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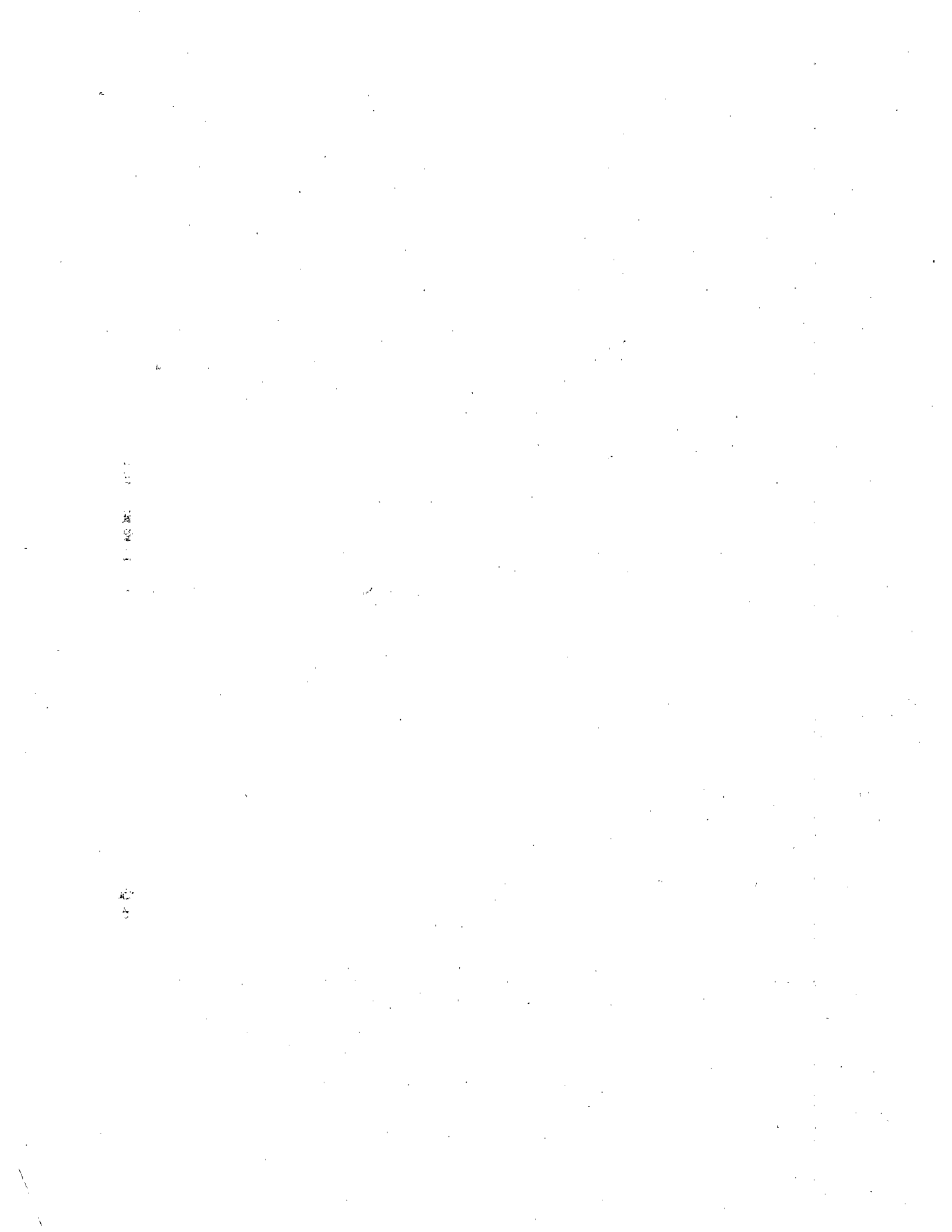
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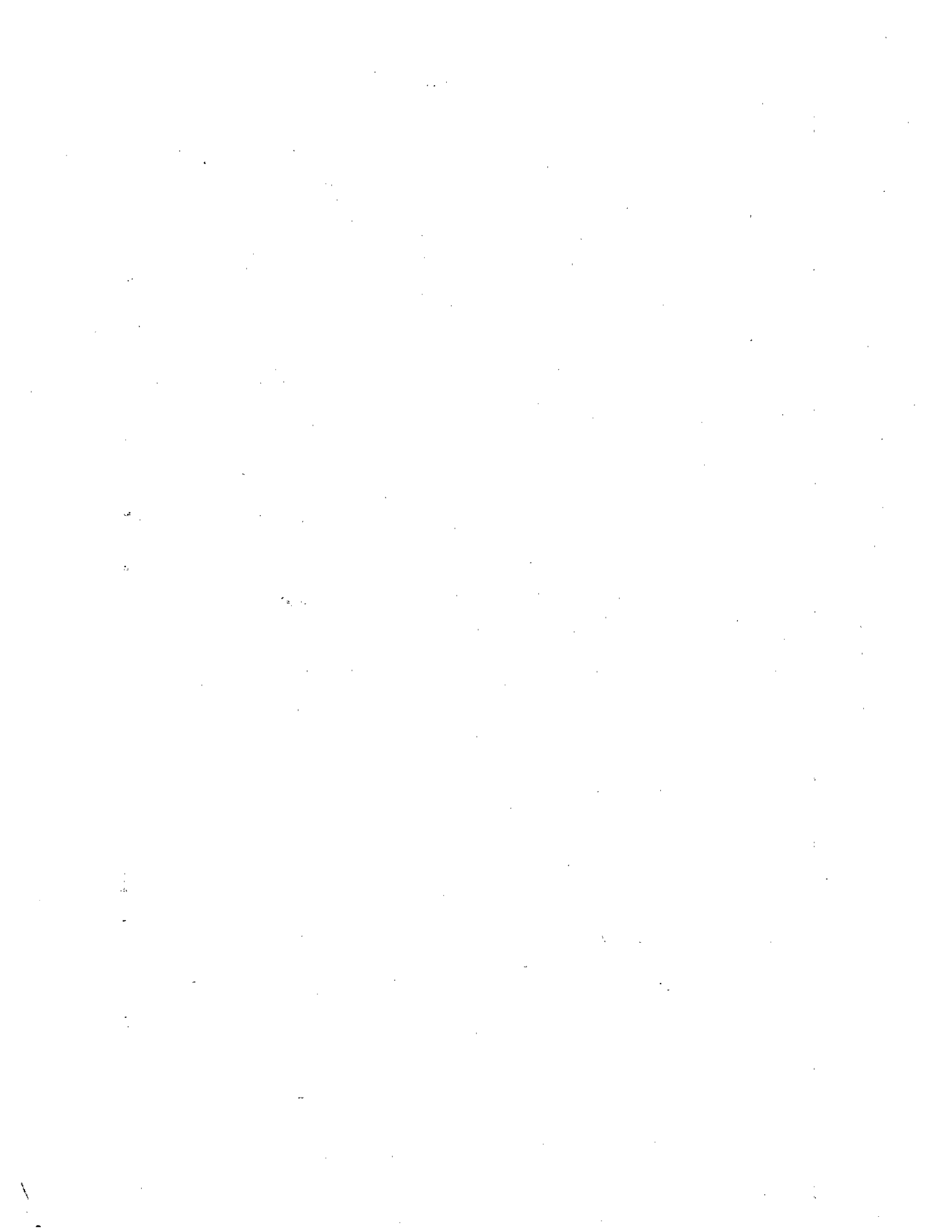
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ABSTRACT

This report provides a systematic method for assessing the commercial feasibility of applying true in situ copper mining at a selected site. Procedures and algorithms are provided for developing design specifications and costs for wellfields and a surface processing facility, and then conducting a DCF/ROR cash flow analysis. This report also describes the environmental requirements to permit an in situ copper mining operation in Arizona, including procedures and monitoring and restoration requirements and costs. Also included are descriptions of tests to obtain site specific input data that are required to conduct a commercial design.



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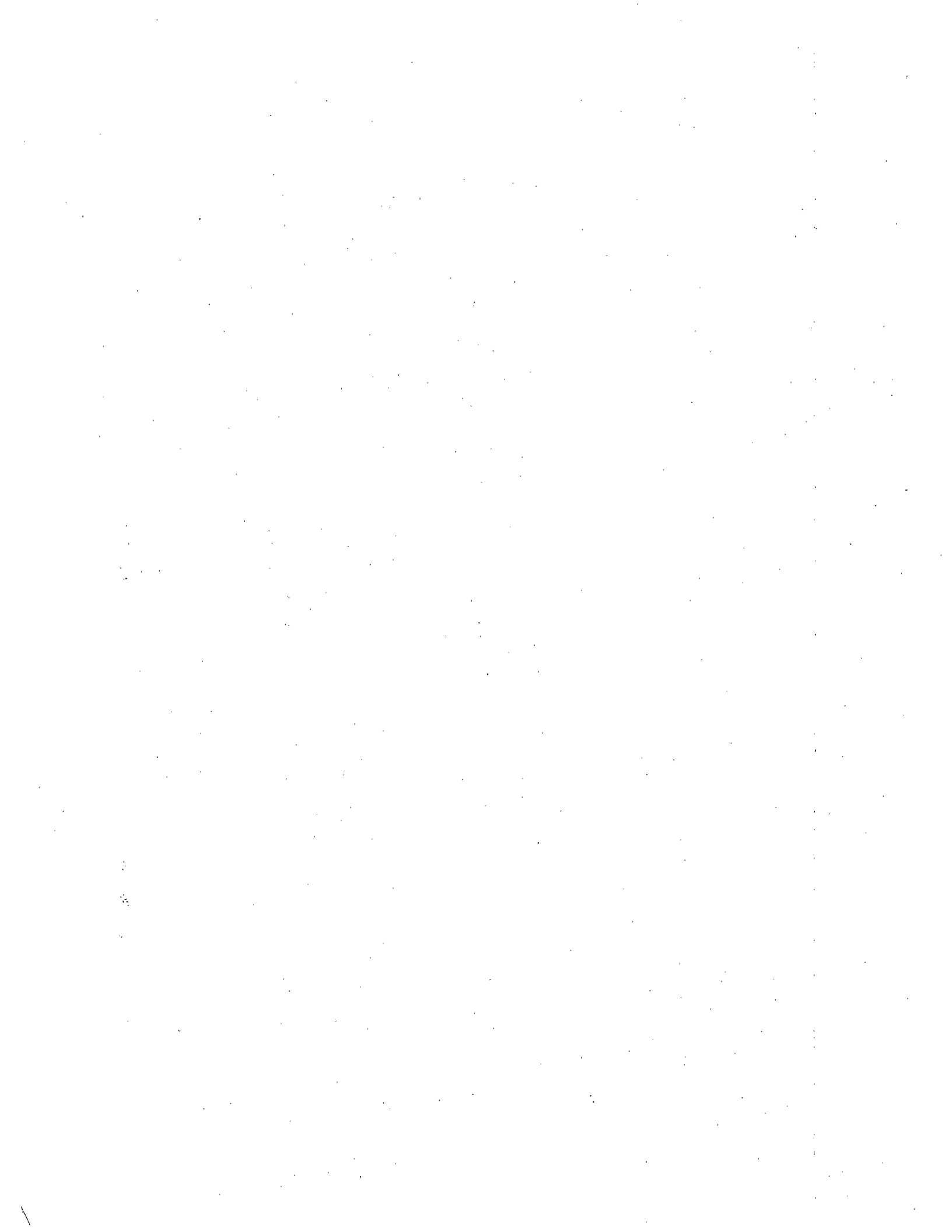
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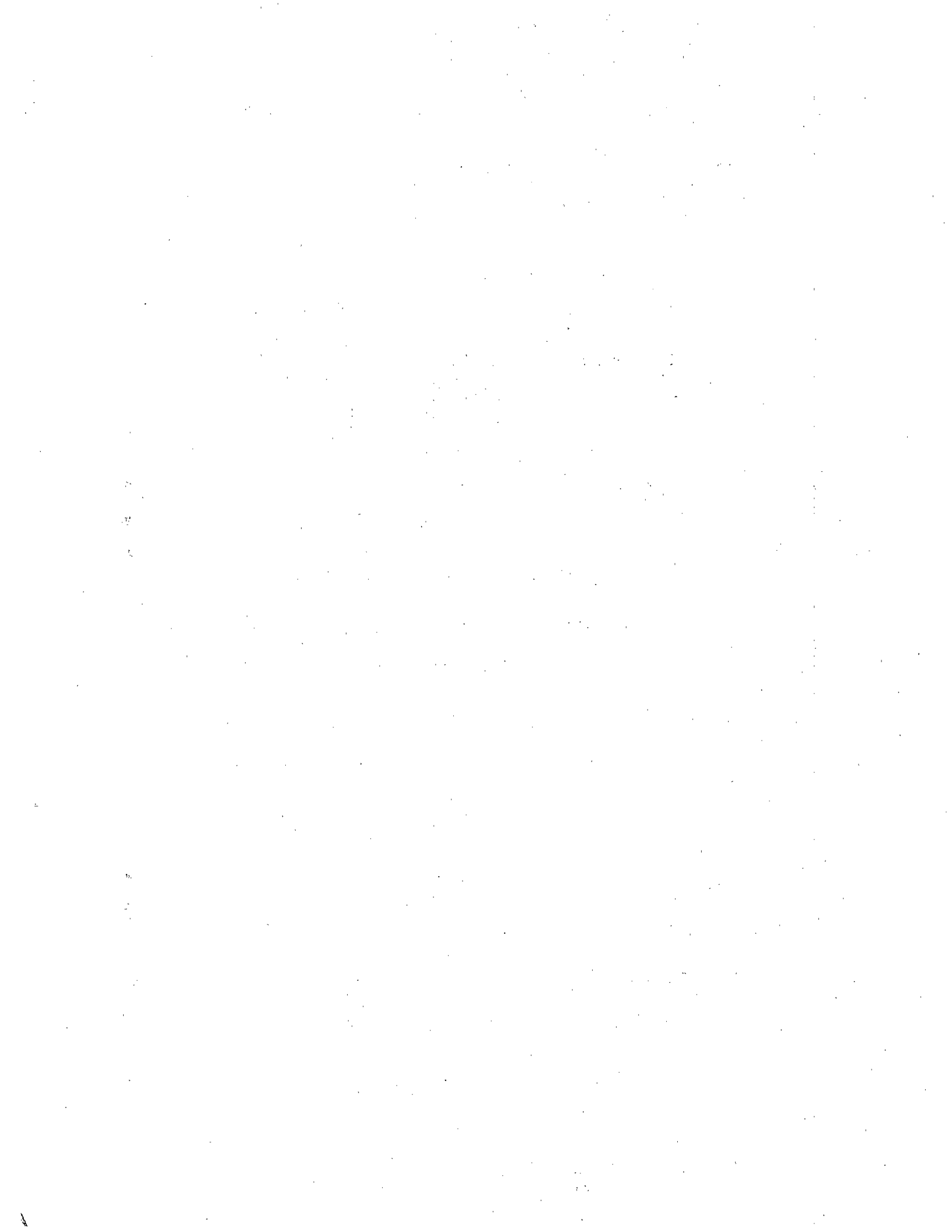
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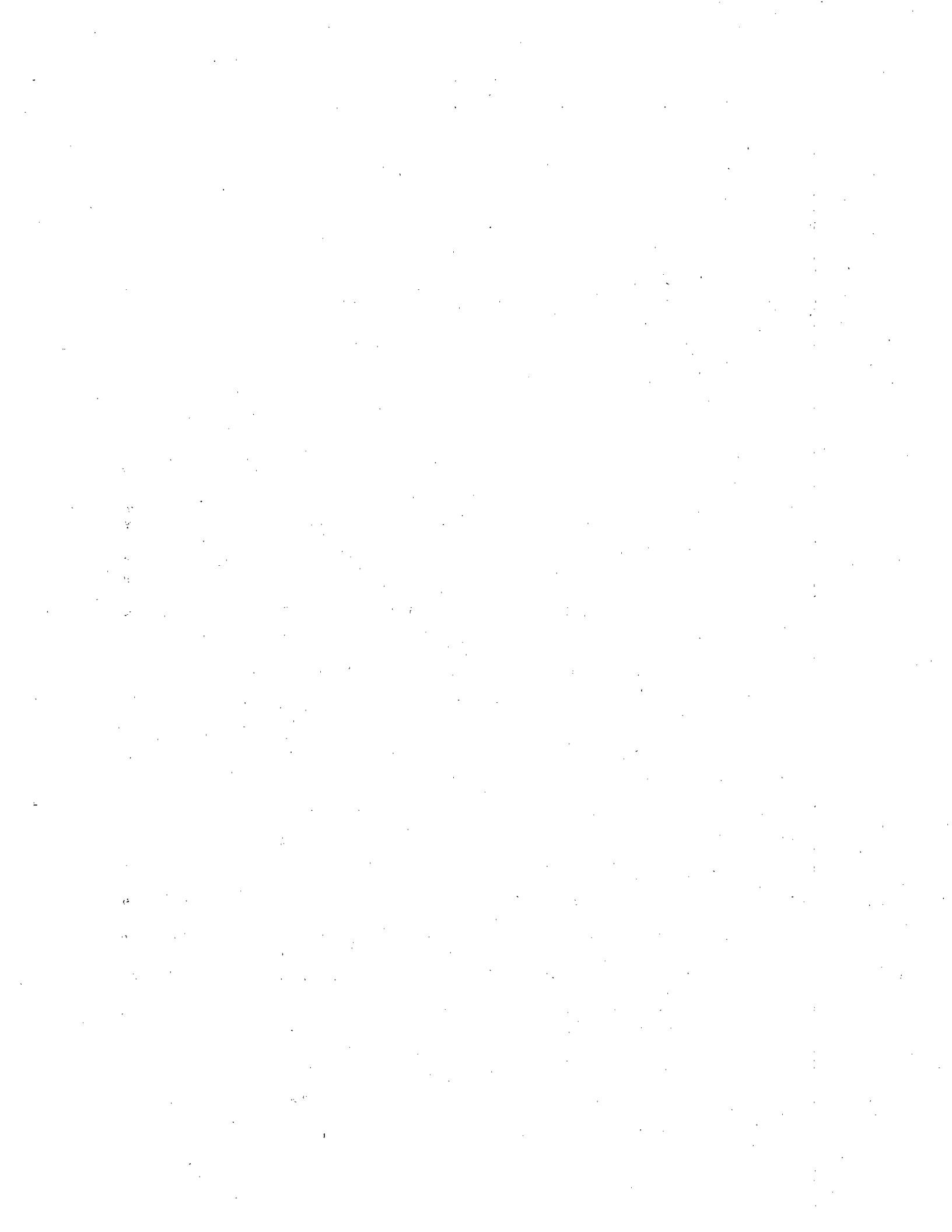


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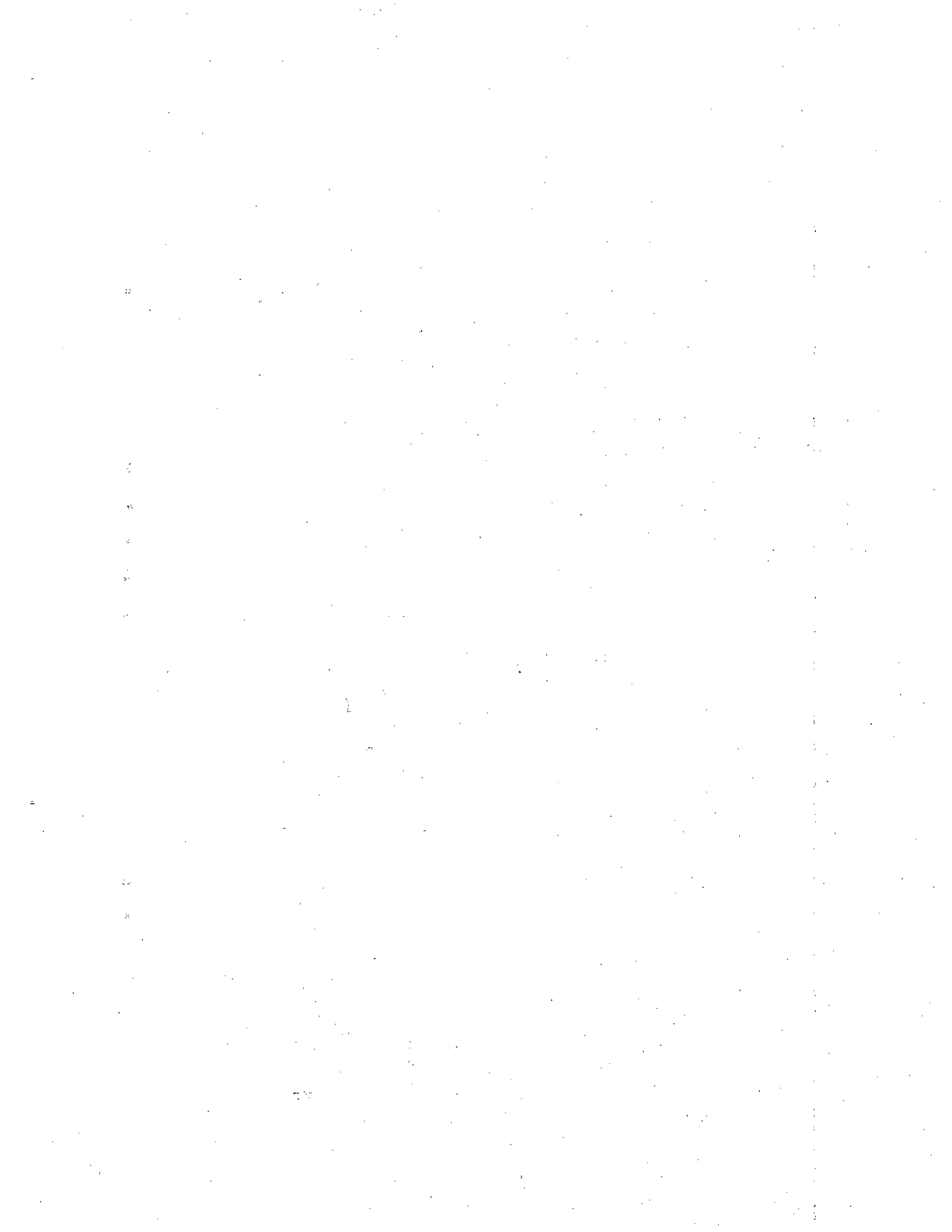


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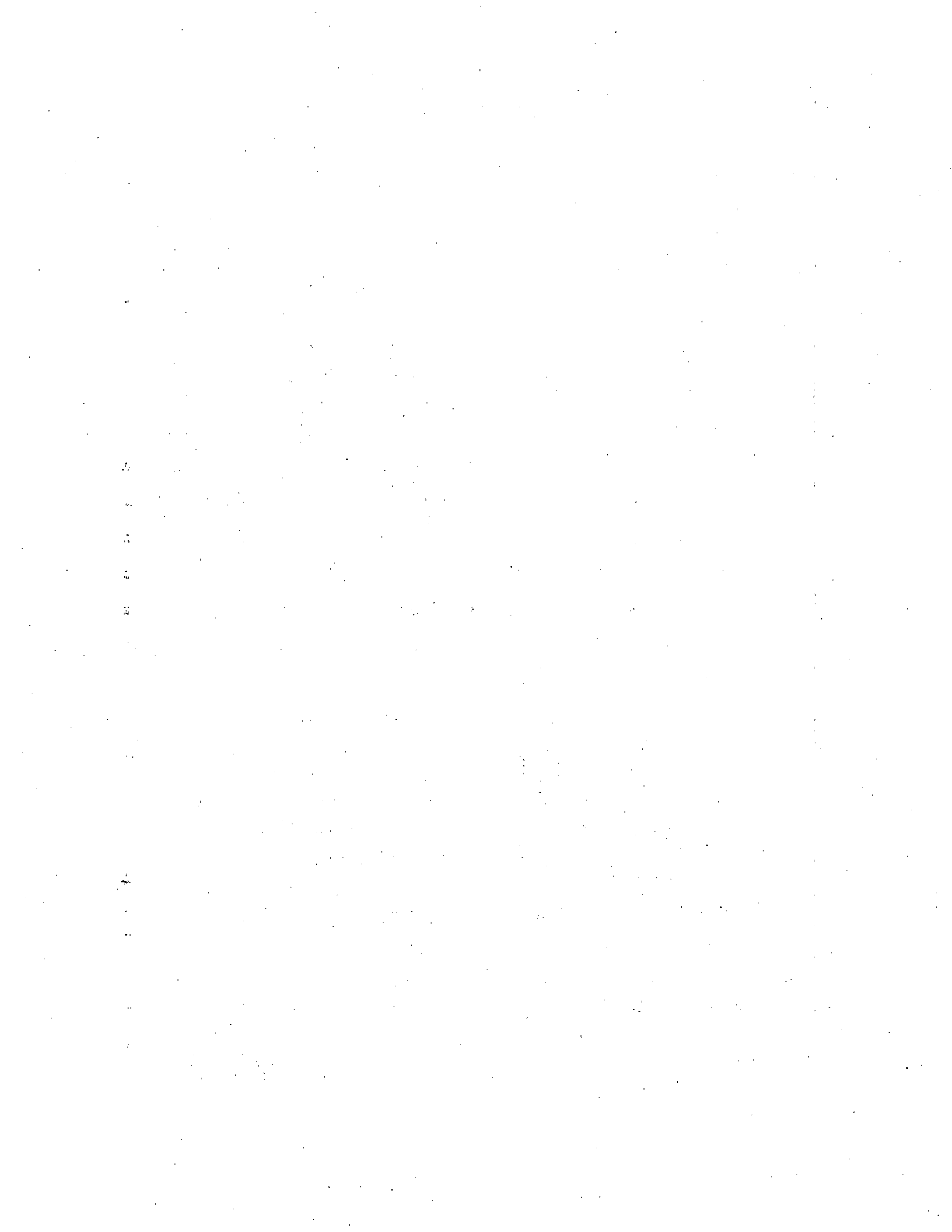
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CHAPTER 1

INTRODUCTION

A long-term objective of the U.S. Bureau of Mines is to maximize the probability of the domestic production of copper by the private sector using in situ mining. An initial step in meeting this objective is to provide industry with this generic design manual for in situ copper mining. This manual provides a systematic method for assessing the commercial feasibility of true in situ copper mining at a selected deposit. The manual contains:

- o A listing of the site-specific parameters that must be quantified to conduct a commercial design and a description of laboratory and field tests to measure these parameters.
- o A listing and description of the design elements and procedures for each component of an in situ copper mining system, and a method of costing individual components.
- o A method of identifying the best of 42 possible mining scenarios which maximizes the DCF/ROR for commercial operation for a specific site.
- o A cash flow model and computer program to conduct a DCF/ROR economic analysis incorporating all capital and operating expenses associated with the wellfield, a electrowinning/solvent extraction plant, and environmental permitting.
- o A description of the environmental procedures, specifications, designs, and costs for permitting, monitoring, and restoration.

CHAPTER 2

OVERVIEW OF IN SITU COPPER MINING

2.1 DEFINITION OF COMMERCIAL TRUE IN SITU COPPER MINING

The criteria for a commercial true in situ copper mining have been established by the U.S. Bureau of Mines for this contract.

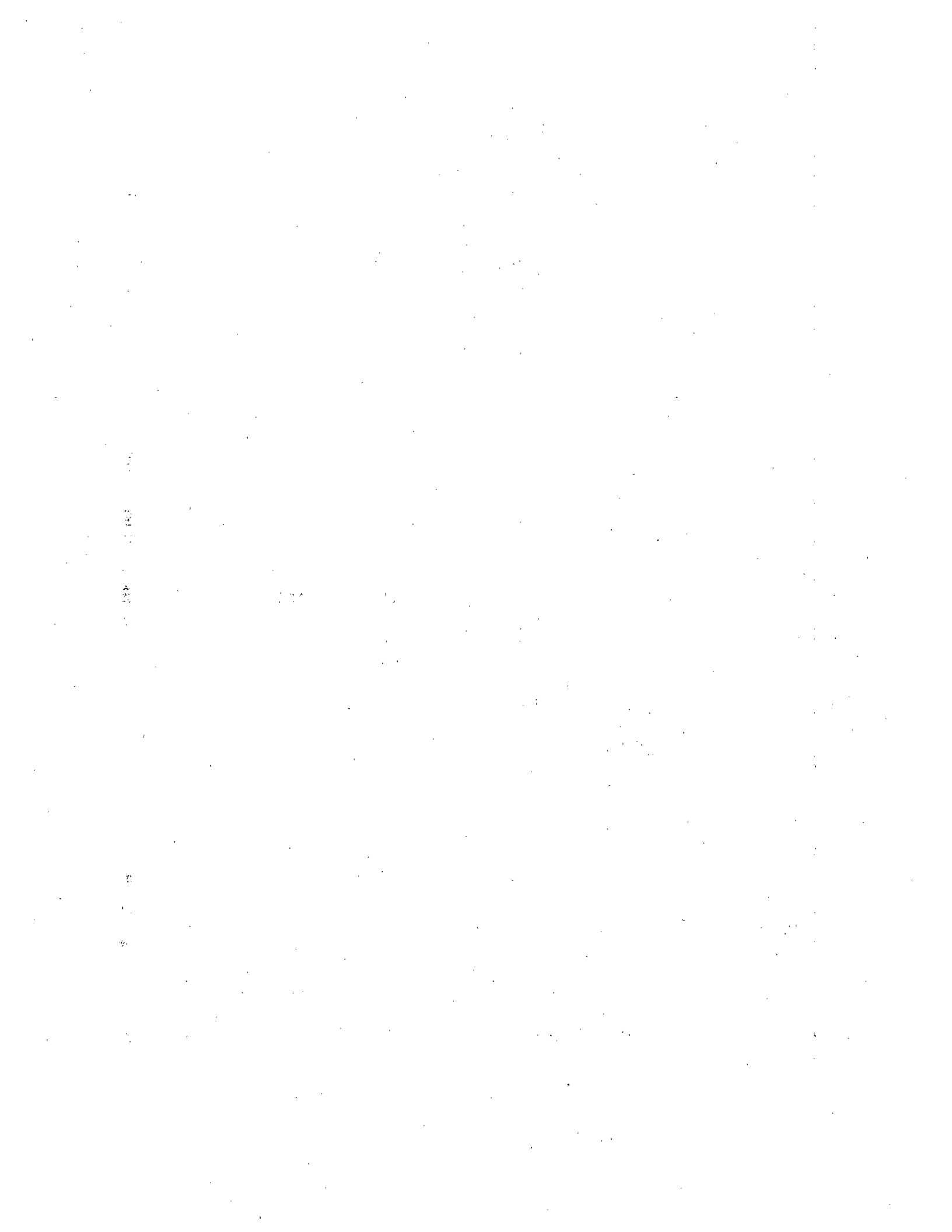
In situ copper mining is defined as the exclusive extraction, through leach solution injection, of the mineral values of an ore body based upon the contact between a leaching solution and the in-place mineral values. In a true in situ operation, the bulk of the rock between boreholes is in its native geologic state. Hydraulic fracturing and borehole blasting should only be considered as methods of increasing solution flow into and out of wells. A commercial mining operation will contain a minimum of 100 million pounds of acid-soluble copper in the ground, averaging 0.2 percent or greater at a depth of less than three thousand feet below the surface, regardless of the initial hydrologic regime in which that deposit exists.

2.2 DEFINITION OF IN SITU COPPER MINING SYSTEM

2.2.1 Technology Involved

In situ copper mining involves the recovery of copper values from the native ore by circulating solvents through the ore in its native geologic state. In contrast, conventional mining processes the ore through rock breakage and transport. The solvent used to recover copper oxide is an acid.

An in situ copper mining operation combines the operation of both surface and sub-surface facilities.



- o Chemicals used to dissolve and maintain copper in solution are first processed through the surface facility.
- o A set of injection wells is used to force the solvent into the pores or fractures of the rock by using a pressure in excess of the hydrostatic pressure in the deposit.
- o Solvent travels through the rock and reacts with the copper mineral, transferring the copper value to the liquid phase.
- o A set of production wells is used to create a low pressure sump where the copper-enriched solution can be collected for transport to the surface.
- o The produced solutions are processed for both copper recovery and acid make-up for an additional trip through the pores in the rock.
- o The solution will make multiple trips through the ore body before the copper in a given well pattern is depleted.

2.2.2 Economic Incentives and Technical Criteria for Success

The cost advantage in using this process lies in not having to mine or move enormous quantities of rock, and that the porosity of the leach mass is maintained low. The latter item is a significant consideration as high porosity holds up solubilized copper solution resulting in an initial negative cash flow. Low porosity does not necessarily result in low permeability, as is often perceived. Porosity reflects total void space; permeability is related to the size of fractures or interconnected pores making up the void space. At a given porosity, many small fractures result in low permeability. Few large fractures result in high permeability. The key elements to successful implementation of the process are:

- o Sufficient flow must be achieved through the natural fractures.
- o Copper mineralization either exists in the main flow fractures or inside fractures that are "fluid" connected to the main flow fractures.

- o A wellfield can be designed and installed that encompasses sufficient copper; ensures that the main flow fractures connect to injection and production wells; provides sufficient residence time to obtain high copper loading at the production well; and maintains that loading for high percentage copper recovery.

Sufficient experience exists to indicate that the above can be achieved.

- o Heap and dump leaching function to a great extent by diffusion of acid into rock interiors and diffusion of copper out to the rock surface through a fluid path. The interior fractures of the rubble very likely existed under in situ conditions.
- o Over the past 15 years, several true in situ copper mining projects have demonstrated the technical feasibility of achieving the key elements discussed above. References describing this work are listed below.
 - + Tucson Daily Citizen, July 22, 1975, Kennecott Trying Mining by Liquid.
 - + Mining Engineering, November 1977, Oxymin Details Plans For In Situ Leaching Project in Arizona.
 - + Arizona Republic, January 12, 1976, Mining Firm Plans Blast at Miami.
 - + Wall Street Journal, June 7, 1979, New Ways to Extract Metals Are Found as Deposits Thin Out and Prices Stay Up.
 - + Arizona Silver Belt, December 13, 1979, Miami Town Council Will Decide Fate of Oxymin Drilling Petitions.
 - + Report Submitted to Miami, Arizona Town Council by Occidental Minerals Corporation, December 18, 1979.
 - + Engineering and Mining Journal, June 1983, Codelco Aim for 1 Million mt/yr of Fine Copper at Chuqui by 1990s.
 - + U.S. Patents

| | |
|-------------|--------------|
| - 3,917,345 | - 4,125,289 |
| - 4,045,084 | - 4,438,976 |
| - 4,079,998 | - 4,386,806 |
| - 4,116,488 | - 4,342,484. |

2.2.3 Factors Affecting Design Specification and Costing

In situ copper mining technology is a simple concept, but involves the integrated design, specification, costing, and operation of numerous surface and sub-surface components. Technical and cost input is required from multiple disciplines:

- o Petroleum engineering
- o Process engineering
- o Geological and geochemical
- o Mining engineering
- o Hydrological
- o Hydrometallurgical
- o Environmental.

This input must consider numerous factors related to design, specification and costing, such as:

- o Annual copper production rate and selling price
- o Size and configuration of surface extraction plant
- o Preparation and reconstitution of lixiviant
- o Collection, processing, and distribution of well fluids
- o Copper concentration in pregnant liquor and recovery factor
- o Number and spacing of injection and production wells
- o Design, installation, completion, stimulation, operation, and recompletion of wells
- o Abandonment and replacement of wells
- o Control of underground movement of fluids
- o Effective removal of metal values from the deposit
- o Understanding and minimizing (to extent possible) the consumption of reagents
- o Controlling deleterious effects of gangue dissolution by the leach fluid
- o Assessing suitability of existing underground entries
- o Designing shafts, declines, and drifts

- o Understanding permeability and other factors relating to fluid flow and assessing matrix modification with a view to enhancement of fluid flow
- o Estimating costs for various elements of the installation
- o Preparing cash flow sheets and assessing the economics of the installation
- o Environmental assessment, permitting, monitoring, and restoration.

2.2.4 Factors Affecting Economic Performance

A final design for an in situ copper mining operation requires specification of the following parameters: total production capacity of the plant, the plant life, the pregnant copper concentration, number of operating wells, well spacing, frequency of well pattern additions, and environmental monitoring systems and wellfield restoration plan. It is likely that several combinations of the above, involving trade-offs of initial capital investment versus operating costs and future investments, will provide comparable economic performance as measured by DCF/ROR.

There are four major areas of capital investment: surface facilities for acid and copper leach solution handling; wellfields; pumps and piping; and well pattern start-up. As would be expected, the level of copper concentration in the pregnant liquor has a significant impact on capital costs.

- o Surface Facility - An in situ copper mining operation also entails a hydrometallurgical plant and cannot be any more economical than the limits of that plant. Plant costs have two components: one related to total production capacity (tons per year), and the other to the total rate gallons per minute (gpm) at which solution is circulated through the system. At a fixed level of production capacity, the gpm related investment declines as copper concentration increases, as smaller volumes of solution can be processed to obtain a fixed tonnage per year of metal. Thus, from the standpoint of surface facility

capital, it is desirable to achieve a high effluent copper concentration. From the standpoint of fixed costs per unit production capacity, these are likely to be lower the higher the production capacity.

- o Wellfield - Total well costs are related to individual well costs, which increase with depth, and the number of wells. Since the individual production capacity of a well is proportional to the product of flow rate and metal concentration in solution, it is desirable to have a high copper concentration to minimize the number of wells. The flow rate of a single well increases as permeability and depth increase as a result of higher rock flow conductivity associated with the former, and higher working injection pressure associated with increasing depth. For wellfields completed in underground workings, costs of shafts, raises, drifts, and crosscuts must be included.
- o Pumps - Pump investments usually increase with both the volume of solution processed and the pressure head against which the fluid must be pumped. High effluent copper concentration results in low solution volumes, while the pressure head is proportional to well depth.
- o Well Pattern Start-up - The pores of the rock in the well pattern are initially filled with water. Each time a well pattern operation is initiated, the solubilized metal is diluted by the pore fluid, requiring at least one exchange of the volume of water in a well pattern (one pore-volume) to attain full production capacity. Prior to this time, operating costs are likely to exceed revenues resulting in a negative cash flow. Since the time required to achieve this one-pore volume displacement increases as the total flow rate of the system is reduced, the negative cash flow of start-up will be higher at increased levels of effluent copper concentration, as the product of total gpm and copper concentration is a constant for a given production capacity. Well spacing is another design parameter that impacts this cost. The larger the spacing the longer the start-up time. However, larger spacings also reflect longer life or less future investment for well pattern replacements. The impact of environmental wellfield restoration costs on DCF/ROR will be affected by the same design parameters that control start-up costs.

Major operating costs are labor, utilities, and acid make-up.

Total labor costs are not likely to differ significantly from the solvent extraction/electrowinning plant, as the wellfield operation is not labor intensive. Utility costs will be primarily related to total production capacity, and the rate at which solutions are moved through

the system at a given pressure level. The latter are governed by copper concentration and deposit depth, respectively. Acid make-up costs are related to acid reaction with copper and gangue minerals. The former is a process given, while the latter always detracts from profitability, and if low can be a key factor in making cash available for initial and future well investments. This is especially important at low permeability, where increased well density is required.

2.3 KNOWN CANDIDATE DEPOSITS

In Arizona as in other states and in other countries, several different types of copper deposits occur. These include porphyry, exotic, stratabound, and other. All types can be sulfide, oxide, or mixed copper occurrences (1).

For this study, only the oxide occurrences are considered. In this regard, genesis of oxide deposits is of interest. It is thought that oxide deposits develop as a result of oxidation of sulfide mineralization. This presupposes that the sulfide host rock had paleopermeability and that oxidation resulted from percolation of meteoric water. The sulfide mineralization when oxidized generates acid and, if produced in sufficient quantities, the copper could be mobilized. Movement of the copper would depend upon the acid consumption by the host rock and country rock. In the case where insufficient acid is generated, the copper may not be mobilized at all and a resultant oxide cap would be developed. Where an intermediate quantity of acid is generated, a secondary enrichment zone may develop. Lastly, if a large quantity of acid is generated the copper may be removed from the host rock into the country rock where an exotic deposit may occur.

Many porphyry type deposits exhibit oxide caps. Some have secondary enrichment, and exotic deposits are known in Arizona and elsewhere. In addition to the large copper occurrences associated with porphyries, Arizona and other states have stratabound deposits of copper (2), (3). These generally are much smaller copper occurrences but may represent suitable targets for in situ leaching (ISL). A compilation of the larger oxide deposits is given in (4) and (5). These include: Santa Cruz, Casa Grande West, Lakeshore, Safford, San Manuel, VanDyke, Blue Bird, Johnson Camp, and the stratabound deposits at the White Mesa Mining District.

2.4 DESIRABLE GEOLOGIC SETTINGS

A number of features will impact the design and therefore the economic attractiveness of a deposit for ISL. These features include surface topography, depth of burial, ore geometry, liquid saturation, porosity, and permeability.

Surface topography may range from virtually flat to mountainous. Mountainous topography will present difficulties for designing and installing roads and well locations when wells are to be installed from the surface. When mountainous terrain is encountered, the engineer should consider installing a group of wells from a single drill location and, as necessary, use directional drilling techniques to place the wells where desired within the ore zone.

The distance from the surface to the top of the ore zone has both a positive and a negative impact on the economics. Greater access costs are associated with increased depth of burial; however, it also permits a greater applied differential pressure which increases flow rate and permits wider spacing of wells which can reduce costs.

Ore geometry will often dictate the configuration of well installation. A tabular geometry will require more wells and a greater well cost per unit of production than a geometry of a vertical cylinder. Further, it is likely that by using vertical wells the deposit will be retreat mined, that is from the bottom up. Therefore it is desirable to have high-grade ore near the bottom of the deposit.

Control of fluid movement in underground porous media can only occur if the deposit is saturated. It is suspected that some deposits in the arid southwestern part of the United States will not be saturated with groundwater. In this case, added costs will be associated with the injection of fluid to fill the pore spaces of the ore with liquid. This of course is a more difficult problem than it first appears. If the pores do not contain liquid, then in their initial state they are filled with air, nitrogen, or some other gas. Air and nitrogen are only slightly soluble in aqueous liquids and will not be displaced from the pores in a piston-like fashion. If the gas is not displaced or dissolved during the productive lifetime of the operation, the gas will prevent lixiviant from contacting a fraction of the ore and will result in a smaller fraction of copper recovery.

Porosity and permeability are rock properties that will impact the design and economics of a project. Porosity is a measure of void space in the rock, whereas permeability is a measure of the rock's ability to transmit fluid. A rock may have porosity and no permeability. However, it cannot have permeability without porosity. The pore spaces must be interconnected to facilitate the transmission of fluids. The magnitude of porosity will impact the volume of lixiviant required to fill the pore spaces and will impact the time required for the fluid pumped into

the injection well to arrive at the production well. On the other hand, permeability will impact the rate of fluid movement through porous and fractured media. A higher permeability will enhance the rate of flow between the injection and production well.

2.5 LITERATURE REVIEW

The literature review is confined to those projects that have been operated in a true in situ copper mining mode. For a general review of all in situ leaching, reference the U.S. Bureau of Mines bibliography (6) and (6A).

2.5.1 In Situ Leaching of A Nuclear Rubblized Copper Orebody, USERDA Report NVO-155, June 1975

This report summarizes the results of a joint study by the U.S. Energy Research and Development Administration, Kennecott Copper, and Lawrence Livermore Laboratory. This study investigated the technical and economic feasibility of using nuclear devices to rubblize a deep lying copper orebody for the purpose of recovering copper by in situ leaching. Although this work does not correspond to a true in situ mining operation, and the economics are based on acid leaching of sulfide ore, there is sufficient economic commonality with a true in situ copper oxide acid leach to warrant review of the results of the economic sensitivity analysis with regard to production capacity (tons per year (TPY) copper production), and costs associated with environmental monitoring and restoration. Components common to true in situ leaching of oxide ore are:

- o The base case production rate is 42,300 TPY copper for 25 years.
- o The ore grade to be mined is 0.5 percent copper.

- o The pregnant liquor feed to the surface plant is 4.6 grams per liter (gpl) copper.
- o The ore body depth considered is 2700 feet deep and the ore interval is 1200 feet thick.
- o Injection well costs are (drilling, casing, and completion) \$78 per foot of depth; production well costs are \$121 per foot.
- o During production, a total of 40 wells (injection plus production) are in operation and, starting with the third year of operation, a set of 40 new wells are brought into production every three years through year twenty-one (\$230/Annual Ton (AT) investment per well set).
- o The surface facility components included long distance piping; well head plant; liquid storage and pumping; liquid ion exchange; electrowinning; and offsites.
- o Environmental activities and costs include initial hydrologic assessment, environmental studies, and six water barrier wells.
- o Operating costs include raw materials, utilities, labor, and G&A.

Components not common to those considered in this manual are:

- o Radioactivity decontamination and oxygen plants (24% of surface facility investment)
- o Emplacement wells and nuclear devices (45% of wellfield costs)
- o Operating costs associated with monitoring radioactivity, and depreciation of capital (28% of total operating costs)
- o Tax rate of 50 percent.

The results of the economic analysis indicate:

- o A 17.8 percent DCF/ROR at 70 cents per pound of copper at a total operating cost of 30.6 cents per pound at 42,300 TPY copper production rate
- o Less than a 0 percent DCF/ROR for production rates under 12,000 TPY
- o Above 40,000 TPY production rate, doubling the TPY provides only a 38 percent increase in DCF/ROR
- o Total environmental related costs in 1974 \$ were estimated at \$66/AT, which adds 1/2 cent/lb to the copper selling price at a 15 percent return on investment.

It is anticipated that at higher copper loadings (the order of 10 to 15 gpl) positive values of DCF/ROR may result at production rates less than 12,000 TPY. Even with cost inflation, a significant level of inflation in environmental activities and constraints could be tolerated without compromising economic attractiveness. A more important environmental constraint is likely to be the impact of the time frame of the permitting process on project initiation.

2.5.2 Kennecott In Situ Mining Project, 1970-1978

Reference materials pertaining to this project are available from a U.S. Bureau of Mines Report (5), a newspaper article (7), and a number of U.S. patents(8),(9),(10),(11).

The key points obtained from the reference material are summarized below.

- o This was an R&D project conducted by Kennecott's Ledgemont Laboratory at the Safford, Arizona, deposit.
- o The deposit contains 2 billion tons of ore, averaging 0.41 percent copper, approximately half of which is enriched oxide ore; mineralization is over 1600 feet thick and lies between 500 to 1300 feet below the surface.
- o The project covered mineralogy, petrology, leaching chemistry, laboratory leaching, permeability testing, geophysical logging, groundwater tracers, directional drilling, blasting, 5-spot pattern leaching, plant design, and economic analysis.
- o Through 1975, expenditures totaled \$8 million, which included 2-hole testing, using 10-inch diameter injection and production wells to depths of 5000 feet. Additional funding of \$4 to \$6 million was projected for 5-hole testing. The technology was developed for sulfide leaching but could readily be applied to oxides.
- o Field test results reported in the patents indicated that a permeability of 2.4 md was measured over a 70-foot thickness of ore; that horizontal communication of solvent and leached copper was obtained over a distance of 70 feet between injection and production wells; and that production wells in ore averaging 3 percent porosity; and that increased injection pressure, below

the fracturing pressure, dilates fractures which provides for increased permeability.

- o The patents also discuss an example commercial design; chemical and hydraulic methods of increasing well flow rates (permeability stimulation); and adaptations of oil well completion techniques for in situ copper leaching.

2.5.3 Occidental Minerals In Situ Leaching Project, 1976-1980

Occidental Minerals (OxyMin) acquired an option for the VanDyke copper deposit at Miami, Arizona, in 1968(12). It began an exploration program shortly thereafter and by 1975 about 40 holes had been drilled throughout the deposit. Drilling delineated about 100 million tons of copper oxide mineralization having an average grade of about 0.5 percent. The top of the mineralization ranges from 1000 to 2000 feet below the surface. Because of the low grade and depth of burial, conventional mining did not appear attractive. This prompted OxyMin to consider in situ leaching (ISL).

In January 1976, OxyMin commenced an ISL pilot test by drilling 2 holes 75 feet apart from the surface to a depth of slightly more than 1000 feet. One well was hydraulically fractured with water and the induced fracture connected to the second well. Observations suggested that the fracture was horizontal. Subsequently a dilute sulfuric acid solution was injected through one hole into a selected portion of the oxide zone and retrieved at the other hole.

In an effort to stimulate fluid injection and production rates, OxyMin proposed conducting fracturing by using a small amount of controlled liquid explosive (13). The test indicated that blasting was not necessary and that it did more damage than good (14). The OxyMin ISL process (15), (16) consists of drilling two or more wells into a mineral

deposit; casing, cementing, and perforating the wells; and installing a hydraulic fracture in each well. These fractures are at different elevations and one is used for a leachant introduction manifold and the other is used for a solution withdrawal manifold.

OxyMin had planned to build a demonstration facility consisting of four injection wells, nine production wells, and two monitoring wells to determine the economic feasibility of its ISL process. The facility would have been located within the town limits of Miami. Failure of OxyMin to obtain permits in a timely fashion resulted in the termination of the project (17). However, from the outset through December 1979, OxyMin expended in excess of \$11 million. If the demonstration facility had been installed, OxyMin would have spent an additional \$16 million to install and operate the facility.

2.5.4 Dowell And Asarco In Situ Leaching Project

A brief discussion of this work appears in reference (18). Dowell, a division of Dow Chemical, formed a 50-50 joint venture with Asarco to use techniques developed in the oilfields to exploit a deposit at Florence, Arizona. This deposit contains 300 to 400 million pounds of copper at a grade less than 1 percent. It is at a depth of about 1100 feet underground.

At the time the referenced article was written, Dowell had started drilling five holes on the site. The holes were to be completed with stainless steel pipe. Four holes were for injection and the fifth was for production. Wells were to be hydraulically fractured with water at pressures around 1000 to 1500 psi. Key design factors were:

- o 3 percent acid would be used for leaching.
- o A flowrate of 40 to 60 gpm was expected.

- o Oilfield triplex pumps were to be used for injection of fluid.
- o Pregnant liquor was to be shipped by truck to Asarco's San Xavier plant.
- o 60 percent of the copper was expected to be recovered in 20 to 25 years.

The literature does not indicate to what extent the project was carried out.

2.5.5 Codelco-Chile In Situ Leaching Project, 1982 to Present

Although no technical information has been published on the Codelco ISL project, it has been reported (19) that after 1986 the firm will concentrate on four leaching techniques one of which is ISL of north and south extensions of Mina Sur. Later the company will consider ISL for Chuqui Norte. This deposit contains 242 million of 0.7 percent ore.

CHAPTER 3

DESCRIPTION OF CONTENTS OF GENERIC DESIGN MANUAL

3.1 MINING SCENARIOS TO BE EVALUATED

To provide the user with the capability to evaluate a broad range of deposits, the design manual contains procedures to develop commercial design specifications and costs to evaluate 42 distinct mining scenarios. These are combinations of seven methods of accessing the ore (deposit access) for placement of wells, three methods of altering the permeability of the rock in the vicinity of the well (matrix modification), and two initial states of the hydrologic setting of the ore body. The elements making up these three categories are listed below. A specific mining scenario consists of a combination of one element from each of the three major categories. Each element is identified by the number or letter designation shown below.

- o Method of Deposit Access
 - + Drilling from the surface - 1
 - + Drilling from existing underground entries - 2
 - + Development of new underground entries with drilling from those entries - 3
 - + Combinations of Type 1 and 2 - 4
 - + Combinations of Type 1 and 3 - 5
 - + Combinations of Type 2 and 3 - 6
 - + Combinations of Types 1, 2, and 3 - 7
- o Method of Matrix Modification
 - + No modification - A
 - + Modification by hydraulic fracturing - B
 - + Modification by using explosives in the borehole - C
- o Initial Hydrologic Setting of the Orebody
 - + No hydrologic modification (saturated) - i
 - + Hydrologic modification (unsaturated) - ii

An example of a mining scenario designation would be 1.A.i, that is drilling from the surface, no matrix modification, and an orebody that is initially saturated.

The generic design manual contains procedures to develop design specifications and costs for a given mining scenario, and then conduct an economic analysis of a commercial operation. Site-specific technical input parameters are used to develop design specifications for the wellfield, surface plant, and environmental monitoring and restoration practices. Based on these specifications and input economic parameters, capital and operating costs are derived and scheduled, and a DCF/ROR cash flow analysis is carried out.

The DCF/ROR does not include sunk costs, such as exploration and property acquisition; fixed costs, such as royalties and taxes; and depletion allowances, depreciation and salvage value. These are user specific. Examples of input parameters, design specifications, and costs are listed below:

- o Input Parameters
 - + Technical Parameters
 - Depth of deposit
 - Thickness of deposit
 - Permeability of deposit
 - Saturated/unsaturated condition of deposit
 - Solution grade versus time (laboratory generated data)
 - + Economic Parameters
 - Price of copper per pound
 - Cost factors per unit
 - o processing plant costs
 - o well drilling, casing, and completion costs
 - o reagent costs
 - o power costs
 - o labor costs
 - o surface pipe costs
 - o shaft costs
 - o underground development (drifting costs)
 - o surface and downhole pump costs
- o Design Specifications
 - + Well System Design
 - Well drilling and casing parameters
 - Well spacing and pattern type
 - Well depth and leach solution inflow/outflow interval
 - Number of injection and production wells for commercial production

- Well casing materials
- Well cementing materials
- Ore zone completion techniques
- Recovery well pump specifications
- Surface fluid distribution line diameter and material
- Shaft and access drift specifications (depth, length, diameter)
- Leach solution injection pressure and flow rate
- Matrix modification specifications
- + Solvent Extraction-Electrowinning (SX-EW) Plant Design
 - All components of the processing system for pregnant solution inflow to lixiviant rejuvenation for reinjection into the well field
 - Design specifications for evaporation ponds, if required
 - A process flow sheet
- + Environmental Monitoring and Restoration Design
 - Number of monitor wells, spacings, locations, depths
 - Monitor well drilling, construction, and completion methods and materials
 - Methods and designs for monitoring unsaturated conditions
 - Mine site restoration design requirements and procedures
- o Capital and Operating Costs
 - + Capital Cost
 - Process equipment
 - Equipment installation/site improvement
 - Building
 - Initial wellfield development
 - Restoration system
 - Permitting
 - Monitoring system
 - + Operating Cost Analysis
 - Wellfield replacement
 - Labor
 - Reagent
 - Utilities
 - Maintenance
 - Make-up water
 - General and administrative.

3.2 STRUCTURE OF DESIGN MANUAL

The design manual is organized by the three major functional design categories. In each section, in addition to the description of the technology, factors involved in sizing and selecting design options are discussed. Following the discussion of functional design categories, optimization of the overall ISL system and the method of economic

analysis are described. Detailed information such as computer program listings and a summary of various design and costing algorithms is contained in the Appendices.

In situ leaching technology encompasses three major subsystems. This manual provides a quantitative framework for evaluating numerous design choices and the means to conduct an economic evaluation of the integrated systems. What appear to be "best" design choices from a subsystem point of view are often not the optimum choices for the integrated operation. The three major functional design categories are:

- o Sub-Surface Facilities (Well System)
- o Surface Processing Facilities
- o Environmental Permitting.

