4. Day Work days @ $ /day	-	
TOTAL RIG UP COST		$ 2,000
Intangible Drilling Cost		
1. Drilling Days 2 @ $ 3,750/day	$ 7,500	
2. Mud Chemicals	100	
3. Cement (Conventional CSG)	1,000	
4. Casing Crew and Equipment Rental	1,500	
5. Transport	-	
6. Rig Day Work 3 days @ $ 3,750/day	11,250	
7. Directional Driller Turn Key 14,000	14,000	
8. Supervision	1,000	
9. Cementing (Branches, etc.)	1,000	
10. Open Hole Logs	2,500	
11. Perforating	-	
TOTAL INTANGIBLE COSTS		$ 39,850
Tangible Costs		
1. Drive Pipe	$ 700	
2. Surface CSG in; ft @ $ /ft	-	
3. Protection CSG 7 in; 500 ft @ $ 7.40/ft	3,700	
4. Production CSG Type Coflexip; 200 ft @ $ 125.00/ft	25,000	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	4,000	
7. Drilling Template(s)	1,000	
8. Tubing Type 2-7/8 ; 500 ft @ $ 3.50/ft	1,750	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$ 36,150
TOTAL COST INJECTION WELL		$ 78,000
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 500 ft @ $ 7.50/ft	$ 3,750	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 500 ft @ $ 7.50/ft	-(1,750)	
3. Packer(s)	-	
4. Pump and Downhole Assembly	6,000	
5. Stainless Steel	-	
Producer(s) Net Additional Cost		$ 8,000
TOTAL COST PRODUCER(S)		$ 86,000

Effective Cost per Drain Area

1-Producer	$ 21,500
+1-Injector	$ 19,500
TOTAL	$ 41,000

Well Type 2,000' Drain

Rig Up Cost			
1.	Site Prep	$ 1,500	
2.	Transport	2,000	
3.	Rig Up Charge	3,000	
4.	Day Work 2 days @ $ 3,750/day	7,500	
	TOTAL RIG UP COST		$ 14,000
Intangible Drilling Cost			
1.	Drilling Days 3 @ $ 3,750/day	$ 11,250	
2.	Mud Chemicals	500	
3.	Cement (Conventional CSG)	4,000	
4.	Casing Crew and Equipment Rental	3,000	
5.	Transport	1,000	
6.	Rig Day Work 6 days @ $ 3,750/day	22,500	
7.	Directional Driller Turn Key 22,300	22,300	
8.	Supervision	2,000	
9.	Cementing (Branches, etc.)	2,000	
10.	Open Hole Logs	2,500	
11.	Perforating	-	
	TOTAL INTANGIBLE COSTS		$ 71,050
Tangible Costs			
1.	Drive Pipe	$ 2,000	
2.	Surface CSG in; ft @ $ /ft	-	
3.	Protection CSG 7 in; 2,000 ft @ $ 7.40/ft	14,800	
4.	Production CSG Type Coflexip; 200 ft @ $ 125.00/ft	25,000	
5.	Conventional Packers	-	
6.	Completion Template(s) and Tubing Hangers	4,000	
7.	Drilling Template(s)	1,000	
8.	Tubing Type 2-7/8 in; 2,000 ft @ $ 3.50/ft	7,000	
9.	Tubing Type ; ft @ $ /ft	-	
	TOTAL TANGIBLE COSTS		$ 53,800
	TOTAL COST INJECTION WELL		$138,850
Additional Cost for Production Well			
1.	Tubing Type 4-1/2 ; 2,000 ft @ $ 7.50/ft	$ 15,000	
2.	Less Tubing Changes from Injection Well Type 2-7/8 ; 2,000 ft @ $ 3.50/ft	-(7,000)	
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	20,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 28,000
	TOTAL COST PRODUCER(S)		$166,850

Effective Cost per Drain Area
1-Producer $ 83,425
+1-Injector $ 69,425
TOTAL $ 152,850

DON R. HOLBERT
CONSULTING PETROLEUM ENGINEER
6637 WEST HINSDALE AVENUE
LITTLETON, COLORADO 80123
(303) 979-4966

November 23, 1979

Dr. Don Dareing
Maurer Engineering Incorporated
10301 Northwest Freeway
Suite 202
Houston, Texas 77018

Dear Don:

Enclosed are the cost estimates you requested. The estimates for the 2000 ft. well incorporate my present tools. These appear to be somewhat heavy duty for a shallow well and I have estimated costs for a light weight set of tools with a well program more suitable to 500 ft. This assumes enough wells will be drilled to justify the manufacture of the tools.