Among these functional categories, only the surface processing facility involves a mature technology. As a result, there are fewer uncertainties in the design relative to sizing and costing, and subsystem configuration is well defined, as discussed in Chapter 5. A number of options exist for the design of the sub-surface systems. These are discussed in Chapter 4 with regard to design specifications and costing. A description of the environmental permitting process in the State of Arizona is included in Chapter 6. The environmental requirements have not yet been established for ISL copper.

The factors involved in selection of an "optimal" mining method are discussed below:

- o Selection of commercial design basis. This involves an evaluation of ISL from a business point of view. These considerations are not the major thrust in this effort; however, they are briefly discussed in Section 3.4.

- o Selection of mining access and orebody modifications. The various options to be evaluated are described in Section 3.1. Relative ranking of different mining access methods may be determined by the methodology outlined in Chapter 9.
- o Selection of flow pattern. Four distinct flow patterns for leaching are considered in this manual. A description of these patterns and quantitative pressure drop-flow rate relationships are discussed in Section 4.2. The selection of a flow pattern among these choices and sizing of wellfield spacing involves optimization per considerations outlined in Chapter 9. Final selection of design options, and selection of design parameters such as wellfield spacing will be based on the economic evaluation. The single determining parameter may be the pre-tax selling price or pre-tax DCF/ROR. The method of economic analysis, the mathematical algorithms for design and costing, and the information flow network is described in Chapter 8.

The method of using the manual and the steps involved in conducting a commercial design are discussed in Section 3.5. The information on orebody characteristics; copper leaching characteristics; business decisions of annual production rate; and ROI needs to be compiled before a design and economic analysis can be undertaken are discussed in Section 3.3. Computational details such as computer listings, typical inputs/outputs, cost data, and equipment design considerations that are the basis for algorithms and base values of constants are summarized in the Appendices.

3.3 INFORMATION REQUIRED FOR COMMERCIAL DESIGN

The following process information is required to size and then cost the components of a commercial in situ copper mining operation.

- o Tons per year copper production
- o Total plant operating life
- o Total system flow rate
- o The well spacing
- o The flow rate per well
- o The maximum injection well pressure and production well fluid head to be lifted

- o Geologic and deposit characteristics
 - + Depth
 - + Ore thickness
 - + Permeability
 - + Porosity
 - + Average grade of copper
 - + Initial water saturation of porosity
 - + Total tonnage of recoverable copper
- o Copper leaching characteristics
 - + Injection liquor acid strength
 - + Acid consumption per unit copper production.

Various combinations of the above are used to develop system design specifications, and then capital and operating costs.

- o The combination of recoverable copper and plant life sizes the production capacity.
- o The production capacity sizes the EW component of the surface plant.
- o The combination of injected acid strength and net acid consumption specifies the pregnant liquor copper concentration.
- o The combination of copper concentration and production capacity specifies the system flow rate which sizes the SX component of the surface plant.
- o The maximum injection well pressure and production fluid head to be lifted are related to the depth of the overburden.
- o The horsepower requirements for pumping wellfield injection and production fluids are related to the combination of depth and system flow rate.
- o The injection flow rate is derived from combinations of permeability, injection pressure, ore thickness, and well spacing.
- o The number of operating wells is a function of the total system flow rate and the injection well flow rate.
- o A combination of ore thickness, ore grade, well spacing, flow rate per well, and copper loading relates to well pattern operating life.
- o The number of well pattern replacements is determined from the plant life and the well pattern life.
- o The start-up time or hold-up time of a well pattern is a function of the porosity, well spacing, ore thickness, and well flow rate.

- o The quantity of well pattern make-up water is related to the well spacing, ore interval, porosity, and initial water saturation.

Average deposit characteristics and geometries as well as the levels of the major operational design parameters that can be selected as mining strategies at a specific deposit can vary over a wide range. Generic design procedures have to be formatted to account for these variations. Unit cost factors must reflect sensitivity to changes in production capacity, system flow rate, and depth of ore burial in order to derive capital and operating costs for economic analysis of a generic design.

However, it is not possible for a generic design manual to provide procedures for dealing with variability within a deposit, or various business strategies for mining a deposit. These are site- and company-specific, but can be developed by using components of the manual. The following serves as an example.

- o Assume that deposit access by surface drilling vertical wells has been identified as the best mining scenario for a 600-foot vertical section of ore.
- o It is likely that along this 600-foot zone of ore both permeability and copper grades vary, and not necessarily in the same way. This variation will be site-specific.
- o The design procedures in the manual can be applied to subsections of the 600-foot ore zone to obtain a number of commercial designs and associated economic performances. This analysis is used to determine which option is best, from both a technical and business point of view, for the specific copper producer involved.

3.4 COMMERCIAL DESIGN BASIS

The first step in developing a commercial design and economic analysis involves sizing the production capacity for in situ mining.

This is a business decision which will be both site- and company-specific and requires providing information on tons per year production capacity, mine life (recoverable copper tonnage), and minimum return on investment. Two of the factors that are involved in this decision process are discussed below.

- o Experience indicates that production life beyond a 20-year time frame is not likely to improve the DCF/ROR, and that 20 years represents a viable life for the SX/EW plant.
- o The maximum production rate is given by the total recoverable copper divided by the chosen life. However, only a percentage of this capacity may be produced in a 20-year period for a number of reasons:
 - + The operator may not have sufficient capital to construct the larger facility.
 - + The greater production rate may not be consistent with the operator's share of the market, or it may distort the market and adversely affect the price of the commodity.
 - + The operator may be utilizing in situ production to supplement production at a specific site. In this case an SX/EW facility may already be in place, and the economic analysis would be used to calculate a transfer price for copper produced from the in situ operation.
 - + The initial in situ operation may be targeted for a high grade portion of the ore body.

The procedures provided in this manual can be used to aid in this decision process by using them to conduct an economic sensitivity analysis as a function of production capacity, either as a stand alone operation (with SX/EW plant) or as a supplemental production (SX/EW plant in place). The minimum production capacity is 2500 TPY, which is derived from the Bureau of Mines definition of the 100 million pounds minimum recoverable copper assumed to be recovered in 20 years. Once a design basis is arrived at as a base case, the manual can also be used to conduct sensitivity analyses for all the key process parameters. This information can be used to prioritize field tests to obtain the

data that has the greatest impact on economic performance, and to rank geologic properties for exploration purposes.

3.5 METHOD AND STEPS INVOLVED IN CONDUCTING COMMERCIAL DESIGN

There are two methods available to the user of the manual for completing a commercial design. Worksheets may be used with manual calculations to conduct a commercial design. The other option is to utilize the computer program which accompanies the manual to conduct the calculations. The program is available for the IBM PC/AT computer.

The major steps involved in conducting commercial design are as follows:

- o Compilation of Information Required. The input information outlined in Section 3.3 has to be compiled. The geologic data on the orebody in the absence of detailed exploration activities may be incomplete. In case data is not available, that parameter has to be estimated.
- o Selection of Design Options. Design options of interest should be determined. This includes selection of a method of mining access (surface or underground), type of flow pattern selected for leaching, and pregnant solution copper loading.
- o Selection of Design Parameters. Select values of design parameters such as piping diameter for injection and production wells, well spacing, leach interval height, and well diameters.
- o Conduct Economic Analysis. Utilize either the worksheets or the computer program to conduct economic analysis and determine either copper selling price or ROR. The overall information flow network is shown in Figure 3.1. The compiled information, selected design options, and parameters form the inputs to various functional design and costing algorithms. The costs of various items are compiled into either a copper pre-tax selling price or a DCF/ROR depending on the user's choice.
- o Iterate Economic Analysis. Evaluate the economic analysis and various calculated design parameters such as wellfield life, injector well flow rate, etc., to determine whether additional economic evaluations at different design options or parameter values are to be conducted. Repeat economic analysis steps until all desired alternates have been determined and "best" choice design selected.

- o Conduct Sensitivity Analysis. Review compiled information to determine levels of variability in a parameter (e.g., changes in permeability or ore grade within the deposit of interest). Also review the compiled information to determine level of uncertainty in the data. Conduct economic analysis to determine the effect of uncertainty and variability on the overall economics and the design. Select the "best-choice" design.

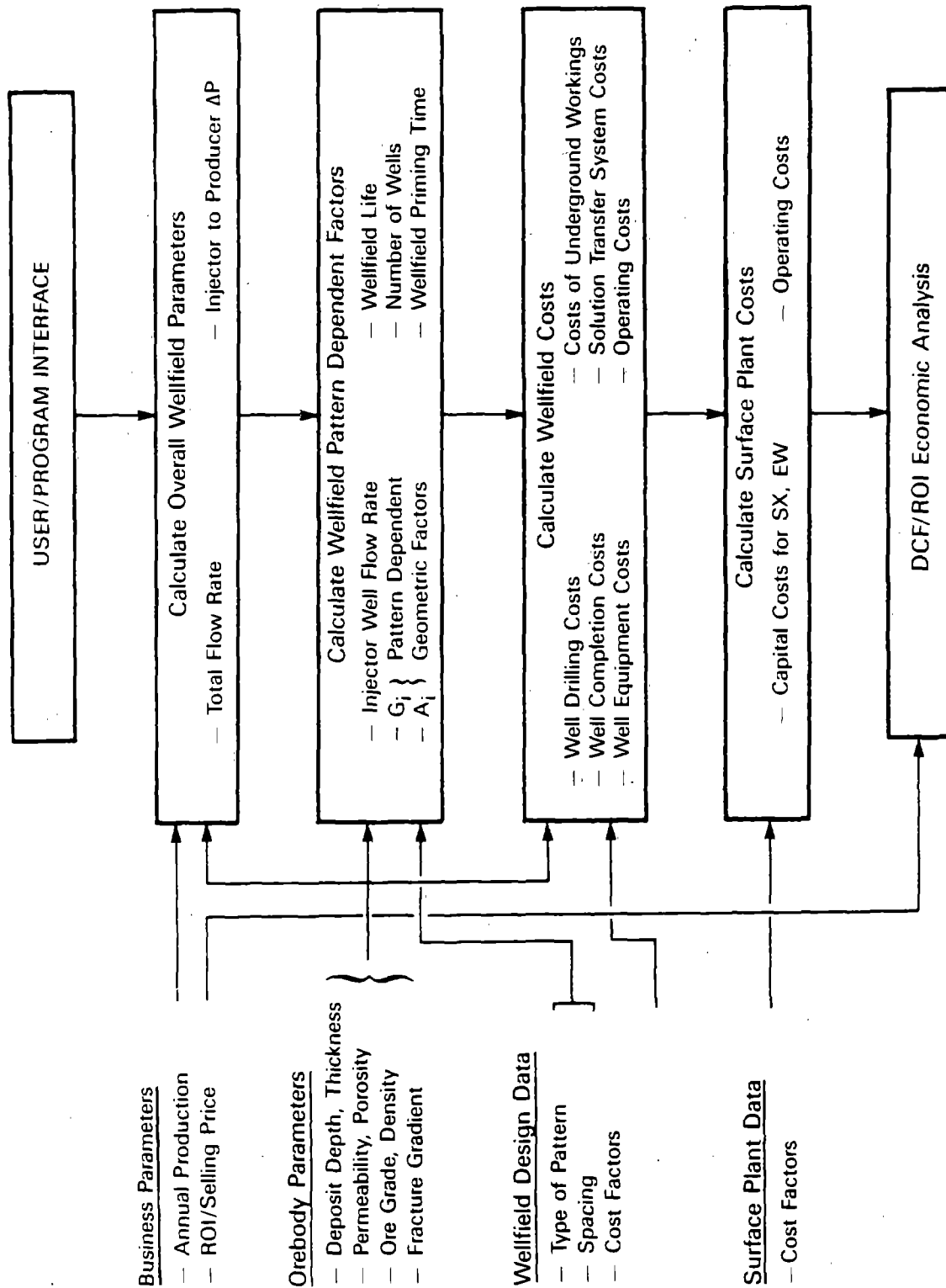
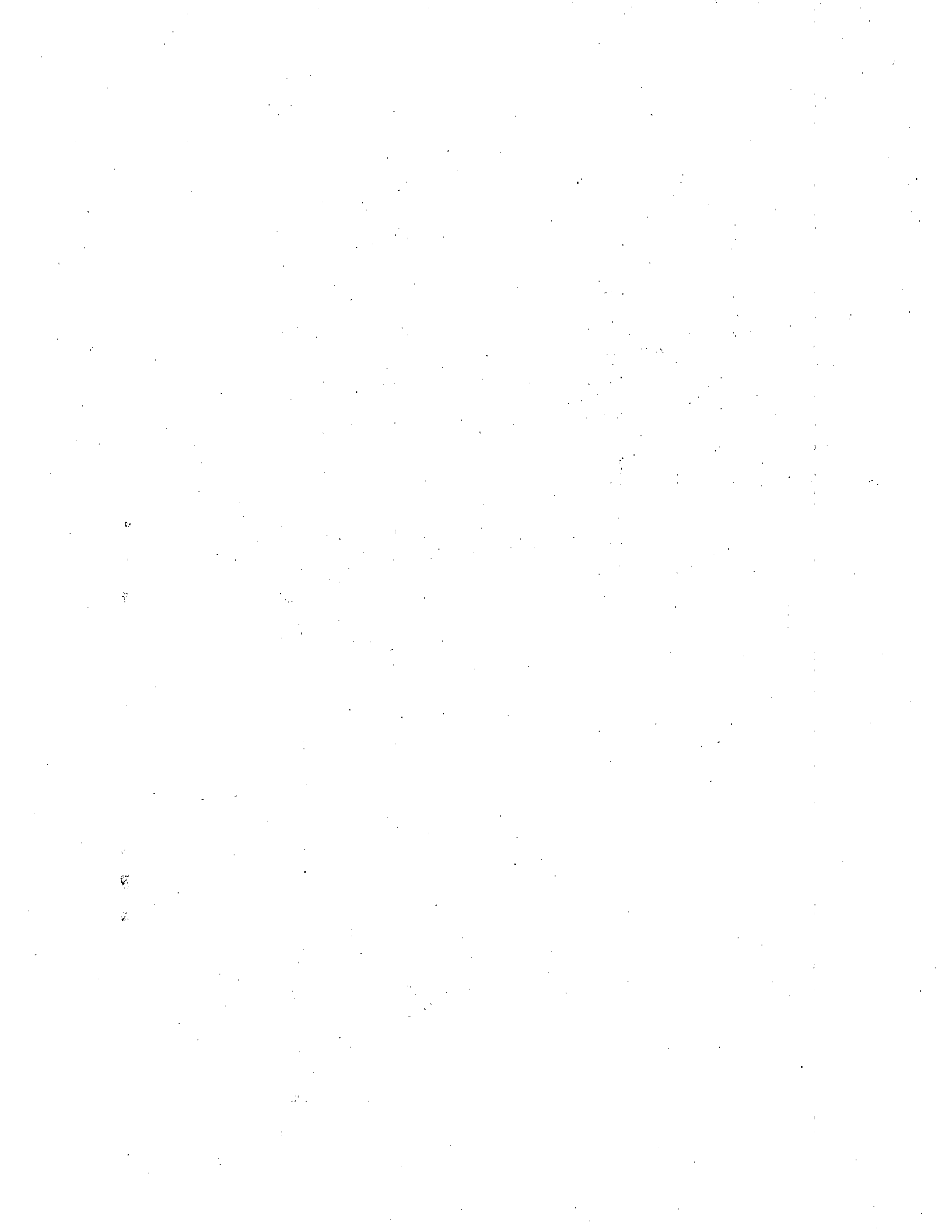


Figure 3-1. Overview Information Flow Network



CHAPTER 4

SUB-SURFACE FACILITY SPECIFICATIONS AND COSTS

4.1 DEPOSIT CHARACTERIZATION

Prior to initiation of a design for a commercial facility, it is necessary to obtain adequate information concerning the deposit. Obtaining such information has been termed deposit characterization. This includes information on permeability, porosity, water saturation and quality, geology, mineralogy, topography, geometry, underground workings and matrix modification. In this regard field tests will be required to obtain in-situ flow related data and an evaluation of geologic and topographic data from an ISL perspective will be needed.

Flow related properties are primarily porosity, permeability, and liquid saturation. Each of these three properties influence either flow rate, residence time, or lixiviant contact with mineral values. Field measurements of these properties provide the data for the design and economic assessment. Tests to obtain field data are discussed in Chapter 7.

The ore body geometry and size required for in situ leaching (ISL) can be obtained from geologic studies for conventional mining operations. However one will often find that ISL mining ore reserves, unlike conventional mining ore reserves, are more closely related to geologic ore reserves. One of the more useful maps for deposit characterization is the grade-thickness contour map. These can be developed for various ore-grade cutoffs.

Mineralogy studies should address not only the various copper minerals but also the gangue minerals, particularly the lixiviant

consuming minerals. It is important to evaluate acid soluble ore grade as opposed to total ore grade, when considering ISL for copper oxides. Further, lixiviant consumption should consider consumption as a result of lixiviant flowing through the pore space as opposed to lixiviant consumed by crushed ore (which often exposes more consumers than otherwise would be encountered).

Although a saturated deposit completely bounded by impervious barriers is desirable, these conditions are unlikely to occur. The engineer should determine the quality and quantity of fluid in and about the deposit. Seldom would the deposit associated with a porphyry be deemed an aquifer because of the low porosity and permeability of the host rock. Frequently the surrounding country rock will likewise have low porosity and permeability. It is incumbent upon the engineer to make those characterizations concerning the hydrologic system. Field tests described in Chapter 7 will be useful.

Surface terrain characterization can be accomplished by a site visit and procurement of a surface topographic map.

Underground workings often occur in formerly mined or currently mined deposits. Should accessible workings be present the engineer will find it necessary to evaluate design options that these workings present. Even though accessible workings may not be available the engineer will want to evaluate the alternative of installing workings and developing the well field from underground in addition to installing wells from the surface.

Matrix modification, also called well stimulation, consists of several techniques to enhance the flow of fluids into or out of the deposit. These techniques include hydraulic fracturing, acidizing and

wellbore shooting, or explosive stimulation. The engineer may find in his design that the injection or production rate per well is insufficient to permit an economic operation. At this stage the designer should consider the application of well stimulation. Key factors that influence selection of a particular application are: natural geologic structures and orientation; total depth; depth of ore below any aquifers; initial water saturation; and rock fracturing properties.

Deposit characteristics outlined above are required prior to a commercial design. These impact wellfield and well design. Permeability, depth of burial of deposit, and ore intercepted by the well relate to flow rate per well. This in turn translates into number of wells required at any one time to provide the required flow rate to the surface plant.

Porosity is related to the inventory of lixiviant that must be injected into the deposit prior to breakthrough of pregnant liquor. Porosity and flow rate translate to residence time of the lixiviant. Residence time must be sufficient to maximize copper loading but not so long as to cause depletion of the acid and cause precipitation of the metal values.

The deposit must be saturated with liquid to permit control of fluid movement. Saturation of less than 100 percent of the deposit is associated with less control of fluid and lower copper recovery. Native water quality, porosity, and permeability will impact how the deposit is designated with regard to a source of underground drinking water and will translate into permit and monitoring requirements.

Geology, geometry, and depth of burial are related to wellfield design and well design. Geometry and mineralogy translate into well replacement frequency, and mineralogy to cost of lixiviant.

Topography translates into well pad design, selection of well installation procedures, location of surface plant location, and layout of fluid transmission lines, road location and power distribution.

Underground workings (existing) result into reduced deposit access costs and reduced well costs. Newly installed underground workings will translate into greater deposit access costs.

Matrix modification provides, higher flow rate per well. This in turn translates into fewer wells per wellfield and reduced wellfield costs.

4.2 WELLFIELD DESIGN

The purpose of the wellfield is to inject and recover leach fluids from an ore deposit in a cost effective manner. The primary determinants of the wellfield design are flowrate, depth, fluid type, well spacing and fluid flow regime. Flow rate requirements determine well equipment diameter, hence well size; depth determines operating pressures, hence equipment type and, to some extent, size. Fluid composition determines materials of construction, primarily as related to corrosion resistance. Well spacing is determined by installed well costs relative to recoverable metal value within the well pattern, in addition to other rock properties. The latter consideration often dictates an iterative approach to wellfield and well system design. Fluid flow regime dictates the type of well completion required.

The manual addresses mining from the surface as well as from underground workings. The types of well patterns discussed include:

- o 5-spot patterns of large diameter vertical wells drilled from the surface or underground workings. Using this type of pattern design procedures are provided for two flow regimes, radial and axial flow. Axial flow can be achieved with horizontal or vertical hydrofracing, depending on deposit depth.
- o Fan patterns of smaller diameter wells drilled along underground crosscuts.

The equations used in wellfield design are derived in Appendix A. These generalized equations have been written to describe flow rate per well, number of wells, well pattern life and total plan area. Different groups of terms can be substituted into these equations for the various patterns. These relationships are summarized in Tables 4.1, 4.2, 4.3 and 4.4.

4.2.1 Vertical Well Patterns

Vertical wells can be drilled from either the surface or underground workings. The relative positioning of these wells by injector and producer forms a specific well pattern; 5-spot; 7-spot, 9-spot, etc. For a discussion of the pros and cons of using these different patterns under production conditions refer to Craig (20). Since this manual only considers wellfield design on a generic basis for homogeneous deposit properties, the 5-spot pattern is used as the basis of design as it minimizes the total number of wells in a large array of wells. The manual design procedures algorithms can be adapted to other patterns when sufficient site specific data is available to define deposit variability.

Within the 5-spot configuration design procedures are provided for three types of flow regimes: radial; axial using horizontal fractures by hydrofracturing; and axial using vertical fractures by hydrofracturing.

4.2.1.1 Radial Flow

In the radial flow geometry fluid leaving the wellbore remains confined to the injection interval spreading over a continually increasing two-dimensional area, Figure 4-1. The pressure declines logarithmically with the distance traveled by the fluid away from the wellbore, and the fluid velocity decreases inversely with the distance traveled. This flow regime has been utilized in uranium in situ leaching and is common practice in oil field water flooding and enhanced oil recovery production operations.

The flow rate may be increased if desired by stimulating the injection and production wells. In the radial flow case, stimulation refers to increasing the effective wellbore radius. For the purpose of fluid flow calculations and costing the wellbore radius is assumed to be increased to 8 feet. This provides approximately a 3-to-1 increase in flow rate using a fracture radius that is small compared to the well spacing.

In actual practice, several methods are available for stimulation. Hydraulic fracturing can be used to create short, propped hydrofractures in the injection and production intervals of interest. These fractures do not change the permeability of the rock mass but provide conduits (usually planar) for fluid flow away from the wellbore. The fractures are only of value when their conductivity is much greater than that of the rock mass.

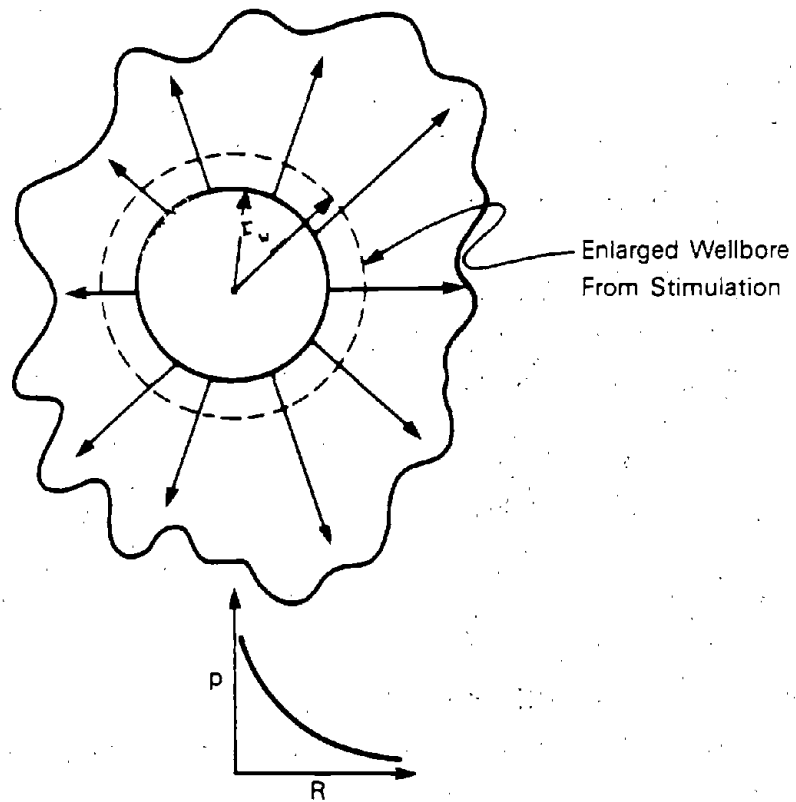
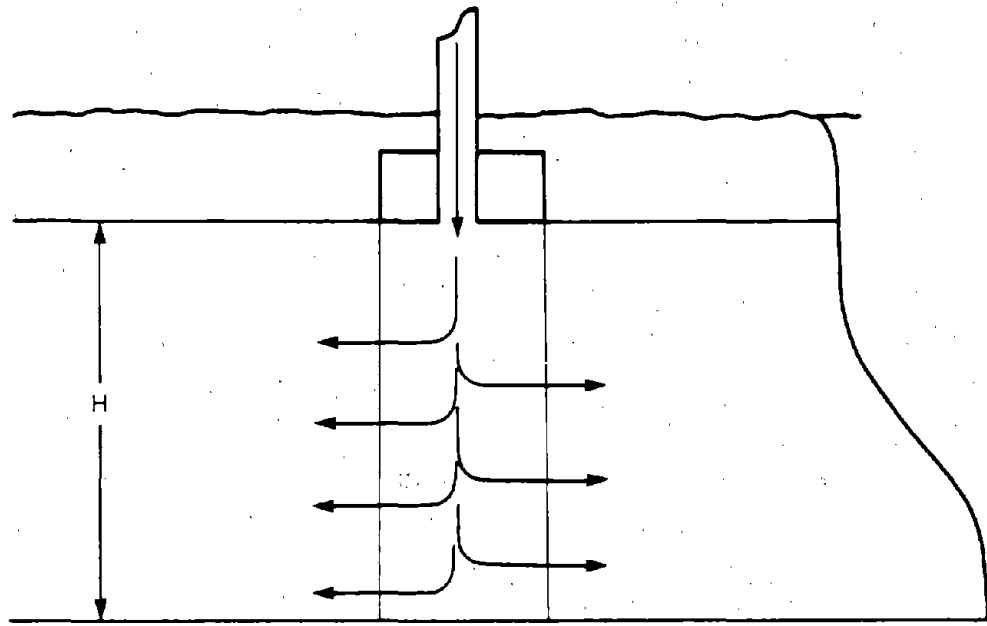


Figure 4-1. Radial Flow Geometry

Explosive or propellant stimulation is another method that may be used to improve flow. In this case fractures are again created near the wellbore to provide conduits for fluid flow. In an ideal case numerous small fractures could be created which would essentially improve the permeability of the rock in the immediate vicinity of the wellbore. Again the maximum improvement in flow can be calculated by quantifying the stimulation as a larger wellbore radius, with an infinite permeability in the fractured zone.

While stimulation may improve the flow rate, its cost may not be justified. If the actual wellbore radius is used in flow calculations, flow will be calculated for the unstimulated case. Because the different stimulation techniques have widely varying costs, the model allows for user cost specification for stimulation. Overall economics must consider whether the increment in flow rate with stimulation is worth the cost increment for stimulation.

Flow rate for the radial case is calculated using the 5-spot radial flow equation. The equation assumes steady state conditions and hydraulic confinement of the ore zone to be leached. In most copper orebodies, this confinement exists only to a limited extent. The algorithms for the radial flow regime are derived and described in Appendix A, and summarized in Tables 4.1, 4.2, 4.3, 4.4, and 4.5.

4.2.1.2 Axial Flow

The axial flow concept may be utilized to obtain acceptable flow rates in cases where radial flow rates are too low. Hydraulic fracturing is used to develop planar fractures that are used in pairs, one serving as an equipotential high pressure plane for injection, the other

TABLE 4.1 SUMMARY OF ALGORITHMS FOR WELL FLOW RATES

q_I = Injection rate per well, gpm

$$q_I = \left[\frac{C_o k \Delta P_T}{\mu} \right] G_i, \quad C_o = 3.34 \times 10^{-5} \frac{\text{gpm} - \text{cp}}{\text{md-ft-psi}} \quad \begin{array}{l} k = \text{permeability, md} \\ \Delta P_T = \text{pressure drop, psi} \\ \mu = \text{viscosity, cp} \end{array}$$

G_i = Well pattern geometry factor, ft

Axial flow horizontal fractures

$$G_1 = \frac{S^2}{H_c} \quad \begin{array}{l} S = \text{well spacing, ft} \\ H_c = \text{leach interval per fracture pair, ft} \end{array}$$

Axial flow vertical fractures

$$G_2 = \left(\frac{4HS_2}{S_1} \right) \quad \begin{array}{l} H = \text{total ore thickness, ft} \\ S_1 = \text{well spacing perpendicular to} \\ \quad \text{fracture, ft} \\ S_2 = \text{well spacing parallel to fracture, ft} \end{array}$$

Radial flow

$$G_3 = \left(\frac{\pi H}{\ln \left(\frac{S}{\sqrt{2} r_w} \right) - 0.619} \right) \quad r_w = \text{wellbore radius, ft}$$

For the case of wellbore enlargement by small hydrofractures or borehole blasting

$$r_w = 8 \text{ feet} \ll S$$

Fan Wells

$$G_4 = \left[\frac{\pi h}{2} \right] \left[\frac{1}{\left(\frac{d}{h} \right) \left(\frac{\pi}{4} \right) + \frac{\Theta}{\pi} \ln \left(\frac{h\Theta}{4r_w} \right)} \right] \quad \begin{array}{l} h = \text{well length, ft} \\ d = \text{distance between fan} \\ \quad \text{faces, ft} \end{array}$$

- o For the combination of (d/h) and (Θ/π) that maximizes the flow rate per module per unit cost of the module $(\Theta/\pi) = 1/10$, or 11 wells per fan face, and $(d/h) = 0.6$
- o Drilling a fan well over 100 feet long is not practical
- o $G_4 = 192 \text{ ft}$, for $r_w = 0.167$ and $h = 100 \text{ feet}$

TABLE 4.2 SUMMARY OF ALGORITHMS FOR NUMBER OF WELLS

N_I = Number of injection wells or patterns
 N_w = Total number of wells
 G_i = Values obtained from Table 4.1

Number of injection wells or patterns

$$N_I = \left[\frac{Q_u}{C_o k \Delta P_T} \right] \left[\frac{1}{G_i} \right]$$

Total 5-spot wells

$$N_w = N_I + \left[\sqrt{N_I} + 1 \right]^2$$

Total fan wells

N_{TF} = number of wells per fan face

$$N_w = N_I N_{TF}$$

N_{HV} = number of = H/h
vertical units

N_{HC} = number of = $(N_I)^{1/2} \left(\frac{d}{2H} \right)^{1/2}$
 crosscuts
 per vertical unit

N_{HF} = number of = $(N_I)^{1/2} \left(\frac{2h^2}{dH} \right)^{1/2}$
 fans per crosscut

TABLE 4.3 SUMMARY OF ALGORITHMS FOR WELL LIFE

t_w = well life, years

$$t_w = \left[\frac{Q\mu}{C_o k \Delta P_t} \right] \left[\frac{E_s E_L E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{11} X Y} \right] [X_i]$$

X_i = well pattern life geometric factor, ft^2

Axial flow horizontal fractures

$$X_1 = H_c H$$

Axial flow vertical fractures

$$X_2 = S_1^2 / 4$$

Radial flow

$$X_3 = \frac{S^2}{\pi} \left[\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619 \right]$$

Fan pattern

$$X_4 = \left[\frac{4hd}{\pi} \right] \left[\left(\frac{d}{h} \right) \left(\frac{\pi}{4} \right) + \left(\frac{\theta}{\pi} \right) \ln \left(\frac{h\theta}{4r_w} \right) \right]$$

$X_4 = 6237 \text{ ft}^2$, for $h = 100$ feet, $d = 60$ feet, which is a minimum cost fan module

E_s = % sweep efficiency
 E_L = % leach efficiency
 E_R = % recovery efficiency
 E_p = % on stream plant time
 F_c = % ore grade

ϕ = % porosity
 ρ_b = grain density lb/ft^3
 Y = tons per year copper production rate
 Q = total plant gpm

TABLE 4.4 SUMMARY OF ALGORITHMS FOR WELLFIELD PLAN AREA

A_w = plan area of wellfield, ft^2

$$A_w = \left[\frac{Qu}{C_o k \Delta P_T} \right] [R_i]$$

R_i = well pattern area geometric factor, ft.

Axial flow horizontal fractures

$$R_1 = H_c$$

Axial flow vertical fractures

$$R_2 = \left(\frac{S_1^2}{4H} \right)$$

Radial flow

$$R_3 = \frac{S^2}{\pi H} \left[\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619 \right]$$

Fan pattern

$$R_4 = \left[\frac{4dh}{\pi H} \right] \left[\frac{d\pi}{h4} + \frac{\theta}{\pi} \ln \left(\frac{h\theta}{4r_w} \right) \right]$$

$R_4 = \underline{6237}$, for $h = 100$, $d = 60$ feet, which is
 H
 minimum cost fan module

TABLE 4.5 WELLFIELD SPECIFICATIONS COMMON TO ALL PATTERNS

Wellfield Water Make-up Requirements

GA = gallons required to saturate wellfield pores

$$GA = 7.48 \times 10^{-4} A_w H \phi (100 - s_w)$$

Wellfield Hold-up Time

t_{wH} = years for one pore volume displacement in the wellfield

$$t_{wH} = 1.42 \times 10^{-9} A_w H \phi \left(\frac{E_H}{Q} \right)$$

Number of Wellfield Replacements

N_{wR} = Number of wellfield replacements over life of mine

$$N_{wR} = \frac{t_P}{t_w} - 1$$

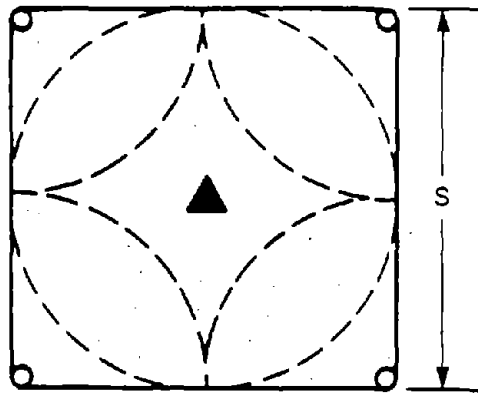
Total Wellfield Plan Area Over Plant Life

$$A_{wT} = 2 \times 10^{11} \times Y t_P \left[\frac{E_P}{E_S E_L E_R F_c} \right] \left[\frac{1}{(100 - \phi) \rho_b} \right]$$

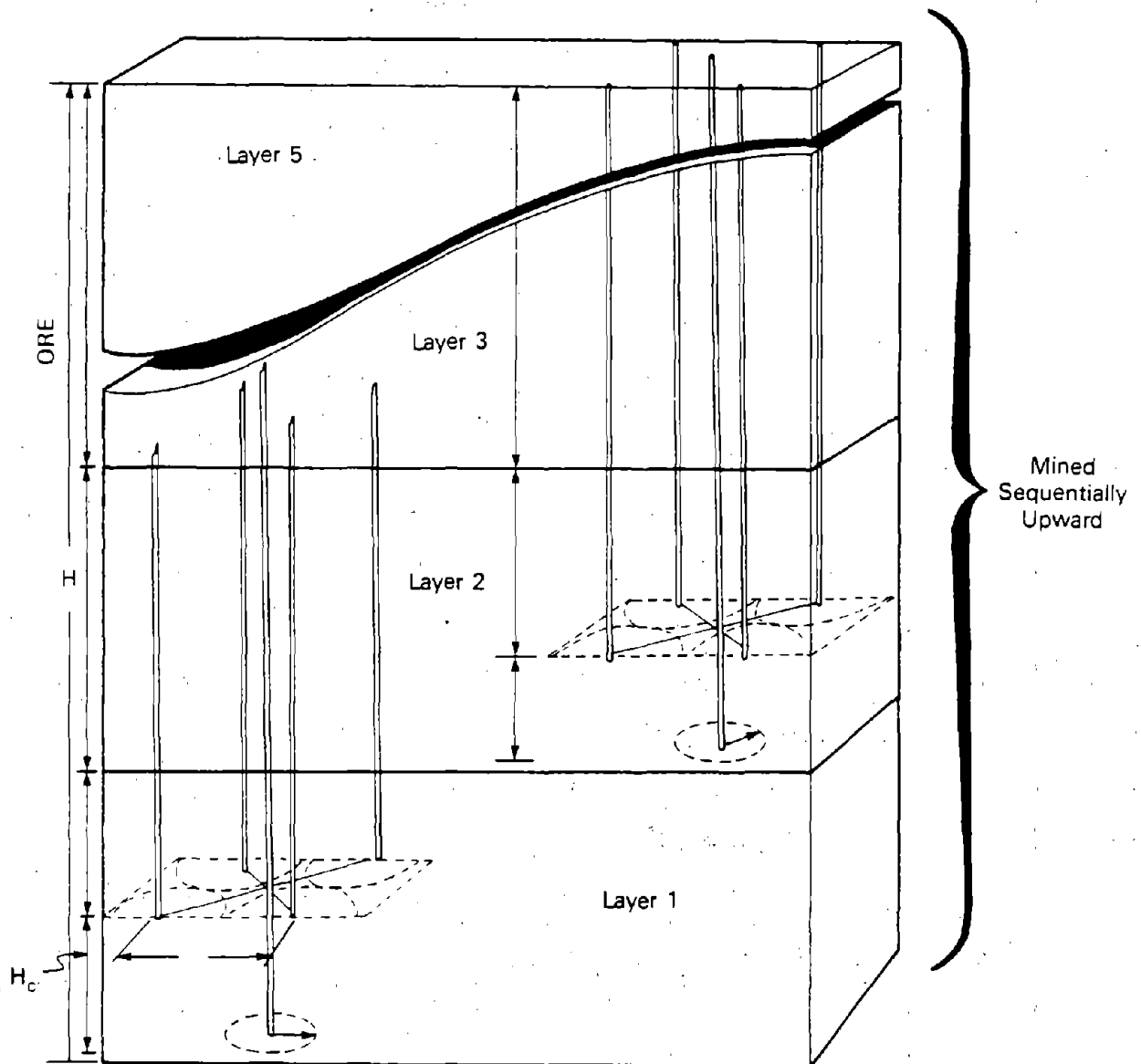
s_w = % initial water saturation

E_H = % of one pore volume used in hold-up time

as an equipotential low pressure plane for production. The pressure declines linearly between the two equipotential planes. Depending on the depth below the surface at which the fracturing is carried out the fractures may be horizontal or vertical. At shallower depths horizontal fractures are expected. The depth at which the orientation switches from horizontal to vertical will vary from deposit to deposit. As a general guideline for depths below 1000 feet the probability of obtaining vertical fractures increases. Well pattern flow geometry designs are provided for both horizontal and vertical fractures, Figures 4-2 and 4-3. For additional information on fracture orientation see references (21). Regardless of the orientation, if the fracture planes overlap the desired manifold effect can be obtained. Flow rates using this concept can be estimated by using Darcy's law for flow between the planes. The distance between planes is an input variable in the model somewhat analogous to well spacing. The flow between planes must be substantially improved over the radial case in order to justify the additional expense of the fracturing concept. However, these fractures will permit a wider spacing between wells. Pressure drop due to friction also occurs in the fracture, and is a function of the fracture width and the conductivity of the fracture proppant. At high flow rates, pressure drop within the fracture may be a result of turbulent flow. The generic design does not account for friction drop. Also complete fracture overlap is assumed. These assumptions are made to reduce the complexity of the algorithms. Design specifications and costing procedures are provided for fractures. In the model the user has a choice between fractures that are completely vertical, and fractures that are completely horizontal. In the horizontal case the



Plan View
Horizontal Fractures



Vertical View
Horizontal Fractures

Figure 4-2. Axial Flow Horizontal Fractures

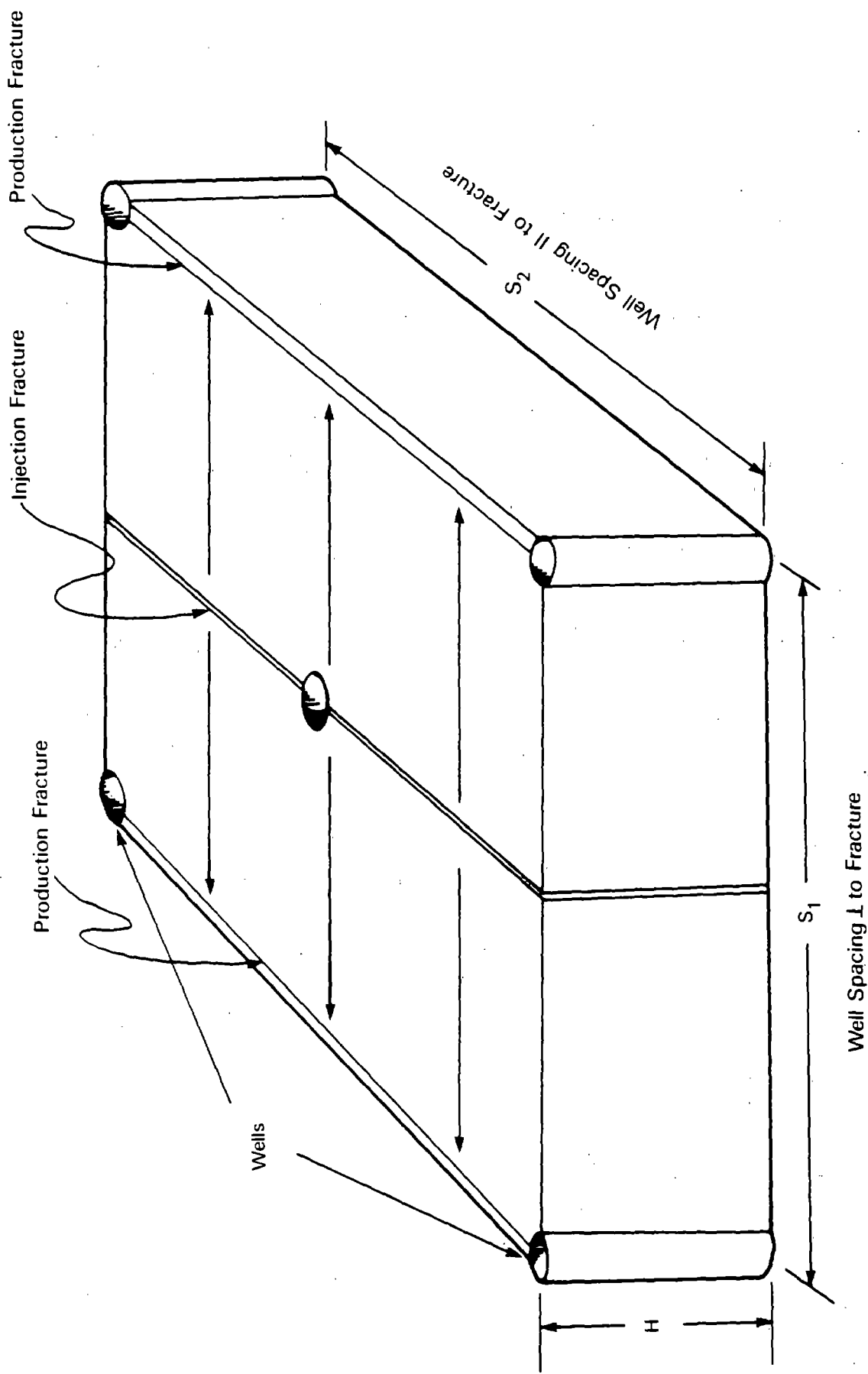


Figure 4-3. Axial Flow Vertical Fracture

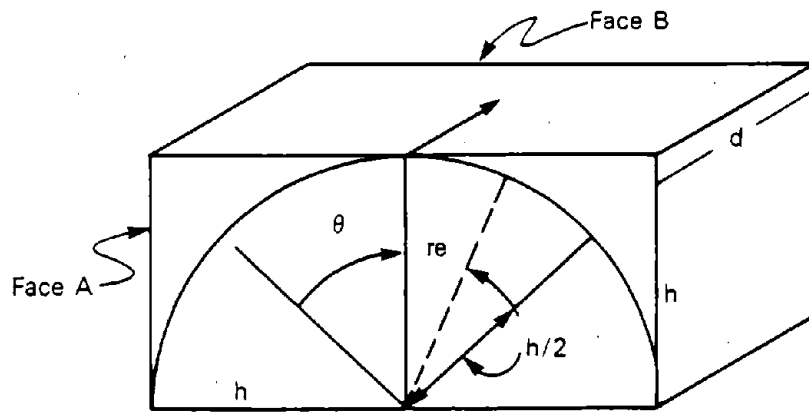
overlapping fractures are repeated vertically until the ore thickness has been leached. The manual contains fracturing cost algorithms, which allows for an economic comparison between axial and radial flow.

Well pattern design algorithms are summarized in Tables 4.1, 4.2, 4.3, 4.4, and 4.5.

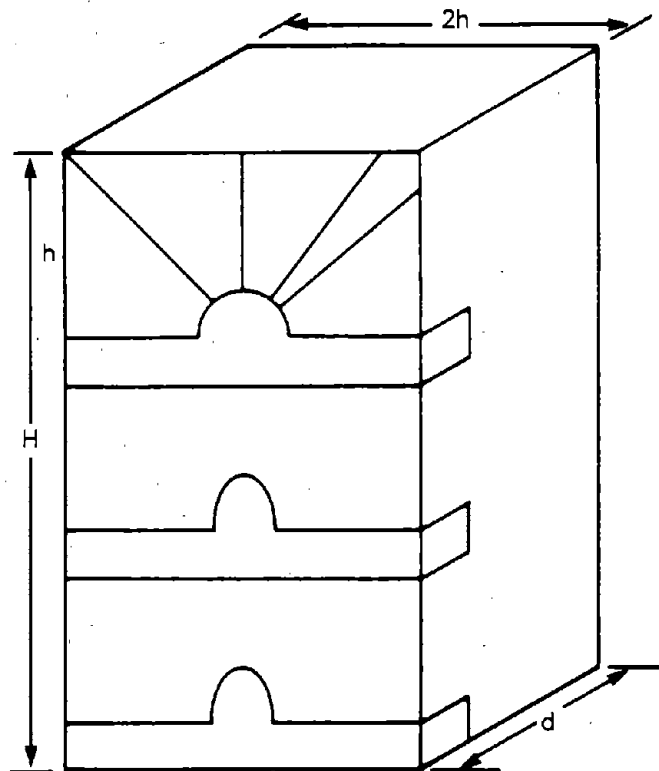
4.2.2 Fan Well Patterns

This design is a method using fan patterns drilled radially from crosscuts, see Figure 4-4. In the fan concept, small diameter holes are drilled radially from stations in parallel drifts running underneath the ore zone to be leached. Fluid is injected in one fan face (A) and flows parallel to the crosscut to another fan face (B). Leachate is collected by gravity from the fans and the crosscut. In ore bodies having a considerable vertical thickness of ore, one or more additional levels is used to gain access. A practical height to drill a fan well is 100 ft. A fan module consists of face A and face B.

Fluid flow rate between fans is calculated by using the radial flow equation for pressure drop in the immediate vicinity of the injection and production holes. Linear flow is used to predict pressure drop between the fans. Algorithms pertaining to well pattern specifications are derived in Appendix A and summarized in Tables 4.1, 4.2, 4.3, 4.4, and 4.5. Flow variables include the number of holes per fan, the distance between fans, and the applied pressure difference (expressed again as a function of fracture gradient). In Appendix A a procedure is developed which minimizes cost per unit flow rate.



One Fan Module



Vertical Stacking
of Fan Modules

Figure 4-4. Fan Pattern Flow

4.2.3 Design Criteria

The maximum well pattern flow rate occurs at an injection pressure equal to the fracture gradient. The value of the fracture pressure gradient has a range between 0.7 and 1.0 psi per foot of depth. This fracture gradient is a user input variable. The production well is assumed to be pumped off so that essentially no pressure exists in this well. In an actual mining operation, a small amount of hydrostatic column exists in the production well, since the pump is normally set above the producing interval and some Net Positive Suction Head (NPSH) is required to prevent pump cavitation. The total injection pressure at the interval of interest is the sum of the hydrostatic column of fluid to the surface plus any head supplied by injection pumps. The user will choose an injection pressure gradient below the fracture gradient for leaching.

The procedure for estimating the best mining scenario outlined in Chapter 9 can be used to determine which method of deposit access is likely to be least expensive, and what range of copper loadings are most likely to maximize DCF/ROR. If the best mining scenario does not involve fan wells then a selection of radial versus axial flow is required. This first involves geologic and engineering input with regard to the practicality of installation. All things being equal the final criteria for selection is which pattern provides the least cost per flow rate per well.

Next well spacing can be chosen. In the axial flow case, the distance between fractures is chosen. With all other variables chosen, the model can be run and iterations made to help determine an optimum well spacing. These calculations are independent of sweep efficiency

(percent of rock in well pattern swept by fluid), so the user must base estimates of copper recovery on sweep efficiency associated with the pattern design, to some extent.

In the radial flow case it is apparent that the well spacing determines the capital cost per unit volume of rock, the flow rate (as a log function), and the residence time of the fluids. Based on past experience, in low permeability rocks, in situ copper leaching well spacings are designed in a range from 50 to 150 feet.

In the axial flow case the well spacing is determined by the cost of fracturing, the fracture conductivity, and the fracture shape and orientation. Prior experience exists for designing and installing horizontal fractures of 50 to 100 feet radii in copper deposits (15). Experience developed in the oil industry would suggest that fractures with greater radii could be induced. In the case of vertical fractures experience is limited. Several vertical fractures have been installed in one deposit but only one measurement was made to determine its vertical extent. The vertical extent was about 100 feet. It is probable that a greater vertical height could be obtained. However one would expect the fracture to be initiated near the top of an interval to be fractured. It is not clear whether a vertical fracture as it develops will grow upward or downward in a copper deposit. A fracture induced in stages may be more readily controlled.

During the past 15 years a concept of massive hydraulic fracturing (MHF) has been developed and many installed. These fractures often have been induced in low permeability gas sands having a long vertical intercept. Design procedures (22) have been developed. MHF can be designed to have vertical heights between 100 and 350 feet and lengths

between 1000 and 2500 feet. It is not clear that MHF is suitable for ISL of low permeability copper deposits.

After a pattern flow rate has been calculated, the number of patterns needed for mining is estimated by dividing the total plant flow rate by the pattern rate. The number of wells is then given by the number of patterns, assuming a square wellfield geometry.

Based on any given pattern design, it is necessary to estimate the overall recovery of copper that is expected from leaching the pattern. For this purpose, the model utilizes an overall recovery factor comprised of individual factors called sweep, leach, and recovery efficiency. These factors, when multiplied together give the overall recovery.

Leach efficiency can be defined as the copper recoverable from core sized specimens leached in the laboratory. If copper grade is only expressed in terms of acid soluble assay, then leach efficiency may be influenced by such factors as quartz filling, gangue mineralogy (wad, clay, zeolites) and natural fracture location with respect to the ore minerals.

Sweep efficiency can be defined as the degree of contact between ore and moving lixiviant. Because copper deposits are not really homogeneous it is probable that some quantity of ore is not swept by the moving fluid. This factor represents the percentage of rock contacted. It is essentially a measure of permeability anisotropy. Typical geologic causes include fault and shear zones, cemented and clay filled areas, localized lack of fractures, etc. It is also related to the degree of confinement in a well pattern, where stream lines travel variable distances between injection and production wells, even in a homogeneous deposit.

Recovery efficiency refers to the percentage recovery of leaching fluids. In some cases, hydraulic confinement of the orebody may not exist, leading to the escape of copper in the fluids. The recovery efficiency must be high, because fluid control in the wellfield design must limit excursions for high economic performance. Water makeup is calculated in the model based on the recovery efficiency. Water losses may also occur from a plant bleed stream, but these are independent of recovery efficiency.

For purposes of the model, the user must estimate the copper loading that is expected as an average grade of the pregnant liquor. This is best approached by examining acid consumption. The assumption can be made first that almost all acid is consumed in the ground. This is necessary in actual practice to prevent poor equilibrium during solvent extraction. In actual practice, flow rate must be low enough and distance between wells far enough for this to occur. The acid consuming nature of the rock is another variable that must be considered. Some idea of acid consumption can be obtained from column and core leach tests. Consumption is normally expressed on a pounds acid/lb copper basis, and is affected by:

- o Acid strength
- o Nature of gangue
- o Injector-producer distance and flow rate
- o Grade of copper (oxide)

Net increase in copper loading per pass of solution through the wellfield is determined by the initial acid strength and the acid consumption. For example, if the initial acid strength is 20 gpl and acid consumption is 4 lb acid/lb copper then an average copper loading of 5 gpl results.

It is apparent that copper loadings can be increased by using stronger acid strength for leaching. Increasing acid strength also gives a higher acid consumption on a pound for pound basis. Thus an economic tradeoff exists. Normally acid concentration in the range of 2 to 10 percent may be considered for practical operations. Acid concentrations greater than 10 % rapidly corrode 316 stainless steel if copper or iron (III) are not present as inhibitors.

4.3 DEVELOPMENT OF UNDERGROUND WORKINGS

The main functions of the underground workings are to provide access for drilling and workover equipment, and to provide for power and fluid transportation to the mining areas. A small amount of muck haulage is anticipated from development headings after production has started.

In the case of mining using vertical drilling from underground stations, a mine level is chosen above the ore interval. Drill stations are excavated over each drill hole. Stations are constructed along parallel crosscuts, which are connected to drifts. The drifts provide access to shafts or declines leading to the surface. It may be desirable to provide a separate mine level under the station level to separate fluid piping, ventilation, and power distribution from the muck haulage and drill rig mobilization. Pregnant liquor collection could then be by gravity. A pump station would be provided to lift pregnant liquor to the surface.

For the case of the fan drilling, a mine level would be placed directly under the orebody, with the fan patterns drilled upward into the ore. The holes would be of nominal 4 inch diameter, drilled with a

down-the-hole hammer rig. Hole depths would be approximately 100 ft, and about 11 holes would be drilled per fan. Injection holes would be equipped with tubing and packer, but production holes would not have any equipment. Drill rigs for percussion drilling of the fans are expected to be smaller than the rigs used for the vertical patterns. Drift sizes of 12 ft x 12 ft and 10 ft x 10 ft are thought to be reasonably sized drifts for vertical drill development and fan pattern development, respectively. Collection of pregnant liquor is then by gravity drainage from the fan patterns and the back and ribs of the crosscuts. Again a utility level may be considered below the level for the fans to allow for collection of fluids, power distribution, ventilation and escape.

Costs are categorized by access to the ore interval and those associated with the well patterns. Mine development costs for the leaching areas are calculated by totalling costs per pattern and are then a function of the number of patterns developed. For example in the case of vertical drill hole development (axial/radial), cost per pattern for crosscut, pipe and drill station are summed. Total costs then for all patterns are found by simply multiplying by number of patterns. In the fan leaching case, crosscut cost per ft and piping cost are summed per fan pattern. This is discussed in 4.4.3 and 4.5.3.

Total capital costs for access include:

- o Access to ore body depth
- o Mine Plant (at surface)
- o Ventilation
- o Power

For both vertical or fan pattern leaching, shafts are sunk or declines are driven to reach the bottom depth of the orebody. Drifts are driven horizontally to reach the orebody. Because some orebodies

are dipping, the mine plan may include declines or multiple levels to follow the ore.

To estimate costs for development workings (not in the mining area) in the model, the user can draw up a mine plan and estimate the footage of the following workings:

- | | |
|-------------|---|
| 1. Declines | 3. Raises |
| 2. Shafts | 4. Adits and Drifts and Crosscuts used to reach the mining area |

The average cost per foot is estimated for each type of working, including ground support costs.

4.3.1 Development of Access

To develop a generic cost algorithm to estimate access costs it is assumed that two shafts are required to be sunk to depth and that one raise will be required for ventilation. Additionally, a 2000 ft drift is assumed to connect the vertical workings to the mining areas.

Ventilation requirements will be largely set by the diesel equipment used for drifting, drilling, and other mine development. This capital cost item includes fans, bulkheads, refrigeration, etc. Mine workings are not included in this category.

The mine plant includes items such as headframe, hoist house, compressors, shops and offices. It also includes mining equipment that is not accounted for in the cost of advancing workings. It is a separate item from the SX/EW plant, and wellfield power and piping. Mine plant costs are based on data obtained from the Mining Cost Service, Western Mining Service, Spokane, Washington, 1986.

Mine power on the surface will be required for hoisting, air compressors (if needed), lighting and miscellaneous uses. This power is separate from SX/EW requirements. Power underground will be required for the pumps and instruments. Drilling equipment may also be run using electric power.

Piping for lixiviant and pregnant liquor could be polyethylene for collection lines and plastic lined steel for injection pipe. In crosscuts with fan patterns 316 ss pipe is a likely choice for injection pipe because of the potential for external corrosion from dripping pregnant liquor. In fan patterns leaching ditches could be used to collect the liquor from the mining areas. Pregnant liquor can drain to a collection pump station for transfer to the surface. Pipes used for carrying solutions in and out of the underground mine will probably be lined steel.

4.3.1.1 Shafts and Raises

Costs for shafts, raises and crosscuts used to develop access are described in generic format as follows:

- o Shafts and raises for vertical wells are assumed to penetrate from surface to the top of the ore interval, with costs given by (4.1).

$$ES = (D-H)(2C_s + C_r) + (DR)C_{da} \quad (4.1)$$

- o Shafts and raises for fan wells are assumed to penetrate to the bottom of the ore interval, with costs given by (4.2).

$$ES = D(2C_s + C_r) + (DR)C_{da} \quad (4.2)$$

4.3.1.2 Mine Equipment

- o Fixed costs are equal to the sum of the mine plant, ventilation, and electrical equipment.

- + Mine plant capital costs consist of surface structures such as headframe, hoist, maintenance shops, and fans. Costs are given by EM, which is estimated to be \$2,500,000.

$$EM = \$2,500,000 \quad (4.3)$$

- + Ventilation costs consist of fans, air doors, and bulkheads; costs are by given EV, which is estimated to be \$120,000.

$$EV = \$120,000 \quad (4.4)$$

- + Electrical equipment costs are those associated with the mine plant and ventilation costs are given by EE, which is estimated to be \$200,000.

$$EE = \$200,000 \quad (4.5)$$

4.3.2 Wellfield Drift Costs

It is assumed that for each vertical layer of crosscuts that two drifts are required to service the crosscuts. For a vertical well system crosscuts are only required at the top of the ore interval, since the wells are drilled through the total length of the ore interval. Should a fan pattern be used in conjunction with an ore thickness in excess of 100 feet, then multiple vertical layers of crosscuts will be required, each layer containing two drifts.

Total drift costs are computed by multiplying a unit drifting cost (\$/foot) by the total feet of drift in the wellfield. The latter equals twice the unit distance between crosscuts, S for vertical wells and $2h$ for fan wells, multiplied by the number of crosscuts per layer multiplied by the number of vertical layers. Cost associated with vertical wells are expressed by (4.6) and for fan wells by (4.7). EW_d is incurred each time a new wellfield is brought into production.

o Vertical wells

$$EW_d = 2(N_T)^{1/2} SC_{da} = 2(Q/q_T)^{1/2} SC_{da} \quad (4.6)$$

- o Fan wells

$$EW_d = 2N_{HC}N_{HV}(2h)C_{da} = 4(Q/q_I)^{1/2} \left(\frac{d}{2H} \right)^{1/2} HC_{da} \quad (4.7)$$

4.3.3 Wellfield Crosscut Costs

The total crosscut costs are computed by multiplying a unit crosscut development cost (\$/foot) by the total footage of crosscut in the wellfield. The total footage for the 5-spot pattern of vertical wells equals the well spacing S times the number of rows of injectors multiplied by the sum of the rows of injectors and producers. The total footage for the fan pattern equals the unit distance between fan faces d times the total number of fan units. Cost algorithms are expressed by (4.8) for vertical wells and (4.9) for fan wells. EW_c is incurred each time a new wellfield is brought into production.

- o Vertical wells

$$EW_c = [2(Q/q_I) + (Q/q_I)^{1/2}]SV_x \quad (4.8)$$

- o Fan wells

$$EW_c = (Q/q_I)dV_x \quad (4.9)$$

4.4 WELL DESIGN

4.4.1 Vertical Wells Drilled from the Surface

Well design is best initiated by determining well equipment size requirements, based on flow rate and depth. To provide flexibility to wellfield operations, it is assumed that all wells within the wellfields are of similar size, and may be equipped to act as either producers or injectors. Usually recovery pump diameter is the limiting determinant of well size.

Upon defining equipment sizes, the well casing may then be designed. In addition to accommodating injection and production equipment, the casing must withstand forces associated with casing installation, cementing, well stimulation and fluid injection operations, and must also resist corrosion by process fluids.

The well drilling program is based primarily on casing size, cementing program, well depth and geologic conditions. Hole diameter is based on casing outside diameter plus an allowance for the cement sheath. Drilling methods are based primarily on economics. Selection of the circulating fluid used is based largely upon its predicted effect of minimizing near-wellbore ore permeability damage.

Well cementing provides a seal against fluid leaking between the well casing and the drilled hole, in addition to providing mechanical support for the casing. The cement grout must be compatible with prevailing geologic conditions, leaching fluids, and casing materials. The grouting process and equipment should also provide a good seal and good casing support.

Well completions refer to the means by which fluids are transmitted into and out of the well, and well stimulation (matrix modification) techniques to methods used to promote higher flow rates to or from the formation. The type of well completion and stimulation method used is interrelated and dictated by the wellfield design chosen for use.

Well logging may be utilized for several purposes in ISL mining. An initial application in the well system design is for formation logging of the open drill hole. This is carried out to gather geologic data and obtain drill hole information for all phases of developing an operating well. Other logging applications include measuring the

quality of cement bonding to the casing and formation, and measurements related to pressures and flow rates inside the well which are used for testing and diagnostic purposes.

The sequence of well design functions is listed below. The reason for selecting this sequence is that the flow per well and depth are used to size the equipment which in turn sizes the diameter of the hole to be drilled.

- | | |
|---------------------------|----------------|
| 1. Drill Site Preparation | 5. Cementing |
| 2. Well Equipment | 6. Completions |
| 3. Well Casing | 7. Logging |
| 4. Drilling | |

4.4.1.1 Drill Site Development

Drill site development involves creating a sufficiently large level area from which drilling and other well installation and service operations are conducted. Included in this space are requirements for: the drill rig and drill rods and equipment; pits or other drilling fluid handling and treatment equipment; casing storage; and room for cementing, logging and other contractor equipment and operations. These area requirements depend on many factors, including scheduling, and are expected to vary within the range of 3000 to 20,000 square feet. Cost of obtaining the leveled area is extremely site specific, being affected by factors such as rock or soil conditions, topography, climate, vegetation, regulations, and existing structures and utilities. The cost per well is represented by C_A , which is assumed to be \$2,400.

$$\text{\$ for site development} = C_A = \$2,400 \quad (4.10)$$

4.4.1.2 Well Equipment

An upper limit range for the flow rate per well of 200 to 300 gpm is obtained by using the radial and axial flow equations to estimate well injection rates. Based on experience and knowledge of copper oxide deposits it is unlikely that a deposit exists with an ore column of over 1000 feet thickness and 10 md permeability, at a depth greater than 3000 feet. Based on these assumptions, radial flow in a 5-spot pattern is calculated not to exceed a flow rate per well of 255 gpm. For axial horizontal fracture flow between fracture planes separated by 50 feet, using a horizontal hydrofracture radius of 100 feet the maximum expected flow is 265 gpm.

Composition of the lixiviant is dilute sulfuric acid which contains amounts of various cations (including copper) resulting from recycling of fluids. Leachate composition contains less free acid and more copper than the lixiviant. In leaching copper chloride minerals, such as Atacamite, chlorides are expected to exist in the leach fluids. Operating temperatures are expected to be ambient or slightly higher, unless the deposit is in a geothermally active area.

Suitable materials of construction for handling these fluids include both metallics/and non-metallics. Choice of materials depends on strength, elasticity, size requirements, and the expected service life of the application. In general, metallics are more expensive than non-metallics. A wide variety of metallic and non-metallic materials are available, suitable for use in the proposed dilute sulfuric acid environment. For site specific design it is common to test a variety of materials in the actual leach solutions to optimize material selection. For the purpose of generic design the following general information and references are provided.

o METALS

The following common forms of metal attack (23) are expected to be important in the proposed ISL environment:

1. Uniform corrosion - Attack of the entire surface area, uniformly.
2. Crevice corrosion and pitting - Localized severe attack, caused by buildup of H^+ and Cl^- concentrations in stagnant areas. This mechanism is self-accelerating and can occur in absence of noticeable uniform corrosion.
3. Stress corrosion cracking - Crack formation in corrosive environments, perpendicular to direction of applied stress. Common in some stainless steels in presence of chlorides and oxidizers.
4. Galvanic corrosion - Caused by electrical coupling of two metals of dissimilar E.M.F. potential.
5. Intergranular corrosion - Attack of metal grain boundaries, usually due to concentration or depletion of elements at the grain boundaries.
6. Selective leaching - Selective removal of one element from an alloy, by corrosion.
7. Erosion - Directional grooves, waves, holes, and gullies caused by fluid movement, usually at high velocity, from: abrasion; removal of dissolved ions and passivated layer; and removal of solid corrosion products.

Methods for preventing the above include:

1. Eliminate critical environment, such as stagnant fluids, crevices or aggravating chemical elements, if possible.
2. Use cathodic protection, either by supplying electrical current or sacrificial metal cathodes. (This does not work for passivated surfaces, such as stainless steel which may be protected anodically.)
3. Use a more resistant metal alloy.
4. Lower mechanical stress, in the case of stress corrosion cracking.
5. Use corrosion inhibitors where possible.

In the case of ISL operations, item 3 above is often the only practical alternative.

Corrosion resistance of stainless steel generally results from formation of a non reactive, or passivated layer covering the metal surface. This layer may form and exist under a wide range or only a narrow range of fluid conditions such as concentration, composition and temperature.

Since it is not entirely clear what causes these protective layers to form and disappear, it is sometimes impossible to predict the best alloy for a given environment. Data collected through testing and operating experience in somewhat similar environments may be applicable to ISL copper, (24), (25). However, since none of the referenced environments are exactly like the proposed ISL environment, it is uncertain that specific metals will perform as described in the published data. Lixiviant/metallic systems will require testing and evaluation under site specific operating conditions.

Within the stainless steel alloys, it appears that increasing Ni content resists stress corrosion cracking, increasing Cr content resists the effects of chlorides and oxidizers, and increasing Mo content resists the effects of chlorides.

o NON-METALS

Non-metals are subject to three types of damage:

1. Swelling or weight gain - Sometimes resulting in delamination of layered materials.
2. Strength loss - Sometimes resulting in plastic flow, permanent deformation or cracking.
3. Disintegration or dissolution.

These mechanisms are primarily dependent on the environmental variables listed below:

1. Chemical environment - Concentration, composition.
2. Temperature - Usually all 3 types of damage are accelerated by increasing temperatures.
3. Physical environment - Mechanical stress, abrasion, fluid velocity.

A survey of nonmetallics test data(24) indicates a wide selection is available, suitable for the proposed temperature and concentration ranges proposed. The primary limitations to use of non-metallics are physical properties, such as low tensile strength, elasticity or sometimes brittleness, which make most of them unsuitable for high pressure applications.

o Materials Recommendation

Based on prior experience with copper ISL projects, those materials listed in Table 4.6 are recommended to provide adequate corrosion resistance. Physical characteristics and commercial availability in product form restrict uses of many of the materials to low pressure applications, often on the surface. Presence of chlorides in the fluids at a concentration above approximately 0.1 to 5.0 grams per liter is thought to require a higher alloy than AISI 316 stainless steel, depending on the application and expected lifetime. Components of 316 alloy requiring long lifetimes should only be used at the lower chloride concentrations.

Coatings such as plastic or paint on carbon steel were not considered, due to corrosive attack of the structural (steel) member in the very likely event of even minor physical damage to the coating.

TABLE 4.6 RECOMMEND MATERIALS FOR COPPER ISL

| Material | Comments |
|----------------------|--|
| <u>Metals</u> | |
| - AISI 316 | 17% Cr, 12% Ni, 2.5% Mo |
| - AISI 317 | 17% Cr, 13% Ni, 4.3% Mo |
| - 904L | 20.5% Cr, 25% Ni, 4.7% Mo |
| - Incolloy 825 HMo | 21% Cr, 42% Ni, 4.5% Mo |
| - Inconel 625 | 21.5% Cr, 61% Ni, 9.0% Mo |
| - Hastelloy C | 15.5% Cr, 54% Ni, 16% Mo |
| <u>Plastics</u> | |
| - Teflon | |
| - Viton | Questionable in CuCl_2 |
| - Penton | |
| - Hypalon | Questionable in CuCl_2 and FeCl_3 ; experience indicates suitability |
| - Kynar | |
| - Dynel | |
| - Kal-Rez | DuPont product similar to Viton |
| - Polyurethane | Not recommended for Dilute H_2SO_4 |
| - Polypropylene | |
| - Polyethylene | |
| - A.B.S. | |
| - P.V.C | |
| - C.P.V.C | |
| - Epoxies | Some types questionable in Dilute H_2SO_4 |
| <u>Elastomers</u> | |
| - Isoprene | "Natural Rubber"; questionable in Dilute H_2SO_4 |
| - Butyl | Questionable in Dilute H_2SO_4 |
| - Buna N | "Nitrile"; questionable in Dilute H_2SO_4 and CuCl_2 , FeCl_3 |
| - Neoprene | |
| - E.P.R. | "E.P.D.M." |
| - Epichlorhydrin " " | "ECO" |
| - Hypalon | See "Plastics," above |

o Equipment Types and Design

Various types of production and injection well equipment are shown in Figures 4.5, 4.6, 4.7, 4.8, 4.9. Equipment specification consists of the following general categories:

- o Tubing
- o Packer
- o Recovery pumps
- o Wellhead
- o Fluid level instrumentation

+ Recovery Pumps

The purpose of recovery pumps is twofold; to lift well fluids to the surface for treatment, and to maximize drawdown in the recovery well, which increases the pressure differential between the injection and recovery wells.

Many types of downhole pumps exist, mostly for applications in petroleum and water production. The most suitable type for the range of depths and flow rates associated with ISL is the electric submersible pump, from the standpoint of efficiency, capacity, drawdown and capital cost.

Submersible electric pump design parameters include the range of well flow rates expected, (individual pumps do not cover a wide range of flowrates), total dynamic head, fluid temperature, density and viscosity, pump setting depth, corrosive and abrasive nature of well fluids, and gas content of fluids. An appropriate power supply is assumed to be available. To simplify the design, it is assumed that well fluids have the characteristics listed in Table 4.7.

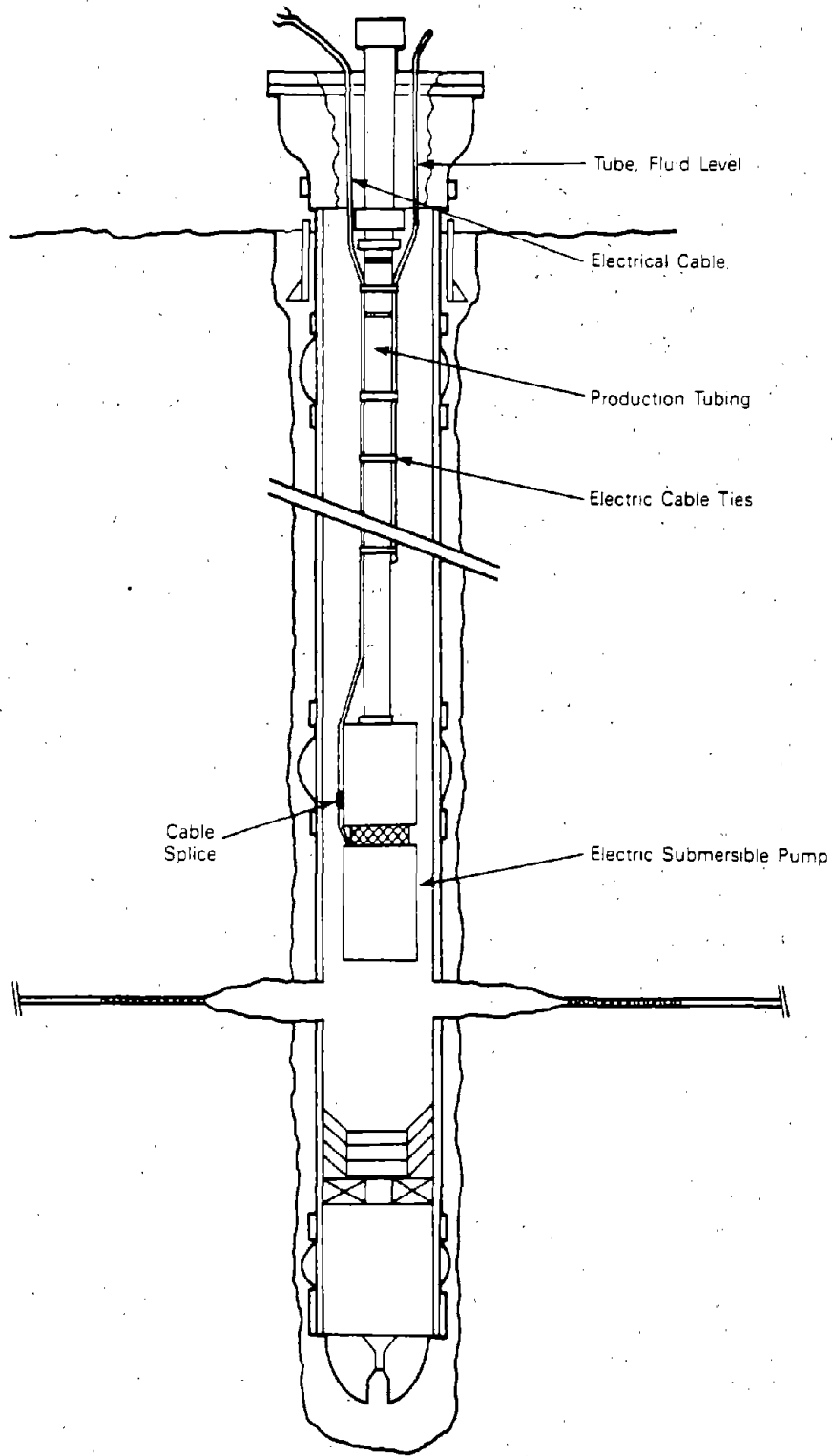


Figure 4-5. Recovery Well Equipment

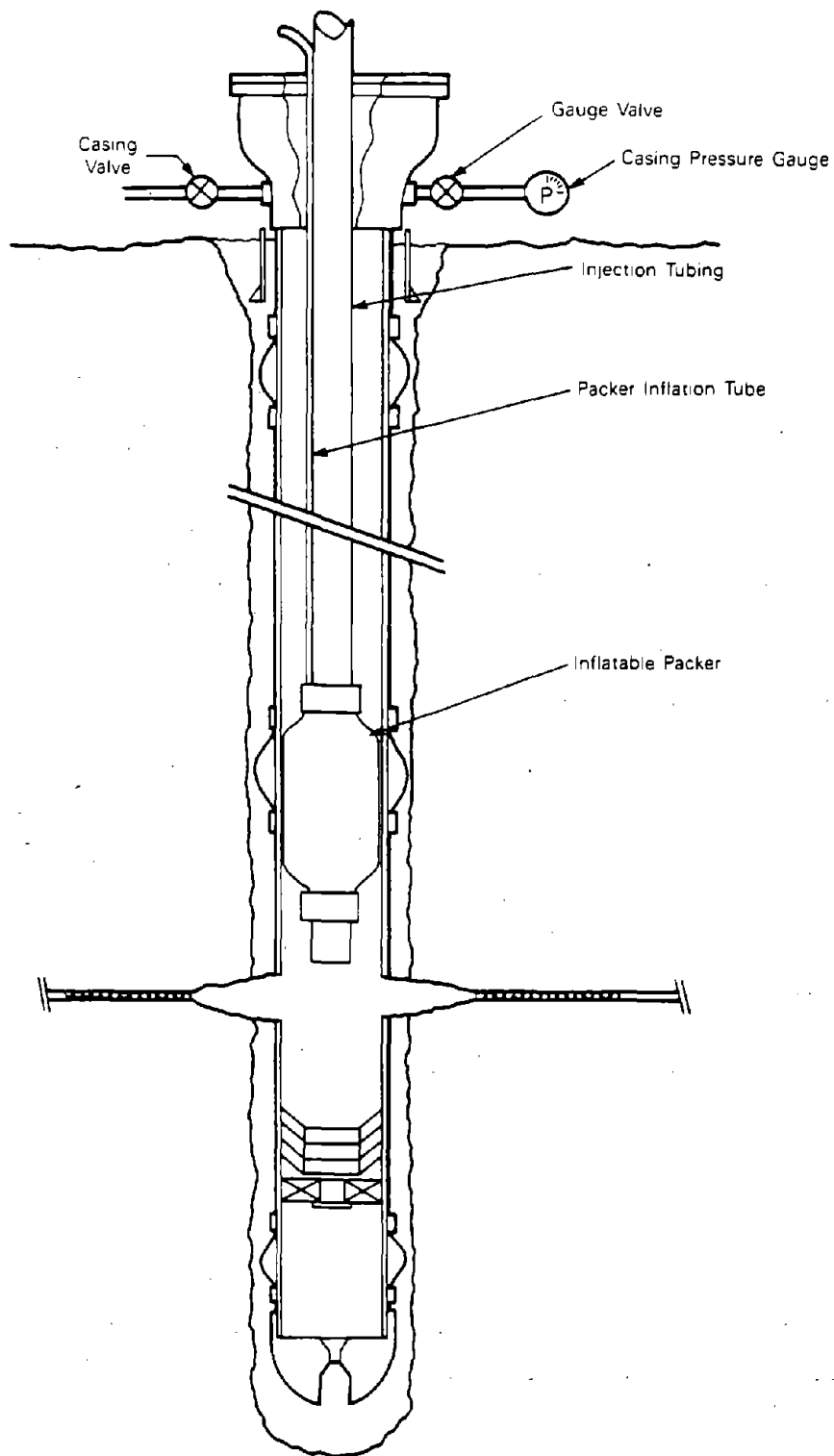


Figure 4-6. Injection Well Equipment

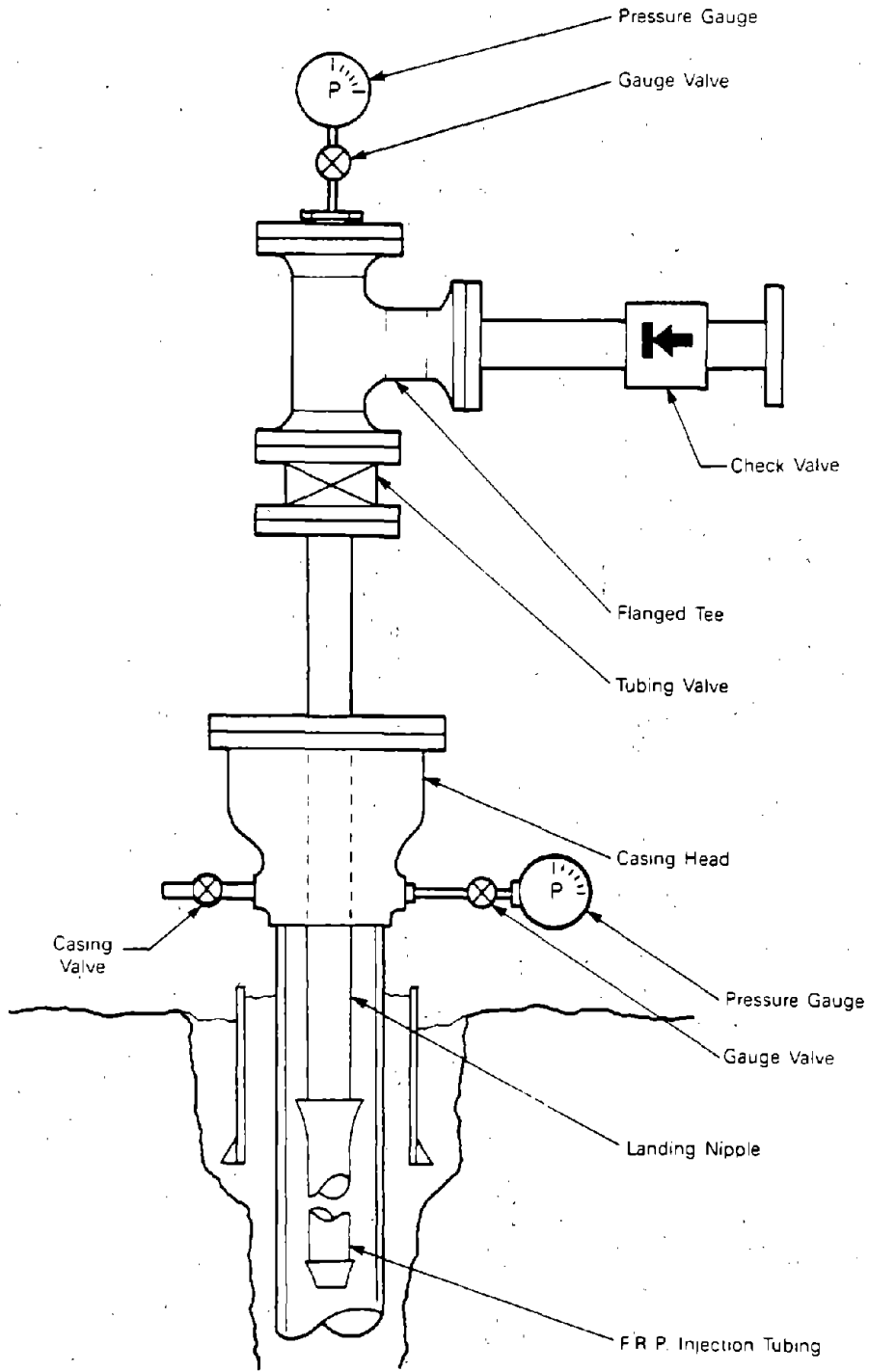


Figure 4-7. Injection Wellhead Equipment

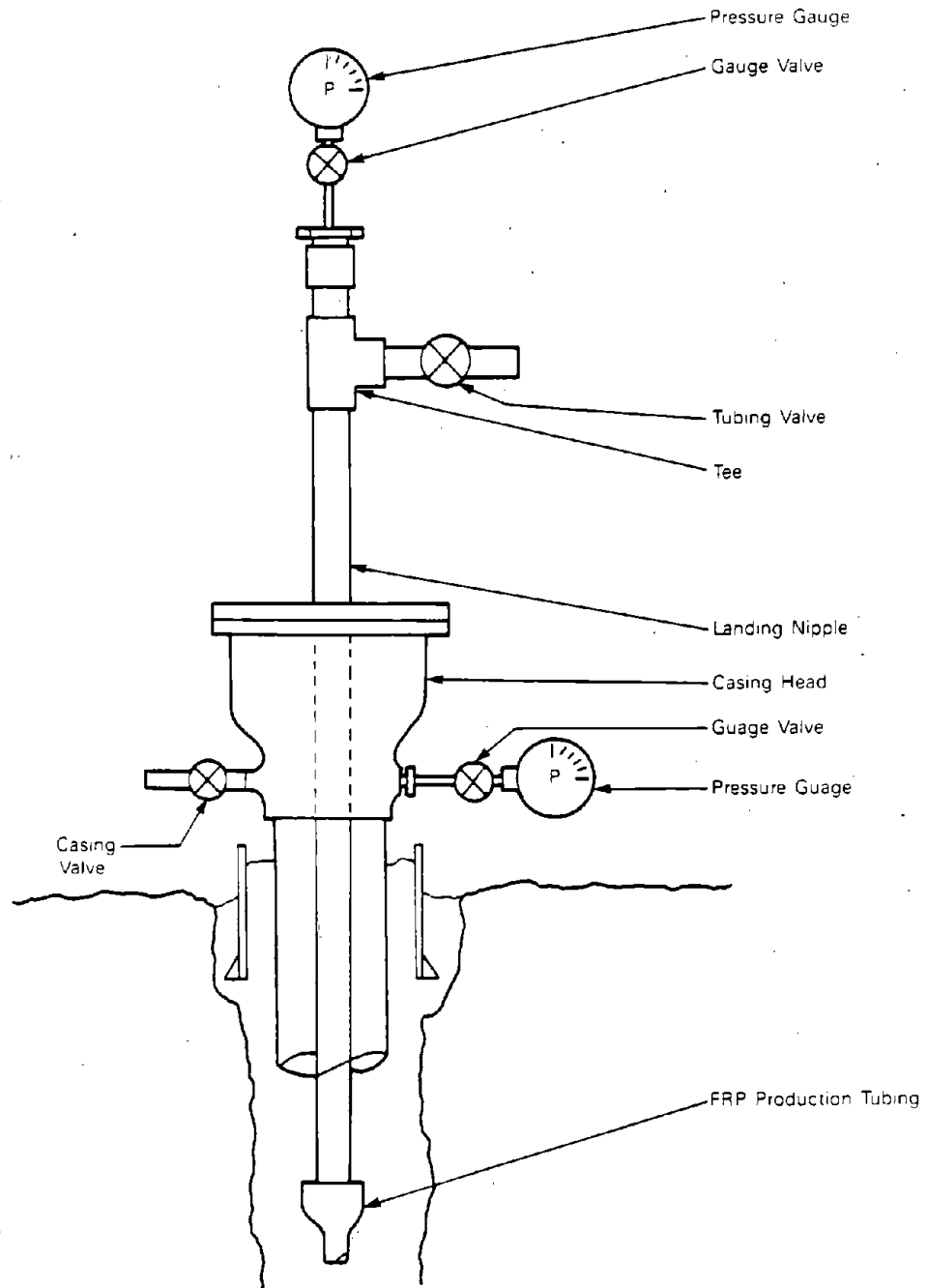
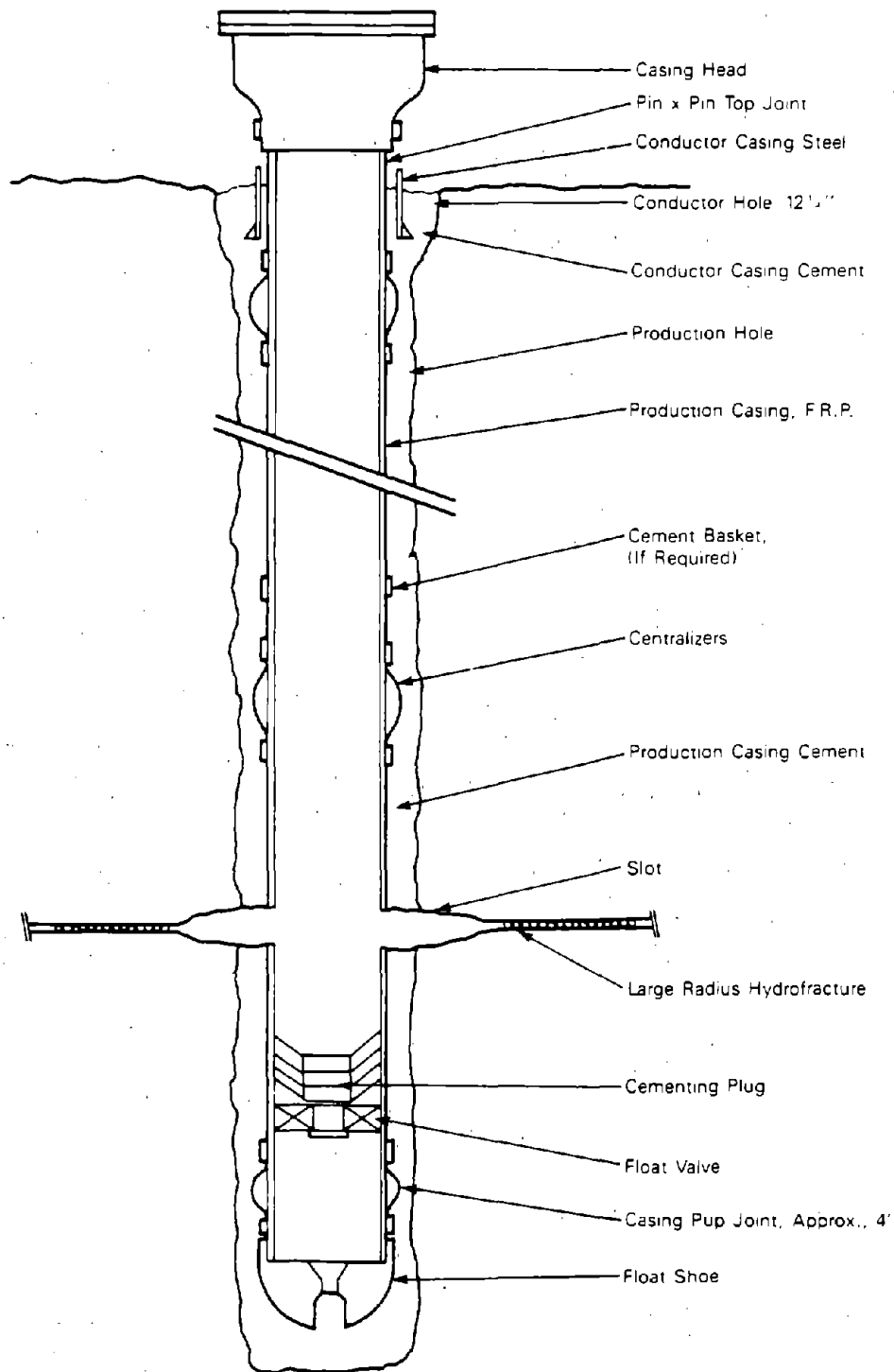


Figure 4-8. Recovery Wellhead



**Figure 4-9. Typical Installation
(Using Large-Radius Hydraulic Fracture)**

TABLE 4.7. DESIGN PARAMETERS FOR DOWNHOLE PUMP

| | |
|----------------------|---|
| Viscosity | 1.0 cp - 2.0 cp |
| Temperature | 70°-80°F |
| Density | 62.4 lb/ft ³ (same as water) |
| Abrasives | none (copper ISL operating experience verifies this) |
| Corrosive conditions | see Table 4.6 |
| gas | none |
| Total dynamic head | predicted by model, variable up to 1400 psi or 3300 ft of water |
| Flow rate | Predicted by model, assumed constant over the life of well. |

To cover the wide range of flow rates and depths the generic design manual will consider a wide range of pumps will be required. Pump and motor diameters are related to flow rate and head requirements. Small pumps which fit in 4 inch I.D. wells are limited to the lower flow rate range of the depth range specified. Cost and efficiency quickly become problems outside this range. Similarly, pumps for 6 inch wells provide the medium range of flow rates, and 8 inch pumps provide the high flow rates. These broad design ranges generally reflect capabilities of commercially available pumps made of suitable alloys and materials. Pumps for certain flow/head combinations may not be commercially available.

Calculated costs are based on: pump size and horsepower requirements for the motor; horsepower requirements for fluid end; electric cable; and controls. Efficiency of both the pump and motor is assumed as 70%.) Costs for these items are listed in Table 4.8, and total pump cost is represented by (4.14).

$$N_p = [N_I^{1/2} + 1]^2 \quad (4.11)$$

$$q_p = Q/N_p \quad (4.12)$$

$$HP_L = 3.61 \times 10^{-4} q_p (D-H) \quad (4.13)$$

$$C_{RP} = (HP_L)(M_x + 92) + B_{xq} + (D-H)(B_{RPW} + B_{WLT}) + B_{RPC} + B_{PI} \quad (4.14)$$

TABLE 4.8. DOWNHOLE PUMP AND COMPONENT COSTS

| Well Casing Size (in) | M_x (\$/HP) | B_{xq} (\$/Pump) | B_{RPW} Electric Cable \$/FT | B_{RPC} Electric Controls (\$)/Pump | q_p Approx. Flowrate Range (gpm) | B_{PI} Fixed Costs (\$)/Pump |
|-----------------------|---------------|--------------------|--------------------------------|---------------------------------------|------------------------------------|--------------------------------|
| 4 | 325 | 0 | 1 | 1100 | 0 - 55 | 1811 |
| 6 | 70 | 500 | 3 | 1300 | 50 - 100 | 1811 |
| 8 | 102 | 1000 | 5 | 2500 | 100 - 300 | 1811 |

+ Tubing

The purpose of well tubing is to provide a mechanical and hydraulic connection to downhole equipment. Tensile strength, internal pressure rating, suitability of connections, and corrosion resistance are the primary design parameters. The tubing must operate up to a flow rate of 255 gpm, at internal pressures up to 2400 psi, at depths to 3000 ft, in corrosive fluid environments. Two types of tubing are suitable for this application, fiberglass reinforced plastic (FRP) and stainless steel of AISI 316 or higher alloy. FRP tubing is commercially available from a variety of manufacturers, and at least one tubing manufacturer is producing high-alloy stainless tubulars. Both types of materials provide suitable pressure ratings, tensile strength, size range and connections for ISL copper use.

For purposes of costing in the generic model, FRP tubulars were selected, based on suitable operating performance and lower unit cost. One limitation of FRP tubing is its low axial compressive strength, which requires avoiding use of well equipment which would impose an axial compressive load upon the tubing (such as compression-set packers). Experience indicates that FRP threaded connections are less prone to damage from repeated use than similar stainless steel connections. To ensure low friction loss over the wide range of proposed flowrates, it was necessary to base the design on 3 tubing sizes. Table 4.9 lists specifications and costs for these tubing sizes. Well tubing size is commonly specified by its outside diameter. Reduced diameter couplings are available if greater casing-tubing clearance is required at the tubing joint connections. Tubing costs are given by (4.15).

$$C_{TP} = B_t(D-H) \quad (4.15)$$

TABLE 4.9. TUBING SPECIFICATIONS AND COSTS

| Nominal O.D. (in) | Max O.D. (in) | I.D. (in) | Internal Press. (psi) | Tensile Rating (lb) | B_t Approx. Cost/FT (\$) | Flow rate Range (gpm) | Friction Loss Per 100' (psi) |
|-------------------------|---------------------|--------------|-----------------------------|---------------------------|-------------------------------------|-----------------------------|------------------------------------|
| 2 3/8 | 3.8 | 1.92 | 2500 | 17,000 | 5.41 | 0- 55 | 0 -2.3 |
| 2 7/8 | 4.6 | 2.42 | 2500 | 21,200 | 7.35 | 50-100 | 0.9-2.5 |
| 4 1/2 | 7.3 | 4.04 | 2500 | 48,000 | 15.80 | 100-300 | 0.3-2.7 |

+ Packers

Packers are used to isolate fluids within one or more intervals of the wellbore. In the case of ISL, packers are used in conjunction with tubing in injection wells to isolate the high pressure lixiviant within the desired injection interval, and to avoid exposing the remaining well casing to lixiviant fluids and injection pressures. This practice provides additional protection of the well casing from damage, and is likely to be mandated by environmental regulations.

Packer selection for ISL purposes is governed by well casing and tubing size and type, operating pressures (both internal and differential), and fluid corrosivity. Flow rate is a secondary consideration, since pressure drop across the relatively short packer length is generally unimportant. Extremely high flow velocity could represent corrosion problems for some metals.

A wide variety of packers exist, most finding application in the petroleum industry(26). Experience has shown that only two types of packers are compatible with FRP tubing and well casing in addition to being commercially available in suitable materials of construction. Compatibility with FRP tubing implies that axial loading must be neutral or tensile, compression is unacceptable. For operation within non-metallic casing (such as FRP) under high pressures, use of slips is inadvisable due to the possibility of casing damage. (Slips are holding devices which use sharp serrated metal "teeth" to engage the casing and resist packer slippage.) Use of opposed cup packers is not recommended due to the possibility of entangling the lower cup in voids or debris associated with casing perforations or well completions, which could make the packer difficult or impossible to remove. Polished bore

receptacle (PBR) type packers usually employ slip-type anchors, and are therefore unacceptable in FRP casing. Most of the above types of packers are not commercially available in suitable materials of construction. Two packers that are acceptable from a design point of view are inflatable types, and a tension-set type which engage the casing at casing joint connections without use of slips. Both are available commercially in 316 ss or higher alloys. The inflatable type packer was selected for use in the generic model, due to its availability for all proposed well sizes. Experience has shown suitability of use of the tension-set variety in specific ISL applications. Costs of this type are somewhat lower than comparable inflatable types.

Table 4.10 lists characteristics of inflatable packers for the 3 well sizes used in this design manual. The cost per well is given by (4.16).

$$C_{pp} = B_k + B_i (D-H) \quad (4.16)$$

TABLE 4.10. PACKER SPECIFICATIONS AND COSTS

| Casing Size, I.D. (in) | Packer I.D. (in) | Uninflated O.D. (in) | Differential Pressure Rating (psi) | B_k Cost per Packer (\$)/Packer | B_i Inflation Tube Cost (\$/ft) |
|------------------------|------------------|----------------------|------------------------------------|-----------------------------------|-----------------------------------|
| 4 | 1.25 | 3.5 | 2000+ | 3000 | 1.00 |
| 6 | 2.0 | 5.25 | 2000 | 5000 | 1.00 |
| 8 | 2.5 | 6.5 | 2000 | 7000 | 1.00 |

In applications requiring greater than 2000 p.s.i. injection pressure, the differential pressure may be reduced sufficiently by water-filling the tubing-casing annulus. A small high-pressure tube must be run outside the production tubing, to inflate the packers. Other inflation methods using tubing pressure require a more complex mechanism.

+ Wellheads

The wellhead includes equipment which holds the downhole tubing string in place and provides pressure sealing and control of the tubing-casing annulus (the casing head). Additionally, wellhead equipment includes the various pressure gauges, instruments, valves, fittings and pipes associated with controlling flow into or out of the well, measuring pressures, and flow rates and sampling fluids.

Schematic diagrams of typical injection and recovery well wellheads are shown in Figures 4.7 and 4.8. Since instrumentation and piping costs are widely variable over the models, flow rates, and pressure ranges considered, wellhead costs were estimated on the basis of a standard casing head cost and an additional cost which includes piping, instruments, valves, etc., and are listed in Table 4.11. Commercially available painted carbon steel oilfield type casing heads have proven adequate to resist corrosion under normal operating conditions, and have adequate strength for proposed pressures and depths. The cost is C_{pw} .

$$C_{pw} = B_h \quad (4.17)$$

TABLE 4.11. WELLHEAD SPECIFICATION AND COSTS

| Well Casing Size (in) | B_{CH} Casing Head (\$) | | B_{WH} Wellhead Equipment (\$) | = | B_h Total (\$)/Wellhead |
|-----------------------|---------------------------|---|----------------------------------|---|---------------------------|
| 4 | 540 | + | 700 | = | 1,240 |
| 6 | 540 | + | 700 | = | 1,240 |
| 8 | 712 | + | 1,000 | = | 1,712 |

+ Fluid Level Measurement

During ISL operations it is necessary to monitor fluid levels in the casing/tubing annulus of production wells in order to maximize drawdown while maintaining the net positive suction head required by the pump. In injection wells, changes in annulus fluid level indicate malfunctions of the packer, tubing, or casing.

For normal operations it is not necessary to know these fluid levels to a high degree of accuracy. Pressure gauges on injection well tubing/casing annulus are usually sufficient. Primary design parameters are depth, fluid characteristics, and cost. Common types of fluid level measuring devices are:

1. Electric sensors which indicate fluid levels by conducting electric current through the fluid or, alternatively, reduce measured resistance in proportion to submergence in well fluids.
2. Piezometric downhole pressure gauges, which use electric wires to conduct pressure data to a surface readout unit.
3. Sonic devices which measure travel time of a pressure pulse through air in the annulus as it is reflected by the air-liquid contact.

4. Pressure-tube devices which measure the gas pressure required to displace well fluid from a small downhole tube extending from the surface to below the liquid levels.

Most of these devices can be used for control of pump operations, alarming, etc., if properly connected. Experience with operations in highly conductive and corrosive ISL fluid environments has indicated the pressure-tube devices to be most reliable and economic within the accuracy range desired. Sonic devices are only accurate within approximately the length of one tubing joint (approximately 30 ft), and cannot conveniently be connected to pump controls. Electrical devices are prone to corrosion and short-circuiting.

For most applications, a high pressure regulated gas source (typically nitrogen) and a small high pressure plastic tube fastened to the well tubing string, connected to suitable valves and pressure gauges, is sufficient. Costs associated with this monitoring device involve surface equipment estimated at \$250 and downhole tubing estimated at \$0.10/ft. This cost is represented by (4.18) and is included in the cost of the production pump.

$$C_{pf} = 250 + 0.1 (D-H) \quad (4.18)$$

+ Flow meter

The injection well is equipped with a flow meter, the cost is represented by C_{PM} .

$$C_{PM} = \$2,000 \quad (4.19)$$

+ Summary of Well Equipment Costs

Well equipment costs for injection and production wells are summarized by equations (4.20) and (4.21).

$$C_{WEI} = C_{TP} + C_{PP} + C_{PW} + C_{pm} \quad (4.20)$$

$$C_{WEP} = C_{RP} + C_{TP} + C_{PW} \quad (4.21)$$

4.4.1.3 Well Casing

Well casing acts as a conduit for well equipment in addition to isolating well fluids from formations overlying the ore which are penetrated by the well. Casing design parameters depend primarily on well depth, equipment sizes, well fluid properties, and temperature.

Well equipment design is based on three casing sizes for the flow rate ranges considered, and well depths to 3000 feet below the surface. Fluid properties dictate suitable materials for resisting corrosion during the projected well life, which usually varies between several months and several years. (See Table 4.6.) Depth related design parameters are internal pressure, collapse pressure, tensile strength and compressive strength. Internal pressure results from fluid injection and matrix modification operations. The internal pressure resistance of casing is greatly increased by attaining a good external cement sheath, as described in the following section. Collapse pressure may arise from hydraulic forces associated with cementing (both hydrostatic and dynamic), and from certain geologic conditions such as expanding clays or plastic salt beds. Tensile forces are usually a product of casing string weight and length, but may also arise from cementing operations. Compressive forces (along the casing axis) may result from cementing operations in which a low density casing is

cemented with standard density (or more dense) cement which, in turn, is displaced with a low density fluid such as water. These conditions may result in a net buoyant force on the casing, which is normally anchored at the surface, thus causing an axial compressive stress on the casing string. Metal casing materials are normally sufficiently dense and heavy and have sufficient compressive strength that buoyancy is not a problem. Lightweight casing materials such as FRP and PVC, especially with large diameters in deep installations, may be adversely affected by buoyant forces during cementing operations. For the depth range considered in this model, assuming a geothermal gradient of approximately 1°F per 100 ft. and a 70°F ambient temperature, a maximum bottom hole temperature of 100°F is calculated. This temperature is insufficient to cause problems in most common types of casing, except PVC, which is structurally weakened by a relatively small increase in temperature.

Well casing is available in several materials of construction including carbon steel, high-alloy steels (usually special-order), PVC, ABS, and FRP. From a corrosion resistance standpoint, only carbon steel is unacceptable. (Coatings are not considered to be an acceptable design consideration.) High alloy metal casing is economically very unattractive in comparison with the other materials. In addition it is not readily available. At the greater depths addressed by this manual, ABS and PVC become structurally inadequate, primarily from the collapse resistance and tensile strength standpoints. For these reasons, FRP casing was selected for exclusive use in the design manual. Site specific designs may be improved by using other casing types, including combinations of two or more. Design for PVC well casing is adequately described in the literature(27). FRP casing is commercially available

from a variety of manufacturers in standard sizes, various pressure ratings, utilizing a variety of thread forms and seals. Table 4.12 lists the characteristics selected for the design manual.

TABLE 4.12. CASING SPECIFICATIONS

| Casing Size d_c (in) | Joint O.D. (in) | Internal Pressure (psi) | Collapse Pressure (psi) | Tensile Load (lb) | Dead Weight (lb/ft) | Compressive Load (lb/ft) | Joint Type |
|---------------------------|--------------------|----------------------------|----------------------------|----------------------|------------------------|-----------------------------|------------|
| 4 | 5.9 | 1800 | 5670 | 115,000 | 5.4 | Not | A.P.I. |
| 6 | 8.3 | 1400 | 2990 | 193,000 | 8.9 | Recom- | 8-round |
| 8 | 11.3 | 2000 | 2250 | 130,000 | 17.2 | mended | threads |

In addition to the production casing string described above, other required casing equipment includes:

- o Conductor Casing: A short (approx. 20 ft.) joint of carbon steel casing which is cemented in place to prevent surface caving during following operations. The conductor casing I.D. must be sufficiently large to allow all drilling equipment to pass through it. Corrosion is not a consideration.
- o Cementing equipment items that are attached to the casing during the cementing operation are included in the casing design and costs:
 - + Centralizers, which center the casing within the drilled hole thus promoting a uniform-thickness cement sheath and aiding in efficient drilling fluid removal during cementing. These are proposed to be placed at 90 ft. intervals, (corresponding to every third casing joint). To simplify the generic model, it is assumed that centralizer costs for all three casing sizes are equal.
 - + Float equipment consists of two, one-way check valves designed to prevent displaced cement from flowing back into

the casing after pumping operations end. This allows the casing internal pressure to be relieved during cement setting. This prevents formation of a "microannulus," (a very small annular void between the casing and cement sheath) which results from maintaining pressure on the casing while the cement is setting, and subsequently releasing the pressure, thus allowing the casing to elastically return to its unpressurized diameter. One of these check valves is called a float valve, and is located several feet above the end of the casing string. The other is called a float shoe and is attached to the bottom of the casing. Its rounded bottom end facilitates installing the casing. Two valves are used for redundancy.

- + Pup Joints are short casing joints used to obtain the correct casing string length and to separate the float valve and float shoe (to avoid filling an entire full length joint with cement). Pup joint costs per foot are higher than full length casing joints, and several are usually required for spacing application. It is assumed for the generic model that a uniform fixed cost will purchase sufficient pup joints. Also included is a short pin X pin threaded top joint to allow direct connection to the casing head box threads.

Table 4.13 lists the parameters used to develop well casing costs. The cost per well is calculated from equation (4.22). R_{cs} averages 130 ft/hr.

TABLE 4.13. WELL CASING COSTS

| Well Size | B_c Casing Cost (\$/Ft) | B_B Central-izers (\$/ft) | B_f Float Valve (\$ Ea) | B_s Float Shoe (\$ Ea) | B_{cc} Conductor Casing (\$) | B_p Pup Joints (\$) | B_{wc} Total Fixed Cost (\$)/Well |
|-----------|---------------------------------|-----------------------------------|---------------------------------|--------------------------------|--------------------------------------|-----------------------------|---|
| 4" | 15.00 | 0.56 | 180.00 | 265.00 | 200.00 | 1,400.00 | = 2,045 |
| 6" | 26.00 | 0.56 | 180.00 | 265.00 | 200.00 | 1,400.00 | = 2,045 |
| 8" | 35.00 | 0.56 | 180.00 | 265.00 | 200.00 | 1,400.00 | = 2,045 |

$$C_c = D \left(B_c + \frac{B_d}{R_{cs}} + B_B \right) + B_{wc} \quad (4.22)$$

4.4.1.4 Drilling

Drilling provides the hole into the ore body, in which well casing and cement and equipment are installed. Many site specific variables dictate selection of drilling methods, equipment, fluids and drilling schedule, in addition to hole sizes and related specifications resulting from equipment and casing design. This section provides an overview of drilling design parameters and generic methods of costing. Site specific drilling designs should be based on local drilling experience, and are often and significantly influenced by equipment availability, water sources, transportation conditions, etc.

Drilling design primarily addresses the following:

- | | |
|--------------------------------|-------------------------------|
| 1. Hole diameter | 4. Drilling method |
| 2. Hole depth | 5. Circulating fluid |
| 3. Hole straightness/deviation | 6. Type of drilling equipment |

Hole diameter is determined by casing size (see previous section), and cementing considerations.

Generally, cementing requires a hole diameter approximately 2 to 3 inches larger than the outside casing body diameter with sufficient clearance for the outside coupling diameter. Drill bits are available in a wide variety of standard sizes and types.

Hole depth is slightly greater than the proposed casing depth, typically by 10 to 20 feet, to provide a void for debris which may slough off the hole wall or settle out of the drilling fluid during casing operations.

Hole straightness is a measure of the well's radius of curvature, or rate of change of hole direction. Hole deviation is an indication of

displacement of the hole from its surface (collar) location at a given depth, usually expressed as an angle relative to a vertical line passing through the collar location. Hole straightness is a consideration in drilling to avoid "keyseats," which are small slots worn in the hole wall by rod abrasion, which cause difficulty in drilling and rod removal. In casing operations these "keyseats" can cause casing sticking or damage and excessive well curvature may result in damage to large-diameter items such as pumps during installation. Hole deviation is of concern in wellfield design because fluid flow control between adjacent wells requires a given spacing. Often all or most wells drilled in a wellfield will deviate in similar directions and distances, thereby somewhat minimizing the bottom-hole well spacing variations in a well pattern. With good drill string design and drilling practices, it is usually possible to achieve vertical hole angles of less than 2 degrees. At greater depths it may be necessary to use directional drilling techniques to keep bottom hole locations within specifications. Down hole surveying methods are used to determine hole straightness and deviation.

Drilling method refers to the category of drilling operation utilized. Of the variety available, including rotary, percussion and cable tool, only the first two are normally cost effective. Rotary methods usually utilize a drill bit which derives its cutting action from weight and rotation, which is supplied either through rotating drill rods or by a hydraulically driven downhole motor. Percussion methods employ a bit which derives its cutting action by impacting the rock. These bits are most commonly driven by a downhole air hammer, or a reciprocating string of drill steel attached to the bit. Some more

exotic drilling methods which utilize thermal phenomena, ceramic "bullets" and other techniques are in experimental stages but not in commercial application at this time.