Please note the rig time and drainhole cost estimates are per drainhole.

If you need additional data please let me know.

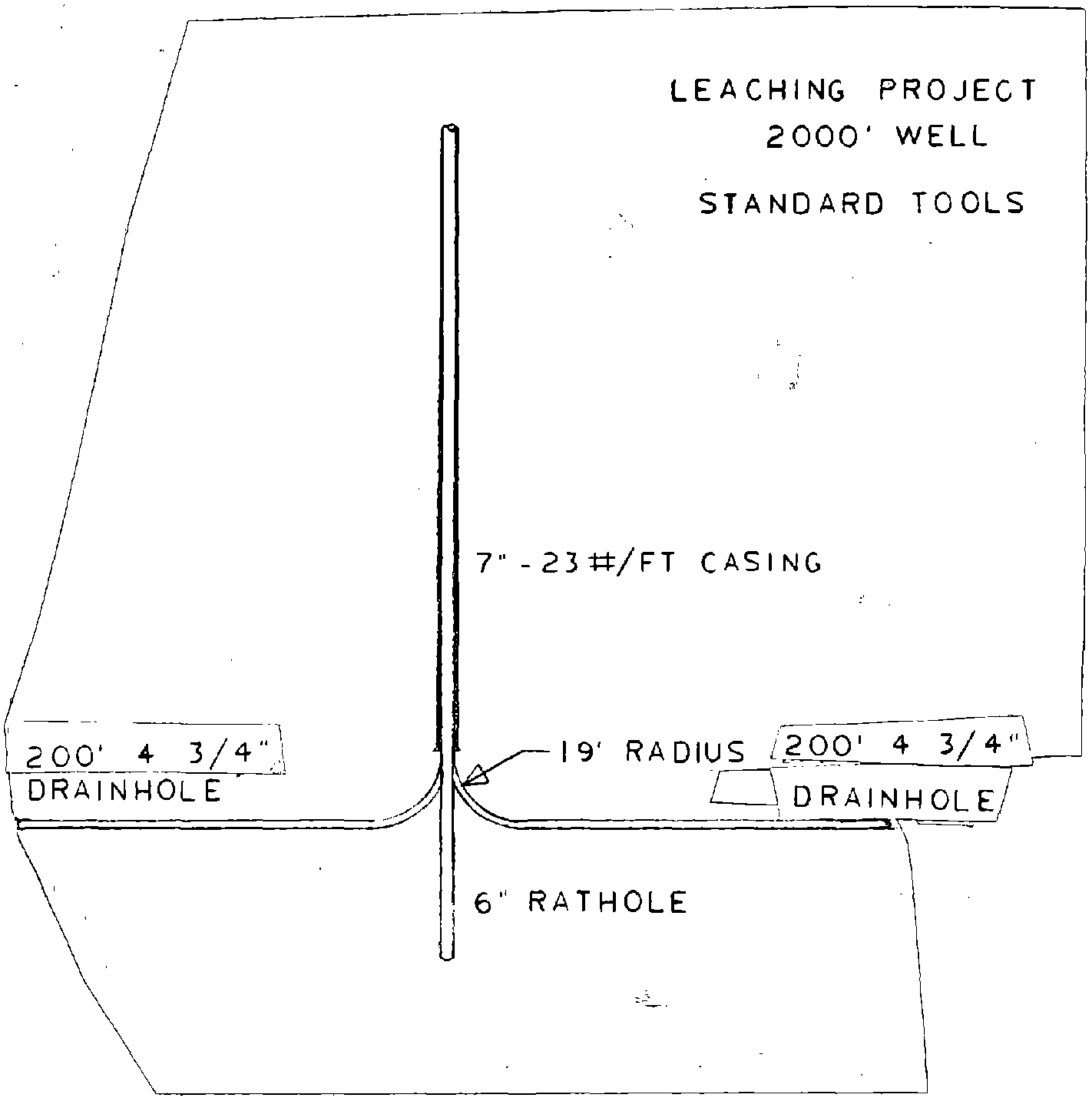
Yours truly,

Don R. Holbert

Don R. Holbert

DRH:bd
Enclosure

LEACHING PROJECT 2,000' WELL STANDARD TOOLS



WELL PROGRAM

LEACHING WELL WITH TWO DRAIN HOLES

2,000 FEET AVERAGE DEPTH

1. Drill 16-20" surface hole as required.

2. Run and cement 12-1/4" casing to TD.

3. Drill 8-3/4" hole to ± 25 feet above midpoint of pay (around 2,000 ft) with deviation less than 5° at TD.

4. Run appropriate open hole logs.

5. Run and cement 7"-23 #/ft - K-55 casing.

6. Drill out cement and drill 6" rathole through pay. (Pay may be cored, oriented if natural fracture system is of interest.)