Circulating fluid serves to cool and lubricate the drill bit and rods, remove cuttings from the vicinity of the bit ("cleaning" the bit), and transport cuttings to the surface for disposal, in addition to providing hole support. Drilling fluids in common use include bentonite and polymer based ("mud") systems, water, air, foam (water and a foaming agent), and "stable foam" (a carefully controlled foam system utilizing back pressure control methods to optimize cuttings transport properties of the system.) Any of these circulating systems may suffice for drilling purposes. For ISL purposes, bentonite mud systems should be avoided if possible due to likelihood of near-wellbore permeability impairment by invasion of the mud into the formation. Polymer muds may be removed by use of a suitable "breaker" chemical following drilling, thus making them suitable. Air and foam systems usually do not cause significant formation damage, but may not provide adequate hole support.

Drilling equipment includes bit type, fluid circulating system, drill string equipment, and rig characteristics. Bit type is selected on the basis of formation characteristics such as hardness, clay content, and abrasiveness. In the hard abrasive rock types usually associated with copper oxide deposits, rotary bit selection is usually (but not necessarily) limited to hard formation mill-tooth or carbide button bits. Air hammer percussion bits also utilize carbide buttons. If the deposit is contained within or overlain by softer formations (especially if containing clay lenses or layers), more than one bit type or drilling method may be most economical. Rotary drilling of large

diameter holes requires considerable bit weight and drill rig hoisting capacity. Choice of a circulating fluid and system is governed primarily by permeability damage and hole support considerations. From this standpoint, depending on drilling experience near a specific site, either polymer based mud systems or foam systems are logical choices. In areas expected to produce high water inflow rates, in weak formations, foam drilling may not provide adequate hole support and may require abnormally high air pressures and flowrates to remove the water during drilling. Often, remedial steps such as cementing water inflow zones (outside the ore zone) will alleviate these problems. Water is seldom used in drilling large deep holes due to high rates of loss, low viscosity (for cuttings transport) and poor lubricating properties.

Circulation may involve flowing the drilling fluid down through the drill pipe and bit and back up the hole-drill rod annulus ("regular" circulation), or pumping it down the annular space between tubes in special double-walled drill rods, up past the bit and inside the drill rod inner tube ("reverse" circulation). Reverse circulation has the advantage of avoiding hole erosion, and is superior in chip sampling accuracy.

A primary consideration in circulation system design is to assure fluid velocity/viscosity combinations high enough to transport cuttings out of the hole, while maintaining velocities below a level which causes erosion. Design rules are available in the literature for these considerations.

Drill string equipment, excluding the drill bit (previous section), includes drill rods, collars, stabilizers and reamers, downhole hammers and mud motors. A brief explanation of these items follows; additional information exists in the literature.

- o Drill Rods serve to suspend the drill bit and equipment from the rig, transmit torque for bit rotation, and to conduct circulating fluids. Drill rod O.D. must be considered in designing circulating fluid velocity.
- o Drill Collars are thick, heavy drill rods, used to provide necessary weight on the bit for optimum penetration rates. Most of the drill string, including the rods are suspended in tension during drilling in order to achieve a straight vertical hole by the "pendulum effect." Rotary drill bits typically require 5000 to 9000 lb. per inch of bit diameter; air hammer bits require considerably less, on the order of 500 pounds per inch of bit diameter. Since 20 to 30 percent of collar weight should be held in tension to promote hole straightness, considerable total collar weight is required. Drill collars typically are located immediately above the bit and, due to their stiffness, tend to promote hole straightness.
- o Stabilizers are devices inserted in the drill string at various locations, usually to assist in maintaining hole straightness. Stabilizers are usually one to several feet long and have an outside diameter only slightly smaller than the hole diameter, to assure contact with the hole wall in the event of drill string bending, thus promoting hole straightness. They are available in a variety of sizes, lengths, and materials. Some types rotate with the drill string while other types employ bearings to avoid abrasion of the hole walls by preventing stabilizer body rotation. Straight or helical flutes are usually employed to permit passage of drilling fluids and cuttings around the stabilizers.

The generic design is based on the following assumptions which reflect drilling experience in ISL copper applications.

- o Hole Depth: maximum of 3000 feet
- o Hole Diameters: As required by casing design and cementing practice, 7, 10, and 12 inch diameter.
- o Hole Straightness: Minimum approximate curvature radius for various size holes are: 7 in. = 200 ft. radius; 10 in. = 300 ft. radius; 12 in. = 400 ft. radius (Based on FRP casing limitations).
- o Hole Deviation: Within one degree of vertical is assumed; more or less deviation may be allowable at a given site, for a specific wellfield design.
- o Drilling Method: Downhole air hammer drilling is assumed. Operator input allows cost estimates to reflect other drilling methods and circulating fluids.

- o Circulating Fluid: Air or foam is assumed. No problems related to circulation are assumed.
- o Drilling Equipment: A rotary drilling rig equipped to perform air drilling with a suitably designed downhole hammer, bit and drill string for the specified geologic environment. Operator input of hourly drilling costs and average drilling rates in the cost algorithms reflects site specific conditions. For purposes of the generic model, the following inputs are suggested as being representative:

Table 4.14 lists basic constants used to calculate drilling costs. The cost to drill a well is represented by equation (4.23).

$$C_d = B_d D / R_d \quad (4.23)$$

Table 4.14 Drilling Costs

| d_c Casing Size (in) | d_H Hole Size (in) | B_d Drill Cost (\$/hr) | Drill Rate R_d (ft/hr) | Well Screen Unit Cost B_w (\$/ft) |
|------------------------------|----------------------------|--------------------------------|-----------------------------|---|
| 4 | 7 in. | 175 | 30 | 15 |
| 6 | 10 in. | 200 | 20 | 32 |
| 8 | 12 in. | 250 | 15 | 45 |

4.4.1.5 Cementing

Well casing is cemented into the drilled hole to provide mechanical support for the casing (in both vertical and radial directions) and to prevent fluid flow in the annular space between the casing and hole.

Several methods of well cementing are known, but for the range of depths described by the generic model, conventional oilfield cementing methods are assumed. Cementing procedure involves circulating various fluids down the well and up the casing-hole annulus in order to condition the well for cementing. Placement of a calculated volume of cement slurry into the casing is followed by introduction of a cementing plug into the casing. This plug is pumped to the bottom of the casing

by a displacement fluid, thus forcing the cement slurry into its desired location in the casing-hole annulus.

Primary cement design parameters for copper ISL wells include casing and hole specifications, and corrosion considerations and site geology. In addition, drilling fluids used, geological/hydrological systems, hole size variations, hole straightness, and regulatory requirements must also be considered.

A brief discussion of design parameters follows, with subsequent discussion of design procedures and cost estimating.

o Design Parameters

+ Drilled Hole

- Diameter and size variations for calculating cement volume and correlation with drilling and logging data to indicate intervals of fluid loss, caving, etc. Hole size variation is detected by wireline caliper logging methods and dictates to some extent location of centralizers on the casing string.
- Hole depth, in conjunction with the local geothermal gradient and the cement density determines bottomhole temperature and maximum hydrostatic pressure bearing on the casing and hole walls. Well depth and temperature, in conjunction with cementing procedures, determine the minimum length of time the slurry must remain pumpable ("thickening time"). Hydrostatic pressure, in addition to the dynamic component of pressure associated with friction, bear on design of slurry viscosity, casing burst and collapse pressure ratings, displacement fluid density, slurry fluid loss additives and (in conjunction with formation fracture gradient), likelihood of losing cement to the formation by unintentionally-induced hydraulic fractures.

+ Casing specifications

- Collapse pressure rating indicates the net differential pressure between the inside and outside of the casing which will cause the casing to collapse. (Associated with depth, cement and displacement fluid density, and friction pressure.)
- Burst pressure rating (or internal operating pressure rating) indicates the net differential pressure (as above)

which will cause casing damage by splitting or (in the case of F.R.P. casing) leakage by "weeping." In cementing operations this could be caused by an instantaneous pressure surge caused by the cementing plug seating on the float valve at a high pump rate, or an obstruction in the casing-hole annulus during cement displacement.

- Tensile strength specifications, combined with internal casing cross sectional area dictate the maximum allowable pressure which can safely be applied to suspended, closed ended casing without causing tensile failure. Maximum allowable suspended string length also depends on tensile strength.
 - Casing weight and density, in combination with cement and displacement fluid density and casing volume, determines net buoyant force on the casing during cementing operations. Cement slurry density may be adjusted within approximately the range of 9 to 15 lb. per gallon using various types and amounts of weight reducing additives. Higher density cement is generally not desirable, but could be achieved by addition of weighting additives to the standard 15 lb. per gallon neat cement slurry. The magnitude of casing buoyancy at various stages of the cement job, particularly the final displacement phase, determines if the casing is in tension, neutral or in compression (axially). This must be considered in casing material selection and operation planning to assure the casing is not damaged or "floated" out of the well during cementing operations.
 - Casing compressive strength (axially) is important only in consideration of buoyant forces which may arise during cementing, as described above. If subject to sufficient compressive forces, the casing may "buckle" or the casing material may be sufficiently damaged to cause leakage or even parting. (P.V.C. casing is more prone to buckling, whereas FRP is prone to material damage; metal casing seldom suffers from buoyancy-related problems due to its much greater weight and strength.)
- + Corrosion Resistance
- Cement corrosion in a sulfuric acid environment occurs by dissolution of components of Portland type cements, resulting in loss of strength and weight. A coating forms on corroding cement surfaces during this process, thus retarding the corrosion rate. Acid strength, flow velocity and cement composition are the primary variables in this process. Corrosion of the cement sheath around well casing in ISL operations is generally confined to areas in the immediate vicinity of flow into or of the formation, generally through perforations or slots which penetrate the casing, cement and formation. This does not

pose a flow control problem, since flow across the casing/cement boundary is desirable at these points. Experience in operations of ISL test wells has indicated that cement sheath corrosion does not occur at a rate sufficient to affect fluid seal or mechanical integrity of the cement (except possibly near perforated or settled areas which are exposed directly to flow of leaching fluids), during periods associated with the expected well life. These observations have been supported by geophysical logging and pressure transient analysis. For these reasons more exotic and expensive cementing materials such as "synthetic cements" are not considered necessary for proper cement performance in this environment, over the required periods of time for I.S.L. mining. Some types of cements, notably Portland type V, are more resistant to attack by sulfates than other types. Casing corrosion resistance is covered in the preceding section ("Casing Design").

+ Geologic factors

- Cement loss to the formation by means of natural or induced fractures. Drilling experience and geophysical logging may indicate presence of high conductivity natural fractures. Additives (fluid loss and density), careful pressure control, cement baskets and stage cementing are methods which can be used to alleviate this problem. Whole cement is not lost to the formation through porous high permeability zones, (as true liquids may be) due to the formation of a "filter cake" of cement particles on the permeable zone.
- Knowledge of the formation's hydraulic fracture gradient is desirable, in order to avoid exposing the formation to pressures in excess of this gradient, which may result in cement loss to the induced fractures. As a general rule, fracture initiation gradients vary from as high as 3.6 psi per ft. at shallow depths to as little as 0.7 psi/ft. at greater depths. For ISL design purposes, a gradient of approximately 1.0 psi/ft. can be used in most cases, if the actual gradient is unknown. Methods of preventing this type of cement loss are similar to methods for avoiding loss to natural fractures. Low density cement and low displacement rates and pressures are commonly specified.
- Water inflow experienced during drilling is usually an indicator of high permeability zones which may present a cement loss problem, as discussed above. Due to the relatively greater density of cement compared to water, cement hydrostatic pressure is likely to be greater than water (formation) pressure, thus diminishing the chances of significant cement dilution.

- Clay layers, if composed of swelling or plastic clays may expand into the hole and either form a seal in the casing-hole annulus, or damage the casing (or both), prior to cementing. Formation of such a seal would prevent flow of cement past the annular obstruction, possibly resulting in excessive displacement pressures and/or having the casing partially filled with cement which could not be displaced. This problem is best avoided by avoiding use of fluids which would cause clay expansion during drilling, and performing casing and cementing operations as soon as possible following drilling. Similar problems and solutions apply to the case of running (unconsolidated) sand layers or other types of hole instability.
- Drilling circulating fluid usually forms a filter cake or other coating on the hole wall (even in the case of foam drilling). In order to achieve good bonding of cement to the hole wall and casing, this drilling fluid and filter cake must be removed prior to cement displacement. In the case of mud drilling fluid systems, common practice involves circulating the mud, while lowering its density and viscosity ("thinning") by use of additives or water. This leaves the hole full of fluid with more desirable characteristics for cementing operations, in addition to confirming that no annular blockage exists, to reducing filter cake strength and thickness somewhat. This operation is usually followed by introduction of a fluid designed to remove the mud and filter cake completely. Since such removal contributes to hole instability, this fluid volume is kept to a minimum, and followed by a small fluid "spacer" or sometimes directly by cement slurry. The cement slurry is followed directly by the cementing plug and the displacement fluid, to force the slurry out of the casing. From the time the mud thinning begins until cement displacement ends, it is desirable to continue pumping. Cement displacement may be designed to result in turbulent, laminar or plug flow within the casing-hole annulus, depending primarily on cement viscosity, formation fracture gradient and casing pressure rating. It is desirable to use turbulent flow if possible, since it results in better filter cake removal than the other flow regimes. Reciprocation and rotation of the casing are also desirable for filter cake and mud removal, if practical. Use of volumes of cement in excess of annular volume requirements helps assure good cement quality by displacing out of the annulus the initial volume of cement which may have mixed with mud and other cementing fluids. Some of these procedures may be omitted in cementing a hole drilled with air or foam, which forms a much weaker filter cake.
- Mix water quality should always be determined prior to mixing the cement, since large variations in strength, setting time and other properties may result from mix water impurities.

- Regulatory requirements depend largely on location, local hydrology and intended well use. Regulatory requirements should be understood prior to cementing design; these may include items such as cement type, isolation of specific zones, cement bond logs, casing pressure integrity tests, etc.

- o Cementing Design Procedures

Following is a discussion of cementing design procedures appropriate to ISL copper mining. These procedures are suitable for cementing of wells designed in the range of conditions previously specified in the generic ISL manual.

Due to the large variety of variables associated with cementing design, only basic procedures are discussed here. Site specific designs should utilize the experience and capabilities of specialists knowledgeable in this aspect of well installation. The following procedures assume well sizes and casing specifications described in previous sections, and geologic conditions which do not pose special problems.

- + Casing equipment, as described previously, is located on the casing according to hole diameter variations, and geologic conditions.
- + Cementing material is designed to achieve desired density, setting time, corrosion resistance, viscosity and fluid loss characteristics. Technical assistance is very valuable here. The generic manual assumes use of cement with characteristics similar to Portland type V or API class A or B, depending on sulfate resistance desired (type V is best) and availability and cost restraints (API class A or B is less expensive and often easily available). Corrosion resistance may be enhanced by addition of small amounts of additives as described previously. Cement slurry density of approximately 11 lb. per gallon is assumed in order to avoid placing the FRP casing in compression by buoyant forces. This low density is achieved by use of hollow microsphere type additives which are available commercially. (Other less expensive lightweight additives such as perlite, gilsonite, pozzolan, bentonite, etc. will not achieve sufficiently low density without greatly sacrificing strength and/or greatly increasing set time.) Thickening and setting time can be controlled by use of retarders or accelerators, as can viscosity and fluid loss characteristics be controlled by suitable additives. Cost for this cement material

is estimated to be within the range of 10 to 20 dollars per cubic foot, for model purposes. An excess cement volume of 20% is also assumed.

- + Preflush, spacer and displacement fluids are selected for compatibility with existing well fluids and site geology. Costs for these fluids are considered negligible for modelling purposes.
- + Fluid flow regime (turbulent, laminar or plug) is determined, based on filter cake removal requirements, site geology and casing pressure ratings, as described previously. Since this is primarily a matter of pumping pressure and rate, costs associated with this are assumed to be incorporated in the average installation costs as \$4 per ft³ for blending cement and a fixed set-up charge of B_{FCS} .
- + Cement mixing and sampling are accomplished by either batch or jet mixing, continuous density monitoring and periodic grab sampling in suitable containers. Continuous records of density, pressure, rate and cumulative volume versus time are often available from cementing contractors. Grab samples are useful primarily as only general confirmation of cement set time and quality, since downhole conditions are much different than surface conditions during the setting period.
- + Curing time ("wait on cement," or W.O.C. time) is usually specified as no less than 8 hours and usually no longer than 24 hours, depending on materials and conditions. During this time no work should be done on the well which may affect cement setting, such as causing shock, vibration or pressure surges within the casing. Casing fluid pressure should be released and backflow monitored to assure float valve operation prior to leaving the wellsite, as described earlier.
- + Bond logs may be desirable or required by regulation, to confirm good cement integrity. For the generic model it is assumed that only one fourth of all installed wells will be so logged. Costs for this are included in the "well logging" section.

o Costing

Equation (4.24) relates cementing costs to hole dimensions and unit costs. Refer to Table 4.14 for values of d_H and d_c as a function of flow rate per well. B_G values range between \$10 per ft³ and \$20 per ft³, depending on cement type.

$$C_{CM} = \frac{\pi D}{576} (d_H^2 - d_c^2)(B_G + 4) + B_{FCS} \quad (4.24)$$

4.4.1.6 Well Completions

Well completions describe mechanical methods of achieving fluid transmission into and out of the well, and are interrelated to "matrix modification" techniques applied for purposes of improving the fluid transmission rate or developing fluid flow patterns ("Flow Regime") between injection and production wells. The matrix modification methods are discussed in 4.4.1.7.

Selection of an appropriate well completion method is a function of wellfield design based on fluid flow and leaching efficiency, economic considerations and the wellfield operating plan. For the purposes of developing a generic design, a variety of assumptions are made which allow a general mine operating plan to be used. The effect that these assumptions have on well completion design often dictate leaching of a large volume of ore by using a single, large-scale completion treatment. In absence of these assumptions (primarily rock homogeneity, and isotropy), the preferred approach would usually be to leach similar volumes of ore in several shorter time periods, utilizing a greater number of smaller-sized completion treatments. The cost differences in these approaches appears to be small, thus allowing the simplified approach to reflect reasonable costs and operating schedules for use in the generic model.

Fluid flow in an ISL wellfield is controlled by points of high pressures (injector well completions) and low pressures (recovery well completions), distance between these pressure sources and sinks, and properties of the rock transmitting these fluids (primarily permeability). Two types of fluid flow geometry are assumed for generic modeling purposes, those being radial or axial. Radial flow will result

from merely providing a means for fluid to flow into or out of the well, and is limited by well diameter and rock permeability, among other things. Radial flow may be enhanced by "stimulation" techniques which provide an enlarged "effective wellbore radius," by altering near-wellbore rock permeability, usually by fracturing methods. Axial flow is established by creating two parallel planes having higher fluid conductivity than the surrounding rock, and applying a pressure difference between these planes. No additional stimulation or "matrix modification" techniques are considered for axial flow completion. Explosive stimulation of hydrofractures have been performed and reported (28), but are not considered necessary or desirable for ISL operations. Borehole blasting is discussed in 4.4.1.7.

- o Open Hole completion is the simplest type of ISL well completion, involving only an open hole drilled through the ore zone, below the well casing bottom. This method is seldom used unless the ore is very competent rock, unlikely to cave or produce fines during operation. A variation of this type of completion is underreaming, or drilling a larger diameter hole below the casing point. Underreaming is actually a stimulation method which serves to increase flow into or out of the well by increasing the wellbore radius. Since only minor wellbore radius increases are possible by underreaming, and it is an expensive and risky procedure in hard rock at depth, it is not included among stimulation methods suitable for the generic model. The associated open hole completion costs are included in the drilling costs of the well.
- o Screened completion is a variation of the open hole completion in which a well screen is installed below the cased portion of the well. The screen serves to prevent the open hole portion of the well from filling up with debris from the formation, and prevent production of fine particulates with the well fluids. Screens are often used with a designed sand filter or "gravel pack" to provide additional hole support and filtration(29). Screened completion cost estimates for the generic model involve only well screen cost (B_w) and drill rig installation time (B_d). The cost per well is given by (4.25). B_w values are listed in Table 4.14.

$$C_{sc} = H(B_w + B_d/R_{cs}) \quad (4.25)$$

- o Perforated completions involve opening an interval of cased well to the formation by means of installing multiple holes through the casing and cement sheath. Several methods of casing perforation exist, such as mechanical tools, hydraulic tools utilizing abrasive slurries, bullet types driven by propellant charges and jet types, utilizing shaped explosive charges. The jet perforation method was selected for use in this design. Due to availability, good penetration (up to 12 inches into the formation), relatively rapid and economic installation and acceptable perforation hole size (up to 1/2 inch diameter). Costs are based on use of 4 jet shots per foot of perforated casing, using jets which deliver perforation sizes and depths similar to that described above, and are fired from a hollow carrier type device to avoid shock-related damage to FRP casing. Experience with similar systems indicates adequate performance without detectable casing damage. Costs associated with perforated completions include jet cost (\$6/foot based on \$1.50/jet and 4 jets/foot) and wireline contractor setup costs (B_{ps}). The cost per well is given by (4.26).

$$C_p = 6H + B_{ps} \quad (4.26)$$

4.4.1.7 Matrix Modification

- o Explosive Stimulation methods rely upon high explosives or propellants to create a series of fractures extending from the wellbore to increase near-wellbore permeability. Various techniques have been developed by the petroleum industry for application of explosive stimulation in wells. These methods include nitroglycerin-filled torpedoes, sand-stemmed high explosive devices (30), (31) and liquid-stemmed high explosive devices (34). The primary difference in these techniques appears to be the use of either high explosives or propellants. High explosives are distinguished from propellants by their much faster pressure rise time, their uncontrolled burn rate (detonation) and the detrimental effect on well components from the resulting shock wave. In order to avoid well casing and equipment damage, high well cleanout and repair costs and to achieve greater stimulation effects, only propellant based stimulation methods are considered for the generic model. Experimental work has indicated that propellant based "high energy gas fracturing" HEGF techniques can greatly improve near wellbore permeability without substantial damage to well components. The near-wellbore rock particle crushing and associated generation of fine particles which is believed to reduce permeability in high explosive stimulations is absent in HEGF stimulations. (32), (33), (34), (35)

The literature indicates that HEGF is likely to provide wellbore enlargement up to a 16 foot radius. Since no data exists for the use of HEGF in copper bearing rock an 8 foot radius for

wellbore enlargement is used here. The costs cited in this design are based on an average of the range of depths and well diameters proposed. Following is a brief description of HEGF stimulation procedure. The stimulation propellant charge is designed based on site parameters such as well diameter, depth, rock strength and well fluid properties. The device is lowered into the well on a wireline and positioned opposite the desired interval. The propellant devices are available in a variety of lengths, but long stimulation intervals require a number of tool runs. A calculated amount of well fluid must be present above the interval to act as "stemming" to confine the resulting gas pressure. Upon initiation of the propellant, pressures rise to levels sufficient to initiate fractures in the rock. Gas generated by the propellant flows into these fractures, extending them radially outward from the well and also transports some formation particles into the fractures. Photographs of HEGF stimulated wells (33) and mineback experiments (32) indicate these induced fractures radiate outward from the well in several directions, apparently unrelated to local rock stress conditions. Only minor amounts of metallic "junk," resulting from tool disintegration, remain in the well following stimulation. In order to perform HEGF stimulation, the desired casing interval must first be perforated. Perforation costs must be added to stimulation costs. HEGF stimulation costs per well consist of: fixed engineering and wireline service company set up charges, estimated at \$2800; and propellant, labor, and wireline costs per foot of ore interval, estimated at \$235/foot. The cost per well is given by (4.27).

$$C_{ex} = B_{EXS} + 235H \quad (4.27)$$

- o Short-Radius Hydraulic Fracture Stimulation involves creation of a number of small propped hydraulic fractures in the stimulated interval. The stimulation effect of these fractures is primarily related to their radius. A variety of methods are available for calculation of this effect (36), and hydrofracture design (37) (contractor participation in design is recommended).

The principle of hydraulic fracturing is thoroughly described in the literature (38). It primarily involves hydraulic pressure to overcome local in situ rock stress to initiate and extend fractures into the rock mass. The fluid can also be utilized to transport sand or similar materials into the fracture to prevent closure upon release of hydraulic pressure.

A procedure for installing a series of short radius hydraulic fractures in a perforated casing interval involves the following sequence:

1. Isolate the casing interval to be stimulated by use of tubing and packer equipment and suitable plugging techniques below the interval if necessary.

2. Rig up fracturing contractor equipment on the surface.
3. Initiate fracture utilizing proppant-free fluid (often water); record fracture initiation pressure.
4. Following initiation continue fracture extension using fracturing fluid designed for maximum efficiency in the site geologic environment.
5. Introduce suitable proppant into the fracturing fluid at concentrations designed to yield effective proppant transport and deposition within the fracture.
6. Upon pumping sufficient fluid and sand volume the treatment is either stopped or sand mixing is stopped and ball sealers are utilized to block fracturing fluid flow into perforations which are accepting flow (connected to fractures), to divert the flow to other perforations. This sequence is continued until the desired number of fractures have been initiated. Evidence of fracture initiation is a sudden drop in pressure, usually shown on a chart pressure vs. time recorder.
7. Upon completion of fracturing the well is shut in, allowing fracturing pressure to bleed off over a period of time. Fluid backflow out of the well is undesirable since it may remove some of the proppant from the induced fractures, prior to formation.
8. After a suitable time following pressure bleedoff, chemicals within the fracturing fluid will reduce its viscosity (often by "breaking" polymer chains). At this time it is allowable to open the well and perform recovery or injection operations, or flow tests to evaluate fracture performance.

The generic model assumes installation of parallel circular hydraulic fractures of approximately 8 ft. radius, one for each 5 vertical feet of stimulation interval height. For site specific designs it is possible that significant cost reductions would result from altering either of these stimulation designs. The formula for predicting small radius hydrofracture stimulation cost is given by (4.28). Table 4.15 lists cost data used to develop (4.28).

TABLE 4.15. COST DATA SHORT RADIUS HYDRAULIC FRACTURE

| COST ITEM | \$ COST PER FRACTURE | DERIVATION |
|----------------------|--|---|
| <u>MATERIALS</u> | | |
| Frac. Fluid | 0.95 | 0.08\$/Gal x 0.06 Gal/ft ² x 198 ft ² |
| Proppant Sand | 11.52 | 0.06\$/lb x 0.97 lb/ft ² x 198 ft ² |
| Ball Sealers | 0.20 | 0.10 \$/ea. ÷ 0.5 efficiency |
| <u>EQUIPMENT</u> | | |
| Pumping | 37.62 | 0.19 \$/ft ² x 198 ft ² |
| Blending | 19.80 | 0.10 \$/ft ² x 198 ft ² |
| Total Variable Costs | 70.09 \$/Frac | |
| Variable Costs 1 Ft. | = (70.09 \$/Frac) ÷ (5 Ft/Frac) = 14.02 \$/Ft. | |
| <u>FIXED COSTS:</u> | | |
| Equip Setup | 1900\$/Well | |
| Personnel | 600\$/Well | |
| | 2500\$/Well | = B _{SRS} |

$$C_{HS} = B_{SRS} + 14H \quad (4.28)$$

- o Large Radius Hydraulic Fracturing. The purpose of axial flow in ISL operations is to increase leaching well flowrates in low permeability rock without reducing well spacing to uneconomic levels. The concept is to create parallel fractures of high permeability and large areas, separated by a specific thickness of the lower permeability ore. The large fracture area exposes an equally large surface area of ore to leaching fluids and pressures, while the high permeability of the installed fractures allows fluids to be conducted into and out of the fractures at sufficiently high rates. The amount of flow into a fracture through the ore and out of the adjacent fracture into another well is a function of fracture permeability, ore permeability, ore thickness (distance between fractures), pressure difference across the fractures, and fluid viscosity (as explained in the wellfield design section of this manual). This section deals only with installation of the fractures, comments on their permeability and spatial orientation and cost predictions.

The principle utilized is hydraulic fracturing. Since this method is generally believed to produce a single large, planar fracture, as opposed to many smaller fractures of random orientations produced by "explosive" techniques. Hydraulic

fracturing theory holds that since a rock mass has low or no tensile strength, a fracture may be created by overcoming the smallest force which holds the rock mass together, by application of sufficient hydraulic pressure to the rock mass. Orientation of the resulting fracture plane will therefore be perpendicular to the direction of the smallest confining force (least principal stress axis).

In a tectonically relaxed geologic environment, the least principle stress axis theoretically changes gradually from vertical to horizontal at depths between approximately 1000 and 3000 ft. In order to avoid ambiguity and to simplify the generic model, the fracture orientation is user-specified as either horizontal or vertical.

Further assumptions utilized in the model include: insignificant friction drop for flow within the fractures; circular and symmetrical fracture geometry; and the ability to create sufficiently large-radius fractures to meet wellfield design specifications.

High fracture permeability is achieved by installing a thickness of uniformly sized, well rounded proppant, (sand or other materials) to prevent closure of the fracture by natural forces. This proppant layer has much greater permeability than the surrounding rock.

Installation procedures for large radius hydraulic fractures are generally similar to procedures described previously for hydrofracture stimulation. Exceptions are:

1. For horizontal fractures a larger opening into the formation than the perforations provide is desirable for friction reduction and fracture localization. This can be a slot cut through the casing and cement sheath by a hydraulic abrasive jet tool
2. Since only one fracture plane is desired, the process is not stopped or interrupted by use of ball sealers
3. The large-radius design may require contractor pumping and blending equipment suitable for relatively larger flowrates and (possibly) higher pressures.

Equations (4.29) and (4.30) are used to estimate costs. These relationships are derived from experience with the formation of a fracture of radius of 100 feet, where the cost per area of fracture face was known, see Table 4.16.

$$C_{HC} = \left[B_{LRS} + 0.41 S^2 \right] \left[\frac{H}{2H_c} + \frac{N_p}{N_w} \right], \text{ horizontal fractures} \quad (4.29)$$

$$C_{HC} = B_{LRS} + 0.41 S_2 H, \text{ vertical fractures} \quad (4.30)$$

TABLE 4.16. DERIVATION OF COST ALGORITHM FOR
LARGE RADIUS HYDRAULIC FRACTURING

| Item | Unit Cost (\$/ft ²) of Fracture Area | Derivation (from 100 ft radius design) |
|--------------------|---|---|
| Materials | | |
| Frac. Fluid | 0.06 | (19,000 gal x 0.08 \$/gal) ÷ (π 100 ²) |
| Sand Proppant | 0.06 | (30,000 lb x 0.06 \$/lb) ÷ (π 100 ²) |
| Equipment | | |
| Pumping | 0.19 | \$6034 ÷ 31415 ft ² |
| Blending | 0.10 | 3108 ÷ 31415 ft ² |
| TOTAL | 0.41 | |
| Fixed Costs | | |
| Equipment Setup | 1900 | For horizontal fractures the cost per well equals the cost per fracture times the fractures per well $\left[\frac{H}{2H_c} + \frac{N_p}{N_w} \right]$ |
| Personnel | 600 | |
| Slot Installation | 2500 | |
| TOTAL | 5000 = B_{LRS} | |

4.4.1.8 Logging

Wireline geophysical logging, in addition to being used in geologic data gathering, is used in well drilling, installation, completion, leaching, and repair operations, as the principal diagnostic quality assurance test.

Following is a brief discussion of the types of logging operations and information which will support a commercial ISL operation.

- o Drilling operations are assisted by caliper logs which indicate hole size variations which may be associated with caving and washouts or diameter reductions commonly associated with clay layers. Temperature logs may be used to detect zones of fluid loss or water inflow, as may certain other tools. Hole straightness and deviation are indicated by downhole directional survey tools, some of which are commonly run on nonelectric wirelines.

- o Geologic and Hydrologic information is supplied by a wide variety of logging tools and methods which measure a variety of responses to active and passive geophysical measurements. A brief summary of common tool is provided below and discussed in more detail in Chapter 7.

| Geophysical Property Measured | Physical Property Inferred |
|--|---|
| - Electrical resistance or conductance | Degree of Fluid saturation and fluid characteristics. |
| - Electrical "Self-Potential" | Degree of invasion of drilling fluids into the rock; rock and fluid characteristics, lithology changes. |
| - Temperature and differential temp. | Geothermal gradient and changes in gradient. |
| - Sonic velocity and 3-D seismic | Rock mechanical properties, fracture density and orientation. |
| - Gamma density | Rock density, lithologic change, porosity. |
| - Neutron (thermal) | Fluid saturation, porosity |
| - Downhole flowmeter (spinner) | Fluid velocity, entry into and exit from well. |
| - Radio-isotope (Tracer) | Fluid flow within and near well; entry and exit locations. |
| - Caliper | Hole diameter and variations. |
| - Pressure | Analysis of pressure transient data indicates rock permeability, type of flow, flow barriers, etc. |
| - Downhole Televiewer | Observe (visually) well conditions. |

- o Well Installation utilizes temperature and cement bond (sonic) logs to indicate quality of cement setting as indicated by variations in temperature from cement hydration, and quality of bonding to casing and formation by seismic methods. Caliper logs indicate locations for placement of casing equipment such as centralizers, and indicate cement volume requirements.

- o Completion operations utilize logs to verify mechanical condition of the well such as amount of bottom fill, casing slot width and depth and definition of perforated intervals. Flow into or out of the casing can be located and measured by temperature, flowmeter and radioisotope tools. Rock mass permeability and near-wellbore permeability reduction or enhancement can be calculated by analysis of pressure transient tests. Downhole televiewer can be very useful, if available, for observation of casing condition.
- o Leaching operations may require definition of flow rate variation with depth (flow profile) within a long perforated casing interval in order to optimize operations by attempting to alter the profile. Flowmeter, temperature and radio-isotope tracer logs (often referred to as "production logs") may be utilized for this. In some instances detection of temperature anomalies and low level gamma radiation (if radio-isotopes are utilized) may be used to detect fluid flowing past, but not entering the well.
- o Well Repair usually implies correction of well installation inadequacies such as localized poor cement bonding or absence of cement behind casing, casing damage, retrieval of stuck or dropped downhole equipment, or alteration of existing well completions. Repair of high permeability flow paths ("short circuits") between wells or from a well to some other undesirable location may also be required. Production logging tools in various combinations are usually utilized in analyzing downhole conditions prior to designing repair operations and after repairs, for evaluating post-repair performance.

Detailed analysis of these logging methods is beyond the scope of this manual. References to log analysis literature are found in Chapter 7. Some analysis methods require modification to account for use of lightweight cement, FRP well casing, and non-sedimentary host rock characteristics. Frequently, log calibration is based on sedimentary rock which commonly form petroleum reservoirs.

Costs associated with logging include setup and tool charges (fixed) and depth related charges (variable). Experience indicates that running a full set of lithology, drilling, and other logs as described above, for ISL wells averaging 1000 ft. in depth, will exceed fixed costs of \$12,000 for multiple setup and tool charges. Depth dependent

costs for many logging operations at these depths represent only approximately 20% of fixed costs. Assuming that a commercial ISL well will require approximately one fourth of the logging activity associated with test wells, and that costs for diagnostic logging associated with well repair are included in the wellfield maintenance budget, the following cost algorithm was developed for initial well installation. Site specific logging costs may vary greatly depending on contractor charges, mobilization costs, information requirements, etc. Based on the experience of R.V. Huff and Associates, the cost per well is given by (4.31).

$$C_{WL} = B_{FWL} + 2.7 D \quad (4.31)$$

4.4.2 Vertical Wells Drilled From Underground

Well systems consisting of vertical wells to be installed and operated from underground workings are identical to vertical wells installed from the surface, in terms of design procedures, system components and sizes, materials of construction, drilling methods, completions and logging operations. Primary differences are equipment limitations imposed by the much smaller and more confined well sites underground. These limitations dictate use of smaller drilling machines; shorter tubing and casing joints; smaller logging, cementing and fracturing equipment. In addition, actual operations involve a great deal more delay and inconvenience than associated with surface access operations.

Underground access operations benefit from reduction in costs associated with shorter overall well lengths, and require higher unit costs for most well installation operations, in addition to the cost of

installing underground workings. The following sections briefly describe the changes in well costs associated with underground operations, employing the same design and installation procedures for surface operations described in Section 4.4.1. Well depth for underground vertical wells is equal to deposit thickness (H).

4.4.2.1 Drill Site Development

Drill site development consists of enlarging the size of the existing underground opening from approximately 12 ft X 12 ft to a larger cross section, particularly increasing the vertical dimension to allow use of drilling and service rigs with reasonable mast heights. It is assumed that a suitable drill site can be provided at a cost of approximately \$5000.

$$C_A = 5000 \quad (4.32)$$

4.4.2.2 Well Equipment

Underground well installations require the same equipment and materials of construction, operate at similar pressures and flow rates, within the same casing sizes as surface-installed wells. The only change in equipment involves use of shorter joints of tubing, necessitated by drill site height limitations underground. The remaining packer, pump, wellhead, and fluid level indicator equipment is essentially unchanged from surface installation specifications. For vertical well modeling purposes, it is assumed that submersible pumps will lift the produced fluid to the surface, without aid of transfer pumps. This allows pump designs and costs to remain unchanged from those shown in Section 4.4.1.

The equations for estimating costs for injection and production in well equipment are modified for underground access use by increasing tubing cost by a factor of 2.2 to account for the shorter, more expensive tubing joints.

- o Injector Well Equipment:

$$C_{WEI} = (D-H)(2.2B_t + B_I) + B_k + B_h + C_{PM} \quad (4.33)$$

- o Producer Well Equipment:

$$C_{WEP} = (D-H)(2.2 B_t + B_{RPW} + B_{WLT}) + (HP_L)(M_x + 92) \\ + B_{xq} + B_{RPC} + B_h + B_{PI} \quad (4.34)$$

Cost factors associated with various well sizes are listed in Table 4-8.

4.4.2.3 Well Casing

Underground access casing design and sizes remain unchanged from surface access design (Section 4.4.1). Casing costs are increased by a factor (2.2) to reflect use of more expensive 10 to 12 ft. long pup joints underground, as opposed to the 30 ft. joints commonly used in surface access operations. Other costs associated with cementing equipment remain unchanged. Higher cost of casing installation is reflected by changing the installation rate from 130 ft per hour to 65 ft per hour. Casing costs are calculated using (4.35).

$$C_c = H \left(2.2 B_c + \frac{2B_d}{R_{cs}} + B_B \right) + B_{wc} \quad (4.35)$$

4.4.2.4 Drilling

Drilling operations in the restricted space will have to utilize shorter drill rods and specialized drilling equipment, probably powered by compressed air or electricity. This will most likely result in higher average hourly drilling costs. This is accounted for by assuming a 2-to-1 reduction in the drilling rate. Values for contractor hourly cost (B_d) and surface drilling rate (R_d) are listed in Table 4.14.

$$C_d = 2 \left(\frac{B_d \cdot H}{R_d} \right) + C_{AU} \quad (4.36)$$

4.4.2.5 Cementing

Cementing holes underground will utilize the same materials and procedures as cementing from the surface (as described in Section 4.4.1). Pumping and mixing equipment will require modification for underground operation, or utilization of a very long string of high pressure pipe to enable pumping and mixing equipment to remain on the surface. The generic model assumes that all equipment will be located underground and increases fixed costs from \$1425 to \$5000 to account for the additional expense associated with underground operations. The following equation is used to predict underground cementing costs:

$$C_{cm} = \frac{H\pi}{576} \left(d_h^2 - d_c^2 \right) \left(B_g + 4 \right) + B_{FCU} \quad (4.37)$$

4.4.2.6 Well Completions

Design and application of completion methods for underground access is identical to that for surface access, as described in Section 4.4.1. As for other aspects of well installation, additional costs will be

incurred, arising from specialized equipment and additional costs of operating underground. Following are comments on individual underground completion costs:

- o Open Hole

No costs are associated with this type of completion.

- o Screened

Costs differ from those installed by surface access only in increased installation costs associated with lower installation rates.

$$C_{sc} = H \left(B_w + \frac{2B_d}{R_{cs}} \right) \quad (4.38)$$

- o Perforated

Underground access costs reflect an increase in setup and operating time, but reflect identical costs per foot of perforation as surface access costs:

$$C_p = 6H + 2B_{LS} \quad (4.39)$$

4.4.2.7 Matrix Modification

- o Explosive Stimulation

Underground access costs reflect only an increase in setup and operating time over surface costs. It should be noted that this stimulation method may prove impractical for application immediately below the well collar due to lack of a sufficient column of liquid or other stemming material to confine the generated energy. Damage to underground openings could also result. Costs are projected by the formula:

$$C_{ex} = B_{EXU} + 235 H \quad (4.40)$$

- o Short Radius Hydrofracture Stimulation

Application, design and installation procedures remain unchanged from those by surface access described in Section 4.4.1. Equipment modifications and setup will add costs to the procedure performed underground, as reflected in the formula below. Due to possible local rock stress field changes resulting from installation of underground workings, problems could arise from use of this stimulation technique immediately below the access drift. These problems are probably related

more to loss of efficiency of the stimulation than to damage to the tunnel.

$$C_{HS} = B_{SRU} + 14 H \quad (4.41)$$

o Large Radius Hydrofracture

Application design and installation procedures for underground access are the same as for surface access as described in section 4.4.1. Equipment modification and setup charges have been incorporated into the cost formula below. Setup charges are assumed to be twice the cost for surface drilling.

+ Horizontal fractures

$$C_{HC} = \left[2B_{LRS} + 0.41 S^2 \right] \left[\frac{H}{2H_c} + \frac{N_p}{N_w} \right] \quad (4.42)$$

+ Vertical fractures

$$C_{HC} = 2B_{LRS} + 0.41 S_2 H \quad (4.43)$$

4.4.2.8 Logging

Wireline logging applications are expected to be the same underground as by surface access. Specialized equipment, suitable for work underground, will be required. Setup and operating time is predicted to increase underground as reflected by a cost factor of 1.5; depth-dependent costs should remain unchanged. Generic model costs are estimated from (4.44), which contains the same unit cost factors used for surface drilling:

$$C_{WL} = 1.5(B_{LS}) + 2.7H \quad (4.44)$$

4.4.3 Fan Wells

In the fan concept, small diameter holes are drilled radially in parallel drifts running underneath the ore zone to be leached. Fluid is injected in one fan pattern and flows parallel to the crosscut to another fan. Leachate is collected by gravity from the fans and the

crosscut. In orebodies having a considerable vertical thickness of ore, one or more additional levels is used to gain access. A reasonable height for a fan is 100 feet.

For the case of fan drilling, a mine level would be placed directly under the orebody, with the fan patterns drilled upward into the ore. The holes would be a nominal 4 inch, drilled with a down-the-hole hammer rig. The 4 inch hole is thought to be a reasonable size for installing well equipment such as tubing and packer, and yet provide an economical drilling rate. A hole length of 100 feet has been chosen for the model. For this length hole spacing can be accurately controlled, and the distance between holes at the outer radius of the fans is thought to be close enough to prevent poor sweep of the ore. Injection holes are to be equipped with tubing, packer, wellhead valve and a flow meter. Production holes are not equipped, since pregnant liquor can drain by gravity. No casing or cementing is planned in these holes. An equation has been developed for determining a cost effective number of drill holes per fan by calculating the fan dimensions that maximizes the flow rate per cost of wells and mining. The derivation and determination of optimum conditions is discussed in Section A.5 of Appendix A. 11 holes per fan at a fan spacing of 60 feet corresponds to optimum conditions. This well density is likely to provide adequate sweep efficiency.

Drill rigs for percussion drilling of the fans are not expected to be as large as the rigs used for the vertical patterns. Drift sizes of 12 feet x 12 feet and 10 feet x 10 feet are thought to be reasonably sized drifts for vertical drill development and fan pattern development, respectively. Collection of pregnant liquor is by gravity drainage from

the fan patterns and the back and ribs of the crosscuts. A utility level may be considered below the level of the fans to allow for collection of fluids, power distribution, ventilation and escape. In the case where the ore thickness is substantially greater than the fan height, multiple levels of crosscuts are used to develop the orebody. The number of levels is given by (H/h) .

Matrix modification is not considered for fan pattern leaching because the cost of stimulating is thought to be much more expensive than drilling and completing the number of holes in the fan patterns. In addition, matrix modification applied to closely spaced wells could significantly alter the mass of ore between the holes from its true in situ state. Hydraulic fractures may also intercept the mine workings, causing short circuits.

Costs for one fan module (pattern) are the sum of injection and production well costs.

o Injection wells

The number of injection wells is half the total wells per fan face (N_{TF}). Total costs of injection wells for one face is given by (4.45), where C_{wfi} is the average cost per foot for completed well.

$$C_{EWI} = \left(\frac{N_{TF}}{2} \right) C_{wfi} h \quad (4.45)$$

o Production wells

Production well costs are given by (4.46), where C_{wfp} is the cost per foot of the completed well, essentially the drilling cost.

$$C_{EWP} = \frac{N_{TF}}{2} C_{wfp} h \quad (4.46)$$

Taking C_{wf} as the average cost per foot for a pair of injection and production wells the cost for one fan pattern is C_{EWF} .

$$C_{EWF} = N_{TF} \cdot C_{wf} \cdot h \quad (4.47)$$

Drilling costs are estimated at \$10 per foot. Since the production well does not contain any equipment C_{wfp} equals \$10 per foot. For the injection well additional costs of \$1600 for a packer and \$400 for 3.2 inch O.D. FRP tubing are estimated. This results in a cost of \$30 per foot for C_{wfi} . Averaging the fan costs yields a value of \$20/foot for C_{wf} . For a 100 foot drill hole, and 11 wells per face (optimum \$ per gpm) the cost of one fan pattern is \$22,000.

4.5 WELLFIELD COST

Total wellfield costs are divided into two components: those that are only a function of the ore volume contained between the wells, and those that are specific to the type of well pattern used. The former are discussed as wellfield start-up and shut-down, the latter as: vertical well drilling from the surface; vertical well drilling from the underground; and fan well drilling from the underground.

4.5.1 Wellfield Start-up and Shut-Down Costs

o Wellfield start-up

Each time a new wellfield is started up it is assumed that no saleable cathode is available until one pore volume displacement has taken place. During this time all operating costs are incurred. This start-up time is t_{WH} . The algorithm for t_{WH} is given in Table 4.5. During this time no saleable copper is available, and tons T_{LH} are

subtracted from the annual production in each a year a wellfield is started-up

$$T_{LH} = Yt_{WH} = 1.42 \times 10^{-9} A_w H \phi (E_H / Q) \quad (4.48)$$

o Wellfield water make-up

Each time a new wellfield is brought into production it is assumed that it will be 100% saturated. These require water make-up volume to attain 100% saturation if the ore zone is not initially saturated. The algorithm for this make-up volume is provided in Table 4.5 as GA.

$$EP_{ww} = (GA) (C_7) = 7.48 \times 10^{-4} A_w H \phi (100 - s_w) C_7 \quad (4.49)$$

o Wellfield restoration

Each time a wellfield is taken out of production it is assumed that restoration costs will be incurred. These costs are represented as a % (x_1) of the wellfield start-up costs.

$$EP_{ws} = (x_1 / 100) (t_{WH}) (EP_o) \quad (4.50)$$

4.5.2 Vertical Wells Drilled from the Surface

The total wellfield cost is the product of the number of injectors (N_I) times the cost of an injection well C_{EWI} plus the sum of the producers $(N_I^{1/2} + 1)^2$ times the cost of a production well. N_I equals the total system flow rate divided by the injection well rate.

o Wellfield Well Costs

$$EW_w = (Q/q_I) C_{EWI} + ((Q/q_I)^{1/2} + 1)^2 C_{EWP} \quad (4.51)$$

o Total Initial Wellfield Costs

$$EW = EW_w + EP_{ww} \quad (4.52)$$

o Replacement Wellfield Costs

$$EW_{PR} = EW + EP_{ws} \quad (4.53)$$

4.5.3 Vertical Wells Drilled from Underground

The total wellfield cost consist of; initial costs to develop access to the underground; drifts and crosscuts to service the wellfield; and total cost of wells.

o Access costs - Initial cost only

$$EA = (D-H)(2C_s + C_r) + EV + EM + EE + (DR) C_{da} \quad (4.54)$$

o Wellfield drift and crosscut costs

$$\begin{aligned} EW_d + EW_c &= 2(Q/q_I)^{1/2} SC_{da} \\ &+ [2(Q/q_I) + (Q/q_I)^{1/2}] SV_x \end{aligned} \quad (4.55)$$

o Wellfield well costs

$$EW_w = (Q/q_I) C_{EWI} + ((Q/q_I)^{1/2} + 1)^2 C_{EWP} \quad (4.56)$$

o Total initial wellfield cost

$$EW = EA + EW_d + EW_c + EW_w + EP_{ww} \quad (4.57)$$

o Total replacement wellfield costs

$$EW_{RP} = EW_d + EW_c + EW_w + EP_{ww} + EP_{ws} \quad (4.58)$$

4.5.4 Fan Wells Drilled from Underground

The total wellfield cost consist of; initial costs to develop access to the underground; drifts and crosscuts to service the wellfield; and total cost of wells.

o Access costs - Initial cost only

$$EA = D (2C_s + C_r) + EV + EM + EE + (DR) C_{da} \quad (4.59)$$

Drift and Crosscut Costs

$$EW_d + EW_c = 4(Q/q_I) \left(\frac{d}{2H} \right)^{1/2} \left(\frac{H}{h} \right) h C_{da} + (Q/q_I) dV_x \quad (4.60)$$

o Wellfield well costs

$$EW_w = N_{TF} (Q/q_I) C_{wf} h \quad (4.61)$$

o Total initial wellfield cost

$$EW = EA + EW_d + EW_c + EW_w + EP_{ww} \quad (4.62)$$

o Total replacement + wellfield cost

$$EW = EW_d + EW_c + EW_w + EP_{ww} + EP_{ws} \quad (4.63)$$

4.6 WELLFIELD OPERATION

It is desirable to begin operations in the portion of the ore deposit that can yield the best return on investment. Normally, this is the higher grade sections. If possible a mine plan should consider this quick payback. In an actual operation it is also desirable to maintain a compact wellfield. With a compact design, a minimum amount of producing wells are possible for a given number of injectors. The model considers the ore to be of uniform grade and the wellfields to be of square geometry.

After startup, some time is required for the pore space in the ore to be filled with lixiviant. This amounts to reagent inventory. The amount of reagents and time should be estimated which is done in the model. Injection and production are started and the flow rate multiplied by time gives the inventory of acid before copper is produced in significant amounts. This time delay is expressed in terms of pore volumes. This number of pore volumes is a user input. In a normal

operation, one or two pore volumes can be assumed for the inventory. The porphyry host rocks for copper mineralization are normally of relatively low porosity when compared to the sandstone formations hosting uranium deposits.

Initial copper loadings are normally low and build with time. This is due to initial dilution of the pregnant liquor with formation fluid containing little or no copper. In addition, copper values can be precipitated in the rock mass by depletion of acid, until sufficient acid is present to react with acid consumers. With time, copper loadings increase until a peak is reached; then a decline occurs. As the copper in the pattern is mined out, the loadings gradually decline. Eventually, the copper values reach a cutoff grade in the pregnant liquor below which uneconomical operations occur. At this point the leach zone is no longer mined, and a new leach zone started to make up for the lost production. Since the rate of copper production must pay for acid, pumping, SX/EW, and overhead, the approximate grade of solution can be calculated at which the pattern is no longer economic.

In the case of leaching between horizontal fractures, when the ore has been depleted between fractures the well pattern is recompleted with additional fractures (stepping up the well), and a new vertical interval is leached. A new well is drilled when the entire vertical column of ore has been exhausted by the stepped fracture (axial) leaching method.

The model considers the copper loading to be an average value over the pattern life. Copper remaining in the orebody after cutoff is considered to be accounted for in the efficiency for overall recovery. Acid cost is a significant cost in most designs. Acid consumption is treated in the same manner as the copper loading. That is, an average

value over the life of the pattern is used in calculation. In actual practice, acid consumption (lb/lb) may gradually increase from the beginning to the end of leaching. Reversal of injection and production wells can be considered to improve the acid consumption during pattern leaching. This assumes that the design of the wells and wellfields can permit switching.

It is assumed in the economic analysis that the wellfield productive life can be represented by the generic curve shown in Figure 7-4. Key characteristics impacting costing are:

1. Between start-up and time t_{c1} , the hold-up time, dilution of wellfield copper is significant and no net copper production is achieved
2. Between time t_{c1} and t_{c2} the wellfield produces copper at the average assumed design level.
3. At t_{c2} the copper concentration rapidly declines due to depletion of wellfield copper or limitations in the rate of copper solubilization. At this time a new wellfield must be brought into production. Laboratory core leach tests can be used to obtain an estimate of t_{c2} . This is discussed in Section 7.2.4. In a parametric analysis t_{c2} corresponds to the welllife at a given product of the well pattern sweep, leach, and solution recovery efficiencies.

o Well Maintenance for Surface Operations

Operation of ISL wells requires maintenance of the well installation, well equipment, changes in leaching intervals involving installation of new well completions ("recompletion"), and occasionally repair of undesirable fluid flow paths ("short circuits") which may develop as a result of continued leaching.

Diagnosis of these problems utilizes certain logging techniques, as previously described in 4.4.1.8. Repair operations involve service-type drill rig equipment, often cementing or other well contractor services

which occasionally utilize specialized materials and equipment, and sometimes to replacement of worn or damaged well equipment.

A variety of commonly used well repair methods such as squeeze cementing are described in the literature, (39), while some other methods have been developed for specific application to copper ISL operation (15), (16).

Since no long term commercial copper ISL operating experience exists, it is estimated that annual maintenance costs will be approximately 10% of installed wellfield capital costs. This estimate compares favorably with other industrial plant experience involving corrosive processes (40), and appears reasonable in view of field test and pilot plant operation experience. Annual wellfield maintenance costs are represented by (4.64), where EW equals total initial wellfield capital costs.

$$C_{wm} = 0.1 \text{ EW} = \$/\text{year} \quad (4.64)$$

o Wellfield Maintenance for Underground Operations

The types and frequency of wellfield maintenance operations are assumed to remain unchanged from those discussed for surface operations. Due to increased costs associated with underground operations, annual wellfield maintenance costs are expected to be significantly higher than for the case of surface access. Also, the smaller wellfield capital cost resulting from shorter wells underground, must support amounts of maintenance work similar to surface access requirements. For modeling purposes maintenance cost has been projected at 15% of wellfield installation capital costs, as shown by the following formula:

$$C_{wm} = 0.15 \text{ EW} = \$/\text{year} \quad (4.65)$$

CHAPTER 5

SURFACE PROCESSING FACILITIES

The surface processing facilities consist of a solvent extraction, electrowinning plant and support facilities. The SX/EW plant receives copper rich wellfield solution from the production wells and returns copper depleted, acid enriched solution to be reinjected into the leaching zone. The surface facilities are operated continuously providing for the continuous recycle of leach solution in the leaching zone.

The model for the generic facilities is based on an existing design for solvent extraction, electrowinning plants which are in commercial operation. A detailed description of the facilities is presented in Section 5.2.2. Figure 5-1 is an overview of the surface plant process. In general, the surface processing facilities consist of:

- o Leach solution storage and pumping for both production well solution and wellfield injection solution. These solutions are also referred to as pregnant leach solution and raffinate solution respectively.
- o Solvent extraction facilities consisting of a single train design with two extraction and two stripping stages.
- o Associated solution storage, handling, and pumping equipment for the organic and aqueous solutions.
- o Electrowinning tankhouse based on current commercial scale design and operating parameters. The model includes all associated production and material handling equipment to produce commercial, high quality, copper cathode.