7. Run Gamma Ray - Neutron or appropriate logs.

8. Run single shot survey to determine deviation <u>and</u> direction for rathole.

9. Compute anchor length and whipstock face orientation that will achieve the desired drainhole elevation and orientation.

10. Run whipstock assembly into hole off bottom 5 to 10 feet.

11. Orient whipstock face with gyroscopic surveys into orienting sub above whipstock latch, surveying after every surface rotation.

12. Plant whipstock after properly faced, disengage and pull out of hole with running assembly.

13. Go into hole with angle building assembly and drill 3°/ft (19 ft radius) portion of drain hole. This should be ± 30 ft drilled. Change mud to incorporate extreme pressure lubricating properties.

14. Pull drilling assembly out of hole and survey with magnetic 120° angle unit instrument to verify 90° turn achieved.

15. Go into hole with stabilized drilling assembly.

16. Drill 50 to 80 ft of lateral.

17. Pull out of hole and survey.

18. Repeat Steps 15 through 17 until 200 ft of total drain hole drilled.

19. Pull stabilized drilling assembly out of hole.

20. Run final survey.

21. Run in hole with whipstock latch, recover whipstock assembly and trip out of well.

22. Compute new anchor length and whipstock face orientation to achieve the desired second drain hole.

23. Repeat Steps 10 through 20 for second drain hole.

24. Retrieve whipstock and come out of hole laying down drill pipe.

DRAINHOLE DRILLING

STANDARD TOOLS

2,000-foot Depth

Assume 80 ft/hr pen. rate at $\frac{45,000}{9.75/12}$ = 55,400 #/ft. @ 100 RPM

Use 5,000 # on 4 3/4" bit and 50 RPM (12,600 #/ft)

$$P.R. = 80 \text{ ft/hr} \times \frac{50}{100} \times \frac{12,600}{55,400} = 9 \text{ ft/hr}$$

200 ft = 22.2 24 hrs
12 hrs if RPM not significant

Assume 60 ft sheath pipe - 4 trips
4 surveys

Rig Time

Orientation	12-18 hrs
Drilling	12-24 hrs
Trips	16 hrs
Surveys	4 hrs
TOTAL:	44-62 hrs

DH Tool Cost	Several Wells	One Well	
Minimum	$ 4,200 to	$12,600	(minimum red to 5 days by drilling 3 or more wells per contract)
Royalty	420	1,260	
	$ 4,620	$13,860 st	
Drilling in 4,000 to 6,000 wt range	$ 7,200	$14,400	
Royalty	720	1,440	
	$ 7,920	$15,840 st	
Survey	400	400	
Supervision	1,800	5,400	
Travel	1,750	3,250	
Motor Valve/Pump	500	500	
TOTAL:	$16,990	$39,250	

Third Party Costs	Several Wells	One Well
1. Add Extreme Pressure Lubricant to Mud	$ 1,000	$ 3,000
2. Single Shot 120° Angle Unit	400	900
3. Stokenbury Tools	450	1,200
4. Gyroscopic Orientation	2,000	2,500
5. Miscellaneous Special Subs	250	500
6. Wireline Unit to Run Surveys	1,000	5,000
7. Trucking	210	1,000
	$ 5,310	$14,100
Drainhole Drilling Totals for one 200-foot DH (Exclusive of Rig Time) for 2,000-foot well	$22,300	$49,350