The generic model has been developed to provide the cost of facilities over a range bounded by annual production and copper loading. Annual production ranges between 2,500 TPY, the minimum commercial scale scenario operated over 20 years, and 50,000 TPY, a large commercial

scale plant. Copper loadings range from 2 to 20 grams per liter. The lower value corresponds to concentrations slightly better than mine waste, while the higher represents an expectation for the true in situ process where lixiviant/mineral contact in flow fractures is maximized. This results in an extreme wellfield volumetric range as shown in Table 5.1.

TABLE 5.1. SYSTEM FLOW RATE RANGE

| <u>Annual Production (TPY)</u> | <u>Copper Loading (gpl)</u> | | | |
|--------------------------------|-----------------------------|-----------|-----------|-----------|
| | <u>2</u> | <u>6</u> | <u>12</u> | <u>20</u> |
| 2,500 | 570 gpm | 190 gpm | 95 gpm | 57 gpm |
| 50,000 | 11,400 gpm | 3,800 gpm | 1,900 gpm | 1,140 gpm |

The generic surface model has been developed for plants that have flow rates near the middle of this range, 1,000 to 5,000 gpm. The high volume case would use multiple solvent extraction trains and all costs would be adjusted by the number of trains. The low volume cases would follow the unit costs except for staffing where there would be no reduction in the number of employees from a small plant case, which is associated with 12,500 TPY production capacity.

5.1 Support Facilities

The generic model is based on the concept that the processing facilities are an independent operation and not operated as a part of a larger existing or to be built complex. This requires that maintenance and personnel facilities be provided. Maintenance facilities are designed to support the routine maintenance of the processing plant and wellfield. It is assumed that in the case of the smaller operations,

that contract maintenance would perform some of the maintenance services that would not be economical to be done in-house, and that the cost would be the same as the equivalent service for a larger plant. The selection of which services are performed inhouse or contracted is beyond the intent of the model, however, costs have been included to allow for the proper maintenance and personnel support of the facilities. The model provides for the following support facilities:

- | | |
|-------------------------------------|--------------------------|
| o Changehouse and shower facilities | o Shipping and Receiving |
| o Laboratory | o Security |
| o Administrative Office | o Safety |
| o Employee parking | o Environmental |
| o Maintenance Shop and Warehouse | o Fire protection |

5.1.1 Roads

The manual assumes that full service roads are available to the plant site and therefore are not included within the scope of the generic model. The roads are required to be all-weather and allow easy passage of commercial truck trailer rigs normally operated on paved highways. Service roads within the operating boundaries of the processing plant and wellfield are included in the model costs.

5.1.2 Off-Sites

The model does not include any off-site costs for shipping. If rail service is available at the site, it is assumed that the costs of the spur and track maintenance are included in the unit transportation costs. No allowance is included in the model for product shipping other than loading.

5.1.3 Power

The model assumes that the necessary electrical power is available and that a local utility company will provide the power to the plant battery limits. Power transmission lines to the plant site are not included in the model. The electrical power cost (\$/kWh) used in the cost algorithms follows this basis. If a power generation facility or transmission line is required, the power rate should be adjusted to reflect these expenses.

The major uses of electrical power are electrowinning and injection well and production well pumping, and in those cases where underground workings are used power is required for servicing the shaft.

5.1.4 Water

The model assumes that water of required quality and in sufficient quantity is available at the battery limits of the plant. No provisions are made for wellfields, dams, pump systems, or pipelines. The cost of such items should be included in the unit cost of water. Water requirements for the surface facilities are divided between the processing plant and the wellfield. The processing plant requires potable water for both personnel and processing needs. The wellfield requires water to saturate the pores of the rock if they are not initially 100% saturated. This water must not contain particulates which could clog the injection wells.

5.2 Copper Leach Solution Plant Specifications and Costing

5.2.1 Overall Material Balance

5.2.1.1 Copper Production Rate and Total System Flow Rate

The surface facility receives solution from the wellfield at a concentration $[Cu]_2$ of copper at a total flow rate Q . The process path that this stream follows is shown in Figure 5-1. An overall material balance is depicted in Figure 5-2.

- o The product $[Cu]_2 Q$ is proportional to the copper entering the surface plant.
- o An electrolytic bleed is used to control impurities, principally iron, that accumulate in the electrolyte. The bleed is rich in copper and is returned to the extraction stage of SX to recover the copper. Impurities are diluted and follow the aqueous discharge from the plant. The net copper loss from the plant is assumed to be negligible.
- o The SX recovery operation is not 100 percent efficient, and for this generic model is assumed to be 84 percent efficient, including internal process bleeds. The copper not recovered in SX leaves the surface plant and is reinjected into the wellfield. This rate of reinjection is noted by $[Cu]_1 Q$ and equals $0.16[Cu]_2 Q$.
- o Solution passing through the wellfield picks up copper at a concentration $\Delta[Cu]$ by acid leaching the oxide ore. The total rate at which copper leaves the wellfield is $[Cu]_d Q + 0.16[Cu]_1 Q$, which equals $[Cu]_2 Q$ the rate of copper entering the surface plant.
- o The rate of cathode production is equal to the difference between the rate at which copper enters the surface plant, $[Cu]_2 Q$, minus the rate at which copper leaves the surface plant, $[Cu]_1 Q$. This net difference in $[Cu]_d Q$, which is the rate of copper extraction from the ore.
- o This model assumes:
 - + Negligible fluid losses, and operation of the wellfield at equal injection and production rates.
 - + Negligible loss of copper in the bleed stream in the surface plant.

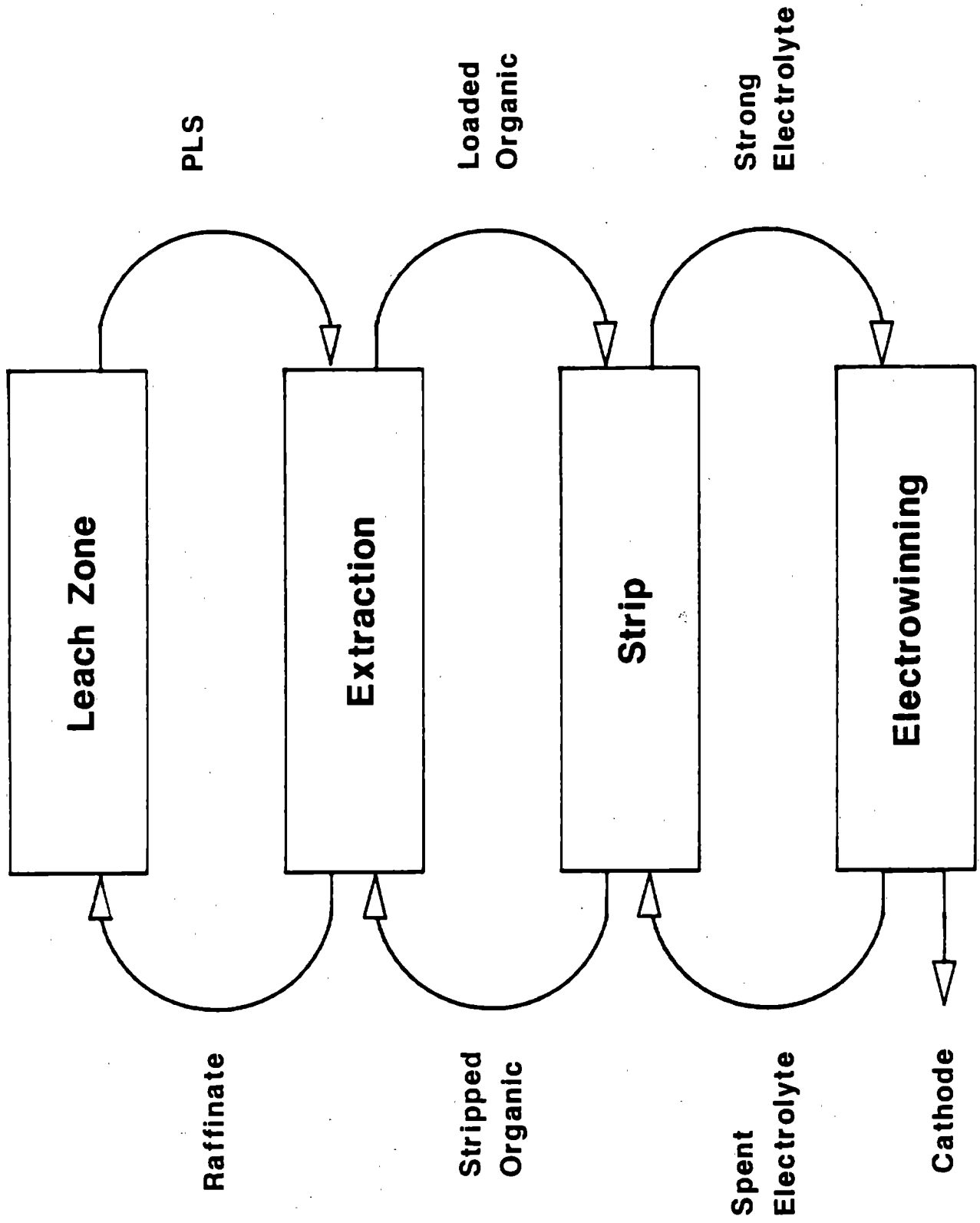


Figure 5-1. Generic Overall Flow Sheet

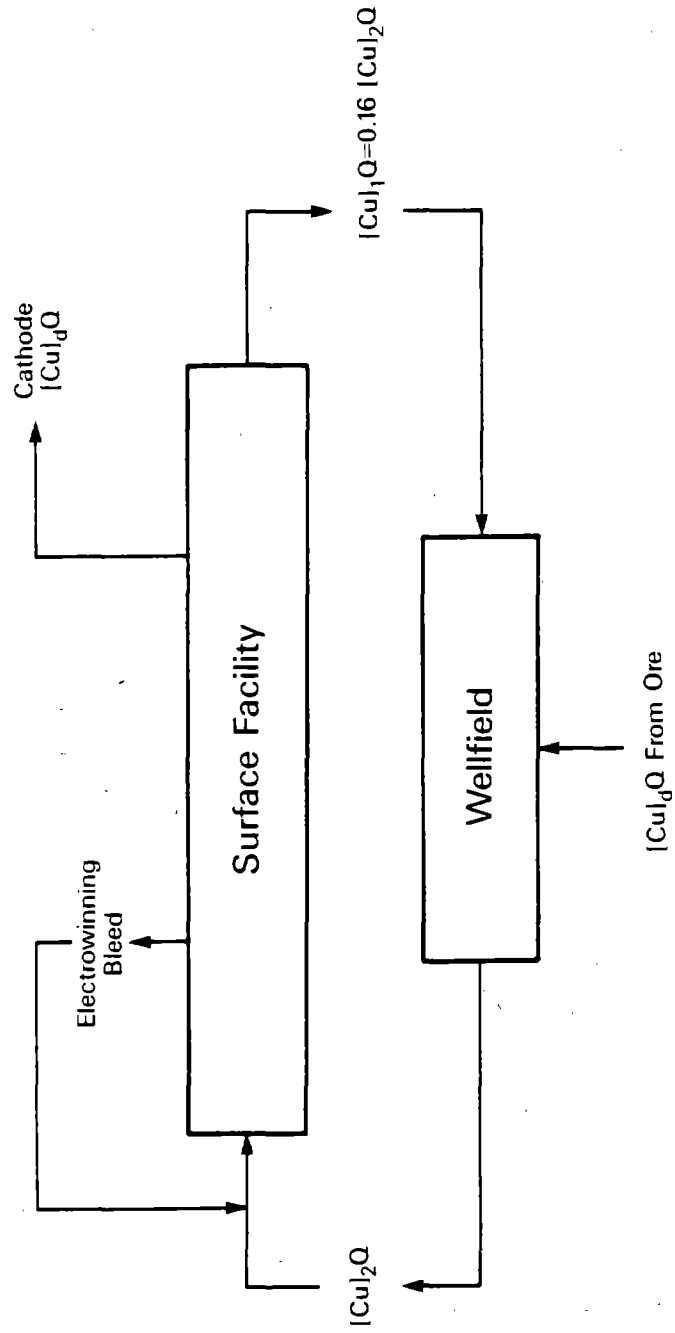


Figure 5-2. Overview Material Balance



The total system flow rate is defined as the volumetric flow rate of wellfield solution coming from the production wells. This solution is the incoming solution to solvent extraction, and is referred to as pregnant leach solution. This value is used to measure the relative sizes of wellfield production and solvent extraction volumetric capacity, and is related to plant production capacity Y in tons per year copper and copper loading in gpl. This relationship expressed as gpm system flow rate is given by (5.1).

$$Q = 0.456 \frac{Y}{[\text{Cu}]_d} \quad (5.1)$$

5.2.1.2 Compositions

o Injected Acid Concentration

It is assumed that the acid consumption by gangue material and copper is related to the net copper pick-up in the wellfield. The wellfield solution composition parameters are as follows:

- + Pregnant leach solution composition corresponds to a net copper pick-up of $[\text{Cu}]$.
- + Acid concentration in raffinate, which is also the wellfield injection fluid, is as follows:

$$[\text{H}_2\text{SO}_4] = [\text{Cu}]_d [W_7 + W_4] \quad (5.2)$$

- + W_7 equals the acid consumption stoichiometry of copper mineralization, see Table 7.7.
- + W_4 equals the acid consumption stoichiometry of gangue material, expressed as acid consumption by gangue per unit copper pick-up.

o Gangue Composition of Pregnant Liquor

The gangue composition of the pregnant liquor in both absolute levels of concentration and mix will vary widely from one deposit to another. It is not possible to represent this in generic form. However, it is the iron in the pregnant liquor that impacts the performance of the SX/EW operation. For purposes of estimating the cost impact of iron on copper extraction and cathode quality the following concentrations are selected.

Wellfield product solution, Pregnant leach solution:

copper = 7.0 gpl
 acid = 1.0 gpl H₂SO₄
 iron = 8.0 gpl Ferric

Raffinate:

copper = 1 gpl
 acid = 14.0 gpl H₂SO₄
 iron = 8.0 gpl Ferric

Cathode:

copper = 99.96 %

5.2.1.3 Bleed Streams

The largest bleed stream is the electrowinning bleed to control impurities in the electrolyte. The principle impurity is ferric iron (Fe⁺³). The effect of ferric iron is essentially chemical in that it dissolves copper and is converted to ferrous iron at the cathode.



This corrosive effect is very pronounced and diminishes the current and power efficiencies. One major problem caused by this corrosion is the decay of starting sheet loops and the eventual failure of the loops, resulting in the cathode dropping from the suspension bar. This can damage the protective cell liner and produce a short circuit in the affected cell.

Iron concentration in the electrolyte is controlled in two stages: through use of an SX reagent with a high copper to iron selection ratio, (commercial reagents have ratios of 300:1 or better), and by bleeding electrolyte from the electrowinning circuit to maintain an iron level less than 1.5 gpl. The electrowinning bleed stream composition is assumed to be:

- o copper = 30.0 gpl
- o acid = 45.0 gpl H₂SO₄
- o iron = 1.5 gpl Ferric

5.2.2 Generic Flow Sheet and Unit Process Specifications - Figure 5-2.

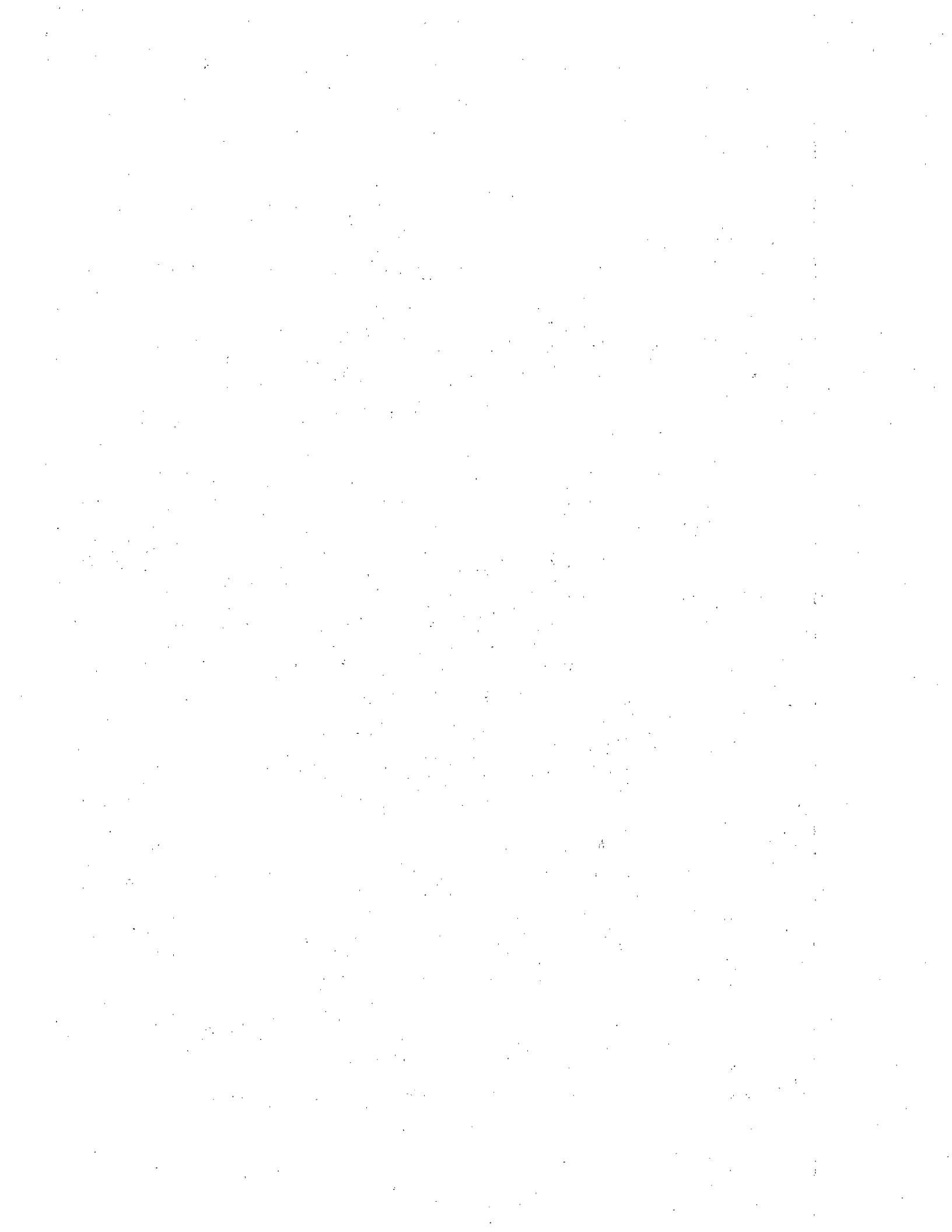
5.2.2.1 Pregnant Leach Solution (PLS) Storage

The pregnant leach solution storage is in a high density polyethylene (HDPE) lined, earthen pond. The pond collects solution from the various production wells as well as intermittent flows from the SX/EW plant. The pond is the source of feed solution for the SX plant.

5.2.2.2 Solvent Extraction (SC) - Figure 5-3.

In the solvent extraction process, the impure, aqueous leachate solution from the wellfield is contacted with an organic extractant reagent dispersed in an inert diluent. The diluent and the aqueous leachate are immiscible. High-flash point kerosene is used as the diluent with various proprietary Cu specific reagents used for the extractant. With the correct pH condition, the copper metal ion and the reagent form a complex which dissolves in the organic phase. A parallel reaction transfers a hydrogen ion from the extractant into the aqueous phase. The contacting of the organic and aqueous phases is carried out in an agitated mixing tank. The aqueous and organic phases flow from the mixing tank into the settler where the two, immiscible phases separate.

The organic phase, now copper bearing, is lighter and is removed from the settler with an overflow weir. The aqueous, acid rich phase with the greater specific gravity is removed with an underflow weir.



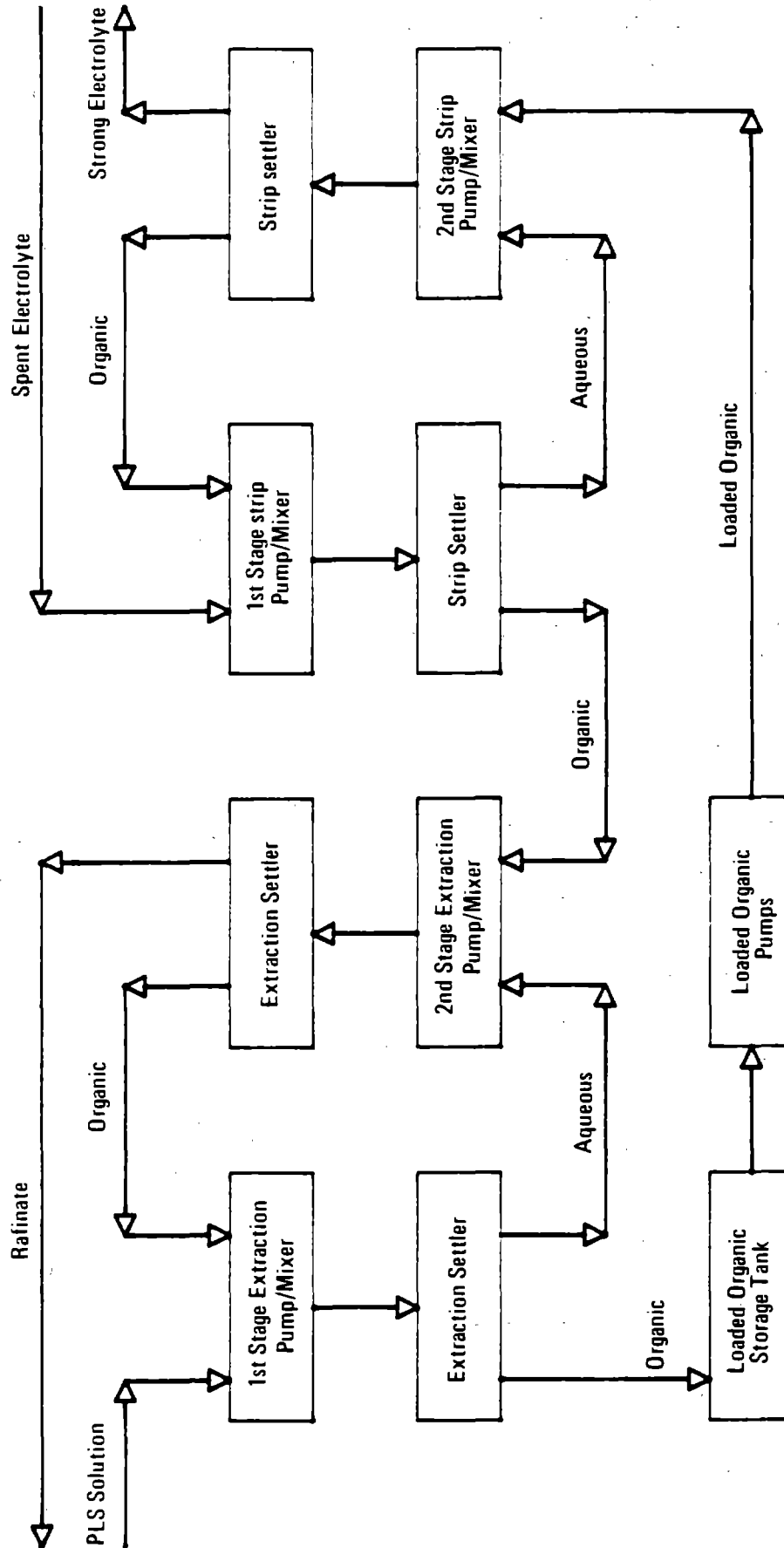
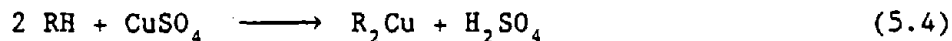


Figure 5-3. Generic Solvent Extraction Flow Sheet



The extraction reaction for copper can be written as follows:



Where R is the copper specific extractant reagent.

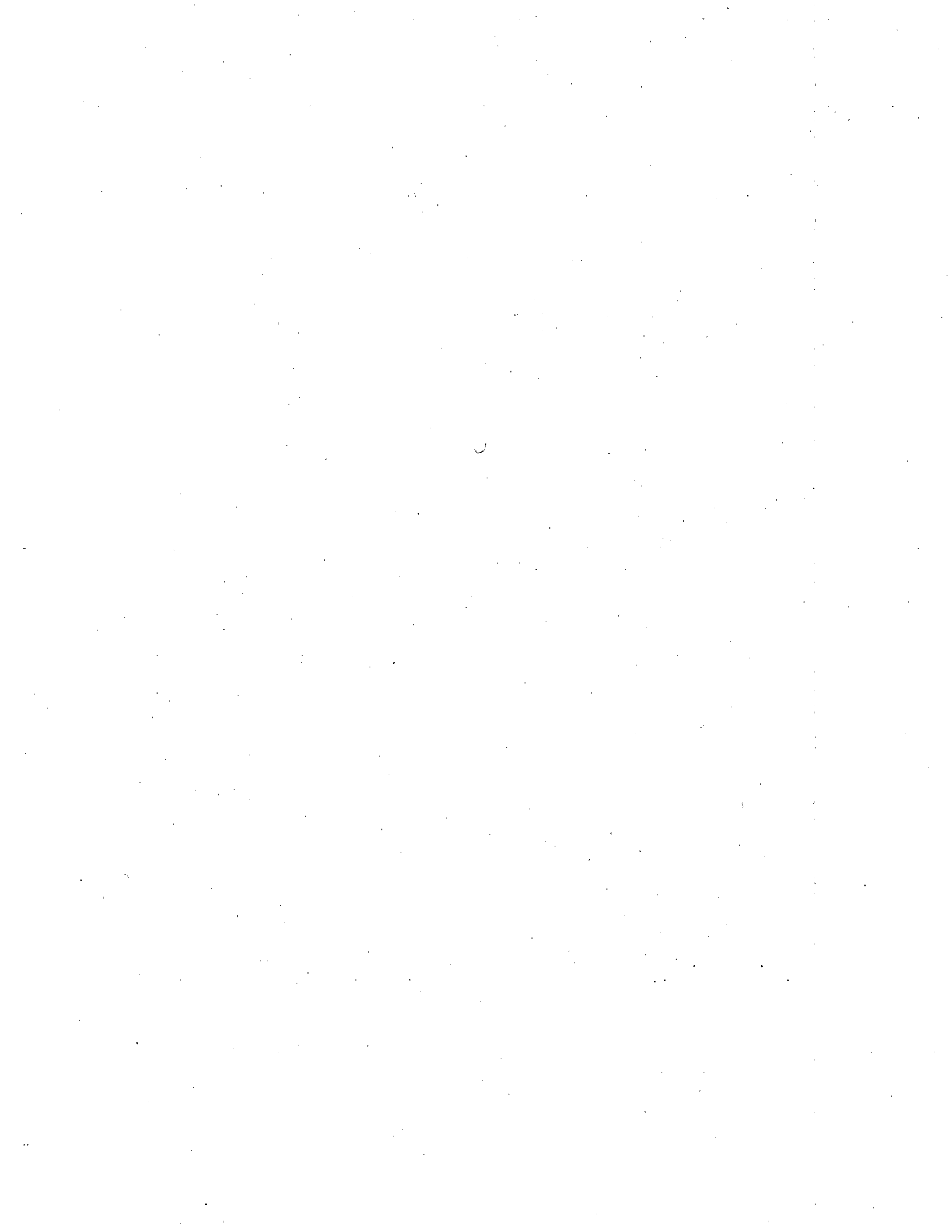
The efficiency of solvent extraction for copper using modern extractants and mixer designs is very high. Eighty-five percent recovery is used as a basis of the generic model. This recovery is achieved using a two stage extraction circuit.

5.2.2.3 Organic Storage and Cleaning - Figure 5-4

Tankage is provided for the organic phase solution used in the solvent extraction circuit as well as storage for the kerosene that will be used to make up for system losses. Solution is drawn from the settlers and centrifuged to remove crud. This term describes the material which collects at the interface of the organic and aqueous phases. It can be the result of:

- o Solid material which entered the SX circuit
- o Solid material which precipitated in the SX circuit
- o Emulsions formed in the mixers
- o Often a net of bacterial growth at the interface collecting precipitated siliceous or calcareous solids.

The cleaned organic solution is returned to the solvent extraction circuit.



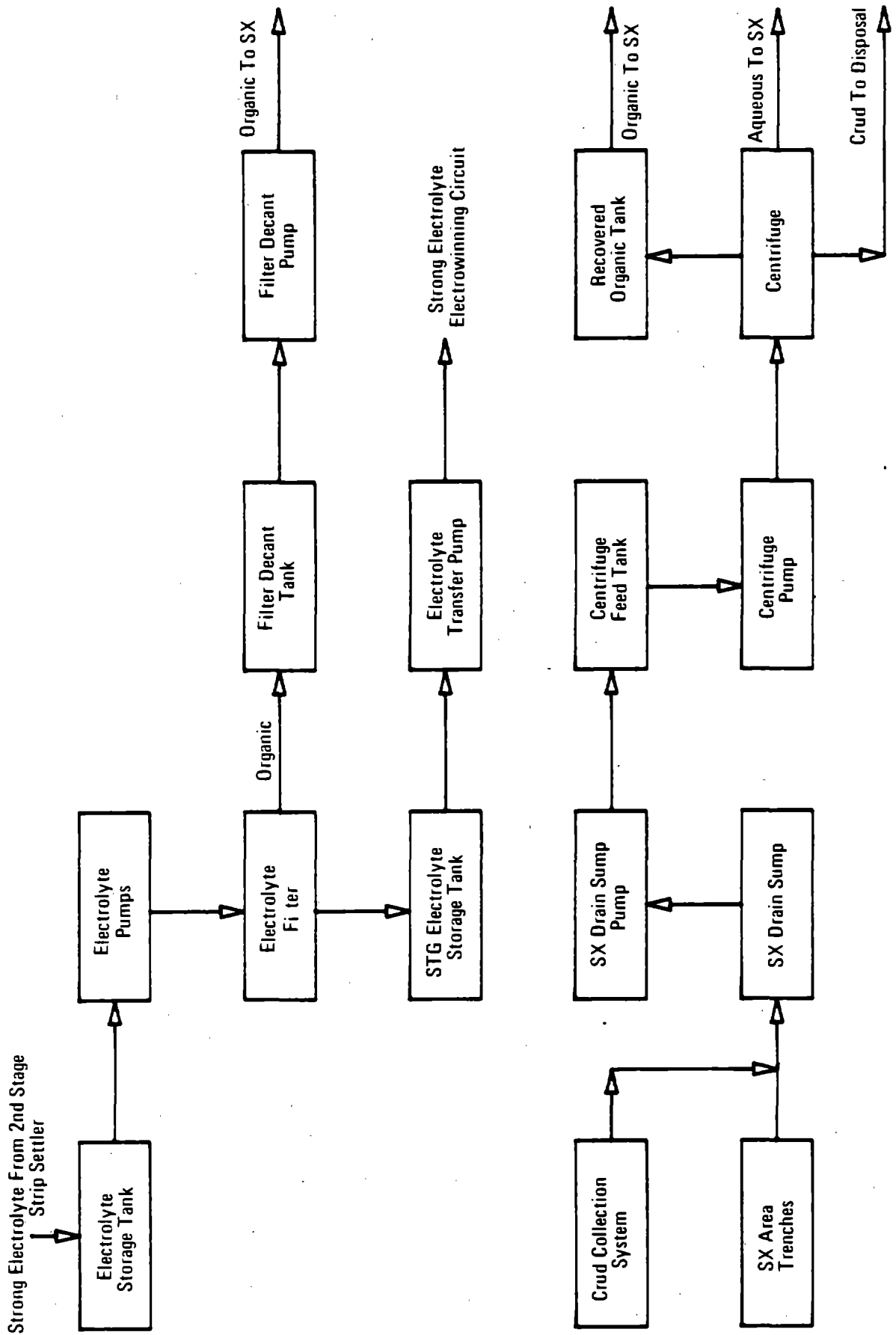
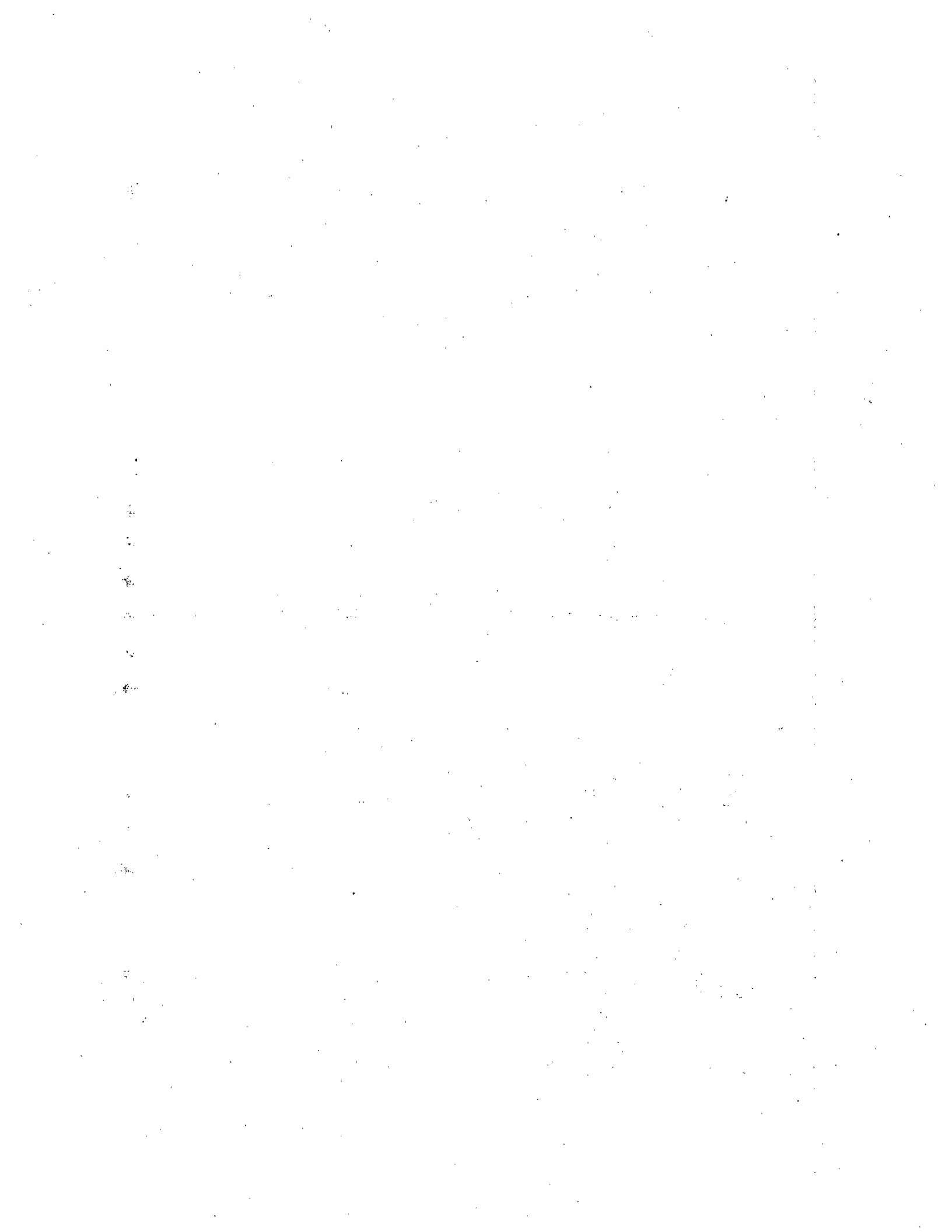


Figure 5-4. Generic Solution Handling Flow Sheet



5.2.2.4 Raffinate Storage and Cleaning

Raffinate solution, the aqueous discharge solution from the extraction stage of the processing plant, is collected in a second pond. This pond and the PLS storage pond are identical in design and construction. These ponds define the limits of the processing plant and the wellfield.

The raffinate flow is recycled for injection into the wells, however, before the raffinate can be reinjected, a bleed stream to remove accumulation of gangue material has to be removed. Any fluid losses in the wells have to be made up and acid added to compensate for acid consumption in the wellfield. In this generic design, net fluid losses in wells are assumed to be zero. Note the acid consumption in the wellfield consists of two sources, gangue material and copper. A bleed stream would be diverted to an evaporation pond. All the consumption by gangue material has to be made up. All the acid consumed by copper minerals is regenerated in the solvent extraction. A portion of the raffinate is bled to eliminate accumulation of gangue. The acid lost in the bleed stream has to be made up. For evaluation of costs it is assumed that 20% of the raffinate from SX is bled to eliminate gangue materials. It is assumed that the acid content of this bleed stream is neutralized by lime. The acid consumption is given by:

$$W_{10} = W_4 + W_7W_8 + W_9 \quad (5.5)$$

The lime consumption to neutralize the acid in the bleed stream is given by:

$$W_6 = W_{12}(W_7W_8 + W_9) \quad (5.6)$$

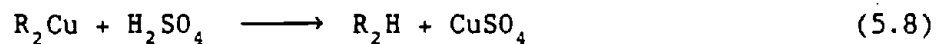
The total metal sulfates in the bleed stream are given by:

$$W_{14} = W_{13}W_6 + W_{15}W_4 \quad (5.7)$$

The addition of acid to the leach solution would be at the discharge of the raffinate pond, before the solution is boosted to the high injection pressures at the injection pumps. Acid is added to replace the solution not recovered from the leaching zone and to make up for the acid consumed by the gangue materials. Any other solution treatment required for leaching would be located near the raffinate pond.

5.2.2.5 SX Strip - Figure 5-2

Copper is recovered from the organic phase by contact with another aqueous solution. Spent electrolyte from the electrowinning operation has a high concentration of acid. When the organic and aqueous phases are contacted under these acid conditions, the equilibrium in the extraction equation reverses and the metal ions (copper and any iron from extraction) move into the aqueous phase and the hydrogen ion moves into the organic phase. The strip reaction for copper can be written as:



The extraction and strip reaction equilibrium is determined by the concentration of hydrogen ion in the aqueous phase.

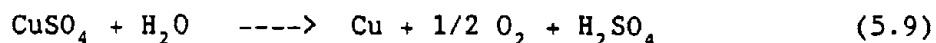
5.2.2.6 Electrolyte Storage and Treatment

Aqueous, copper rich solution from the SX circuit is held in storage before filtering to remove traces of organic solution carried over

from the strip settler. The organics used in solvent extraction are detrimental to the deposition of the copper cathode. Strip settlers are sized to remove all organic that can be separated with the phase separation of the aqueous and organic phases, however, some organic remains entrained in the aqueous phase and must be removed. A sand filter is used to remove the entrained organic phase from the electrolyte. Spent electrolyte, the copper depleted solution from electrowinning, is held in storage before being pumped to the strip mixer. Tankage provides surge capacity between the SX and EW circuits. The electrowinning bleed solution would be drawn from the spent electrolyte storage and pumped to the first stage extraction mixer.

5.2.2.7 Electrowinning (EW) - Figure 5-5

Electrowinning of copper is the cathodic deposition of copper metal from a copper-bearing solution by the passage of an electric current using an insoluble anode. With this process copper is deposited on the cathode and oxygen, from the dissociation of water, is liberated at the anode. The reaction for electrowinning is written as:



The amount of copper that is deposited is defined as an electro-chemical equivalent, i.e., one Faraday, 96489 ampere seconds (coulombs), will deposit the atomic weight of an element measured in grams, divided by the valence. The electro-chemical equivalent for copper is 0.02846 kg/ampere day.

The generation of sulfuric acid during electrowinning allows the spent electrolyte to be used as an aqueous strip solution without the need to increase the acid concentration. In general a SX/EW plant would

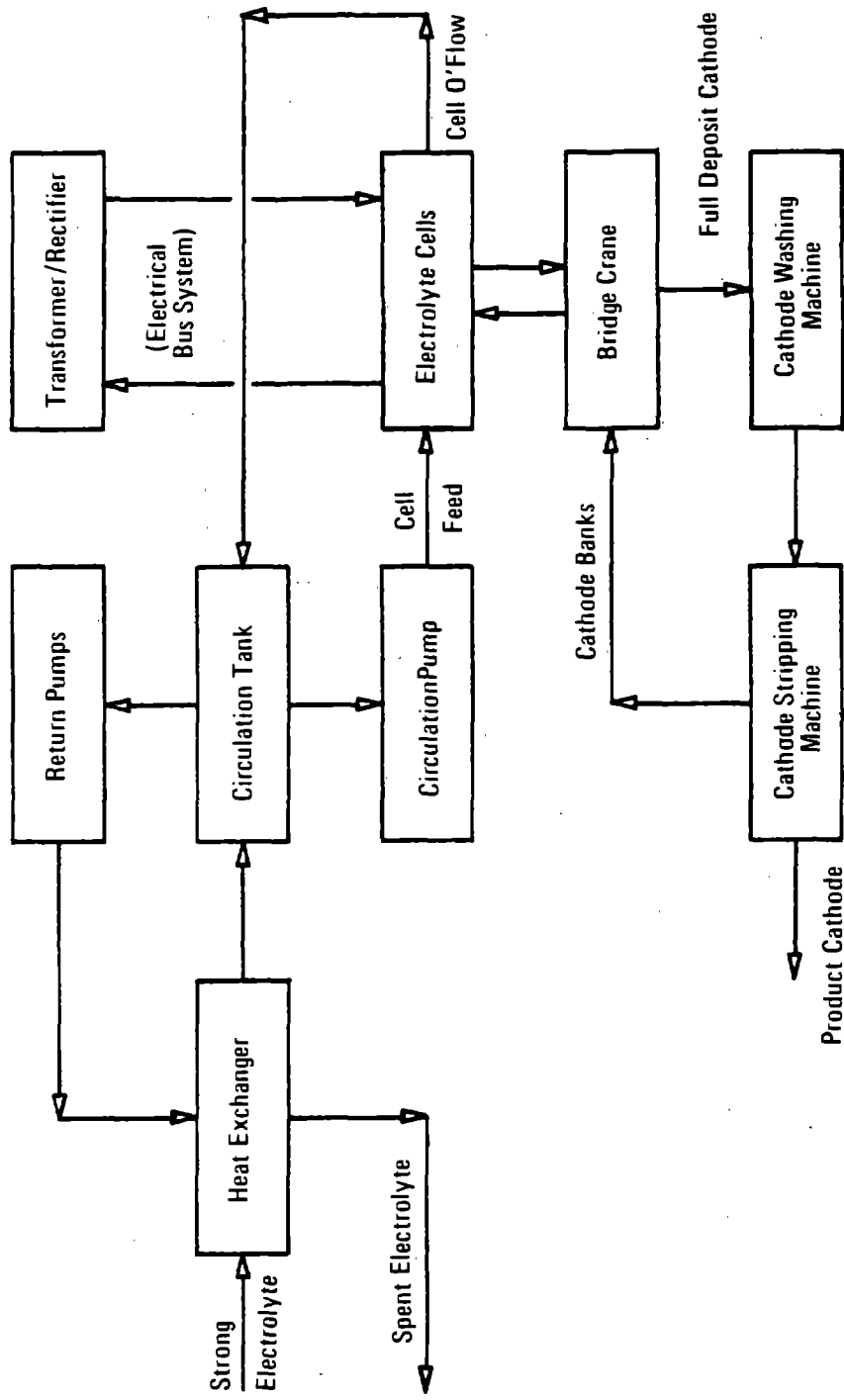


Figure 5-5. Generic Electro-winning Flow Sheet

consume only such acid as required in leaching gangue and that acid lost when bleeding the circuits to remove the accumulation of impurities.

A transformer and rectifier converts the ac power distributed within the plant to the dc current used in electrowinning. The electrowinning dc power supply consists of a dedicated transformer, rectifier and busbar circuit. No other electrical uses are supplied from this system. The electrical circuit is fed by a transformer and rectifier, located outdoors and adjacent to the cell house. The generic model assumes U.S. standards and that the transformer would receive 13.8 kV from an area substation. Thyristor-type rectifiers are used for the model. These units offer high reliability, no tap changes, and voltage and current range spanning from near zero to full value. The rectifier would also include the high voltage switch gear, thyristor control panel, cooling system, and dc isolators.

5.2.2.8 Anode/Cathode Material Handling - Figure 5-5

The tank house is principally a material handling operation. The multiple functions are:

- o Cathode Pulling - Harvesting is done using an overhead hoist or crane. Modern practice is to use large, one meter square cathodes which preclude any manual pulling. The same system is used for anodes, when cells are out of service for cleaning. Cathodes are generally pulled from part of a cell allowing the cell to remain in service. The same hoist or crane is used to transport the loaded cathodes to the washing station and return barren cathodes to the cells.
- o Cathode Washing - This step is necessary to remove electrolyte from the surface of the cathode. Sulfate and oxygen are principal cathode impurities that are contained in the electrolyte. In larger plants, cathode washing is fully mechanized and integrated with the stripping or starter sheet machines. Smaller plants would use a separate station. In both cases, high pressure hot water would be used to clean the surface of the cathode.

There are currently two types of cathodes being used in electro-winning.

- o Starter Sheet Cathodes, which are thin copper sheets suspended from conductive bars and are placed in the cells to become the base for future deposition. When fully deposited, these cathodes are pulled and the suspension bars removed. The initial, thin copper sheets are formed by the deposition of copper on reusable cathode blanks. Similar to the insoluble anodes, these cathodes offer a cathodic surface and do not participate in the electro-chemical reactions. Titanium, stainless steel, and coated copper blanks are used for this purpose. This system requires a special electrowinning circuit, stripping station and starter sheet machine with all the ancillary stations. Depending on the capacity of the cell house these machines range from highly automated machines, including many automatic operations, to manual or semi-manual designs. Their cost is offset by the cost of the permanent cathode inventory. The starter sheet system uses the permanent cathode blanks for the initial deposition only. Therefore, a smaller number of blanks are required compared to an equally sized, total production cathode plant.
- o Total Production Cathodes, which utilize permanent blanks similar to the production of starter sheets, except that the deposition is continued until the cathode has reached full weight. The full deposit cathodes are pulled and the copper is stripped from the blank's surface. The blank is returned to the cell for another deposition cycle. Titanium or stainless steel are used for the reusable blanks. Plants utilizing this system need only a cathode washing station and a cathode stripping station. Again, the level of automation depends on the plant capacity. The costs of a starter sheet system and all associated equipment and that of a permanent cathode system with its reusable blanks and associated equipment are considered equal for this model. After cathodes have been harvested, washed, stripped or had the suspension bars removed, they are weighed, bundled, and strapped, then moved to storage for shipment.

5.2.3 Materials Selection

The combination of a corrosive electrolyte (sulfuric acid) and organics require special construction materials. The following guidelines are used in the design of modern SX/EW plants.

Piping: High density polyethylene (HDPE), low pressures, solvent extraction interstage piping.

| | |
|---------------------|--|
| | Stainless steel, high pressure pipe and valves. |
| | Fiberglass, piping with minimal temperature changes. |
| | Polyvinyl chloride (PVC), electrolyte piping and valves, requires controlled exposure to sunlight. |
| Tankage: | Mild steel, water and concentrated acid. |
| | Stainless steel, high abrasion and temperature variations. |
| | Fiberglass, dilute acid and organics. |
| | HDPE, lining material for concrete vessels or earthen ponds. |
| Equipment: | All wetted parts; stainless steel, HDPE, or PVC. |
| Concrete and steel: | All surfaces with exposure to electrolyte or acid are painted with vinyl based paints or coated with vinylester silica sand protective coating |
| Anodes: | Lead-antimony alloy anodes have been used traditionally, these are being replaced with lead-calcium anodes which offer better corrosion resistance. Some plants remain with lead-silver anodes. The model assumes lead-calcium anodes for costing. |

The cost algorithms are based on these materials of construction which are widely used in solvent extraction, electrowinning plants. If development of a specific in situ site indicates the presence of chlorides, the stainless steel materials of construction will need to be upgraded to have the greater corrosion resistance that is required to handle chloride solutions. For example, 317 stainless steel may be substituted for 316 stainless steel. This cost has been minimized by the SX/EW design, which makes extensive use of plastics: HDPE, PVC, and

fiberglass. These materials are used wherever possible and have sufficient corrosion resistance to be used with the chloride solutions.

Stainless steel is used primarily for mechanical equipment: pumps, centrifuges, and electrolyte filters. Therefore, the cost to upgrade these components does not greatly affect the capital cost of the full facility. The cost of a single equipment item may be greatly affected, but the effect is hidden with the accuracy of the surface facilities estimate.

5.2.4 Component Sizing and Costing

The capital cost of a solvent extraction plant is almost exclusively based on the volumetric throughput. The capital cost of a solvent extraction train is proportional to the size of the settling basins.

These basins are sized on an area per unit flow rate based on the dissociation rate of the organic and aqueous phases. This results in the physical area of the settlers being proportional to the plant flowrate.

For the model it has been assumed that a single SX train will be used.

This assumption is valid based on the use of single train, SX plants which have been designed for flow rates greater than 5,000 gallons per

minute. The design includes PLS and raffinate ponds, extraction and strip mixer/settlers, tankage, piping and pumps, fire protection, instrumentation, electrical power distribution, control room and plant

office. The capital cost of the electrowinning plant is dependent on the plant's production of copper cathode. As with SX, the EW design of the model assumes a unit cell which has a fixed size and production.

For EW the model is based on a standard unit cell defined by deposition

area, current density, and cell voltage. The electro-chemical equivalent for copper is fixed. This results in a constant weight of copper produced from a unit cell and, therefore, production is proportional to the number of unit cells. The unit cell has a fixed physical size so that the capital cost is proportional to the number of cells or to the annual plant production.

The method of designing a SX/EW plant based on unit rates results in a capital cost that is linear when expressed in terms of costs per unit rate.

The capital cost of the electrowinning plant includes the tankhouse building, cranes, electrowinning cells, anodes, hardware, transformer-rectifier, piping and pumping, ventilation, cathode washing, starter sheet or permanent cathode systems and associated material handling equipment, control room and offices.

The design that the model is based upon uses the following size criteria:

- o Pumps and pipe systems are designed with a 15% margin. During warm weather the SX plant could be operated at 115% of rated capacity with minimal loss of recovery because of the higher phase separation coefficient, but during cold weather the SX plant could operate at higher than the designed flow rate but would experience some reduction in recovery.
- o Electrowinning transformers and rectifiers are sized with the same 15% margin; the instantaneous rate for the cell house could be increased by this amount.
- o The SX/EW plant could be operated at 115% of its design capacity if required by the well field production rate for limited periods of time.
- o The SX flowrate could be reduced to 20% of design capacity by utilizing recycles and spill back lines on pumps. The EW section could operate at minimum current density of 50 amps/m², to prevent anode spalling and cathode contamination. This is less than 25% of capacity. Minimum pumping and solution rates would be 20% of design. Extended operation at reduced rates would

require heat to be added to the electrowinning circuit through the existing electrolyte heat exchanges. This operation would be unusual and the cost of this extra heat is not included in the model.

- o The overall volumetric operating range of a SX/EW plant is 25% to 115% of design capacity. Assuming constant copper loading and no loss of recovery, production could range from 25% to 115%.

The following unit rates define the SX/EW model:

- o Copper loading, [Cu], grams per liter of copper in the production well solution.
- o Flow rate, Q, the volume of copper rich well field solution coming to the solvent extraction plant in gpm.
- o Annual Production, TPY, based on copper loading and flowrate.

$$TPY = 2.19[Cu][Q] \quad (5.10)$$

- o Unit Cell Production, UCP, and Unit Power Rate, UPR, are based on the following:

| | |
|--------------------|----------------------|
| Current density | 200 A/m ² |
| Deposition area | 1 m ² |
| Current efficiency | 90 % |
| EW availability | 95 % |
| Cathode/cell | 50 |
| Cell voltage | 2.5 v dc |

- o Unit Cell Production is annual production of a unit cell with the parameters listed above.

Unit cell production 196 TPY

- o Unit Power Rate, based on the power requirements and production of a unit cell

Unit power rate 0.9 lbs/kWh

The total capital cost of the SX/EW facility is divided into two components.

- o The first component is the same for all flow rate dependent costs, and for this analysis can be approximated as a constant C_x (\$/gpm) multiplied by the total system flow rate Q. C_x has been determined to have a value of \$2,500/gpm.

- o The second component is the sum of all costs that are proportional to the production rate, and for this analysis can be approximated as a constant C_E (\$/TPY) multiplied by the production capacity Y . C_E has been determined to have a value of \$650/TPY.

The total SX/EW capital cost in dollars expressed in generic format is given by EP_1 , in equations (5.11) and (5.12).

$$EP_1 = C_x Q + C_E Y \quad (5.11)$$

$$C_x = 2,500, C_E = 650 \text{ for this analysis} \quad (5.12)$$

The algorithm for EP_1 is based on recently designed SX/EW plants by Davy McKee Corporation, either in commercial operation or under construction. Data from these actual plants were recast to reflect the cost of similar plants built in the Southwest United States. This algorithm compares with published costs of plants recently built by other firms in the same area. If the algorithm is to be used outside of the Southwest United States, costs should consider the plant's location. The algorithm assumes a plant site with minimal earth work or soils problems. If a location is selected and requires extensive civil earth work, additional costs need to be added. The algorithm does not represent a given plant but a cost to build a plant that would be used to process solution from an in situ well field.

Based on the experience of Davy McKee Corporation in estimating the capital cost of solvent extraction, electrowinning plants, the capital cost algorithm will give the cost of a SX/EW facility within 20% of the actual plant cost. The capital cost is the summation of the costs incurred in the design, purchase, delivery and construction of the facilities but does not include:

- | | |
|-----------------------|---|
| o land costs | o interest during construction |
| o development costs | o costs to provide materials |
| o taxes and insurance | o water and electricity to the plant boundaries |

The capital cost assumes an 18 month schedule for design and engineering, and 18 months for plant construction. No allowance for escalation during this period is included in the capital cost algorithm.

5.3 Wellfield Surface Facilities Specifications and Costing

The major components for which generic operating specifications and cost algorithms are developed in this section consist of: plant/wellfield interconnecting piping; interconnecting piping between wells; injection pumps; and production pumps for fan wells.

Distribution of lixiviant to and from the wellfield will be handled with low pressure PVC pipe. From the injection pump, located in the wellfield area, plastic lined carbon steel pipe will be used. This will consist of one large diameter pipe to a central location in the wellfield and smaller diameter pipe from a header to each injection well. Connections from the pipes to the wellhead are made using reinforced rubber hose (EPDM rubber).

Specifications and costs for production pumps for vertical well patterns are contained in Chapter 4, since each vertical production well contains a pump. In the case of fan wells, the well pattern design utilizes gravity drainage in each production well, with subsequent centralized accumulation of production fluids for lifting to the surface with one or several large production pumping units. Although these lift pumps are located underground, specifications and costing are contained in this section because both are primarily related to total system flow rate and lift head.

The manpower requirement for operation and maintenance of the wellfield is contained in Section 5.6. Maintenance costs for wellfield equipment are specified in Chapter 4.

5.3.1 Interconnecting Piping

Design parameters that must be considered in sizing and costing piping are: the maximum operating pressure; materials of construction; maintaining low friction drop; the total length of piping; and the cost of pipe per foot of length.