Well Type 5,000' Single Drain

Rig Up Cost		
1. Site Prep	$ 2,000	
2. Transport	3,000	
3. Rig Up Charge	3,000	
4. Day Work 2 days @ $ 4,550/day	9,100	
TOTAL RIG UP COST		$ 17,100
Intangible Drilling Cost		
1. Drilling Days 8 @ $ 7,000/day	$ 56,000	
2. Mud Chemicals	5,000	
3. Cement (Conventional CSG)	8,000	
4. Casing Crew and Equipment Rental	4,500	
5. Transport	2,500	
6. Rig Day Work 6 days @ $ 6,500/day	39,000	
7. Directional Driller days @ $ /day Flat	23,300	
8. Supervision	2,500	
9. Cementing (Branches, etc.)	1,000	
10. Open Hole Logs	3,000	
11. Perforating	-	
TOTAL INTANGIBLE COSTS		$143,800
Tangible Costs		
1. Drive Pipe	$ 2,000	
2. Surface CSG 9-5/8 in; 300 ft @ $ 11.60/ft	3,480	
3. Protection CSG 7 in; 5,000 ft @ $ 7.40/ft	37,000	
4. Production CSG Type Coflexip; 200 ft @ $ 125.00/ft	25,000	
5. Conventional Packers	-	
6. Completion Template(s) and Tubing Hangers	4,000	
7. Drilling Template(s)	1,000	
8. Tubing Type 2-7/8 ; 5,000 ft @ $ 3.50/ft	17,500	
9. Tubing Type ; ft @ $ /ft	-	
TOTAL TANGIBLE COSTS		$ 89,980
TOTAL COST INJECTION WELL		$250,880
Additional Cost for Production Well		
1. Tubing Type 4-1/2 ; 5,000 ft @ $ 7.50/ft	$ 37,500	
2. Less Tubing Changes from Injection Well Type 2-7/8 ; 5,000 ft @ $ 3.50/ft	-(17,500)	
3. Packer(s)	-	
4. Pump and Downhole Assembly	31,000	
5. Stainless Steel	-	
Producer(s) Net Additional Cost		$ 51,000
TOTAL COST PRODUCER(S)		$301,880

Effective Cost per Drain Area
1-Producer $ 150,940
+1-Injector $ 125,440
TOTAL $ 276,380

Horizontal Hole Out of High Curvature Borehole

Our estimate of drilling cost for the slant hole is based on drilling rate from a similar well recently drilled by Esso Resource, Ltd. of Canada.

The well was drilled at Cold Lake, Canada, and penetrated a Tar Sand Zone with about 1,000 ft of near horizontal hole. The actual time frame from spud in to completion was 42 days. Table 12 gives a breakdown of the various drilling tasks.

Table 12

TIME ANALYSIS

	Time (Days)	% of Total
Drilling	2.9	6.9
Ream Hole to Larger Size	5.3	12.6
Surveys	3.8	9.0
Tripping	2.9	6.9
Run Casing	3.6	8.3
W.O.C., Head-up, Drill Out	4.3	10.2
Ream to Bottom	3.1	7.4
Miscellaneous Operations and Problems	16.2	38.6

The total measured depth, or arc distance for the Esso Resources well is 2,955 ft. The TMD of the slant hole leaching scheme is 1,099 ft or about one third the length of the Esso well.

According to Table 12, 26 days were used to drill and case about 3,000 feet of a high angle slanted hole. We estimate one-third this time to drill the 1,000-foot leaching wellbore or 9 days. The Esso well required 16.2 days of miscellaneous operations and problems or 38.6 percent of total drilling and completion time. Assuming about the same percentage (40%) for contingencies, we estimate total time to drill and complete the leaching well at 11 days.

The cost estimate breakdown then is:

Rig Cost (11 days at $11,384/day)	$125,000
Directional Drilling Equipment and Driller (11 days at $2,000/day)	22,000
Mobilization and Site Preparation	10,000
	$157,000

Corresponding footage cost is about $157/foot.

The cost summary for drilling and completing one slant hole with a 400-foot horizontal section at 500-foot depth is given in Table 12.

For depths greater than 1,147 feet a conventional rig with conventional drilling equipment is used. Cost estimates at 2,000 feet and 5,000 feet reflect conventional rig costs.

SLANT HOLE 500 FT TRUE VERTICAL DEPTH, 400 FT HORIZONTAL

Drilling

Build Angle (1,099 ft @ $157/ft)	$172,543
Horizontal (11,334/day rig rate)	11,000
Rig Cost for Installing Steel or RFP (4 days @ $3,500/day)	14,000
Steel Casing (9-5/8" $11.60/ft)	12,750
Plastic Pipe (5-1/2" $10.90/ft)	17,429
Cement	4,000

Completion

Rig Time @ $2,500/day (5 days)	$ 12,500
Mobilization	7,500
Perforate and Clean Out	5,000
Logging Horizontal Hole	2,000
Other (roads, location, supervision)	15,000
TOTAL (one slant hole)	$273,722
Cost of two slant holes	$547,444