The maximum operating pressure is governed by the depth to the top of the orebody and the fracture gradient, since the injection pressure during operation is maintained below the rock fracturing pressure. This maximum pressure at the surface is equal to the difference in fracturing and water gradients multiplied by overburden distance, equation (5.13). For underground patterns this maximum pressure equals the fracture gradient times the overburden distance (5.14).

$$P_{IS} = (a_f - a_w) (D - H) \quad (5.13)$$

$$P_I = a_f (D - H) \quad (5.14)$$

Typical values for a_f range between 0.7 psi per foot to 1 psi per foot, the latter value is associated with generating horizontal fractures at shallow depths, approximately less than 1000 feet below the surface. An upper limit of 1300 psi for P_{IS} is calculated using: 0.7 psi per foot; 3000 feet of depth (maximum for this design manual); and 0.433 psi per foot hydraulic gradient. It is assumed that the same pressure rating is used on the production lines since it is likely that production wells could be used as injection wells, and vice versa, at some point in the operation.

Piping should be sized to ensure that the friction drop does not exceed 0.06 feet of head per foot of length. Pipe sizes which meet this criterion are listed in Table C.2 as a function of flow rate. The

flow rate used for wellfield interconnecting piping is the rate per hour per row of injectors. For a 5-spot pattern this flow rate (q_{I0}) is equal to the total system flow rate divided by the number of rows of injectors, and is given by (5.15). For a fan pattern this flow rate (q_{I0}) equals the system flow rate divided by the total number of crosscuts, and is given by (5.16).

$$q_{I0} = [Qq_I]^{1/2}, \text{ 5-spot} \quad (5.15)$$

$$q_{I0} = [Qq_I]^{1/2} \left[\frac{2h^2}{Hd} \right]^{1/2}, \text{ fan pattern} \quad (5.16)$$

To determine pipe sizes connecting the wellfield to the SX/EW plant the total system flow rate Q is used in Table C.2., page 391, to select the appropriate pipe diameter.

The total length of interconnecting piping for the 5-spot pattern is calculated by multiplying the spacing per pattern by the sum of the rows of injectors and producers. Experience with piping layouts indicate this number should be multiplied by two to account for piping between wells and row manifolds.

$$L_{TW} = 2S[2Q/q_I + 2(Q/q_I)^{1/2} + 1], \text{ 5-spot} \quad (5.17)$$

The length of interconnecting piping for the fan pattern equals the total length along the crosscuts and drifts. It is assumed that at each vertical layer two drifts are used to service all crosscuts. For costing purposes the total length is multiplied by two.

$$L_{TW} = 2d(Q/q_I) + 4(Q/q_I)^{1/2} \left[\frac{dH}{2} \right]^{1/2}, \text{ fan pattern} \quad (5.18)$$

The total cost for wellfield interconnecting piping EP_4 is obtained by multiplying the total length (L_{TW}) by a unit cost factor C_{PLW} . Typical values for C_{PLW} are listed in Table C.2 page 389.

$$EP_4 = C_{PLW}L_{TW} \quad (5.19)$$

The total cost for piping connecting the SX/EW plant to the wellfield is noted by EP_5 which equals the total footage L_{TT} multiplied by a unit cost factor C_{PLT} listed in Table C.2 page 389.

$$EP_5 = C_{PLT}L_{TT} \quad (5.20)$$

5.3.2 Injection Pumps

Injection pump capital costs are calculated in the model on a cost per horsepower basis. This is an initial, one-time cost. These pumps are normally 80 to 90% mechanically efficient. Operating cost is related to power consumption and the cost of electric power and is discussed in section 5.4.1.

Injection pumps are normally of centrifugal or plunger designs. They must have a long life for use with a corrosive lixiviant. The plunger pumps are more flexible in terms of pressure and flowrate, but have more moving parts. Pump suction should be adequately designed to prevent cavitation. Plunger pumps should be equipped with safety relief valves and pulsation dampeners on the pump discharge. Multiple pumps with redundant capacity are required to allow for maintenance and unscheduled downtime.

The total horsepower required for injection is proportional to the system flow rate times the pumping head divided by the % efficiency of the pump, equation (5.21). It is assumed that injection pumps for both

surface and underground mining are located on the surface within the wellfield area.

$$HP_I = 0.000252 \left[\left(\frac{a_f}{a_w} - 1 \right) (D-H) \right] Q/\eta \quad (5.21)$$

The total cost for injection pumps is obtained by multiplying the injection horsepower by a cost per horsepower, equation (5.22).

$$EP_2 = C_{HP} HP_I \quad (5.22)$$

The value of C_{HP} is obtained by averaging single or multiple pump costs over the horsepower range considered. A recommended value is \$150/HP.

5.3.3 Fan Well Production Pumping

Pregnant solutions are to be gathered from the underground workings by gravity collection at a central sump. The liquor is then lifted to the surface using large plunger or multistage centrifugal pumps. This is a one-time initial capital cost.

The total horsepower required for lifting production fluids is proportional to the system flow rate times the total pumping head divided by the % efficiency of the pump, equation (5.23). The production pumps are located in the underground workings. Where multiple vertical layers of fan modules are used the lifting head may exceed the overburden. However, for costing purposes it is assumed equal to the overburden on a generic basis.

$$HP_p = 0.000252[(D - H)]Q/\eta \quad (5.23)$$

The total cost for production pumps is obtained by multiplying the injection horsepower by a cost per horsepower, equation (5.22).

$$EP_p = C_{HP} HP_p \quad (5.24)$$

5.3.4 Vertical Well Pumping

The capital cost for vertical well pumps is given in Chapter 4 as part of the production well cost. Horsepower requirements for power to lift the total system flow rate from a power cost standpoint are given by (5.23).

5.4 Utility Requirements

5.4.1 Electricity

Electrical power demand is the largest, single utility requirement of the surface facilities and electrowinning accounts for 95% of the surface plant's demand excluding wellfield pumping. The consumptions of water, steam and compressed air are small and the associated costs are included in the the plant electrical costs. For this model electro-winning power requirements can be simplified to 0.9 lbs/kWh.

5.4.2 Water

Personnel requirements are 50 gal/man/day. The main point of water consumption in the surface plant is in electrowinning where water is consumed in the electrolytic process. This rate is based on the cathode production rate and is 0.034 gal/lb cathode.

5.4.3 Fuel

No requirement is specified.

5.5 Staffing

5.5.1 Administration

The administration staffing for the model assumes that the operations are independent and provide for the daily supervision and administration of the facilities. No provisions are made for sales and marketing of the cathode, or corporate management. Typical staffing would be:

| Position | Number of employees |
|--------------------|--|
| Plant Manager | 1 |
| Metallurgist | 2 |
| Wellfield Engineer | 1 |
| Chemist | 1 |
| Technicians | a |
| Clerical | b |
| Accounting | c |
| Traffic | d |
| Total | half of the EW staffing (a + b + c + d) + professional staff |

5.5.2 Operations

The wellfield operation is not labor intensive and the staffing is as follows:

| Position | Number of people |
|----------|------------------|
| Foreman | 4 |
| Operator | 4 |
| Labor | 2 |
| Total | 10 |

By the nature of their design solvent extraction plants require minimal attention. There are few pieces of rotating equipment and their operation is constant. The plant does require close metallurgical monitoring for best performance. A typical staffing for solvent extraction circuit would be:

| Position | Number of people |
|----------|------------------|
| Foreman | 4 |
| Operator | 4 |
| Labor | 2 |
| Total | 10 |

This staffing would be constant up to 5,000 gpm for a single train plant. If multiple trains are to be used for flow rates greater than 5,000 gpm, the staffing should be adjusted accordingly.

The operation of an electrowinning plant requires manpower in proportion to the production of the plant. The work is mostly dedicated to material handling and quality control. Typical staffing would be:

| Position | Number of people | | |
|------------------|------------------|--------------|-------------|
| | Small plant | Medium plant | Large plant |
| Foreman | 4 | 4 | 4 |
| Elec. Operator | 4 | 4 | 4 |
| Lead Operator | 0 | 4 | 4 |
| Crane Operator | 1 | 2 | 4 |
| Cell Top Crew | 2 | 4 | 8 |
| Machine Operator | 2 | 2 | 6 |
| Shorts Crew | 2 | 2 | 3 |
| Circulation Op'r | 4 | 4 | 4 |
| Fork Lift Op'r | 2 | 3 | 4 |
| Labor | 3 | 4 | 5 |
| Total | 24 | 33 | 46 |

5.5.3 Maintenance

Maintenance staffing reflects the needs for the surface plant. A larger plant can afford a large staff with specialized employees; a small plant requires the same capabilities and employees with multiple skills. For the model the maintenance staffing was assumed to be half of the operations staff. Typical staffing would be as follows:

| Position | Number of employees |
|---------------------------|--|
| Maintenance Foreman | 1 |
| Mechanical Foreman | 1 |
| Electrical Foreman | 1 |
| Instrumentation Repairman | 1 |
| Journeyman & apprentices | a |
| Total | half of the EW staff (a) + supervision |

The total manpower in numbers (ST) is represented as a function of total production capacity Y. Below 12,500 TPY staffing remains constant. For other levels of TPY staffing is calculated by interpolation.

- o Small plant (12,500 TPY)

$$ST = 3.2(Y/1000) + 32 \quad (5.25)$$

- o Medium plant (25,000 TPY)

$$ST = 2.4(Y/1000) + 32 \quad (5.26)$$

- o Large plant (50,000 TPY)

$$ST = 1.6(Y/1000) + 32 \quad (5.27)$$

5.6 Surface Facilities Operating Costs

5.6.1 Salaries

| | Number of employees | Annual cost(\$) |
|------------------------|---------------------|---------------------|
| Administration | | |
| Plant Manager | 1 | 84,000 |
| Tech. Staff | 4 | 252,000 |
| Admin. Staff/1,000 TPY | | |
| small plant | 0.8 | 33.6/TPY |
| medium plant | 0.6 | 24.8/TPY |
| large plant | 0.4 | 16.8/TPY |
| Operations | | |
| Wellfield | | |
| Foreman | 4 | 224,000 |
| Employees | 6 | 294,000 |
| SX | | |
| Foreman | 4 | 224,000 |
| Employees | 8 | 294,000 |
| EW | | |
| Foreman | 4 | 224,000 |
| Employees/1,000 TPY | | |
| small plant | 1.6 | 67.2/TPY |
| medium plant | 1.2 | 50.4/TPY |
| large plant | 0.8 | 33.6/TPY |
| Maintenance | | |
| Foreman | 3 | 150,000. |
| Employees/1,000 TPY | | |
| small plant | 0.8 | 39.2/TPY |
| medium plant | 0.6 | 29.4/TPY |
| large plant | 0.4 | 19.6/TPY |
| Totals | | |
| Salaried Staff | | 1,138,000 |
| Employees | | |
| small plant | | 588,000 + 140 x TPY |
| medium plant | | 588,000 + 105 x TPY |
| large plant | | 588,000 + 70 x TPY |

Annual labor cost

$$EP_1 = 1,746,000 + 140 \times \text{TPY} \quad (\text{small plant}) \quad (5.28)$$

$$EP_1 = 1,746,000 + 105 \times \text{TPY} \quad (\text{medium plant}) \quad (5.29)$$

$$EP_1 = 1,746,000 + 70 \times \text{TPY} \quad (\text{large plant}) \quad (5.30)$$

Annual labor costs include the basic salary plus 40% for benefits and four indirects.

5.6.2 Consumable Materials

A properly designed and operated SX/EW plant conserves its material cost by recycling solutions. Some solutions are discarded and must be replaced; while not consumed in the process, they can be treated as consumables. Costs for a typical operation are developed in terms of a unit cost and a usage rate. Typical or recommended values are shown in Table C.2.

The annual cost of consumables is divided into flow rate and production rate dependent costs.

o Flow rate dependent annual cost

This consists of the SX costs for extractant (C_1W_1Q) and SX costs for diluent (C_2W_2Q). The total cost is represented by EP_{c1} using (5.31).

$$EP_{c1} = Q(C_1W_1 + C_2W_2) \quad (5.31)$$

o Production capacity dependent annual cost

This consists of: EW reagent cobalt sulfate (C_3W_3Y); anodes (C_5W_5Y); sulfuric acid ($C_4W_{10}Y$); and lime (C_6W_6Y). Values for W_{10} and W_6 are given by (5.5) and (5.6). The total annual cost is represented by EP_{c2} using (5.32).

$$EP_{c2} = Y(C_3W_3 + C_5W_5 + C_4W_{10} + C_6W_6) \quad (5.32)$$

The total annual cost of consumables is given by (5.33).

$$EP_c = (EP_{c1} + EP_{c2})(E_p/100) \quad (5.33)$$

The algorithms do not include any allowance for the delivery of the materials to the plant site. Therefore, the unit costs of these materials should include the necessary freight cost to deliver to and unload at the plant site, i.e., FAS Owner's warehouse.

5.6.3 Utilities

o Electricity

The cost of electricity includes: power for electrowinning; all other components of the processing plant; and wellfield injection and lifting of fluids. Annual costs are computed by multiplying power usage by unit cost factors. The power for all non-electrowinning components excluding the wellfield, is taken at 105% of the electrowinning power. Unit cost factors L_3 and L_{10} are listed in Table C.2. Horsepower for injection and lifting of wellfield fluids is given by (5.21) and (5.23). The annual power cost is given by (5.34) in generic format. When underground wellfields are used, the horsepower for the mine plant electricals, HP_M , is added to HP_I and HP_P .

$$EP_E = C_{e1} [\alpha_{10} (HP_I + HP_P) + \alpha_9 Y] (E_p/100) \quad (5.34)$$

o Water

The annual water costs include water for personnel requirements and process usage. This cost is given as:

$$EP_w = [18,250 ST + 68 Y (E_p/100)] C_7 \quad (5.35)$$

The total cost of utilities is given by

$$EP_U = EP_E + EP_w \quad (5.36)$$

The algorithm does not include any allowance for the transmission of electricity to the plant's boundaries. Therefore, the electrical unit cost should include the cost to deliver electricity to the plant site.

5.6.4 Maintenance

Annual maintenance costs include the processing plant and the wellfield. The former is assumed to be 3% of the installed capital cost of the SX/EW plant, the latter is assumed to be 10% of the wellfield cost for surface drilling and 15% for drilling from the underground.

- o Surface plant

$$EP_{MS} = 0.03 EP_T \quad (5.37)$$

- o Wellfield

$$EP_{MW} = 0.10 EW, \text{ surface drilling} \quad (5.38)$$

$$EP_{MW} = 0.15 EW, \text{ underground drilling} \quad (5.39)$$

The total annual maintenance cost is EP_M :

$$EP_M = EP_{MS} + EP_{MW} \quad (5.40)$$

5.6.5 Environmental Monitoring Cost

The annual cost for monitoring has been estimated to be \$80,300 in Section 6.5.3.

$$EP_{EM} = \$80,300 \quad (5.41)$$

5.6.6 Total Annual Operating Cost

The total annual operating cost is noted by EP_o .

$$EP_o = EP_1 + EP_C + EP_U + EP_M + EP_{EM} \quad (5.42)$$

5.7 Initial Environmental Costs

5.7.1 Environmental Permitting Costs

Section 6.5.1 discusses the requirements and estimated costs that are likely to be related to permitting an in situ copper mining

facility. The cost is represented by EP_6 , and for this analysis has been estimated to be \$462,500. The user has the option of varying this parameter in the economic analysis.

$$EP_6 = \$462,500 \quad (5.43)$$

5.7.2 Monitoring Well Costs

Section 6.5.2 discusses the development of a generic algorithm for estimating monitoring well costs. It is assumed that one set of wells are drilled to the bottom of the ore zone at a given areal density, and that a second set of wells are drilled to straddle the water saturation level at a second areal density. The water saturation level is assumed to be approximated at 500 feet below the surface. The generic cost algorithm is given by EP_7 .

$$EP_7 = [C_{MA} D + C_{MW} WD] A_{WT} \quad (5.44)$$



CHAPTER 6

ENVIRONMENTAL PERMITTING IN STATE OF ARIZONA

6.1 OVERVIEW OF PERMIT REQUIREMENTS AND KEY ISSUES

The environmental permit process associated with the construction, operation and reclamation of an ISL facility in Arizona involves federal, state and local regulatory agencies and several environmental issues. Due to the nature of the ISL approach to mining copper, the primary issues are those related to the protection of groundwater quality and the conservation of the groundwater resources. In conjunction with these groundwater protection concerns are those of minimizing impacts on surface water quality, soil/vegetation/wildlife resources, air quality, cultural resources and visual/noise conditions.

Environmental laws relating to underground injection are designed to protect groundwater quality or manage the groundwater resource. The legislative intent of these laws is administered through the rules and regulations of three agencies: the U.S. Environmental Protection Agency (EPA), the Arizona Department of Health Services (ADHS) and the Arizona Department of Water Resources (ADWR). The EPA presently maintains regulatory authority in Arizona through the Underground Injection Control Program (UIC) which was promulgated under Part C of the Safe Drinking Water Act (SDWA) and the Resource Conservation and Recovery Act (RCRA). The general provisions, requirements for state programs and technical standards of the UIC Program are contained within Parts 144 through 146, 40 CFR, Chapter 1. Through the EPA UIC rules and regulations, the EPA encourages each state to establish and administer a UIC program by seeking and receiving approval of a specific plan, as

outlined in 40 CFR, Chapter 1, Part 145. To date, Arizona does not have such a program.

Since July of 1984, water pollution control in Arizona has been administered by the ADHS as specified in Article 2, Chapter 20 of the Arizona Compilation of Administrative Rules and Regulations (R-9-20-201 through 226). However, the entire Arizona environmental permit structure and degree of regulatory authority related to aquifer protection is now in a period of transition due to the enactment of the Environmental Quality Act (EQA) of 1986 (House Bill 2518, Chapter 368). The effective date of this enabling legislation was August 13, 1986, but two to three years of rulemaking will be required to implement the intent of the new law.

The Arizona EQA is viewed as one of the most comprehensive state environmental laws now in existence. The EQA authorizes the formation of a new Department of Environmental Quality (DEQ) on July 1, 1987, with the authority to protect the state's water resources from all activities that have the potential to degrade water quality. The new DEQ permit structure will require the permit applicant to demonstrate the use of the best available demonstrated control technology (BADCT) to ensure aquifer protection. The EQA initially classifies all aquifers in Arizona as sources for drinking water. Exemptions to the general aquifer classification will require specific hydrologic evaluations and assurance that adjacent sources of drinking water are protected. Modeled after the federal superfund law, the EQA establishes the financial structure and DEQ authority to remediate water pollution problems.

The ADHS/DEQ is obligated by the EQA to establish a UIC program for Arizona. A draft regulatory agenda recently issued by the ADHS targets April of 1988 as a submission date for draft UIC regulations. Following review and public hearings, a certification date of December, 1988 is tentatively planned. To acquire primacy over the EPA for injection control, the new DEQ will need to emplace UIC rules and regulations in conformance with the UIC-EPA requirements. Those EPA requirements do not preclude Arizona from adopting a more stringent or more extensive program (40-CFR-145).

In Arizona, the management of surface water and groundwater resources is administered by the ADWR. Due to a long-term overdraft problem in some of Arizona's large alluvial groundwater basins in the central and southern portions of the state, a comprehensive groundwater management act was passed by the Arizona legislature in 1980 (The Groundwater Code). The Code established four active management areas (AMAs) and three nonexpansion areas, as shown on Figure 6.1. Generally, the use of groundwater in the AMA's is more strictly regulated, with explicit mandatory conservation measures required. The Code basically restricts the withdrawal of groundwater to those with groundwater rights or permits, and institutes a 45-year management and conservation program.

In an effort to conserve the groundwater resources within an AMA, the management plans have established conservation requirements for metal mining facilities. These requirements obligate the operators of existing and new facilities to apply the latest commercially available conservation technology which is consistent with a reasonable economic return. Although the specifics of the AMA management plans normally

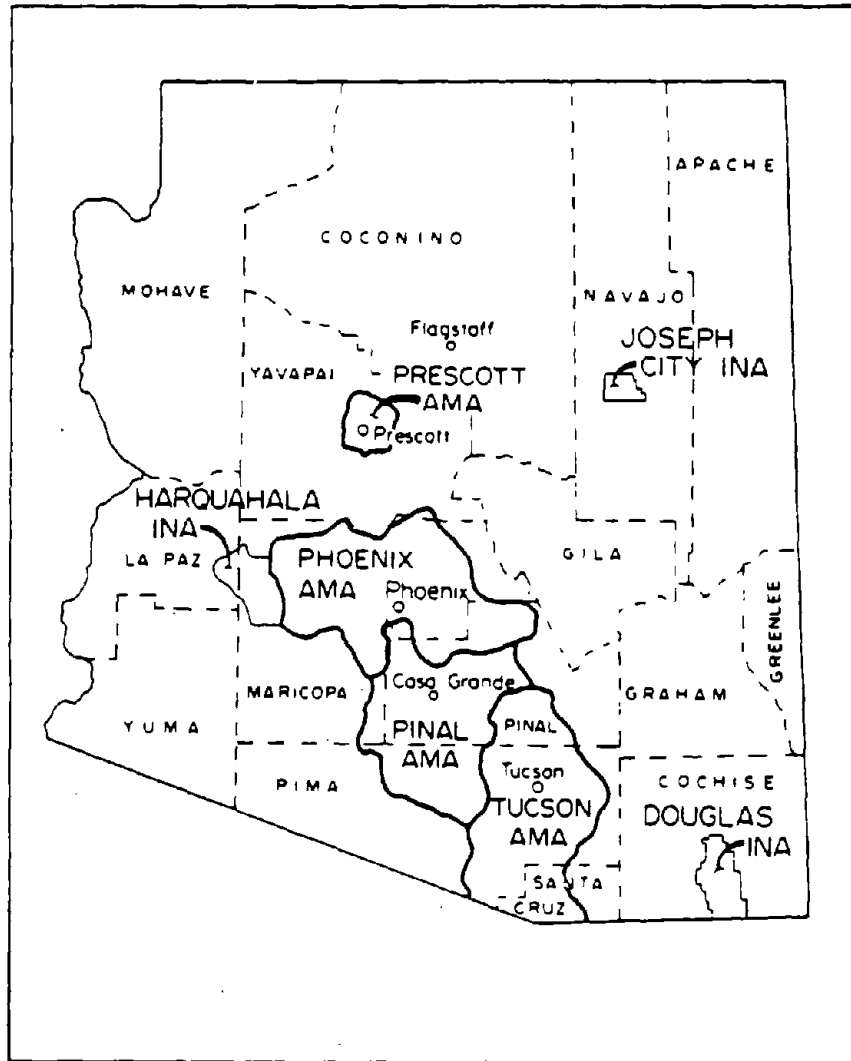


Figure 6-1. Active Management Areas and Irrigation Non-Expansion Areas in Arizona

deal with water consumption in the tailings disposal operation, the ISL process would be scrutinized to evaluate its consumptive use and methods to conserve the resource. The AMA plans also specify monitoring and reporting requirements, and recommendations for cooperative research and long-range conservation for the mining industry.

In its designated role in water resource management, the ADWR also regulates the construction of wells and licensing of well drillers, as specified in the rules and regulations of Title 12, Chapter 15, Article 8 (R12-15-801 through 821) and the Arizona Revised Statutes, Title 45, Chapter 2, Article 10 (45-591 through 604). In brief, the ADWR sets quality standards for the rehabilitation, deepening, replacement, completion and abandonment of wells, and administers the testing and licensing of well drillers. Within an AMA for entities which hold prior rights, the deepening or replacement of a well requires the filing of an Intention to Drill. The ADWR subsequently reviews this notification and approves or disapproves of the actions in accordance with specific rules and regulations. The same holds true for new or replacement wells in an area not subject to active management. Within AMAs, new construction is subject to a permit process. The permit application specifies well construction details, well location, ownership and other data, and is subject to ADWR approval within 60 days of submission. For the deepening of existing wells and the construction of new or replacement wells, all work must be performed by a duly licensed well driller who is required to file a completion report within 30 days for each well.

Although regulatory jurisdiction in Arizona is not clearly defined, the state entities discussed above will probably assume that the

environmental permit and compliance requirements of their particular agency are in force, regardless of land ownership. By far, the most unclear situation relative to this issue is the jurisdiction over Indian lands administered in trust by the U.S. Bureau of Indian Affairs (BIA). The BIA, in turn, utilizes the U.S. Bureau of Land Management (BLM) as a "mining supervisor" on mining lands covered by a permit or lease. The staff of the permits section of the ADHS contends that the language of the ARS 36-1865 provides the ADHS with regulatory authority on Indian lands. Whether the DEQ will continue to consider Indian lands within their jurisdiction remains in question.

The preservation and protection of environmental resources on federal lands administered by the BLM or BIA is entrusted to those agencies and subsequently defined by the federal regulations of 43-CFR-3570 and 25-CFR-216, respectively. The technical requirements of these two bodies of regulations are quite similar; in fact, the BIA regulations now specify that the BLM will assist in the supervision of the environmental requirements. The regulations establish several overall objectives in addition to environmental protection, including the promotion of effective prospecting, avoidance of loss of the mineral resource, and worker health and safety.

The BLM/BIA regulatory structure requires the submission of several plans by the mining operator. These plans are grouped into an Operating Plans category, which includes exploration plans, mining plans and revegetation plans. Contained within this body of environmental submittals are descriptions of preventive measures to protect the environment, proposed methods of mining, reseeding plans and proposed reclamation actions. These regulations are broad and quite narrative, resulting in considerable latitude for administering the intent of the

regulations. It should be expected that the degree of characterization of the natural and cultural resources required will be contingent upon the perception of potential deleterious impacts. As an example on Indian lands, the potential for impacting archeological resources may trigger considerable preconstruction site studies to adequately define and mitigate any environmental consequences.

Should a proposed ISL project be located on federal lands administered by the U.S. Forest Service (USFS), the regulatory requirements may differ from those of the BLM or BIA. Mining development on USFS lands normally involves more vegetated terrain, significant wildlife habitats, and regions of perennial stream flow and groundwater recharge. The permit structure of the USFS is twofold. First, the USFS requires the submission of a comprehensive operating plan similar to that required by the BLM (36-CFR-228.0). In addition, an environmental assessment or impact process can be put into motion as a result of a notice of intent to mine. The scope of such a process is again contingent on the size of the project and the anticipated level of environmental impact.

The most comprehensive body of environmental regulations related to underground injection control are those promulgated by the EPA-UIC program on July 24, 1980. The UIC program establishes a regulatory format based upon an injection well classification system and authorization to inject by rule or by permit. For the subject ISL mining scenarios, two well classifications are involved. The EPA has designated one category of wells (Class III) for installations which are used to extract minerals from ore bodies which have not been conventionally mined. Injection wells and other solution mining

techniques applied to the extraction of minerals from previously mined areas falls under a broad miscellaneous classification (Class V). As will be discussed at length in Section 6.2.2 of this document, the underlying difference between the Class III and Class V wells is the fact that the Class III well is authorized by permit, whereas the Class V is authorized by rule. The permit process is much more involved, in terms of the level of site and process characterization required, and reporting/monitoring requirements.

Part 145 of the EPA-UIC regulations establishes guidelines and requirements for the establishment of state UIC programs. To obtain primacy over the EPA, the Arizona DEQ will be obligated to conform to these requirements. One can expect the Arizona UIC regulations to parallel the EPA-UIC regulations. As such, the Arizona program will specify construction standards, reporting/monitoring requirements, a permit format, plugging and abandonment guidelines, a schedule of compliance and assurance of financial responsibility.

Although subordinate to the environmental issue of protecting water quality, the development of an ISL facility will involve another permit process for the protection of air quality. Air quality regulations in Arizona are administered by the ADHS or, in some cases, county air quality control districts. As specified in ACRR, Title 9, Chapter 3, installation and annual operating permits are required. These permits are designed to specify the allowable quantities of fugitive dust and volatile organic contamination.

Should a proposed ISL facility have the potential to impact the environmental quality of navigable waterways, lakes, streams or wetlands, the Department of the Army maintains regulatory jurisdiction

as authorized by Section 10 of the River & Harbor Act of 1899, Section 404 of the Clean Water Act and Section 103 of the Marine Protection, Research and Sanctuaries Act. The regulatory program is administered by the U.S. Army Corps of Engineers and is normally identified as the 404 Program. As defined in 33-CFR-320.0 through 330.0, the 404 Program permit application process requires the identification of the location, purpose and nature of the proposed activity and the submission of design drawings. The application is then subject to agency and public scrutiny.

Although not considered to be environmental in nature, the prospective ISL operator should be aware of a variety of permit processes and conformance to codes which could impact project schedule and cost. In brief, the Arizona county governments maintain building and fire codes, and enforce standards for the installation of septic disposal systems. The State Mine Inspector regulates mining activities and abandonment procedures as they relate to worker and public safety. The ADWR regulates the construction of dams and issues dam safety permits. Tribal entities on Indian lands in Arizona maintain the right to approve or reject mining plans of operation and establish specific restrictions related to employment and protection of cultural resources.

The EPA is in the process of developing regulations for mine wastes under Subtitle D of RCRA. Recently, the EPA issued a decision that mine wastes should not be categorized as hazardous waste under Subtitle C (40-CFR-261.0). This latest action instructs EPA to pursue the revision of Subtitle D regulations for the inclusion of mine wastes, as they were originally designed to regulate municipal wastes. Studies are now underway, with the intent of proposing revisions to Subtitle D criteria

by mid-1988. Much of the emphasis related to mine wastes deals with tailings disposal practices and heap leach facilities. In what manner an ISL operation would be involved with these regulations is unclear. The key issue is the definition of waste as applied to the operation and subsequent abandonment of an ISL facility. An example is the potential for classifying the remnant process fluids in the ore body as a waste. If this is considered appropriate by the EPA, the RCRA Subtitle D regulations may impose some constraints on the level of restoration required. In actuality, it is not anticipated that such RCRA involvement would cause a significant change in the closure requirements already delineated by the EPA-UIC program and the Arizona EQA.

During discussions with professionals in the mining industry, the project team and representatives of the various agencies, several key environmental issues have arisen. These issues are significant because they embody all the potentials for water and air quality degradation. The environmental permit application processes for any ISL development will need to address these issues in some manner. As related to these issues, the remaining portions of this chapter further identify the permit requirements, methods to satisfy these requirements, and delineate the regulatory stance on some of the concerns. Some of the issues are too site specific to be fully answered within the context of a generic document.

The following summarizes the key environmental and regulatory concerns expressed during development of this generic presentation.

- o Inherent design features of the ISL process which protect overlying or adjacent sources of drinking water.
- o The potential water quality impacts on overlying aquifers resulting from leakage upward through exploratory drill holes.

- o Degree of hydrologic isolation required to protect groundwater quality.
- o Potential environmental effects of employing polymers to eliminate short circuits.
- o Acceptable methods and level of monitoring required.
- o Determining the necessity to restore ore body water quality, the degree of such restoration and the timing of required restoration.
- o Defining what constitutes an aquifer and opportunities to exempt.
- o Potential for environmental effects resulting from matrix modification by blasting or stimulation by hydraulic fracturing.
- o Regulatory provisions for the creation of saturated conditions in a previously unsaturated profile.
- o Nature of the process fluids and potential for air/water quality degradation in SX-EW above-ground circuit.
- o Upon cessation of operations, fate of various spent fluids and solid wastes in SX-EW plant.
- o Degree of hydrogeologic characterization prior to permit acceptance and role of hydrological modeling.

Of the variety of environmental factors which affect ISL process feasibility, restoration encompasses the most uncertain arena. Questions exist as to its technical effectiveness, cost, and whether permitting will require active restoration. Aquifer restoration is defined as the reduction of the concentrations of lixivants and other mine-related contaminants within a saturated ore body to acceptable levels following the completion of mining activities. The regulatory definition of acceptable levels will vary, depending on site specific conditions. For some ISL operations, it could be necessary to reduce contaminant levels to baseline water quality levels. For ore bodies which are hydrologically isolated from sources of drinking water, the active restoration of baseline water quality levels may not be required.

6.2 REGULATORY PROVISIONS, AUTHORIZATION AND CONSTRAINTS

Considering the lack of a specific Arizona UIC program and the general descriptive nature of other federal regulations (BIA, BLM, USFS), the EPA-UIC regulations provide the most current insight into the regulatory constraints that will be imposed on the ISL program. The EPA program is used as a basis for discussing the permitting criteria and requirements, with comparative and supplemental discussions of the other regulations. As previously mentioned, groundwater quality protection is the focal environmental issue.

6.2.1 Aquifer and Underground Sources of Drinking Water - Definitions and Aquifer Exemptions

As defined by the EPA in the UIC regulations, an aquifer means a geological formation, group of formations or part of a formation that is capable of yielding a significant amount of water to a well or spring (146.3). The new Arizona EQA has adopted similar language in defining an aquifer; a geologic unit that contains sufficient saturated permeable material to yield usable quantities of water to a well or spring (36-3501). There appears to be adequate latitude in both the Arizona EQA and the EPA definition of an aquifer to classify a saturated copper ore body as an aquifer. In both cases, however, sufficient flexibility is provided so as not to preclude ISL mining under certain conditions.

In terms of the EPA regulations, the exemption of an aquifer is first contingent upon the fact that the geologic unit meets the criteria in the definition of an "underground source of drinking water" (USDW). A USDW is defined as an aquifer or its portion which meets the following criteria (146.3):

- o Supplies any public water system; or
- o Contains a sufficient quantity of groundwater to supply a public water system; and
 - Currently supplies drinking water for human consumption; or
 - Contains fewer than 10,000 milligrams/liter (mg/l) total dissolved solids; and
- o Which is not an exempted aquifer.

Should the geologic unit containing the ore body meet the definition of an USDW, the EPA regulations (40 CFR 146.4) provide criteria for exempted aquifers, as follows:

- o It does not currently serve as a source of drinking water; and
- o It cannot now and will not in the future serve as a source of drinking water because:
 - It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible;
 - It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;
 - It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or
 - It is located over a Class III well mining area subject to subsidence or catastrophic collapse; or
- o The total dissolved solids content of the groundwater is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

In summation, the issue of aquifer definition and classification in terms of the EPA-UIC program appears to provide three avenues by which saturated ore bodies could be mined by ISL methods. First, low

permeability and poor water-bearing characteristics could preclude the initial definition of the ore body as an aquifer. Secondly, should aquifer yield be considered significant, the aquifer could be insufficient in its water-bearing characteristics or water quality to be classified as a USDW. Finally, a portion of a USDW could be exempted if it meets specific criteria.

The language of the new Arizona EQA approaches the issue of aquifer standards, classification and exemption in a different manner. The DEQ is instructed to adopt, by rule, numerical water quality standards for all waters. Numeric limitations on the concentrations for 126 toxic priority pollutants will be adopted by 1990. The EQA initially classifies all aquifers in the state for drinking water use. Other uses require reclassification under a stringent set of guidelines paraphrased from Arizona EQA (8/13/86) Section 36-3524:

- C.1 The aquifer or part of an aquifer is or will be so hydrologically isolated from other aquifers or other parts of the same aquifer that there is no reasonable probability that poorer quality water from the identified aquifer or part of an aquifer will cause or contribute to a violation of aquifer water quality standards in other aquifers or parts of the same aquifer.
- C.2 Water from the aquifer or part of an aquifer is not being used as drinking water.
- C.3 The short-term and long-term benefits to the public that would result from the degradation of the quality of the water in the identified aquifer or part of an aquifer below standards would significantly outweigh the short-term and long-term costs to the public of such degradation. Benefits and costs to be considered include economic, social and environmental.
- D. Owners or operators of facilities whose discharges are solely responsible for creating an aquifer may petition the DEQ for a classification of the aquifer for a nondrinking water use.
- E. Public participation is mandatory. At least one public hearing is to be held at a location near the aquifer proposed for reclassification.

After reclassifying any aquifer to a nondrinking water status, the DEQ will adopt standards specifically for the exempted aquifer (36-3523). Standards established for pollutants used as a basis for reclassification will minimize unnecessary degradation, with all other standards remaining the same as those for drinking water aquifers.

As aquifer definition relates to the overall issue of regulatory acceptance, it appears evident that any ISL mining proposal will require that the well systems and the hydrogeologic setting afford adequate hydrologic isolation from existing and future sources of drinking water. It is the responsibility of the ISL facility operator/owner to provide sufficient hydrological data and interpretations to support a petition to exempt or reclassify aquifers.

6.2.2 Well Classification

The EPA-UIC regulations classify wells into five categories, two of which apply to in situ leaching of copper ore (144.6). Class III includes wells which inject for the extraction of minerals, including the in situ production of metals from ore bodies which have not been conventionally mined. Class V is a miscellaneous category which includes solution mining of conventional mines such as stopes leaching and wells used in experimental technologies.

Between the two well classes discussed above, the inherent difference is between authorization by rule and authorization by permit. Injection into Class V wells is authorized by rule until future regulations become applicable. Wells which fall into this category inject nonhazardous fluids and are generally considered less of an environmental risk. The operator of a Class V well is obligated to provide

generalized inventory information. However, the EPA can require the owner of any injection well to submit additional monitoring, analyses of injected fluids and hydrogeologic data.

New Class III wells are authorized by permit. As is discussed at length elsewhere in this document, the use of Class III wells entails a complex permit application process, construction standards, operating, reporting and monitoring requirements, and the submission of an abandonment plan.

6.2.3 Well Stimulation and Operating Constraints

The EPA-UIC regulations do not preclude the use of well stimulation techniques, including borehole blasting or hydraulic fracturing as a means to improve wellfield performance. During production, injection pressures of the wellhead are not to exceed those calculated to be capable of initiating new fractures or inducing the extension of existing fractures (144.28). At all times, the integrity of the confining zone cannot be compromised by well stimulation techniques.

6.2.4 Area of Review and Point of Compliance

Within the context of the EPA-UIC program, the permit applicant is required to establish an area of review. For area permits which are applicable to the ISL mining process, the area of review is defined as a circumscribing area, the width of which is the lateral distance from the perimeter of the project area, in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an USDW (146.6). Defining the area of review helps establish the position of monitoring wells and assists in the appraisal of potential for water quality degradation.

Considerable latitude is provided as to the calculation of the area of review. For a wellfield, the Theis Equation utilized in the form presented in 40-CFR-146.6 can be applied to the problem of defining the area of review. Modifications to the Theis Equation, such as the one developed by William Benard for the EPA (draft area of review EPA handout, no date), can also be applied. A fixed width of not less than one-fourth mile circumscribed around the project area can also be designated. Other mathematical models can also be utilized.

The Arizona EQA defines a point of compliance as the location at which aquifer water quality standards will be determined (36-3544). In the case of in situ leaching, this point of compliance would be the location of boundary monitoring wells. The point of compliance is further defined as a vertical plane downgradient of the facility that extends through the uppermost aquifers underlying that facility. Little latitude for positioning the point of compliance is provided if the pollutants are considered hazardous. Once again, the intent of the law is to protect drinking water sources, and the EQA language provides some generic flexibility for dealing with all potential sources of contamination. In all cases, the point of compliance will not be further downgradient than the property boundary, at any point of an existing or future source of drinking water, or 750 feet from the edge of the pollutant management area.

6.2.5 Financial Responsibility

The Arizona DEQ and the EPA require information to confirm the financial competence of the owner/operator of an injection facility which has the potential to affect water quality. The nature of this

information is not specified by the Arizona EQA. However, an EPA handout lists several financial instrument mechanisms. For Class III wells, the confirmation of financial responsibility is to assure proper closure and abandonment of the wells at the cessation of operations (144.52).

The financial assurance mechanisms which are acceptable to the EPA are as follows (personal communication, Ms. Jane Carlin, EPA, 3/17/87):

- o Trust fund with deposit equal to the required financial coverage.
- o Insurance policy with assurance of payment of plugging costs up to the face amount.
- o Surety bond established with a licensed surety company.
- o Financial statement.
- o Letter of credit.

6.2.6 Restoration

The Arizona EQA and the EPA-UIC regulations do not specify the need to perform active aquifer restoration. In both cases, it is either stated or implied that postoperation aquifer cleanup and/or monitoring can be required to ensure adequate protection of drinking water sources (146.10). Obviously, the issue as to whether active restoration is appropriate is site specific.

6.3 PERMIT REQUIREMENTS

6.3.1 Permit Conditions and Application Information - Aquifer Protection

The general application information which is specified by the EPA, and currently required by the ADHS for aquifer protection permits is

delineated on Table 6.1. The EPA has the latitude to issue two different types of permits, the well permit and the area permit (144.33). The application for area permit is appropriate for an ISL facility which involves many injection and production wells.

The new Arizona DEQ will issue an aquifer protection permit on a site specific basis. With the current lack of regulations, the future permit application requirements are not clear; however, the EQA provides some guidance. In addition to the background data listed in the second section of Table 6.1, the EQA specifies that a hydrogeologic study be presented which defines and characterizes the discharge impact area, including the vadose zone (36-3543). The DEQ will also be required to structure the permit process to include contingency planning, compliance schedule requirements and postclosure planning. The applicant should be prepared to define the conservation aspects of the control technology applied and the cost of such technology. From past experience, the ADHS/DEQ will require final design plans and specifications prior to granting an aquifer protection permit.

6.3.2 Monitoring and Mechanical Integrity Tests

As interpreted from a reading of the EPA-UIC regulations, the level of water quality monitoring for Class III well programs is based upon the ambient water quality of the receiving formation. If the formation contains water with less than 10,000 mg/1 TDS, monitoring wells shall be completed in the injection zone and into any overlying sources of drinking water. If the formation waters exceed the TDS concentration of 10,000 mg/1, no monitoring wells are required for the injection zone. The case of an unsaturated ore body is not specifically addressed. The

TABLE 6.1. GENERAL PERMIT APPLICATION INFORMATION REQUIRED

1. EPA-UIC Program Area Permit (Class III Wells)General Inventory and Site Design Input

- o Owner and operator name, address and EPA ID number.
- o Operating status of injection wells.
- o Type of project and project name.
- o Mapping of facilities showing surface facilities, project area, public water supply facilities, mining, quarries, residences and roads.
- o Well field mapping showing all wells, with depth and type identified, and other wells, springs and surface water bodies within one-quarter mile of property.

Hydrogeologic Characterization

- o Discussion of regional structural and stratigraphic setting and seismic activity.
- o Presentation of local structural conditions, including maps and cross sections which contour the top of the injection zone and any other significant structural features.
- o Descriptions, by text, geologic cross section and mapping, the hydrogeology of the injection and confining zones and any sources of drinking water. The following data are required.
 - * TDS levels for each formation.
 - * Thickness, age, mineralogy, lithology, structure, bedding and texture of injection and confining zones.
 - * Hydrologic parameters of permeability, porosity, oil/water saturation, reservoir pressure and formation fracture pressure.
 - * Stratigraphic column showing basic geology, hydrologic properties and salinity profile of all formations in project area.
 - * Isopach mapping of confining and injection zones.
 - * Formation water chemistry and flow behavior, including TDS, specific gravity, temperature and direction and rate of regional groundwater flow.

TABLE 6.1. GENERAL PERMIT APPLICATION INFORMATION REQUIRED (continued)

Determination of Area of Review

- o Presentation of which EPA-approved method applied to problem.
- o Description of calculation and assumptions.

Corrective Actions and Contingency Plan

- o Description of the type, construction, location and abandonment status of all wells in area of review.
- o Contingency plan for well failure.
- o Remedial action plan for improperly plugged wells.

Mining Process Description

- o Injection fluid characteristics, including RCRA waste characterization and corrosive potential.
- o Operating data, such as injection rate and pressure, and annular fluid type and pressure.
- o Description of surface facilities, with process diagram and any plans for the disposal of sludges or other deleterious materials.
- o Well construction details, including casing to be used, cementing program, well completion and stimulation techniques and tubing and packer details.
- o Logging program proposed, including geophysics and lithologic logging.

Monitoring Plan

- o Description of mechanical integrity testing.
- o Groundwater monitoring program.

Financial AssurancePlugging and Abandonment Plan

- o Plugging program.
- o Cost estimates.

TABLE 6.1. GENERAL PERMIT APPLICATION INFORMATION REQUIRED (continued)

2. Arizona Department of Health Services [Aquifer Protection Permit]
- General Inventory and Site Design Input
- o Owner and operator names and addresses.
 - o Facility location and type.
 - o Description of proposed activities, including the standard industrial classification code(s) which apply.
 - o Planned commencement date and life of operation.
 - o Listing of other permits.
 - o Description of control measures which will be implemented to protect water quality.
 - o Description of process fluids and any wastes generated.
 - o Site plan(s) showing all structures, impoundments and processing facilities.
- Hydrogeologic Data
- o Well inventory in study area, describing use of groundwater.
 - o Presentation of groundwater quality data.
 - o Depth to groundwater.
 - o Geology.
- Monitoring Program
- Requires site specific input.
- Discharge Impact Assessment
- Contingency Plan
- Closure and Post Closure Plan
- Remedial Action Plan

proximity of such an ore body to an USDW will probably influence the monitoring system design more than the fact that the ore body is considered to be initially unsaturated. When injection will not occur through or above an USDW, the EPA has the regulatory latitude to authorize a permit with less stringent monitoring and other requirements (40-CFR-144.16).

The EPA-UIC regulations are specific concerning some aspects of monitoring a Class III well program. Within the first year of authorization, the owner/operator is required to submit a qualitative analysis and range of concentrations of all constituents of the injected fluid. These data need to be revised and submitted whenever the fluid is modified. In addition, the regulations specify the following monitoring requirements (146.33).

- o Monitoring of injection pressure and either flow rate or volume semimonthly, or metering and daily recording of injected and produced fluid volumes.
- o Demonstration of mechanical integrity or presentation of cementing records to ensure containment.
- o Monitoring of fluid levels in injection zone semimonthly.
- o Measurement of indicator water quality parameters semimonthly.

The monitoring required for the Class III facility can be partially accomplished by manifold monitoring rather than metering each well. A reduced level of monitoring can be anticipated for high TDS saturated conditions and unsaturated, remote locations.

6.3.3 Well Construction Standards

The ADWR administrative rules and regulations (R12-15-8) and the EPA regulations (146.32) address the issue of well construction

standards. In the case of the ADWR permit structure, any ISL production or injection well would be considered as a variance within the well permit process due to the unique nature of the construction. A variance clause is included in the ADWR rules (R12-15-820) to allow for unique well construction which differs from normal installations, but fully assures aquifer protection. The ADWR and the EPA standards are both highly narrative, with the expressed intent of preventing harmful effects upon the quality of the groundwater intercepted. The EPA specifies that logging and other tests be performed during the drilling and construction of new Class III wells. Deviation checks are also required, unless the hole will be cased and cemented (146.32).

Under normal well drilling conditions, the ADWR requires the construction of a surface seal. This seal is to consist of a minimum length of 20 feet of steel casing and cement grout. The ADWR will also require complete borehole isolation between the injection zone and any overlying potable sources of groundwater. The ADWR further specifies the need to abandon all wells. For wells which penetrate a single or multiple aquifer system with vertical flow components, the well column is to be filled with cement grout or bentonite drilling mud (R12-15-816). Wells which are temporarily secured to allow for re-entry require proper capping (R12-15-817).

6.3.4 Reporting and Record Keeping

The Arizona EQA states that permit conditions will delineate record keeping and reporting requirements, but does not specify the nature of these requirements. Alert levels will be established which would require appropriate contingency and remedial action, should a specific

water quality parameter concentration be exceeded. The EPA requirements are equally generic with the following being the only details provided in the regulations for Class III well programs (146.33).

- o Quarterly reporting of all monitoring.
- o Quarterly reporting of the results of mechanical integrity and any other periodic testing.
- o Retention of calibration, maintenance and measurement records for a period of three years.
- o Retention of records on nature and composition of injected fluids for three years after plugging of wells. Subsequent submission of these records to EPA.
- o Notification to EPA before converting or abandoning well(s).
- o Plugging and abandonment report required.
- o Notification to EPA on change of ownership.

6.3.5 Contingency Planning and Corrective Action

Corrective action as used in the context of the EPA-UIC regulations are efforts necessary to prevent migration of injected fluids into sources of drinking water (144.55). It is implied that these corrective actions are performed on improperly plugged or unplugged wells and boreholes which could provide conduits for flow of process fluids from the injection zone to a potable aquifer. It is normal for a large number of exploratory boreholes to be present in an ore body. The requirement is for the applicant to identify all known wells (boreholes) and develop a plan to eliminate the potential for uncontrolled migration through these openings.

The EPA is obligated by regulation to consider the overall effect of the project on hydraulic gradient in analyzing potential water quality impacts upon nearby USDWs (144.55). It is possible that such an

appraisal may result in the finding that no corrective action is required. In such a case, however, the monitoring system would be designed to verify the assumption that no detrimental effects will occur.

Although no technical guidance is provided by EPA or the ADHS, contingency plans are required as part of the UIC Class III permit application (146.33-146.35) or during the ADHS permit procedure. The nature of any contingency plan is to set forth methods by which excursions of process fluids from the injection zone could be arrested. Although this is a site specific issue, such methods as adjusting pumping and injection activities to route contaminants to the system, and grouting techniques could be incorporated into any contingency plan.

6.3.6 Well Plugging and Abandonment

All Class III wells are to be plugged prior to abandonment in accordance with EPA requirements (146.10). The plugging material can be cement or other material approved by the EPA. The placement of cement plugs is to be accomplished using one of the following standards methods.

- o The Balance Method
- o The Dump Bailer Method
- o The Two-Plug Method
- o An alternative method approved by EPA.

Smith (39) describes the balance, dump bailer and two-plug methods of placing cement slugs in boreholes. In the balance method, cement slurry is introduced through a drillpipe or temporary tubing to place a

plug at a prespecified interval. Once the level of cement outside the pipe is equal to the slurry head within the pipe, the string is slowly removed. In the dump bailer method, the cement slurry is carried to the desired interval in a bottom dump bailer suspended on a wireline. A limit plug or other intended obstruction is usually present below the plug interval. The slurry is released from the bailer by actuating the bottom valve. This method usually requires repeated runs with the bailer to emplace a plug of sufficient vertical extent. If the two-plug method is applied, tubing plugs are used at the top and bottom of the cemented interval. The bottom of the interval receives a bridge plug. A baffle tool is then placed at the plug interval. This special tool allows slurry to be introduced into the annulus while the top plug rises and is subsequently caught as it follows the cement. Once the top plug is in the catcher, the surface slurry pressure rises, indicating that the plug has landed.

A state of static equilibrium with the mud weight equalized throughout the borehole must be established prior to full abandonment. A requirement for long-term monitoring can be dictated by the EPA.

The ADWR regulations also specify the need to properly abandon all wells (R12-15-816). Any penetration of one or more aquifer system(s) with vertical flow components requires sealing with cement grout or bentonite drilling mud of sufficient volume, density and viscosity to prevent vertical fluid movement.

6.3.7 Best Available Demonstrated Control Technology

The Arizona EQA contains the stipulation that a discharging facility will be designed, constructed and operated to ensure the

greatest degree of discharge reduction by the utilization of the best available demonstrated control technology (BADCT) (36-3543). To implement such an objective, the new DEQ will first have to define, on a generic basis, what constitutes the BADCT's for any particular class of facility. During the permit application process, site specific factors of process activity, geology and hydrology will also come into play.

The enabling act provides for the consideration of several factors when applying the BADCT stipulation to any particular facility. Site specific conditions which provide a degree of hydrologic isolation can be considered when determining BADCT. Cost may also be taken into account, but only in a generic manner. If a control technology is applied throughout any particular industry, then the financial impact of applying the technology industry-wide can be considered. However, when applying BADCT to any particular facility, a particular proven application cannot be rejected on a financial feasibility basis alone.

As implied in the language of the BADCT concept, any technology implemented to protect water quality will be available and demonstrated. Availability is interpreted to mean practicability, in the sense that any applied technology must be feasible, and its application would not adversely impact the effectiveness of the industrial process. To be demonstrated, the control technology is to be in commercial use and shown to be effective. This demonstration of effectiveness could have taken place worldwide, but must involve a commercial-scale facility.

In the case of a new ISL facility in Arizona, the implementation of BADCT bears heavily on the proven application of control technologies overseas. It will be imperative that such technology be adequately defined so as to demonstrate proven methods to protect groundwater

quality. The use of past or future pilot-scale testing in the United States will probably not be adequate in defining BADCT for the ISL process. There certainly is an opportunity for considerable cross-over from the uranium ISL industry. Current leaching activities involving previously mined areas, such as at the Noranda property, will also be the source of proven control approaches.

A remaining BADCT stipulation contained in the EQA is the conservation of water resources. Should a control technology require the use of large volumes of water, the application of such technology must be weighed in light of the impact on natural resource reserves. It may be preferable to allow limited discharge of nonhazardous substances which do not jeopardize aquifer water quality standards, than to require the use of a high water consumption technology. As with many issues embodied in the Arizona EQA, the BADCT concept must be ultimately applied on a site specific basis.

6.3.8 Water Resource Management

Although the mission of the ADWR is primarily related to water resource management, preventing water quality degradation constitutes a supplemental objective. In terms of permit stipulations, the Groundwater Code of 1980 (Code) directs the ADWR to enforce compliance to a complex body of water resource law, involving rights to withdraw groundwater in four active management areas (AMA's). Outside of these AMA's, the regulatory complexity is substantially reduced, with conformance to the Notice of Intention to Drill formal and specific well standards the only legal stipulations in force. In an AMA, the right to withdraw groundwater involves an exemption opportunity, other previously

acquired rights, and a permit process. The following outlines the regulatory structure as it may be applied to the construction and operation of a new ISL facility in an AMA (45-462 through 599).

- o Grandfathered Groundwater Rights. The ISL facility owner who retains grandfathered rights (GFR) has the expressed right to withdraw groundwater up to the yearly allotment of that right. Three types of GFR's exist: an irrigation GFR, a Type 1 non-irrigation GFR and a Type 2 nonirrigation GFR. The irrigation GFR is nontransferable to other locations and, therefore, may not be usable by the ISL facility owner. The Type 1 nonirrigation GFR normally allows the nontransferable pumping of up to 3 acre-feet of groundwater per acre of land retired from irrigation. The Type 2 nonirrigation GFR usage is based upon a history of prior usage and may be transferred.
- o Withdrawal by Permit. Without a GFR, approval for groundwater pumping may be granted by acquisition of a groundwater withdrawal permit. There are eight types of these permits, three of which may be applicable to the ISL facility. These three permits are dewatering, mineral extraction and metallurgical processing, and poor quality groundwater withdrawal permits. For the purpose of the permitting, dewatering is defined, in part, as water withdrawn from in, under and around ore bodies. This water may be used to meet mineral extraction and metallurgical processing requirements of the permittee. The mineral extraction/metallurgical processing permit is issued if the volume of water available from dewatering is insufficient. A poor water quality permit can be issued if the ADWR deems that no other beneficial use exists for water of substandard quality.

The application requirements for the permit structure discussed above involves submission of statements as to ownership, location, purpose for withdrawal, well construction details, anticipated amount of use, and possibly cost data. Permits normally stipulate well depth-to-water measuring devices required and annual reporting needs.

6.3.9 Air Quality

Prior to initiating construction of the ISL facility, the owner/-operator will be required to obtain an air quality installation permit

through the ADHS or one of six regional air quality control boards (R9-3-301). Currently, it is understood through conversations with ADHS officials that only three of these boards are active, and that the remainder defer the permitting back to the ADHS. As would be expected, the regions which encompass the urban areas of Arizona (Maricopa, Pima and Pinal-Gila) have active boards.

Following the submission of an installation permit, the ADHS or regional board issues annual operating permits to facilities which are capable of impacting air quality (R9-3-306). The SX-EW plant, which would be involved in the ISL process, may not be considered as a major source of air pollutants. However, there appears to be three potential sources of pollutants; dust from access and maintenance roads, vapor from the open storage of kerosene, and sulfuric acid mist. The generic design presented herein would limit acid mist concentrations to 1 milligram per cubic meter due to worker health requirements.

From a reading of the Arizona air pollution control regulations, it appears that a Class C installation permit will be required (R9-3-301). This category is primarily for subordinate sources of contamination. The basis for such a designation is contingent upon whether there is a significant potential for impacting air quality. The same basic premise holds true for the operating permit structure.

The regulations contain provisions for requiring the operator to perform air quality monitoring and collect data over a period of at least one year prior to construction (R9-3-305). This period can be shortened to not less than four months at the discretion of the agency. Air quality models may also be requested. Whether such monitoring and analyses will be required of the ISL operator has not been determined

and would be contingent upon the agency's receipt of a description of the proposed action.

The permit conditions will undoubtedly contain compliance statements with emission limitations, in addition to record keeping and reporting stipulations. Ambient air quality and emissions monitoring may also be required.

6.3.10 Plan of Operations

The requirement for a plan of operation is common to those regulatory entities which manage the mining of natural resources on federal lands (BLM, USFS, BIA). As an insight into the general nature of a required plan of operation, an outline of the information normally provided is presented in Table 6.2.

6.3.11 Miscellaneous Permits and Approvals

The above descriptions of permit requirements has been focused primarily on the environmental concerns of water quality protection. There remains a limited number of permits, approvals or code conformances which, in part, could be interpreted as environmental. As a brief overview of these requirements, a summary of the nature and responsible agency of these requirements is presented in Table 6.3.

6.4 MEETING PERMIT REQUIREMENTS

The objective of meeting all the permit requirements associated with the construction, operation and abandonment of an ISL facility begins at the conceptual planning stages and ends after cessation of

TABLE 6.2. OUTLINE OF INFORMATION NORMALLY REQUIRED
IN PLAN OF OPERATIONS

1. General Information
 - o Parent organization name and address.
 - o Division of parent organization name and address.
 - o Project name and address.
 - o Statement of purpose and need.
 - o General overview of project, including description of each major component, anticipated processing steps, plans for waste disposal, development schedule, etc.
 - o Project facilities maps, including locations of all component alternatives under consideration (1:24,000 or 1:12,000).
 - o Land ownership map for all project facilities.
 - o Processing facilities plot plan showing location of all air emission points and all liquid discharge points.
 - o Project schedule, delineating construction, operation, and abandonment phases.
 - o Estimated production (product quantity) by year, if variable.
 - o Materials/product transportation requirements.
2. Alternatives
 - o Full description of all project alternatives, including location, design, operational alternatives being actively considered.
 - o Brief description of all project alternatives previously considered and dismissed and the reasons for excluding the alternative.
3. Mining Procedures
 - o Well field design.
 - o Well construction standards.
 - o Progression, staging of leaching activity.
 - o Monitoring systems.
 - o Geometry of surface piping.

TABLE 6.2. OUTLINE OF INFORMATION NORMALLY REQUIRED
IN PLAN OF OPERATIONS (continued)

- o Operating schedule.
- o Production estimates.
- o Chemical characteristics of process fluids.
- 4. Processing Facilities
 - o Summary of processing facilities, including location of all facilities, description of each facility area, etc.
 - o Plot plan for processing facilities with location of all air emission and liquid discharge points.
 - o List of all materials/fuels/reagents required in processing, including materials storage and handling plans; estimates of annual requirements for all materials/fuels/reagents.
 - o Process flow diagram identifying all air emission and liquid discharge points.
 - o Summary description of processing sequence.
 - o Project closure information.
- 5. Water Supply
 - o Water supply requirements (volume, water quality, etc.) for process and drinking water.
 - o Location and design of water supply system, including well locations, pump stations, and preferred and alternative rights-of-way; pipeline materials, construction techniques, trench depths, etc.
- 6. Roads
 - o Location of all existing and proposed roads.
 - o Description of all proposed new roads or road realignments/improvements; including surface width, surface materials, access restrictions, etc.
- 7. Sewage and Solid Waste
 - o Description and location of proposed sewage treatment system.
 - o Description and location of proposed solid waste disposal systems.
 - o Methods for handling of toxic or hazardous materials.

TABLE 6.2. OUTLINE OF INFORMATION NORMALLY REQUIRED
IN PLAN OF OPERATIONS (continued)

8. Resource Protection and Pollution Controls

- o Generally, description of all proposed methods for protecting existing resources or limiting pollution.
- o Methods for controlling surface and groundwater discharges.
- o Methods for protecting wildlife, cultural, or other resource values, particularly on public land.
- o Proposed reclamation/revegetation programs for all project components, but especially those on public land.
- o Proposed monitoring programs.

TABLE 6.3. MISCELLANEOUS PERMITS, APPROVALS AND CODES

State Mine Inspector: Enforcement of state laws relating to worker and public safety.

County Fire and Building Codes: Arizona counties utilize uniform building and fire codes normally enforced by county planning and zoning or engineering departments.

Permit for Septic Disposal: Administered by County or by ADHS. Normally requires percolation testing and conformance to written standards.

mining. The process initially involves environmental site characterization and baseline monitoring, and progresses to a compilation of process details and presentations to the agencies. Prior to permit approval, plans for corrective action, contingency response, monitoring, closure, and possibly restoration need development. Once operating, active monitoring under a stringent quality assurance program will be required. Following mining, closure would be implemented and monitored.

Target ore zones for ISL mining can occur in low permeability, saturated, fractured bedrock where groundwater flow patterns are complex and difficult to analyze and model with precision. Comprehensive premining geologic and hydrologic investigations will constitute one of the first steps in the permitting process. The goal of the premining hydrogeologic investigations is to develop a working model that adequately predicts the manner in which the local hydrologic system will behave during the ISL mining operation. During ISL mining operations, the actual flow of lixivants and mine-affected groundwater is then fully monitored and the model is subjected to rigorous empirical verification or modification. Following the close of ISL operations, the monitoring system will probably need to be maintained until verification that water quality in the injection zone has been restored to acceptable levels.

The following report sections describe a normal progression of technical activities associated with the acquisition and maintenance of aquifer protection permits. Generic schemes and options for monitoring of the ISL facility in saturated and unsaturated conditions are presented.

6.4.1 Initial Agency Contacts

To establish a comprehensive and workable understanding on the part of the operator and the agency representatives, early communications and cooperation are essential. These initial activities can provide a forum in which the agency personnel can express their key environmental concerns and the ISL operator can explain the techniques which may be applied to protect water quality, and the nature of the site characterization activities slated for completion. The agency representative is also provided with an opportunity to suggest specific investigative techniques which he believes will resolve concerns about adequate aquifer protection. A timetable should be established which highlights milestone meetings, submission dates for technical data and application information, and review periods.

6.4.2 Hydrogeologic Characterization

To provide a basis for further study, a set of topographic maps of the site area at various scales, showing all existing and planned facilities, should be prepared. This mapping should include the following:

- o Topographic map at 1:24,000 scale (USGS topographic base map) showing locations of all existing and planned surface facilities, the outline of the project area and the area of review, any existing public water supply facilities, mines (surface and subsurface), quarries, residences and roads.
- o Topographic map at an appropriate scale (generally on mine coordinates) showing locations of all existing and planned wells with ID (name and number), depth, type (production, injection, monitoring, irrigation, water supply, enhanced recovery or other), wells, springs, other surface water bodies and drinking water wells located within one-quarter mile of facility property boundary.

Prior to, and in conjunction with, the field characterization efforts, a compilation of all available published and unpublished hydrologic and geologic maps, literature and data should be performed. This information should be continuously reviewed and updated throughout the life of the project, and utilized as necessary during the permitting process.

The data review should encompass all available information pertaining to hydrology, geology, seismic history and the history of mining operations in the site area and the surrounding region. Searches of computerized data bases, such as GeoRef (maintained by the American Geological Institute), may be utilized to ensure complete coverage of the available data.

The following sources of data may be useful in the characterization efforts.

- o Exploratory drill hole data, geologic mapping, topographic maps and aerial photographs obtained for mining purposes.
- o Published hydrologic and geologic mapping and literature available from government agencies and professional societies.
- o Conventional black and white, natural color, false color infrared, and NASA high altitude aerial photography, and remotely sensed LANDSAT imagery.
- o Water well data for existing wells, groundwater and surface water quality data and water use information on file at offices of the ADWR.

Potential ground subsidence due to groundwater withdrawal, mining activities or other phenomena such as salt solution or karst formation should be carefully evaluated in some parts of Arizona. A seismic hazard evaluation may also be advisable in some areas. These analyses are primarily utilized in the engineering safety analysis for surface

structures, but underground facilities and groundwater flow patterns may also be affected.

Areas of known, suspected and potential subsidence and seismotectonics in Arizona have been discussed in a number of published reports. Useful discussions on subsidence, containing bibliographic summaries, can be found in reports by Pewe and Larson (41) and Strange (42). The seismic history of Arizona has been summarized by DuBois, et al. (43).

Field studies to delineate areas of subsidence or recent faulting could include aerial low-sun-angle (LSA) reconnaissance, LSA photography, photo lineament analysis, fault scarp morphology studies and detailed mapping of surface geology.

It will often be necessary to verify or supplement the existing surface geologic information with additional mapping at appropriate scales. Using the same topographic base maps described above for presenting physical data, a set of geologic maps could be developed, as follows:

- o A reconnaissance scale geologic map, probably at 1:24,000 scale, showing the surface geologic units and features in the broader area surrounding the project. This map may generally be prepared from existing geologic mapping with a brief reconnaissance for verification. The reconnaissance may be best accomplished through the use of aerial reconnaissance in a fixed winged aircraft, such as a Cessna 182 or 210. These reconnaissance flights are best flown under LSA conditions; that is, during the approximately two to three-hour period beginning about 1/2 hour after sunrise or before sunset. These conditions give the best opportunity for observing such features as subsidence features, recent faults, etc.
- o A more detailed map at an appropriate scale (generally on mine coordinates) of the site area. Surface geologic data are mapped in as much detail as possible within this area. This information generally should be extremely useful in understanding the site area hydrogeologic system. Important information that should be noted includes the contacts between bedrock and the

various surficial units, the genesis and character of potentially waterbearing units, structural geologic data (location, orientation, spacing and general nature of faults and fracture systems, strike and dip of bedding, foliation or cleavage, folds, etc.) and the geologic factors controlling the localization of seeps and springs.

For permitting purposes, these maps are supplemented with additional geologic data, including:

- o A regional stratigraphic column.
- o A detailed stratigraphic column of the site area listing all formations present with data on their lithology, mineralogy, physical features (texture, bedding), thickness and geologic age.
- o A set of geologic cross sections through the site area, prepared from exploratory drilling data, depicting the target ore zone and surrounding country rock in detail.
- o Isopach maps of confining units and the ore zone, with descriptions of lateral and vertical continuity (e.g. depositional environment, facies changes, unconformities, vertical and lateral extent of clay layers).
- o A structural contour map to the top of the injection formation.

The compilations of available data and reconnaissance level investigations discussed above are used as guides to scope the level of subsequent subsurface exploration. In considering the cases of unsaturated and saturated ore bodies, a gross distinction between the levels of this work cannot be made. One would expect the unsaturated case to require less subsurface hydrogeologic characterization because unsaturated implies hydrologic isolation. This distinction is not assumed herein due to the possibility that the unsaturated ore zone may be in proximity of underground sources of water.

For purposes of these discussions of characterization and subsequent presentations of monitoring technology and options, a generic ore

body is formulated for both the saturated and unsaturated cases. The following describes the features of this working model:

- o 250 million tons of ore at 1 percent copper.
- o Bottom of ore body at depth of 1,000 feet.
- o Top of ore body at depth of 700 feet.
- o Lateral dimensions of about 2,000 by 2,000 feet for leach area.
- o Permeability of 2 millidarcy.
- o 5 percent porosity.
- o For the first case, saturated below 500 feet, with a confining zone between a depth of 450 and 600 feet. Assumption that ore body overlain, but hydrologically isolated from overlying alluvial aquifer.
- o For the second unsaturated case, no overlying aquifer, but source aquifer for drinking water in vicinity. Geometry and hydrologic properties of ore body the same as for saturated case.

The working ore body model, with variations for the two generic cases, provides a rough basis to discuss the objectives of the field characterization, and the methods that can be applied. When applied to a specific case, the level of geologic definition required will depend greatly on the amount and extent of lithologic and hydrologic data gathered during previous exploration efforts. If extensive exploration drilling has occurred, it may also be possible to reenter existing boreholes to perform some of the testing required.

The objectives of the field program can be separated into three broad categories, as follows:

- o Define the hydrologic characteristics of the ore body; and possibly, an overlying aquifer, a confining zone, or geologic formations which separate an unsaturated ore body from sources of drinking water.

- o Define the local geometry and structural fabric of the subsurface profile, with a clear definition of the hydrologic connection, or lack thereof, between the various geologic units.
- o Establish the natural water quality of the saturated ore body which will be affected by the ISL mining activity.

To accomplish these objectives, several methods are available, all of which involve the drilling and testing of boreholes, with the possible exception of surface geophysical surveys. Table 6.4 delineates the variety of investigative tools available. What selection of these methods is applicable to a specific case cannot be fully defined, but several of these methods can be considered generic.

- o In the case of relatively permeable, saturated conditions, the objective is to define the transmissivity and coefficient of storage of the aquifer, possible existence of vertical leakage and impervious or recharge boundaries. This is normally accomplished by the use of constant-discharge, long-term pump tests while observing the temporal distribution of head response in the pumping and outlying observation wells.
- o For low permeability saturated or unsaturated conditions, the coefficient of permeability can be approximated by using small-diameter borehole inflow tests. Three major categories of these tests are pressure tests (packer), constant head gravity-feed measurements and falling-head tests.
- o Water quality determinations require the direct sampling of groundwater from discrete geologic units; obviously, this requires the construction of properly prepared monitor wells.
- o Any subsequent simulation of aquifer flow behavior and solute transport will require a properly designed program of head distribution measurements. These measurements of depth-to-water need to be vertically and laterally distributed in such a manner as to comprehensively depict head variations. The program needs to measure head distributions periodically to determine the effect of nearby pumping and seasonal variation.

A vast body of technical literature is available on hydrogeologic field methods. The reader is referred to two publications, one by the Bureau of Reclamation titled Groundwater Manual: A Guide for

TABLE 6.4. INVESTIGATIVE METHODS FOR HYDROGEOLOGIC CHARACTERIZATION

1. Determinations of Lithologic Profiles
 - o Exploratory drilling with visual classification of soil/rock profile; rock coring with detailed logging of fracture frequency and condition; recording of drill rate and water loss.
 - o Physical testing of borehole samples to measure particle-size distribution, permeability and porosity.
2. Collection of General Hydrologic Data
 - o Water recovery rates during drilling.
 - o Visual estimates during drilling and laboratory determination of moisture content.
 - o Measurements of depth to water and recording first water during drilling.
 - o Periodic measurements of specific conductance, temperature, alkalinity and other parameters of groundwater during drilling.
3. Hydrologic Testing
 - o Constant-discharge pump tests with observation wells.
 - o Isolated interval pressure inflow tests with packers.
 - o Constant-head or falling-head tests.
4. Water Quality Determinations
 - o Construction of monitor wells with single screens or multiple sampling ports; use of well clusters.
 - o Selection and use of sample retrieval systems, including bailers, bladder pumps, submersible pumps or other lift systems.
 - o Sampling and testing under rigid quality assurance and control program.
 - o Sampling program which is designed to establish natural baseline water quality for saturated ore body and other saturated units.
 - o Soil pore water sampling of vadose zone using vacuum-pressure Cysimeters.
5. Measurements of Head Distribution
 - o Use of pore pressure piezometers.

TABLE 6.4. INVESTIGATIVE METHODS FOR HYDROGEOLOGIC CHARACTERIZATION
(continued)

- o Use of open exploratory boreholes.
 - o Use of open-well piezometers.
 - o Establish reliable method and measurement schedule.
6. Geophysical Methods
- o Surface surveys to establish baseline conditions.
 - * Electromagnetic induction.
 - * Complex resistivity (CR).
 - * Seismic reflection/refraction.
 - * Gravity.
 - * Controlled Source Audio-frequency Magnetotellurics (CSAMT).
 - * Transient electro-magnetics.
 - * Self-potential (SP).
 - o Borehole methods to delineate vertical hydrologic and geologic profile.
 - * Resistivity.
 - * Spontaneous Potential.
 - * Gamma.
 - * Gamma-gamma.
 - * Neutron.
 - * Sonic.
 - * Temperature.
 - * Caliper.
 - * Spinner (fluid movement).

Investigation Development and Management of Groundwater Resources, published by John Wiley and Sons, 1981, and one by Driscoll (46) for an overview of the methods discussed herein.

Subsequent to performing field investigations, the permittee is in a position to utilize the acquired data to interpret the potential effect of the proposed ISL process upon the hydrologic system. This simulation and predictive effort can be aided by first completing several tasks, as follows:

- o Graphic compilations of formational thickness, geologic structure, stratigraphy, distribution of aquifers and aquifer characteristics.
- o Calculations of hydrologic parameters by accepted methods.
- o Tabular inventories of all wells, wells/borehole construction details and water quality data.

In many cases, the most effective and comprehensive method of assimilating and analyzing the hydrogeologic data is the computer model. There are several potential problems with the application of these models. These problems are both technical and procedural. The first concern is the lack of knowledge concerning the behavior of highly acidic solutes in the geologic environment. Secondly, there are inherent analytical limitations caused by the structurally complex and heterogeneous nature of the fractured bedrock common in the Arizona copper ore body. The remaining concern is the acceptance by the regulatory body as to the validity of the model. With the exception of the problem of predicting the chemical behavior of highly acidic solutions, the modeling approach appears usable with proper documentation and careful selection to assure that the model is compatible with its intended application.

The computer models adaptable to the subject hydrogeologic appraisal can be identified as a method to predict groundwater movement and solute transport by aquifer simulation. Several models are available which are designed to handle flow in fractured bedrock. To determine the usefulness for any particular application, the user should first analyze both physical and legal requirements. In terms of physical requirements, determinations need to be made as to whether two-dimensional or three-dimensional flow simulation is required, and which analytical approach, finite-element or finite-difference is more appropriate. The input parameters, such as transmissivity and storage, then need to be provided. /

The legal requirements range from whether the computer code is fully documented, whether the model has been previously applied to a similar situation, and if the regulatory agency and the courts have accepted its use. Although the legal requirements of the models presented in Table 6.5 have not been investigated, these models represent the types which may be appropriate for use in geologic settings common to many copper ore bodies. The selection of the models in Table 6.5 does not imply that other models may not be equally useful.

The concept of using a computer model is attractive due to the fact that the model input can be periodically updated following the commencement of ISL operations by using measured head distribution and water quality data. In this manner, the model can be used as a monitoring tool to anticipate excursion and further analyze the potential effectiveness of a particular contingency response.

TABLE 6.5. REPRESENTATIVE COMPUTER MODELS FOR SIMULATION OF
GROUNDWATER FLOW AND SOLUTE TRANSPORT IN FRACTURED BEDROCK

1. Author name(s): Huyakorn, P.S., H.O. White, Jr., V.M. Gumanasen,
and B.H. Lester
 Model name: Trafrap
 Model purpose: Trafrap is a two-dimensional finite element code
which simulates groundwater flow and solute
transport in fractured porous media. Model
processes include interactions between fractures
and porous matrix blocks, advective-dispersive
transport in fractures, diffusion, and chain
reactions of radionuclides.
2. Author name(s): Huyakorn, P.S.
 Model name: Grease 2
 Model purpose: To study transient, multidimensional, saturated
groundwater flow, solute and/or energy transport
in fractured and unfractured, anisotropic,
heterogeneous, multilayered porous media.
3. Author name(s): Gumanasen, V.
 Model name: Motif
 Model purpose: Finite-element model for one, two and
three-dimensional saturated/unsaturated
groundwater flow, heat transport, and solute
transport in fractured porous media. Facilitates
single-species radionuclide transport and solute
diffusion from fracture to rock matrix.
4. Author name(s): Huyakorn, P.S.
 Model name: Ftrans
 Model purpose: A two-dimensional finite-element model to
simulate transient, saturated groundwater flow
and chemical or radionuclide transport in
fractured or unfractured, anisotropic,
heterogeneous, multilayered porous media.

TABLE 6.5. REPRESENTATIVE COMPUTER MODELS FOR SIMULATION OF
GROUNDWATER FLOW AND SOLUTE TRANSPORT IN FRACTURED BEDROCK (Continued)

5. Author name(s): Sagar, B.
Model name: Fracflow
Model purpose: Steady and unsteady state analysis of density-
dependent flow, heat and mass transport in
fractured confined aquifers simulating
two-dimensionally the processes in the porous
medium and one-dimensionally in the fractures,
including time-dependency of properties.

6.4.3 Compilation and Presentation of Process Details

The ISL permit application is a combination of the hydrogeologic characterization discussed above and a compilation of other related information. At a minimum, the preparer of the application will need to supplement the hydrogeologic studies with the following:

- o Layout and design details of SX-EW plant.
- o Wellfield scheme, sequencing and well designs.
- o Character of injected fluids.
- o Operating data - injection rate and pressure.
- o Stimulation plans.
- o Plans to plug existing wells.
- o Logging program.
- o Method of financial assurance.

6.4.4 Monitoring

The task of monitoring the ISL mining operation to assure hydro-logic isolation and detect excursion can be accomplished by employing a combination of diverse methods. Due to regulatory requirements, some of this monitoring will be the same for all operations; namely, the periodic completion of mechanical integrity tests on all production and injection wells and the measurement of injection/recovery flow and pressure. For both the saturated and unsaturated cases, variations in the overall monitoring approach will occur with that portion of the system that is designed to detect excursion independent of the injection/production well system proper. For this independent monitoring, the operator has the opportunity to select from a variety of monitoring well designs and geophysical methods. The proper selection

and integration of these methods to form a reliable monitoring system will be dictated by the local hydrogeologic conditions. For each of the two generic cases, some of the monitoring options are not applicable, but the current state of the technology does provide alternatives for both the vadose zone and groundwater conditions.

Another equally important aspect is involved in developing a comprehensive monitoring program. This aspect can be defined as those procedural details which assure that reliable and useful data are collected at the appropriate intervals, and subsequently reported to the regulatory agency as required. It is essential that the operator develop a schedule for data collection under a rigid quality assurance/quality control system which confirms reproducibility and is legally defensible.

After discussing the various monitoring well schemes and a variety of geophysical methods which may be applicable, two monitoring systems are presented below for the saturated and unsaturated cases. Obviously, there is an array of options to be analyzed to determine what is the most applicable monitoring scheme for an actual hydrogeologic setting. The two cases are only examples which may be helpful in structuring a monitoring program.

The most widely used and conventional method to the problem of monitoring saturated conditions involves the monitoring well. The monitoring well provides direct access to the groundwater for the testing of water quality and depth-to-water measurements. Many variations to the single screen well have been devised, with a varying degree

of success. The most widely used hybrid system is the well cluster, where multiple, isolated well screens are placed at discrete and isolated depth intervals in the same borehole, or in separate closely spaced boreholes (45). The placement of clusters in the same borehole normally creates some completion difficulties, with the proper positioning of intervening seals being a considerable problem in some cases. The multiple borehole approach is obviously more costly due to the need to drill considerably more borehole. There are some innovative and more complex commercially available downhole monitoring systems available. These systems are, for the most part, designed for use in relatively shallow groundwater settings. They normally involve multiple sampling ports isolated in a single borehole with an airlift or suction method used to retrieve water samples (46).

The design of wells in the monitoring system of a typical ISL operation will vary considerably, depending on the intended groundwater intercept of the well (production zone, USDW, confining zone or vadose zone), the local hydrogeologic conditions, and the depth to the zone of interest. The individual wells must be designed to function satisfactorily throughout the period of intended use and must employ materials and methods of construction which will not create erroneous water quality measurements (47). In the following discussions, designs for the idealized monitoring wells shown in Figures 6.2 and 6.3 are discussed. These conceptual designs are intended to serve only as an idealized introduction to monitoring well design for ISL operations and may not be directly applicable to any particular site.

The type of casing selected must be inert under the chemical conditions existing in the natural groundwater setting and should not react

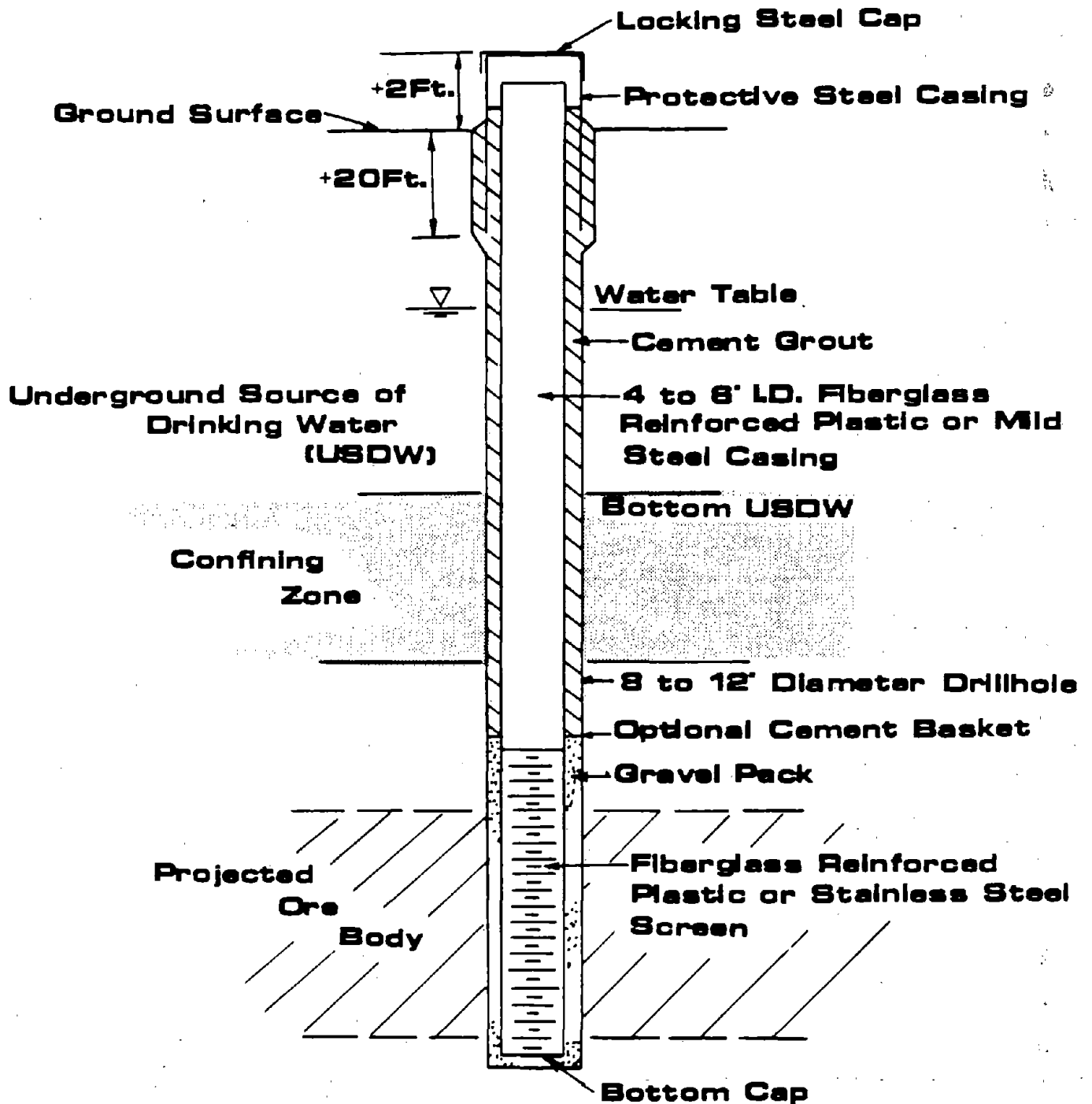


Figure 6-2. Conceptual Design of Typical Injection Zone Monitoring Well for Model Ore Body (Saturated Case)

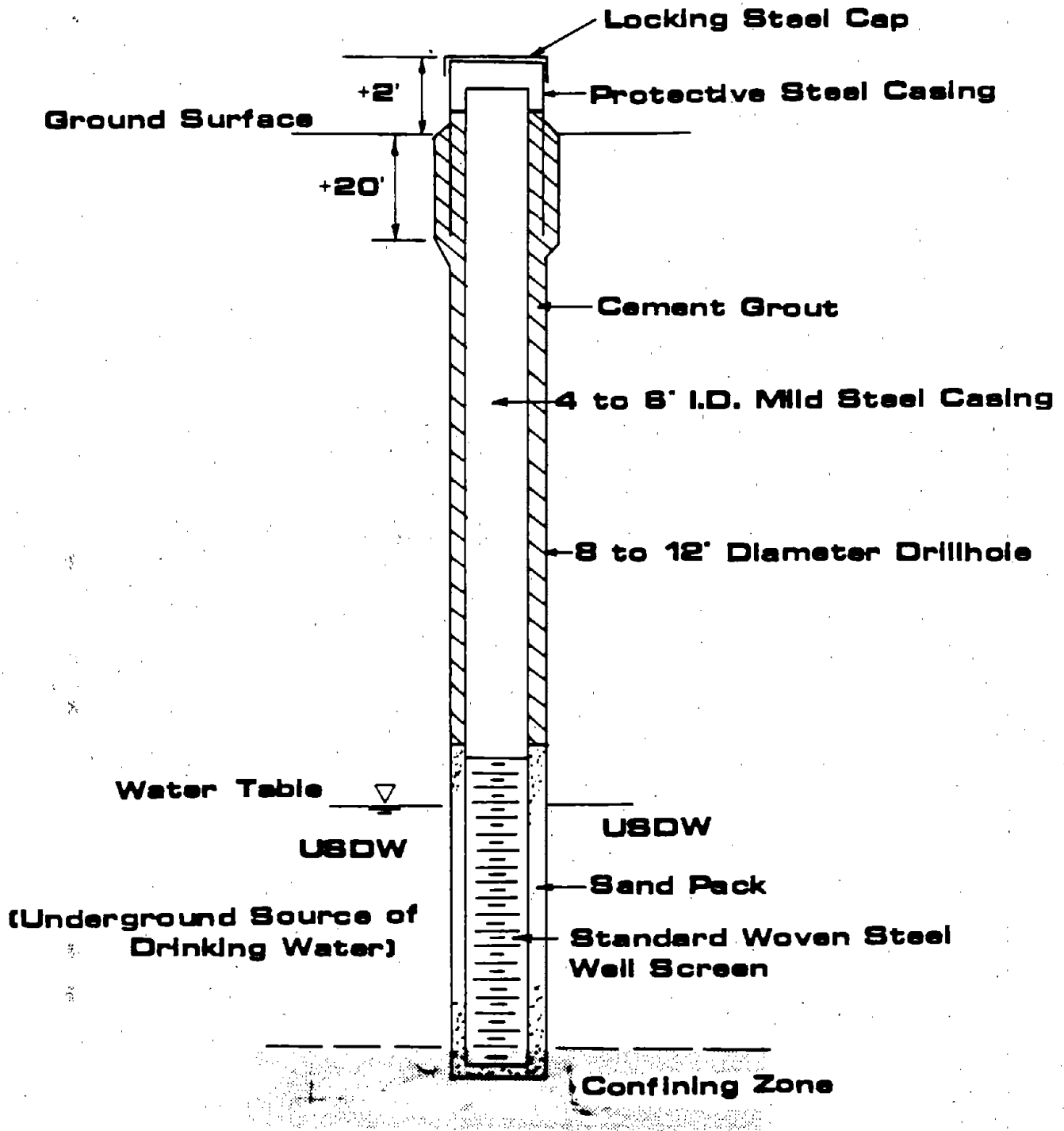


Figure 6-3. Conceptual Design of Typical USDW Monitoring Well for Model Ore Body (Saturated Case)

chemically to lixiviants or other mine-affected groundwater in any manner. For ISL operations, casing used in monitoring wells should be chemically inert to trace and heavy metals, acid lixiviants and any other chemical constituents of the baseline or mine-affected groundwater. Polyvinyl chloride (PVC), fiberglass-reinforced plastic (fiberglass) and stainless steel are commonly used casing materials that may fit this requirement. PVC casing may be susceptible to collapse in wells that are more than 500 feet deep, or where high pressure grout injection techniques are used.

Ray V. Huff and Associates report the successful use of fiberglass casing to depths up to 4,000 feet. As discussed in Section 4.4.1.3, fiberglass casing is considered to be structurally adequate for use in production/injection well construction to depths of 3,000 feet. Fiberglass casing would be equally suitable for monitor well installations. Both mild and stainless steel casing should also be considered.

Casing costs for deep wells will also increase dramatically as the diameter of the casing increases. Therefore, the smallest diameter casing that will adequately perform the desired functions should be used. The size of the pump or other sampling equipment that is to be installed in the well will generally dictate the casing diameter needed. The size of the pump required for sampling monitor wells normally will increase with depth to the interval of interest. The casing diameter must be sufficient to accommodate a pump with the capacity to rapidly evacuate several well volumes to provide a representative sample. Shallow wells (less than 100 feet deep) may be sampled with small diameter pumps that will fit within a 2-inch diameter casing. However, monitoring wells required for ISL operations will generally be considerably deeper. For the deeper wells, 4-inch or 6-inch diameter

casing may be required. As the casing diameter increases, the diameter of the drill hole also will increase and drilling costs will rise accordingly. To ensure proper placement of casing, gravel pack and grout, adequate annular space between the casing and borehole wall must be provided.

Installation of telescoping casings (i.e., installation of casings of successively smaller diameters inside of each other to progressively greater depth) is commonly required to maintain stability of the borehole string. For example, in construction of a 1,000-foot monitoring well, the drill hole may be first advanced to a depth of ± 50 feet. Surface casing, such as 16-inch O.D. black steel casing, is then placed in the drill hole and grouted. Next, the drill hole is advanced to a depth of ± 450 feet and 10-inch C.D. black steel casing is installed through the surface casing. Finally, the drilling is completed to the total depth of the drill hole and 6-inch O.D. fiberglass or stainless steel casing is installed to complete the casing.

For monitoring wells that are screened in intervals that contain significant amounts of fine material, an artificial sand or gravel pack should be placed in the annular space between the well screen and the inside of the drill hole. This allows free movement of water into the well while preventing fine material from entering. The filter pack should consist of clean, well rounded grains of uniform size. These characteristics will increase the permeability and porosity of the pack material. For monitoring of acid lixiviants, clean silica sand should be used, as even a small percentage of calcareous material will react with acids in solution and will prevent accurate water quality results. Particles of shale, anhydrite, gypsum or other potentially reactive

components that may alter the chemistry of groundwater samples should also be avoided.

The filter pack should extend well above the screen to compensate for settlement during development. For monitoring wells screened in bedrock and not containing significant amounts of fine material, the screen could be installed without a filter pack. When a filter pack is required, the annular space between the casing and the side of the borehole above the screened interval must be carefully sealed to prevent any vertical migration of fluids in the borehole. This also provides support for the casing. It is necessary to isolate the grout from the screened interval by some means to prevent plugging off the screen and sample contamination. Where no filter pack is used, this may be accomplished by installation of a cement basket at the top of the screened interval during installation of the casing. A cement basket cannot be used where a filter pack is planned since it would not allow the sand pack to reach the screen. In this case, an inflatable neoprene packer may be attached to the casing during installation and inflated to prevent grout contamination after installation of the filter pack.

The removal of water quality samples from a monitoring well can be accomplished by use of bailers, dedicated pumps or sampling devices, or a portable pumping system. For deep wells, dedicating a suitable pump or sampling system eliminates the difficulty of moving a portable system from well to well. For shallower applications, bailers or a portable pumping system provide an effective and economical alternative.

A variety of small diameter sampling devices and pumps are available for the acquisition of water samples from a monitoring well. Suction lift, submersible, air-lift, bladder, gas displacement, and systems

which use casing packers are the types of lifting systems commercially available. Each system has its limitations, with the suction, air-lift, and gas displacement types only suitable for shallow applications. A majority of these systems introduce air into the sample, which could affect the chemistry of the water. For a variety of reasons, the submersible pump or progressing cavity pumps recommended herein for use in the production wells, appear suitable for deep monitoring well use.

There are two major disadvantages in dedicating a pump to each monitoring well. If the well is screened throughout a considerable depth interval, it may be desirable to selectively sample at several locations in the well. With a permanent pump in place, this selective sampling is not possible. With a combination of a portable submersible pump and air-activated packers, it is possible to largely isolate specific intervals and selectively sample. The portable approach to sampling also leaves the well open for conductivity probes and other geophysical instrumentation.

Monitoring of the vadose zone can be accomplished by direct and indirect methods (48), (49). The direct methods involve the acquisition of soil pore water samples by using vacuum-pressure lysimeters, membrane filter samplers or absorbent methods. The use of lysimeters poses several problems. Lysimeters can only be effectively installed and used for relatively shallow applications due to installation and operational limitations. The use of suction may contribute to sample bias (46). Plugging of the porous segments of lysimeters is also a problem (50). Considering the nature of ISL mining, the use of direct vadose zone monitoring methods appears to have limited application. In contrast, the use of indirect surface and geophysical methods holds considerable promise.

A selected number of surface and borehole geophysical techniques may be applicable to the problem of monitoring the hydrologic behavior of the ISL injection/recovery well system. Of the variety of surface and borehole logging techniques available, surface electrical and the downhole applications of acoustic propagation, galvanic resistivity, neutron and electromagnetic conductivity may have features compatible with the monitoring needs of the ISL process. By using crosshole acoustic and electromagnetic data, geotomographic techniques can be applied to construct two and three dimensional images of geophysical variation. The surface methods of simple electrical resistivity and electromagnetic induction, which are commonly used to detect changes in groundwater quality, have serious depth limitations (51), (52). These techniques cannot effectively probe the geologic profile below a depth of about 300 feet (52). An advanced electrical technique, controlled source audiofrequency magnetotellurics (CSAMT) may have the adequate depth penetration to detect fluid excursions around a deep ore zone (53), (54).

Considering the potential use of CSAMT as a monitoring tool, it appears that this technique could be utilized to detect variations in the unsaturated and saturated profile. This technique utilizes a fixed current source and provides apparent resistivity and phase angle soundings (53). The penetration depth of the induced electromagnetic wave is both frequency and resistivity dependent. The earth resistance can, therefore, be measured as a function of depth if the amplitude of the magnetic and electrical field can be acquired at several frequencies (51).

The CSAMT geophysical technique has been used with apparent success to detect upward leakage of brine through improperly plugged wells (53). CSAMT tests have been conducted in the uranium leach fields of Northern Wyoming (54). Results of this testing program were inconclusive.

For the measurement of moisture changes in the vadose zone, the use of neutron borehole logging is a proven and applicable technique. Neutron logging can be performed in cased borings, either dry or filled with fluid (44). The neutron log uses an active neutron source to measure formational porosity. The downhole system consists of a neutron source which emits a flux of energetic neutrons, and a detector which senses either the low energy neutrons or gamma radiation which results from neutron absorption (51). The porosity of the formation is inferred from the direct reading of hydrogen content. There are three major types of neutron logs in use, with the neutron-epithermal type being the most accurate and least sensitive to external effects.

For saturated conditions, electromagnetic conductivity (EM) logging appears to hold considerable promise. Although in the development stage for borehole use, this method has met with considerable success in mapping contaminant plumes from the surface. The method would require the use of nonconductive casing, but the influence of borehole fluids should be insignificant (55). The electromagnetic method of measuring earth conductivity by induction employs two coils. The transmitting coil is energized with alternating current, causing minute currents in the geologic medium. The other coil has the capacity to detect these inducted currents. As applied to the problem of detecting excursion from an ISL well field, the EM logging would have the capability to detect minor increases in conductivity near a monitoring well. This

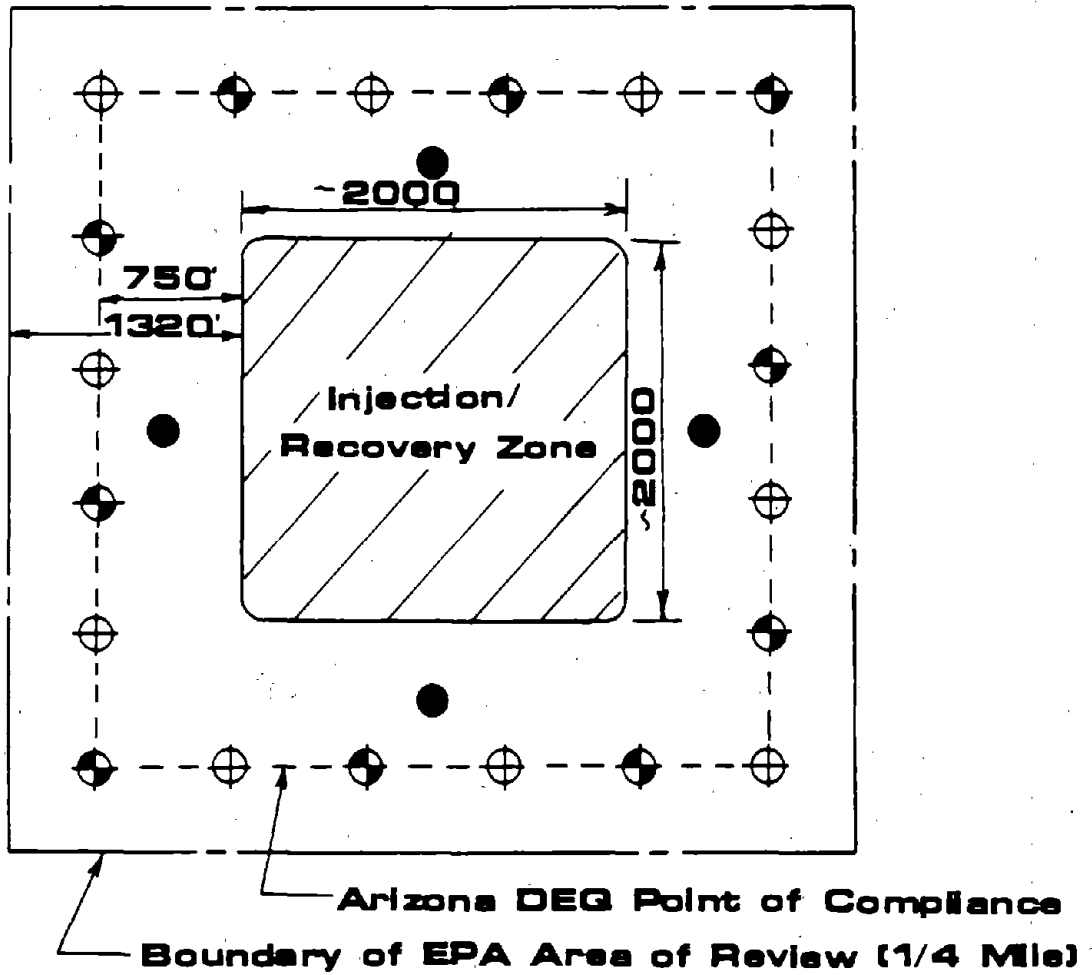
change would be caused by the movement of more conductive lixiviants in the fractured bedrock.

The generation and subsequent cross-borehole detection of compressional and shear waves, coupled with tomographic techniques, may provide a useful ISL monitoring technique. This type of borehole geophysical application is time consuming and requires lengthy interpretation. If velocity contrasts are substantial, ray bending may influence data quality.

Galvanic resistivity borehole logging has been investigated as a potential geophysical tool for the monitoring of an in-situ uranium leaching operation in Wyoming (54). One inherent limitation of the single electrode resistance, multi-electrode spacing and focused logging approaches is the requirement that the hole remain uncased. Even though the casing problem will remain, a more promising technique would be to place receiving and transmitting devices in separate wells spaced in such a manner as to detect resistance changes throughout the injection zone.

The Wyoming test sequence to analyze the effectiveness of downhole galvanic techniques used a transmitter-receiver array placed in each of seven holes in a hexagonally shaped production cell (54). The test results indicate that the geophysical system has the capability to detect resistance decreases caused by the flow of lixiviants in the uranium leach field.

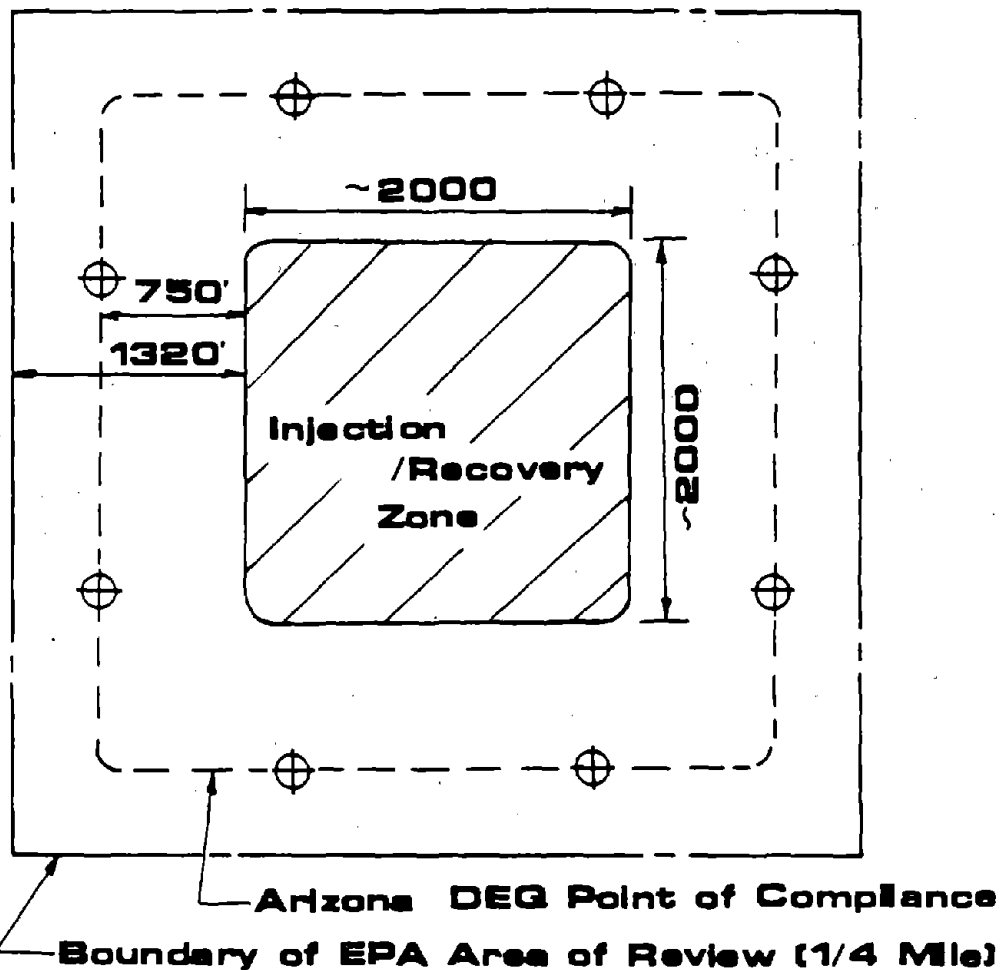
Using a selected number of the monitoring techniques discussed above, two monitoring schemes are presented in Figures 6.4 and 6.5; one for the saturated case and one for the unsaturated case. These schemes



LEGEND

- ⊕ — Monitor Well With Screened Interval Adjacent to Ore Body ; 1000' Deep
- ⊕ — Monitor Well With Screened Interval Near Bottom of Underground Source of Drinking Water (USDW); 450 Feet Deep
- — Monitor Well to Detect Head Distribution Changes In Confining Zone; 850 Feet Deep

Figure 6-4. Conceptual Configuration of Monitoring Well System (Saturated Case)



LEGEND

⊕ - Neutron Monitor Boring

NOTE: Monitoring System Includes The Application of Resistivity Method to Monitor Moisture Condition Over and Adjacent to Ore Body

Figure 6-5. Conceptual Configuration of Monitoring Points—Unsaturated Case

are presented as generic examples developed under hypothetical hydro-geologic conditions, depth-to-ore-body and ore body/wellfield geometry.

The remaining issue involved in the development and operation of an ISL monitoring system is the establishment of a quality assurance/quality control program related to monitoring data acquisition and record keeping. To assure that a valid monitoring record is established, the following issues need to be addressed and specific guidelines established:

- o Proper well sampling procedures.
- o Field testing procedures and record keeping.
- o Proper handling, preservation, storage and retention of water samples.
- o Use of certified laboratory; use of standard lab methods.
- o Proper recording of sample chain of custody.

6.4.5 Restoration

Although the question of whether active restoration will be required by the regulatory entity cannot be answered at this time, several issues and options can be discussed. The bulk of the research and actual attempts at restoring aquifer water quality after in-situ leaching involve uranium ore bodies in Texas and Wyoming (56), (57). The geologic framework of such deposits are extremely different from that of the Arizona copper ore body. These uranium deposits are found in sedimentary bedrock with permeabilities well in excess of those anticipated for the ISL copper ore deposit. Even with this inherent difference, the published evaluations do provide some guidance as to the feasibility and options related to aquifer restoration.

Techniques of aquifer restoration that have been proposed and analyzed by other investigators include the following:

- o Pumping of selected leach field wells (sweeping).
- o Pumping of selected leach field wells in combination with injection into other wells of natural groundwater, treated leach field water or water with reagents added.
- o Natural restoration.

Pumping of selected leach field wells after cessation of lixiviant injection draws uncontaminated groundwater from outside the leach field inward to displace the injected lixiviant and affected groundwater. Under ideal conditions, the unaffected groundwater from outside the leach field would completely displace the affected groundwater and baseline water quality levels would be restored. However, under natural conditions, it may not be possible to completely restore water quality to background levels by pumping alone.

Restoration may be expedited by simultaneously pumping selected leach field wells while injecting natural groundwater, treated leach field water or water with certain reagents added into other selected wells. Injection of natural groundwater may not present a significant advantage if sufficient uncontaminated groundwater can be drawn into the leach field by pumping alone. However, under certain conditions, if an abundant source of relatively clean water is available for injection, the efficiency of the aquifer restoration process may be improved.

The treatment of pumped water to remove residual metal values, lixiviants and other contaminants followed by reinjection of the treated water at other selected wells may present several advantages. The volume of contaminated water that must be disposed of at the surface is

thereby reduced. In addition, the recovery of additional metal values may partly offset the costs of aquifer restoration.

Injection of water containing certain chemicals to neutralize lixiviants within the leach field may also be an effective restoration method. However, such a process has not been attempted at any large scale commercial copper leaching operation to date. A sufficient volume of water would be removed from the leach field by pumping simultaneous with injection to ensure the necessary concentration of the chemical additive in the ore zone aquifer. Simultaneous pumping would also occur to ensure that the injected, chemically treated water is drawn into the leach field, rather than flowing away from it.

Natural restoration is the degradation, neutralization or dilution of lixiviants and related contaminants by natural processes. Dilution may occur simply by mixing of the injected fluids with uncontaminated natural groundwater. Degradation or neutralization may occur as a result of various chemical processes occurring within the ore body.

Natural degradation may be an acceptable means of achieving aquifer restoration in certain cases, such as where the ore zone aquifer is hydrologically isolated, or where processes of dilution or neutralization can be shown to achieve acceptable water quality levels. Some problems associated with the concept of natural restoration include the following:

- o The difficulty of predicting the time and distance required for the contaminant removal process to be effective.
- o The lack of existing data on the effectiveness of natural chemical processes in degrading or neutralizing lixiviants in natural solutions.
- o The uncertainty regarding the ultimate fate of certain ions, compounds or elements introduced into the ore zone.

Sweeping and recirculation could result in the production of large volumes of water at the surface which are unsuitable for discharge. In both cases, the ultimate disposal of the waste waters would require storage and evaporation, probably in lined surface ponds. The sweeping option would create a waste stream which could be disposed of in lined evaporation ponds or treated. As is the case with the recirculation option, this treatment can result in a reduced volume of waste fluids with a higher concentration of dissolved constituents. Reverse osmosis is an example of a treatment option which results in a radical improvement in water quality, but the by-product of the treatment is a brine with an elevated concentration of dissolved constituents. Such active approaches to restoration have the disadvantage of potentially exposing the near-surface hydrologic environment to contamination from the long-term disposal of the residue from large volumes of waste water.

Although it is not deemed feasible to establish a conceptual restoration design for ISL copper mining at this time, the evaluation of potential restoration options does clarify the need to define specific details prior to, and in conjunction with, site-specific design development. These interrelated details are as follows:

- o Predict the effect of natural attenuation processes and the effects of dilution/dispersion in the ore body.
- o Analyze the length of time required to sufficiently reduce contaminant levels.
- o Evaluate the feasibility of treating withdrawn wastes, and the compatibility of such treatment with the chemistry of the process fluids.
- o Appraise the feasibility and site suitability of disposing of providing storage/evaporation facilities for spent fluids and the environmental safety of permanently disposing of the residues of these fluids.

6.5 ENVIRONMENTAL RELATED COSTS

Environmental costs are divided into four categories: permitting the commercial facility; developing a monitoring system; annual monitoring; and restoration of leached out wellfields.

6.5.1 Permitting the Commercial Facility

With the current permit structure of the ADNS, a timetable for the application and agency review process can be approximated. Table 6.6 delineates the schedule of the aquifer protection permit process, including an approximation of the time required to perform site characterization studies.