Cost per 100 x 100 ft sweep area (1/2 cost of two slant holes divided by horizontal distant times 100)$ 68,430

Well Type 400' Slant Well @ 2,000'

Rig Up Cost			
1.	Site Prep	$ 1,500	
2.	Transport	2,000	
3.	Rig Up Charge	3,000	
4.	Day Work days @ $ /day	9,100	
	TOTAL RIG UP COST		$ 15,600
Intangible Drilling Cost			
1.	Drilling Days 19 @ $ 6,000/day	$114,000	
2.	Mud Chemicals	10,000	
3.	Cement (Conventional CSG)	4,500	
4.	Casing Crew and Equipment Rental	2,500	
5.	Transport	1,000	
6.	Rig Day Work 3 days @ $ 6,000/day	18,000	
7.	Directional Driller 15 days @ $ 2,000/day	30,000	
8.	Supervision	3,000	
9.	Cementing (Branches, etc.)	2,000	
10.	Open Hole Logs	5,000	
11.	Perforating	7,000	
	TOTAL INTANGIBLE COSTS		$188,000
Tangible Costs			
1.	Drive Pipe	$ 2,000	
2.	Surface CSG in; ft @ $ /ft	-	
3.	Protection CSG 9-5/8 in; 2,654 ft @ $ 11.60/ft	30,786	
4.	Production CSG Type 5-1/2; 3,054 ft @ $ 10.90/ft	33,290	
5.	Conventional Packers	-	
6.	Completion Template(s) and Tubing Hangers	4,000	
7.	Drilling Template(s)	-	
8.	Tubing Type ; ft @ $ /ft	-	
9.	Tubing Type ; ft @ $ /ft	-	
	TOTAL TANGIBLE COSTS		$ 70,076
	TOTAL COST INJECTION WELL		$273,676
Additional Cost for Production Well			
1.	Tubing Type 2-7/8 ; 2,000 ft @ $ 3.50/ft	$ 7,000	
2.	Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	30,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 37,000
	TOTAL COST PRODUCER(S)		$310,676

Effective Cost per Drain Area

1-Producer	$ 68,419
+1-Injector	$ 77,669
TOTAL	$ 146,088

Well Type 400' Slant Well @ 5,000'

Rig Up Cost			
1.	Site Prep	$ 1,500	
2.	Transport	2,000	
3.	Rig Up Charge	3,000	
4.	Day Work days @ $ /day	9,100	
	TOTAL RIG UP COST		$ 15,600
Intangible Drilling Cost			
1.	Drilling Days 30 @ $ 8,000/day	$240,000	
2.	Mud Chemicals	6,000	
3.	Cement (Conventional CSG)	10,000	
4.	Casing Crew and Equipment Rental	5,000	
5.	Transport	3,000	
6.	Rig Day Work 3 days @ $ 7,000/day	21,000	
7.	Directional Driller 18 days @ $ 2,000/day	36,000	
8.	Supervision	3,500	
9.	Cementing (Branches, etc.)	2,000	
10.	Open Hole Logs	5,000	
11.	Perforating	8,000	
	TOTAL INTANGIBLE COSTS		$339,500
Tangible Costs			
1.	Drive Pipe	$ 2,000	
2.	Surface CSG 13-3/8 in; 300 ft @ $ 17.91/ft	5,373	
3.	Protection CSG 9-5/8 in; 5,655 ft @ $ 11.60/ft	65,600	
4.	Production CSG Type 5-1/2; 6,055 ft @ $ 10.90/ft	66,000	
5.	Conventional Packers	-	
6.	Completion Template(s) and Tubing Hangers	4,000	
7.	Drilling Template(s)	-	
8.	Tubing Type ; ft @ $ /ft	-	
9.	Tubing Type ; ft @ $ /ft	-	
	TOTAL TANGIBLE COSTS		$142,973
	TOTAL COST INJECTION WELL		$498,073
Additional Cost for Production Well			
1.	Tubing Type 2-7/8 ; 4,000 ft @ $ 3.50/ft	$ 14,000	
2.	Less Tubing Changes from Injection Well Type ; ft @ $ /ft	-	
3.	Packer(s)	-	
4.	Pump and Downhole Assembly	30,000	
5.	Stainless Steel	-	
Producer(s) Net Additional Cost			$ 44,000
	TOTAL COST PRODUCER(S)		$542,073

Effective Cost per Drain Area

1-Producer $ 124,518

+1-Injector $ 135,518

TOTAL $ 260,036