Based on the aquifer protection permit timetable presented, costs for permitting have been developed for the example ore body characteristics described in Chapter 10, and are estimated at \$462,500. Details of the development of this cost are provided in Table 6.7. The permitting cost is denoted by EP_6 in Section 5.7.1.

$$EP_6 = \$462,500 \quad (6.1)$$

6.5.2 Development of Monitoring System

The following approach is used to estimate monitoring system costs on a generic basis. It is assumed that the density of monitoring wells is proportional to the total plan area of the deposit for which wellfields will be developed over the life of the leaching operation. In addition, it is assumed that monitor wells will be required to penetrate both to the bottom of the ore zone, and slightly above and below the water saturation level. Unit costs for monitor wells penetrating to the

TABLE 6.6. AQUIFER PROTECTION PERMIT TIMETABLE

| | <u>Duration in Months</u> | <u>Completion Month</u> |
|--|-------------------------------|-----------------------------|
| o Applicant formulates site characterization plans and prepares/submits proposal for permit application | 3 | 3rd |
| o Agency reviews proposal for permit application and notifies applicant as to its completeness | 1 | 4th |
| o Applicant initiates and completes site characterization studies, facility design and prepares permit application | 12 | 16th |
| o Applicant submits permit application | (end of 16th month) | |
| o Agency reviews application and notifies applicant as to its completeness | 1 | 17th |
| o Applicant responds to agency comments and provides subsequent data to eliminate deficiencies | 2 | 19th |
| o Agency performs final review and issues permit | 1 | 20th |

TABLE 6.7. ESTIMATION OF COST OF PERMITTING
COMMERCIAL FACILITY

| <u>Activity</u> | <u>Cost</u> |
|--|-----------------|
| o Administrative support for 1 year, 15 hours/week, one staff | \$ 23,000 |
| o Technical support by operator, 1 1/2 man months, one staff | \$ 6,000 |
| o Consultant support, 6 months, site characterization/agency contact/data compilation and analysis. 9 man months level of effort | \$ 77,000 |
| o Air Quality preoperational monitoring and analysis, equipment and 2-man month contribution | \$14,000 |
| o Acquisition of ADWR water rights/ well construction permits. 1 man month level of effort. | \$4,000 |
| o Hydrogeologic field investigation | |
| + 6500 feet of bore hole | \$162,500 |
| + Install 4 monitor wells | \$100,000 |
| + Hydrologic test program over 4 weeks | \$ 32,000 |
| + Baseline water quality testing | \$ 6,000 |
| + Professional staff support | \$ 32,000 |
| + Travel | \$ 5,000 |
| + Fees, retaining financial responsibility | <u>\$ 1,000</u> |
| | \$462,500 |

bottom of the ore body will be expressed as \$ per square foot plan area per foot of depth, and denoted by C_{Ma} . Unit costs for monitor wells in the vicinity of the water saturation depth will be expressed as \$ per square foot plan area per foot of depth of water table, and denoted by C_{Mw} . The generic form of the total monitoring well system cost, EP_7 , is given by (6.2), where A_{WT} is the total wellfield plan area to be leached over the life of the leaching operation.

$$EP_7 = (C_{Ma})(A_{WT})(D) + (C_{Mw})(A_{WT})(WD) \quad (6.2)$$

Table 6.8 details the computations and assumptions involved in developing C_{Ma} and C_{Mw} for the example ore body used in Chapter 10 to illustrate use of the manual to develop design specifications and costs. C_{Ma} is estimated at $\$1.37 \times 10^{-4}/\text{ft}^2/\text{foot of depth}$, and C_{Mw} at $\$1.83 \times 10^{-4}/\text{ft}^2/\text{ft of depth}$.

The areal density of wells selected for the example ore body is based on geologic experience in detection of hydrologic changes in fractured rock. At present specific values for monitoring well density are not specified by any permitting agency for ISL copper.

6.5.3 Annual Monitoring Cost

Annual operating costs are estimated to include: \$52,500 for labor (1 1/2 professional staff); \$2,000 for record keeping; laboratory analysis of water samples \$13,800; and \$12,000 monitoring equipment maintenance and replacement. The net annual cost is \$80,300. This cost is denoted by EP_{EM} in Section 5.6.5.

TABLE 6.8 DEVELOPMENT OF UNIT MONITORING
SYSTEM COSTS

- o Definition of system
 - + 1000 foot deep ore body
 - + Water saturation 500 feet below the surface
 - + Total wellfield area for 20 year production of 1% copper at 50.6% recovery over 300 feet of ore thickness is 3,900,000 square feet
 - + Assume 10 monitor wells to depth of 1000 feet; 10,000 feet of hole
 - + Assume 10 monitor wells above saturated zone to 450 feet, 4,500 feet of hole
 - + Assume 4 monitor wells to 550 feet, 2,200 feet of hole.
 - + Total of 16,700 feet of hole, 60% at 1,000 feet of depth
- o Total cost of monitoring system

| | |
|--|-----------------|
| + Mobilization and de-mobilization | \$ 3,500 |
| + Casing 12,000 ft @ \$15/foot | \$180,000 |
| + All well drilling operations 16,700 ft @ \$25/foot | \$417,500 |
| + Screen 4,700 ft @ \$20/foot | \$ 94,000 |
| + Misc. \$850/well x 24 | \$ 20,400 |
| + Cement 1 cuft/ft x 12,000 ÷ 27 x 50 | \$ 22,000 |
| + Gravel pack 1 cuft/ft x 4,700 ÷ 27 x \$100 | \$ 17,400 |
| + Pumping system | \$ 25,000 |
| + Logging \$3,000/well x 24 | \$ 72,000 |
| + Well development \$1,600/well x 24 | \$ 38,400 |
| + Labor for design of system | <u>\$ 4,400</u> |
| | \$894,600 |
- o Proportioning costs
 - + $C_{ma} = \$894,600 (0.60) \div 3,900,000 \div 1,000 = \$1.37 \times 10^{-4} / \text{ft}^2 / \text{ft}$
 - + $C_{Mw} = \$894,600 (0.40) \div 3,900,000 \div 500 = \$1.83 \times 10^{-4} / \text{ft}^2 / \text{ft}$

6.5.4 Wellfield Restoration

At this time it is not possible to estimate a generic capital or operating cost for wellfield restoration. The reasons for this are:

- o The regulations defining the level of restoration for in situ copper leaching as well as the specific chemical constituents to be removed from the wellfield have not been developed.
- o The leaching chemistry will be site specific and extraction technology will vary from one site to another.

To provide some estimate of the cost impact of restoration on overall project economics a restoration cost, denoted by EP_{ws} in Section 4.5.1, is applied to each wellfield replacement. It is assumed that this can be approximated as a percent of the total operating cost of wellfield start-up. The user selects the percent to be used, which is represented by variable x_1 .

CHAPTER 7

FIELD AND LABORATORY TESTS TO OBTAIN SITE SPECIFIC DATA

7.1 Data Requirements for Rock and Fluid Characteristics and Copper Leaching

Site specific engineering designs for a commercial in situ copper mining operation require input data pertaining to the following deposit rock and fluid characteristics:

- o Degree of initial water saturation of the rock. This reflects on water make-up requirements of wellfield start up, as well as initial permeability reduction by water/gas displacement.
- o Rock permeability, which translates to flow rate per well.
- o Rock porosity, which translates to well pattern start up time.
- o Chemical communication in a well pattern, which translates to: leach solution recovery; positioning well patterns; and definition of acid/copper residence time reaction requirements.
- o Rock chemical properties relative to concentrating copper in the pregnant liquor, which translates to capital and operating costs for surface and wellfield facilities.
- o Rock response to hydraulic fracturing and borehole blasting, which translates into enhancement of well flow.

This section describes specific tests and procedures to obtain the above data. These tests are listed below and are grouped into two test groups, Sets I and II.

- o Transient pressure test - Set I
- o Geophysical wireline logging - Set I
- o Coring - Set I
- o Laboratory core leaching - Set I
- o Well pattern tracer communication - Set II
- o Well pattern leaching - Set II
- o Matrix modification - Set II.

Set I tests are directed at obtaining data for use in an initial economic feasibility evaluation for a commercial operation, not to

include field acid injection or matrix modification. These tests represent a minimum environmental impact and are not likely to result in a major permitting delay. Results of these tests can also be used for preliminary pilot plant design.

Set II tests are conducted during a pilot scale operation to provide data for a final design of a commercial in-situ copper mine leaching operation. These include: tracer chemical communication tests in well patterns; acid leaching in well patterns; and matrix modification. Permitting requirements will have a significant impact on scheduling these tests.

For each test, discussion focuses on: review and selection of specific tests; description of design and execution procedures; and discussion of data to be obtained and methods of data analysis.

Procedures for analyzing test data are so varied and dependent on site specific deposit characteristics, that based upon experience in field testing of in-situ copper mining, this description of procedures is beyond the scope of this document.

7.2 Set I Type Test - Minimum Environmental Permitting

A number of tests can be conducted to obtain information about the following rock and fluid properties:

- o Rock permeability
- o Rock porosity
- o Initial water saturation
- o Flow distribution from the well into the deposit
- o Copper recovery curve (laboratory).

Tests include transient pressure tests, geophysical wireline logging, coring, and laboratory core leaching. Except for laboratory tests these tests require that fluid can be produced from or injected into the

deposit. The injected fluid required is clear water and therefore should not represent an environmental problem. In order to conduct laboratory leaching tests, which will provide hydrometallurgical data, core must be obtained from each deposit.

7.2.1 Transient Pressure Test

The transient pressure test is conducted to determine permeability, deposit pressure, drilling or other induced permeability changes "skin effect," and to provide indications of flow regime boundaries, barriers and interference between wells. Transient pressure testing consists essentially of pressuring a hole by pumping fluid into it and then carefully measuring decay of pressure versus time. When it is performed on two wells, i.e., an active pressurized well and a second well or multiple passive wells, it is usually termed an "interference" test and it yields data relative to permeability, porosity (provided that rock compressibility is known), and directional permeability. A review of permeability testing for solution mining is presented in a U.S. Bureau of Mines publication (58).

The kinds of instrumentation employed in transient testing include flow rate and pressure measurement devices. Turbine meters, which provide both rate indication and cumulative volume, are both accurate and convenient to use. Pressure measurement devices are numerous, however, special wireline suspended instruments are commonly employed for the following reasons:

- o The pressure gradient in the borehole cannot be accurately estimated or determined.
- o The pressure at the wellhead falls below zero psig during the test.

When pressure in the active well (production or injection) changes several hundred psi during the test, bourdon type gages will suffice. However, if one intends to determine the deposit pressure within 5 to 10 psi, the bourdon type gage may not provide adequate precision. Quartz pressure gages have been found useful for transient testing, especially where high precision is essential.

When interference tests are conducted by injecting fluid in one hole and observing pressure changes at another hole, gages of high precision are essential. The pressure response in the observation hole may be only one or two psi, sometimes less. In these instances one must be cautious to guard against changes in pressure that may be related to barometric or lunar sources, as opposed to those resulting from the active well.

Fluid conductivity in porous rock is termed permeability, and is controlled by rock properties such as: porosity, grain and fracture sizes and texture, fracture or pore connectivity and tortuosity. Based on the complexity of the interaction of these parameters, assuming they could be quantified, a useful method of calculating the value of permeability has not been found. Permeability is a measured parameter.

It should be pointed out that permeability and porosity are related but porosity is a measure of the void spaces in the rock. High porosity does not translate to high permeability. Since porosity reflects the sum total of all of the void spaces, high or low permeability would depend on whether these voids were connected by small or large openings.

Directional stress variations in rock formations often result in preferential flow in one direction versus another. This effect can be evaluated by inter-well pressure testing, in which fluid is injected in

one hole of a pattern and the rate of fluid rise is observed in two equally spaced holes located 90° to each other. A consistent observation of more rapid fluid rise in one direction over the other is indicative of a directional permeability, where fluid movement to and from wells will follow an elliptical flood front. To compensate for the different rates of fluid movement, wells can be spaced in a rectangular pattern, such that equal fluid travel times are obtained. This prevents premature mining out of copper from some parts of the well pattern resulting in solvent eventually passing through mined out sections and diluting enriched solutions from other sections. The worst possible choice of well layouts would be to align injectors and producers along the direction of greater flow.

All flow into or out of the deposit passes through the wellbore and the first areal restriction encountered is the circumferential area of the well. Equal flows can be achieved for highly conductive thin ore zones, or low conductivity thick ore zones. Reduction of field test data provides a kH (permeability ore intercept) factor, the value of which in addition to the measured flow rate, pressure drop, and fluid viscosity is a function of the assumed flow geometry beyond the wellbore.

As fluid moves away from the wellbore three types of flow regimes can form.

- o Linear Flow - Fluid may encounter highly conductive structural planes or hydraulic fractures and move along them into the ore. Pressure gradients in this case will tend to be fairly uniform as fluid moves away from the high pressure source, declining linearly with the distance from the point of injection. A resulting linear plot of pressure rise (or fall off) versus the square root of time for pressure transient data would be indicative of linear flow.

- o Radial Flow - Fluid leaving the wellbore remains essentially in the injection interval, spreading over a continually increasing circular area. The pressure will decline logarithmically with the distance from the well. A resulting linear plot of pressure versus the logarithm of time during pressure transient testing would be indicative of radial flow.
- o Spherical Flow - Fluid leaving the wellbore spreads horizontally and vertically beyond the injection interval in a three dimensional continually increasing sphere. In this case the pressure will decline inversely with radial displacement from the well. A resulting linear plot of pressure versus the reciprocal of the square root of time for pressure transient data would indicate spherical flow.

When tests of short duration are planned and the well head pressure is expected to fall to zero psi rapidly, not only is a downhole pressure sensing/measuring device specified but also a downhole shut-in tool is required. A downhole shut in tool is a device which permits the closure of the well downhole near the test interval. Further, the tool facilitates the measurement of pressure in the wellbore adjacent to the test interval and below the tool. The tool consists of two parts: a seating nipple in the tubing string and the plug which creates the seal when lowered on a wire line into the seating nipple. The plug is suspended a few feet above the nipple while liquid is being injected. Upon termination of injection the plug is lowered into the nipple. If a downhole sensing-surface recording pressure instrument is used the sensor is attached below the plug and electrical signals conducted through the plug and up the wire line to the surface.

Pressure-transient tests require careful design in order to assure that appropriate equipment is available at the test site to conduct the test. The design will provide an estimate of the time required to complete the test, expected flow rates, and pressures.

Although a number of different types of transient tests are available, i.e., buildup, drawdown, multirate, interference, and falloff, the type that

is chosen will depend primarily on hole conditions, degree of deposit saturation and hole spacing. Previous experience suggests that the most easily conducted test is the pressure falloff following water injection.

Details of test design (59) are available elsewhere and will not be repeated here. However, key elements to be considered in the design follow. In test planning, calculations should be made of estimates of factors such as the impact of wellbore storage (fluid stored in the wellbore), general magnitude of pressure response for any given injection rate, and time required to obtain analyzable data.

The most serious problem is wellbore storage effects, and a transient test must be designed to minimize this effect. The engineer should incorporate in the design the capability to shut the well in using a downhole shut-in tool. Otherwise, during the short-duration test wellbore effects can persist throughout the falloff period and useful data will be obscured.

As indicated above transient pressure tests can be conducted using a number of different procedures. However, the procedure most easily employed for mineral deposits is fluid injection followed by measurement of pressure decline. The following activities are part of this procedure:

- o Choose a section of deposit to be tested.
- o Isolate the section by setting a straddle packer or using other means.
- o Install downhole a pressure sensing/recording device and shut-in tool.
- o Inject fluid (water) at a constant rate at a pressure calculated not to exceed rock-parting pressure.
- o After injecting fluid for sufficient period of time, as calculated in the test design, terminate injection, activate downhole shut-in tool and measure pressure falloff versus time. Sometimes the design cannot be followed because estimates of initial conditions were incorrect. In this case adjustments should be made in the field and the test repeated to obtain usable data.

Data should be evaluated during execution of the test. Table 7.1 is a typical data sheet used for pressure transient testing. If down-hole pressure is taken with surface-recording equipment, the data should be reduced as it is recorded to determine if the test is a success or whether it needs to be repeated. To allow for reliable interpretation of data the engineer should have all information concerning the test well, any operations in the vicinity that could distort the data, complete rate and pressure history during execution of the test, condition of fluid, temperature of formation of the test interval, and a complete list of remarks noted by the test engineer as the test was executed.

TABLE 7.1. RECOMMENDED PRESSURE TRANSIENT DATA SHEET

| <u>Date</u> | <u>Time</u> | <u>Rate, gpm</u> | <u>Press, psi</u> | <u>Comments</u> |
|-----------------------------------|----------------------|------------------|-------------------|-----------------|
| <hr/> | | | | |
| Hole No. _____ | Interval _____ | _____ | to _____ | Date _____ |
| Fluid Injected _____ | Packer Depth _____ | _____ | Tubing Size _____ | _____ |
| Downhole Gage: _____ | Press. Element _____ | _____ | Clock _____ | _____ |
| Downhole Shut in Tool Depth _____ | _____ | | | |
| Time bomb on Bottom _____ | _____ | _____ | _____ | Date _____ |
| Time Bomb off Bottom _____ | _____ | _____ | _____ | Date _____ |
| <hr/> | | | | |

Transient testing is a procedure for determining certain formation characteristic such as permeability and the wellbore flow condition. This procedure primarily provides data for calculation of permeability and skin factor. Skin factor is a number related to fluid transmissibility of the rock in the immediate vicinity of the wellbore. A

positive factor indicates reduced (or damaged) permeability in the immediate vicinity of the wellbore. A positive skin factor can be caused by a number of factors including injection of dirty water, precipitation of minerals, inadequate perforations, and damage resulting from drilling mud. A negative skin factor indicates an increase in permeability in the immediate vicinity of the wellbore and can be caused by induced fractures or dilation of flow channels, and also by acid dissolution of the rock.

Although not absolutely required, the test is normally conducted by injecting water at a constant rate for a sufficient period of time to create a pressure disturbance in the formation in the vicinity of the test well. After termination of water injection the pressure decline (or falloff) is measured. If the injection rate is not constant the data can be analyzed using a mathematical concept called the superposition principle. Although effective, the application of this procedure is tedious. Maintaining a constant injection rate permits the use of simple data reduction methods.

There are several flow regimes which can occur in a formation. They are linear, radial, and spherical. A linear regime can occur if a natural or artificial high-permeability flow zone intersects the wellbore in the test interval. An artificial high-permeability flow zone would be an induced hydraulic fracture. The radial flow regime will almost always occur in a permeable formation that is bounded by low permeability or impermeable formations above and below. Spherical flow regime can occur when the test interval is small compared to the vertical extent of the formation. When analyzing test data the interpreter must consider the possibility of the various flow regimes. Often an

understanding of the geology will alert the engineer to the expected flow regimes.

Mathematical equations have been developed to describe the relationship between flow rate, pressure, and time for the various flow regimes. The working equation for radial flow is given by (7.1).

$$P_f - P_w = \frac{162.6 j \mu b}{kH} \log \left[\frac{1.42 \times 10^{-2} kt}{\phi \mu c r_w^2} \right] \quad (7.1)$$

- P_f = injection bottomhole pressure immediately before shut-in, psi
- P_w = bottom hole pressure, psi
- j = injection rate, barrels per day
- μ = viscosity of injected fluid, centipoise
- b = a volume expansion factor, fraction
- k = permeability, md
- H = interval of formation intercepted, feet
- ϕ = porosity, fraction
- t = time, hours
- c = compressibility of system (fractional change in pore volume per unit pressure change), psi^{-1}
- r_w = wellbore radius, feet

The pressure difference is a linear function of the logarithmic value of time. When the pressure falloff is plotted against the log of time the straight line will have a slope of:

$$\text{slope} = \frac{162.6 j \mu b}{kH} \quad (7.2)$$

Similar relationships exist in the linear and spherical regimes(60),(61). For the linear regime pressure difference (Δp) is linearly related to the square foot of time (\sqrt{t}); whereas for the spherical regime (Δp) is linearly related to the reciprocal of the square root of time ($1/\sqrt{t}$).

In the radial flow regime, once the correct semi-log straight line has been determined and permeability has been calculated, the skin factor can be calculated:

$$\text{skin factor} = 1.1513 \left[\frac{(P_{1hr} - P_w)}{\text{slope}} - \log \left[\frac{k}{\phi \mu c r_w^2} \right] + 3.2275 \right] \quad (7.3)$$

P_{1hr} = pressure on straight-line portion of semi-log plot 1 hour after beginning a transient test.

All other symbols are the same as used in equation (7.1).

A practical problem which arises in the measurement of pressure falloff is wellbore storage. This error results when water stored in the well (after injection has stopped) drains into the formation. The procedure used to determine whether wellbore storage effects are significant is to plot $\log \Delta p$ versus $\log \Delta t$. A straight line having a slope of 45° indicates a wellbore storage effect.

Because many factors can influence data interpretation the reader is urged to study the references cited before undertaking the analysis.

7.2.2 Geophysical Wireline Logging

Exploration for minerals by electrical methods, i.e. resistivity, using surface equipment has been practiced since the early 1900's. (62) In the latter part of the 1920's electrical methods were adapted to wireline logging of boreholes. In selecting a suite of logs and recording and quantifying responses, factors such as hole size, nature of drilling fluid, rock characteristics and pore-fluid characteristics must be considered. These original logging tools are recognized as outstanding geological-data gathering tools. In subsequent years a

number of other tools had been developed. Those which have been found useful for in-situ copper leaching are shown in Table 7.2.

TABLE 7.2. WIRELINE TOOLS AND TYPE OF INFORMATION

| <u>Tool</u> | <u>Information</u> |
|-------------------------|--|
| Natural gamma | Intensity of natural radioactivity, potassium |
| Spontaneous potential | Zones of porosity |
| Gamma density | Bulk density, porosity |
| Sonic velocity | Degree of fracturing, porosity, cement bond |
| Thermal neutron | Porosity |
| Electrical resistivity | Fluid saturation, porosity |
| Magnetic susceptibility | Magnetite content |
| Induced polarization | Sulfide content |
| Temperature | Thermal gradient, top of cement, zones of permeability |
| Caliper | Borehole diameter, condition of casing |
| Spinner | Fluid velocity, zones of permeability |
| Radio-isotope | Fluid velocity, zones of permeability |

Many tools need to be calibrated in test pits or in the field prior to operations. Field calibration often assures the engineer that equipment is operating properly. For Set I Tests only tools useful for obtaining values of porosity, water saturation, and fluid-flow profiling will be described.

o Porosity Tools

The most commonly used tools to measure rock porosity are: thermal neutron, gamma density, sonic velocity and electrical resistivity. Each will be discussed in turn.

Neutron logs fundamentally measure the hydrogen content of a rock. Porosity of any rock, whose pores are saturated with water, can readily

and reliably be determined. However, many rocks are composed of minerals containing significant quantities of bound water. One such mineral is clay. If one has a reliable estimate of chemically bound hydrogen in the rock a correction can be made to neutron logging results.

A neutron log is obtained when a source is moved through the hole and emits a continuous flux of energetic neutrons. The energy of these particles is reduced as they pass through a known volume of rock. By measuring with a nearby detector the change in energy the log is generated. With proper calibration the porosity (hydrogen richness) is calculated.

The density log measures the bulk density of rock adjacent to the borehole. If the rock is porous any fluid contained in the pores will influence the measured density.

To determine the bulk density a known volume of rock is irradiated with gamma rays and a nearby detector measures the change in the intensity of the rays. This change is a function of the bulk density. A greater reduction is associated with a higher bulk density. Not only will porosity influence the bulk density but also minerals of greater or lesser density.

The sonic velocity log measures travel time of a compressional wave through a known length of rock adjacent to the borehole. Velocity in the rock is a function of density and rock type. (Different rock types permit the compressional wave to travel at different velocities). Density of the rock is influenced here again by porosity, and the nature of fluid contained within the pore space.

Electrical resistivity log measures the resistance of the rock to the transmission of an applied electrical potential. The resistivity of

rock is primarily a function of the rock type, its effective porosity and conductivity of fluid contained in the pore space. Further if the pore space is not saturated with a liquid the resistivity is altered. If the rock contains highly conductive minerals such as sulfides the resistivity will be influenced.

- o Initial Water Saturation

Water saturation is the fraction (or percentage) of the pore space which is occupied by water. In the phreatic zone (below the water table surface) the pores by definition are 100 percent saturated. However, in the vadose zone the percentage of saturation is less than 100 percent. Information obtained from the resistivity log can be used to calculate water saturation. This requires reliable values for the resistivity of the rock and resistivity of contained water as well as the rock porosity. To obtain reliable porosity values information should be extracted from the sonic, neutron and density log.

- o Flow Distribution (Flow Profile)

Three different logging tools are available to determine qualitative and quantitative fluid exit rates from the well bore. They are the spinner, temperature, and radio-isotope tools. All are commonly referred to as "production logging tools," or "production logs." The spinner and radio-isotope logs are obtained while liquid is injected into the hole. For interpretation of the spinner log the liquid injection rate must be constant, the variation of hole diameter must be available from the caliper log, and the wireline to which the spinner is attached must be moved up or down the hole at a constant velocity. The spinner tool must also be calibrated by moving the tool at a constant velocity in stagnant or constant velocity fluid in a hole of uniform diameter (preferably cased).

A radio-isotope log requires: fluid injection at a constant rate; emission of a small slug of radio-isotope and measurement of the velocity of the slug as it flows with the fluid down hole; and a caliper log to measure diameter variation.

The temperature log is run repeatedly after injection of fluid to measure the relative rate of temperature change of various zones of fluid exit. To establish a suitable temperature, liquid at a temperature significantly different from the rock temperature in the injection interval must be used, and the volume injected must be sufficient to establish a strong anomaly. Frequency of repetitive temperature surveys is a function of the temperature difference between fluid and rock, and rate of injection and total liquid injected. The results are considered qualitative.

Wireline geophysical logging is conducted almost exclusively by service contractors that specialize in such services. Design of the logging program must consider the nature of the deposit, its mineral suite and contained fluid, drilling fluid characteristics, the hole conditions to be expected and physical limitations of tools that may be available from the various service companies. Chief concerns of engineers are that the tool sizes are suitable for the test-hole diameter, that the tools are suitably calibrated and that the suite of logs is sufficient to reliably obtain the information sought.

Some tools (sondes) function well in large diameter holes. Others, because of physical principle upon which they operate, function better in a small diameter hole. These devices often are constructed such that the sonde is forced to move along the wall of the wellbore in large diameter holes. These sondes are referred to as side-wall devices.

Almost all logs are run by lowering the sonde to the bottom of the hole and obtaining the log as the sonde is retrieved. The exception to this rule is running the temperature log and the radio-tracer log while injecting fluid. Although the spinner log can be obtained by either lowering or retrieving the tool, it generally provides greater sensitivity when it is retrieved from the hole. As indicated above the fluid injection rate should be constant, the wireline velocity should be constant and the tool calibrated by movement in a portion of the hole that has a uniform diameter.

Logs are obtained using the following procedure:

- o Mobilize rig and logging company.
- o With the rig on location condition the hole.
- o Remove down hole equipment.
- o Move geophysical equipment and operators on location.
- o Calibrate tools.
- o Lower tool(s) into hole and obtain log.
- o Repeat logs, to assure proper functioning of equipment.
- o Recalibrate after final logging run, if necessary.
- o Rig down and release logging company.

Analyzing data obtained from geophysical wireline logging is equally as complex as analyzing pressure transient data. The user will want to keep in mind that most logging devices have been developed by and for the petroleum industry. These devices have therefore been developed for oil-bearing, sedimentary formations. These formations are primarily sandstones, limestones and dolomites. Of course there are mixed lithologies and shaly sandstones, etc.

Interpretation of logs(62),(63), (64) must consider the nature of the rock and the fluids contained therein. Most logging and log

interpretation is directed to sedimentary rocks whose rock and fluid characteristics will be significantly different from most hard rock mineral deposits. Generally, one can expect the mineral-deposit rocks to exhibit lower porosity and to have a widely different suite of minerals and often relatively large percentage of heavy minerals. Often the response of some logs will be more greatly impacted by hydrous minerals in relationship to the fraction of pore space than would be the case with sedimentary rocks. Often the logging tools will not have been calibrated in a hard-rock environment, therefore, techniques of data analysis using cross plotting will become necessary. To arrive at a reliable value for porosity an independent measure of hydrous mineral and heavy minerals often will be required. Detailed discussions of these interpretation techniques are beyond the scope of this study and the reader is referred to cited references.

Logging tools such as temperature, spinner, radio-isotope tracer and caliper are often referred to as production logging tools(64). These tools often are adequate to provide information about the flow of fluids from the well and in the formation in the immediate vicinity of the well. However, one log alone seldom provides the answer to a particular question(65),(66). Often the subtle features as opposed to the obvious anomalies provide the desired information. Like other down hole logging methods interpretation is complex. The reader is urged to study the cited references which provide a wide range of examples of each of the logging methods and their interpretations.

7.2.3 Coring

Coring design and procedures are no different than conventional coring used during a mining exploration program. However, a triple-tube core barrel is recommended for the activity. This device permits extraction of the core from the barrel with almost no artificial breakage or re-orientation of the core. It facilitates excellent photographic documentation of the undisturbed core and provides a better observation of natural rock fractures.

Cores are normally taken by means of commonly used wireline drilling rigs. A large variety of bit sizes are available, examples of which are listed below:

Series "Q" Wire Line Diamond Bits

| <u>size</u> | <u>core dia. (inches)</u> |
|-------------|---------------------------|
| AQ, AQ-U | 1.062 |
| BQ, BQ-U | 1.432 |
| NQ, NQ-U | 1.875 |
| HQ | 2.500 |
| PQ | 3.345 |

It is required that the drillers do not pulverize the core by excessive beating on the core barrel.

Cores may also be collected by using construction coring equipment. This type of equipment is used to obtain concrete samples and drill through short distances of rock and concrete. This equipment can be used to obtain samples from surface boulders, and ribs and faces in underground workings.

The following procedures should be followed after core removal from the coring device.

- o Sample should be labeled.
- o Core orientation should be noted (if obtained).
- o A general description should be recorded including ore and gangue mineralogy, fractures, porosity, size, etc.
- o A photograph should be taken.

Care must be taken in shipping the cores from the field to the laboratory. They should be placed in plastic bags and packed carefully to prevent breakage.

7.2.4 Laboratory Core Leaching

Laboratory leaching tests are conducted on whole core samples (as opposed to crushed samples) to obtain data that more closely reflect the reactions of in-situ leaching. Most copper-oxide mineral deposits have a crystalline host rock and the bulk of the porosity and permeability is associated with fractures and fissures. Further, most of the metal values are contained within these pore spaces. The core leaching test is used to force acid under pressure through natural fractures of representative ore samples. Thus, mineralized rock samples must be chosen judiciously in order to assure that the sample has permeability.

Tests must be designed to obtain copper loadings and fractional copper recovery versus time or pore-volume throughput. These tests should evaluate the relationship between copper loading, ore grade, and lixiviant concentration. Test results should provide data concerning lixiviant consumption per unit of copper produced. In this regard, recycle tests should be conducted to determine the impact of gangue cations on lixiviant consumption.

To obtain useful data, fluid must be forced to flow through the natural flow channels of the test specimen. Careful selection of samples is necessary, and samples must be mounted so that lixiviant will flow through the native flow channels and not along the outside surfaces. Core leaching provides a means of assessing the potential

response of the sub-surface component of the chemical extraction system.

One will want to determine:

- o Whether copper mineralization is in the flow fractures, or in dead end pores that contact the acid as it moves through the flow fractures. This is accomplished by demonstrating high copper recovery in the effluent spent acid, and by petrographic examination of the leached core.
- o Whether the combination of copper mineral/acid reactivity and transport of solubilized copper is sufficiently rapid and stable to concentrate copper to a high level in the pregnant liquor and maintain it at that level to a high percentage of copper recovery. This information is used to select well spacing and frequency of future well pattern additions, and focuses on selection of well pattern residence time or determining minimum requirements for it. The net rate at which copper can be recovered changes throughout the recovery period, and may be controlled by one or several mechanisms such as:
 - + Chemical kinetics of mineral/acid reactivity
 - + Acid and copper diffusion into and out of porous mineral product layers
 - + Acid and copper diffusion between flow fractures in diffusion paths within the pores of the rock
 - + Chemical equilibria, primarily pH control at levels that maintain solubilized copper in solution
 - + Adsorption of solubilized copper on-rock surfaces.

Core leach data provide a measure of the net effect of the above. Analysis of the data provide information on the impact of well pattern residence times on pregnant solution copper loading.

- o The net quantity of copper produced in the pregnant liquor per unit acid consumed. This number is a function of: injected acid strength; relative reactivity and surface contact of acid with copper and gangue minerals; and the ionic strength and composition of the injected acid. The true in situ process is expected to maximize the contact of acid with copper minerals relative to gangue, which is favorable to producing higher copper loadings at a given acid strength. The in situ process recycles spent acid solutions (following acid make-up) containing solubilized gangue cations through the well pattern between 5 to 20 times. The impact of these cations on subsequent acid consumption is not known at this time, but is thought to have a retardation effect on gangue reactivity with acid. The net acid consumption per pass through the well pattern has a significant impact on process economics. A

reduction in acid consumption of 4 pounds of acid per pound of copper at an acid cost of \$30 per ton of acid results in a \$.06 per pound of copper reduction in operating cost. This provides sufficient cash to replace 20 wells per year in a 25,000 ton per year commercial operation. In addition, the lower acid consumption provides a higher copper loading which requires fewer wells to produce the same total amount of copper at a given flow rate per well (permeability).

- o The net effect of acid reactivity with copper and gangue minerals on the change in permeability. Various mechanisms are discussed below:
 - + The dissolution of minerals may result in an increase in porosity. Should this increase be associated with enlargement of flow fracture dimensions then permeability would be expected to increase. If the porosity increase is not in the flow fractures, then permeability is not likely to change, but the increase in porosity could expose additional copper mineralization to the acid and thus increase copper recovery.
 - + Calcium released into solution by acid attack of clay or calcite in combination with the sulfate component of the acid could result in precipitation of gypsum. Should this occur in the flow fractures, a reduction in permeability would be expected. Gypsum solubility is lower at higher temperature and lower pressure.
 - + Carbon dioxide released by the reaction of carbonate minerals and acid when present as a free gas will also result in a reduction in permeability. Excess free gas could also blind copper minerals from direct contact with acid and reduce copper recovery. The higher the pressure at which the system is operated the lower the probability of having free gas.
 - + Swelling of clay minerals resulting from changes in the ionic strength and composition of the fluid moving through the fractures would result in a significant reduction in permeability.

The core leaching test data provides a measure of the net effect of the above mechanisms on permeability. Simultaneous analysis of permeability and effluent chemical changes over time can identify which of the above is the most significant, and what its impact on field operation is likely to be.

Core leaching tests can be conducted using many different types of testing equipment and core configurations. The key physical design requirement is to ensure that the injected acid is forced through the native in situ flow paths. This requires forming a tight seal between

the outer surfaces of the core and the internal contacting surface of the test apparatus. The most convenient core geometry to use is cylindrical, and samples can be obtained from mineral core hole drilling in sizes from one to 3 1/2 inches in diameter. This provides a regularly shaped outer surface that can be readily sealed against the test equipment surface. Two examples of core configuration that are used during leaching are illustrated in Figure 7.1.

- o In the axial configuration, flow is perpendicular to the face of the cylinder, and sealing is effected on the circumference of the core by applying a hydraulic pressure, or by cementing the core surface to the core holder. The former also provides a means of assessing the effect of overburden stress variations on leaching. The Bureau of Mines has reported on the design and operation of a core test facility(67).
- o In the radial configuration, acid is injected over the core circumference. This increases the probability of acid coming into contact with the fracture network. Sealing the end caps to prevent short circuiting to the center withdrawal hole can be a problem, and the radial configuration does not provide a means of applying an overburden stress.

Petroleum engineering service companies that provide test support for oil production and enhanced oil recovery studies are experienced and have capabilities in design and operation of high pressure core facilities, but are not likely to be experienced in utilizing this equipment for acid leaching of copper oxide ore.

There are two modes of operating a core leaching test, constant pressure drop or constant flow rate, see Figure 7.2.

- o In the constant pressure drop mode, a fixed pressure source is used to displace acid through the core. The flow rate, and residence time, will vary throughout the test as the permeability changes. Changes in permeability are proportional to changes in flow rate, and a means of monitoring flow rate continuously must be provided to measure permeability variations. Effluent copper loadings are likely to increase when the permeability decreases due to the increase in residence. This will also increase metal concentrations in the spent acid, and could eventually result in a sufficient pH rise at the exit section of the core to cause further precipitation and permeability reduction.

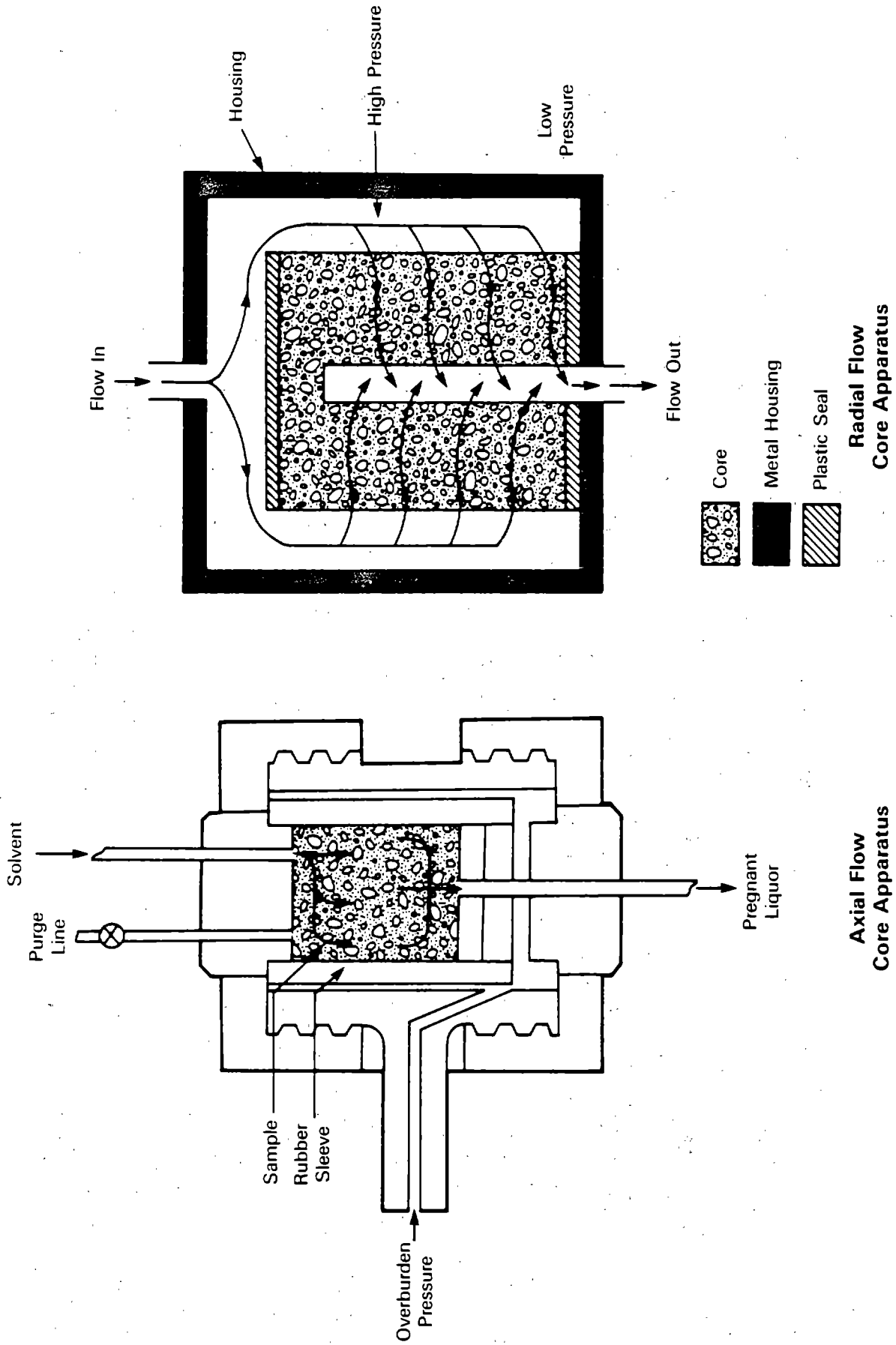
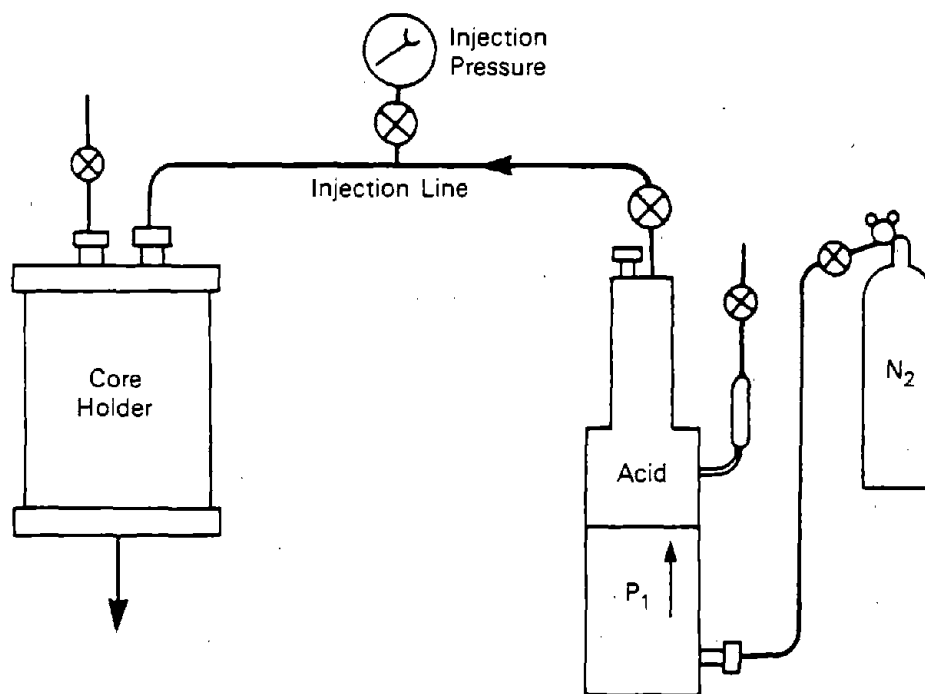
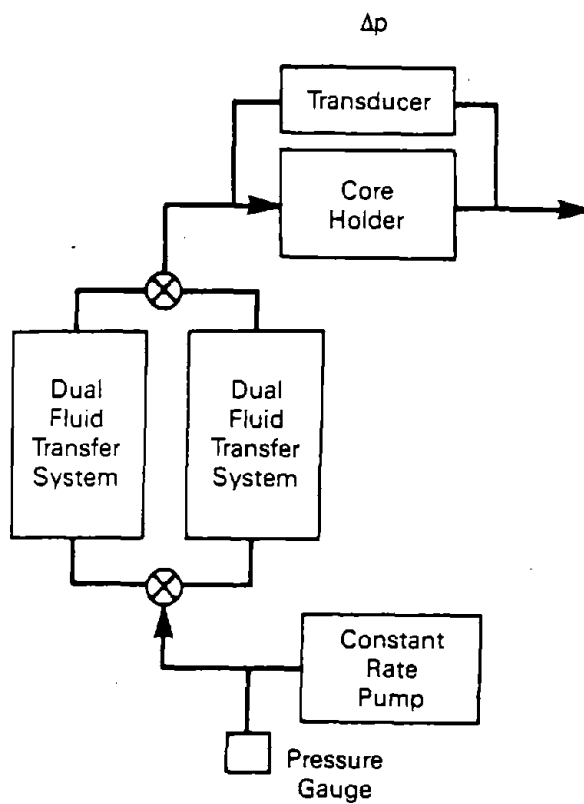


Figure 7-1. Illustrations of Core Configuration During Leaching



Constant Pressure Drop



Constant Flow Rate

Figure 7-2. Two Modes of Operation of Core Leaching

- o In the constant flow rate test, a constant rate pump is used to displace a fixed quantity of acid through the core. The pressure drop across the core varies as permeability changes and the residence time remains constant. Therefore, changes in the effluent concentration of metals over time are direct measures of changes in net mineral/acid reactivity in the core.

The constant pressure drop test is usually easier and less costly to set up but more difficult to control and analyze data. System pressure effects can be tested in both modes of operation by adding a device, such as a valve, to the exit line to apply a back pressure to the entire system.

The preparation and conduct of core leach tests involve three procedures that are discussed in a generic format. These are: core preparation, from obtaining core to initiating leaching; selection of a residence time and test duration; and collection and analysis of data.

In preparing core for leaching an attempt should be made to obtain samples that are representative of the section of the orebody to be leached. Characteristics that should be similar to the entire orebody include:

- o Ore grade
- o Types of ore and gangue minerals
- o Fracture spacing
- o Amount of total porosity
- o Location of ore minerals with respect to porosity and fractures

At the laboratory, the cores should be trimmed to final dimensions with a diamond saw and then dried at low temperature in a vacuum oven.

The dimensions should be recorded, and the specimens weighed.

The cores can be prepared for axial leaching by potting them in epoxy resin. The core is placed inside a piece of pipe, and epoxy resin is poured into the annulus between the core and the pipe. Epoxy can be

prevented from penetrating deep into the core and blocking the permeability by covering the ends with tape and painting the sides of the core. After the epoxy has hardened, the ends of the specimen are machined flat. Again, the specimen is measured and weighed dry.

The effective porosity of the specimen is next obtained by evacuating the air from the sample and then saturating it with water. The saturated core is then weighed again and the porosity calculated from the core's volume and weight gain. The saturated core can then be used for a determination of permeability. This is done by placing the core in a holder and applying water under pressure to one end face. When the flow rate through the core reaches a steady rate using a constant pressure, the permeability may be calculated using Darcy's law. The test is normally repeated at several pressures to make sure that the pressure vs. flow rate relationship is linear. Nonlinearity indicates some degree of non-laminar (non-Darcy) flow.

After the determination of permeability, the core is ready for leaching with acid and a residence time must be selected for the test. Residence times in commercial well patterns are expected to be of the order of weeks or months. This is illustrated by data presented in Table 7.3, assumptions made are:

- o Minimum well pattern volumes (well spacings) obtained by equating copper worth to cost of wells.
- o The flow rate per well is calculated for radial flow geometry without matrix modification.

Previous commercial analyses indicate that economic well spacings are of the order of 200 feet, and well flow rates of the order of 50 gpm can be obtained. Actual residence times of 2-to-3 times (2-to-3 months) the minimum levels listed in Table 7.3 are expected.

TABLE 7.3. SCOPING OF COMMERCIAL WELL PATTERN RESIDENCE TIMES

| Depth D feet | Ore Thickness H feet | Copper Grade F _c % | Copper Recovery E _c % | Porosity φ % | Unit Well Cost C _{dr} \$/ft. | Copper Selling Price e _c €/lb | Permeability k md | Minimum Well Pattern Volume V _m ft ³ | Minimum Well Spacing S _m feet | Well Flow Rate gpm | Minimum Residence Time t _{FR} days |
|--------------|----------------------|-------------------------------|----------------------------------|--------------|---------------------------------------|--|-------------------|--|--|--------------------|---|
| 1000 | 300 | 0.6 | 50 | 5 | 125 | 60 | 3 | 908,000 | 55 | 7.7 | 31 |
| 1000 | 500 | 0.6 | 50 | 5 | 125 | 60 | 3 | 908,000 | 43 | 9.2 | 26 |
| 3000 | 500 | 0.6 | 50 | 5 | 125 | 60 | 3 | 2,738,000 | 74 | 28 | 25 |

S_m = minimum well spacing, feet

H = ore thickness, feet

D = depth of deposit (bottom), feet

V_m = minimum well pattern volume, cubic feet

A_b = rock density, 162 lb/ft³

φ = porosity, %

E_c = copper recovery, %

C_{dr} = unit cost of well, \$/foot of depth

e_c = selling price of copper, €/lb

k = permeability, md

μ = viscosity of fluid, 1 centipoise

a_f = fracture gradient, 0.7 psi/foot

q_I = flow rate per well, gpm

t_{FR} = minimum commercial residence time, days

$$S_m = (1000) \left[\frac{2C_{dr}D}{H\rho_b (1-\phi/100) F_c E_c e_c} \right]^{1/2}$$

$$q_I = \frac{1.7 \times 10^{-5} a_f H (D-H)}{\mu}$$

$$V_m = S_m^2 H$$

$$t_{FR} = 5.2 \times 10^{-5} \left(\frac{V_m \phi}{q_I} \right)$$

It may not be practical or useful to conduct laboratory tests over this extended period of time. Laboratory tests should be designed such that the residence time (time required for one pore volume displacement) is sufficient to achieve effluent pH levels between 2 and 3. In this range a sufficient percentage of the injected acid would have reacted to produce and maintain copper at a high level. The absolute value of that level is a function of the injected acid concentration and the net acid consumption of copper and gangue minerals.

The equations listed in Table 7.4 are used to compute the initial pressure drop required to achieve a given residence time as a function of core permeability, porosity, and length. Also listed are equations for calculating the flow rate and fluid volume per residence time (pore volume) as a function of core diameter and residence time. Example values are also listed for a one day residence time, for core dimensions and properties that are likely to be encountered in practice. Except for permeabilities below 0.1 md, and residence times less than one day, pressure drops in excess of 20 psi are not anticipated. Design of core equipment for high pressure (>100 psi) will be primarily governed by the need to simulate total system pressure and not system pressure drop across the core.

As a means of scoping a potential range of generic residence times consider two limiting mechanisms associated with in situ copper recovery.

- o At one limit it is assumed that the reactivity of copper oxide mineral and acid controls the rate at which copper is concentrated in the effluent stream. Sullivan(68) described the % recovery of copper from varying sized chrysocolla particles in 1% sulfuric acid. For the largest fraction size -0.525" + 3 mesh, 100% recovery resulted in seven days, and 50% recovery in one day. These data indicate that a residence time of the order of 1 to 2 days would be sufficient to achieve acid spending in one pass through the core.

TABLE 7.4. SCOPING OF INITIAL PRESSURE DROPS IN CORE LEACHING TESTS

| Length L_c Inches | Permeability k_c md | Porosity % ϕ_c | Residence Time t_{LR} days | Pressure Drop ΔP_c psi | Diameter d_c Inches | Flow Rate q_c cc/hr | Effluent Volume per Residence Time V_c cc |
|---------------------------|--------------------------|------------------------|------------------------------------|--------------------------------------|-----------------------------|--------------------------------|--|
| 3 | 0.1 | 5 | 1 | 4.9 | 2 | 0.32 | 7.7 |
| 3 | 2.0 | 5 | 1 | 0.25 | 2 | 0.32 | 7.7 |
| 6 | 0.1 | 5 | 1 | 19.6 | 2 | 0.64 | 15.4 |
| 6 | 2.0 | 5 | 1 | 1.0 | 2 | 0.64 | 15.4 |

L_c = core length, inches

$$U_c = 0.0981 \left(\frac{k_c \Delta P_c}{L_c \mu} \right)$$

d_c = core diameter, inches

k_c = core permeability, md

$$t_{LR} = 0.00106 \left(\frac{L_c \phi_c}{U_c} \right)$$

ϕ_c = core porosity, %

q_c = core flow rate, cc/hr

$$\Delta P_c = 0.0108 \left(\frac{L_c^2 \phi_c \mu}{k_c t_{LR}} \right)$$

V_c = effluent volume per residence time, cc

t_{LR} = laboratory residence time, days

$$q_c = 0.497 \left[\frac{d_c^2 k_c \Delta P_c}{L_c \mu} \right]$$

U_c = core darcy velocity, cm/hr

μ = fluid viscosity, 1 centipoise

$$V_c = 24 q_c t_{LR}$$

- o At the second limit it is assumed that diffusion of acid from primary flow fractures to copper minerals connected to these fractures by diffusion paths controls the rate at which copper is concentrated in the effluent stream. In this case the time scale is proportional to the square of the characteristic diffusion length divided by the diffusion coefficient. A typical value of acid diffusion in water is $2 \times 10^{-5} \text{ cm}^2/\text{sec}$. Assuming an effective porosity of 5% (includes both porosity and tortuosity), the value of the effective diffusion coefficient in the rock is $10^{-6} \text{ cm}^2/\text{sec}$. For a diffusion length of 0.5 cm, a characteristic diffusion time of 3 days is estimated, or 12 days for a diffusion length of 1 cm (0.4 inches). Should this length approach the dimensions of the core, then little or no acid spending through the core would be expected for residence times under one week.
- o By using cores having the dimensions of several inches and residence times of the order of days, and achieving significant acid spending and high copper loadings, it can be demonstrated that copper mineralization is in close proximity to primary fracture flow channels.

The core leaching test should be extended to approximately 100% recovery if feasible. Table 7.5 lists the number of pore volumes and testing times required to achieve 100% recovery as a function of ore grade and porosity, effluent copper loading, and residence time.

TABLE 7.5. SCOPING CORE LEACHING TEST DURATION

| Core Copper Grade F_c % | Core Porosity ϕ_c % | Effluent Copper Loading [Cu] gpl | Core Residence Time t_{LR} days | Number of Pore Volume Displacements n_p | Testing Time Core Leaching t_{TL} days |
|---------------------------|--------------------------|----------------------------------|-----------------------------------|---|--|
| 0.6 | 5 | 10 | 1 | 30 | 30 |
| 0.6 | 5 | 10 | 5 | 150 | 150 |
| 0.6 | 5 | 20 | 1 | 15 | 15 |
| 0.6 | 5 | 20 | 5 | 75 | 75 |

$$n_p = \frac{26 (100 - \phi_c) F_c}{\phi_c [\text{Cu}]}$$

$$t_{TL} = n_p t_{LR}$$

A listing of the parameters to be measured at each sampling point is provided in Table 7.6. Reduction of these data provide information for: engineering design of field tests; economic analysis of commercial size operation; and researching in situ mechanisms controlling recovery of copper. Of primary importance are reduction of the data to determine as a function of the degree of copper recovery: the net acid consumption per unit copper production; the rate of copper recovery; and the permeability. Note the following in Table 7.6:

- ° The initial sample point is a baseline established with water after establishing complete water saturation.
- ° The chemical compositions (in) and (out) refer to injected and effluent compositions. The net pick up of chemical in the liquid phase per pass through the core is the difference between out and in. For example, the net pick up of copper is denoted by ΔCu . For a recycle test the in values will increase with the number of times solution is recycled.

At each sample point the sulfuric acid consumed per unit mass copper produced (Ψ) is computed by two different methods, Table 7.7.

- ° The first method assumes that the cations Cu, Al, Mg, Ca, Fe, Na, K measured in the effluent were solubilized by acid reaction with basic oxide material. Ψ_{TC} equals the total acid consumed per unit of copper produced calculated by this method.
- ° The second method utilizes the difference in free acid by analytical measurements between injected and produced solutions as the quantity of acid consumed. Ψ_{TA} equals the acid consumed per unit of copper produced by this method.

Significant variations between Ψ_{TC} and Ψ_{TA} would be an indication of either cation precipitation in the core or analytical chemistry measurement errors.

Table 7.8 is used to summarize data reduction at each sampling point.

- ° Changes in permeability during leaching are represented by a relative permeability parameter (k) at each sampling point. k is the ratio of the flow rate times the viscosity divided by the pressure drop at each acid sampling point relative to the baseline water value.

TABLE 7.6. CORE LEACH DATA SHEET

Core Designation _____, Weight _____, Diameter _____, Length _____, Copper Grade _____, Initial Porosity _____, Core Volume _____,
 Pore Volume _____, Initial Water Permeability _____, Start Date _____, End Date _____, Weight Copper in Core Leach _____,

| A | B | C | D | E | F | G | H | Chemical Concentrations gpl | | | | | | | | | | | | | |
|--------|--------|------|-----------|-----------|--------|-------|-----------|-----------------------------|--------|--------|--------|--------|--------|--------|--------|--------|-----------------|------------------|--------|--------|--------|
| Sample | Volume | Core | Injection | Flow Rate | Total | Total | Effluent | | | | | | | | | | | | | | |
| Time | OC | AP | Pressure | cc/hr | Volume | Time | Viscosity | pH | Cu | Al | Mg | Ca | Fe | Na | K | Cl | SO ₄ | SiO ₂ | Free | Acid | In Out |
| hr | | psi | | A-B | OC | Hr | cp | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out | In Out |

Base Line Data Using Water _____>

Acid Leaching Data _____>

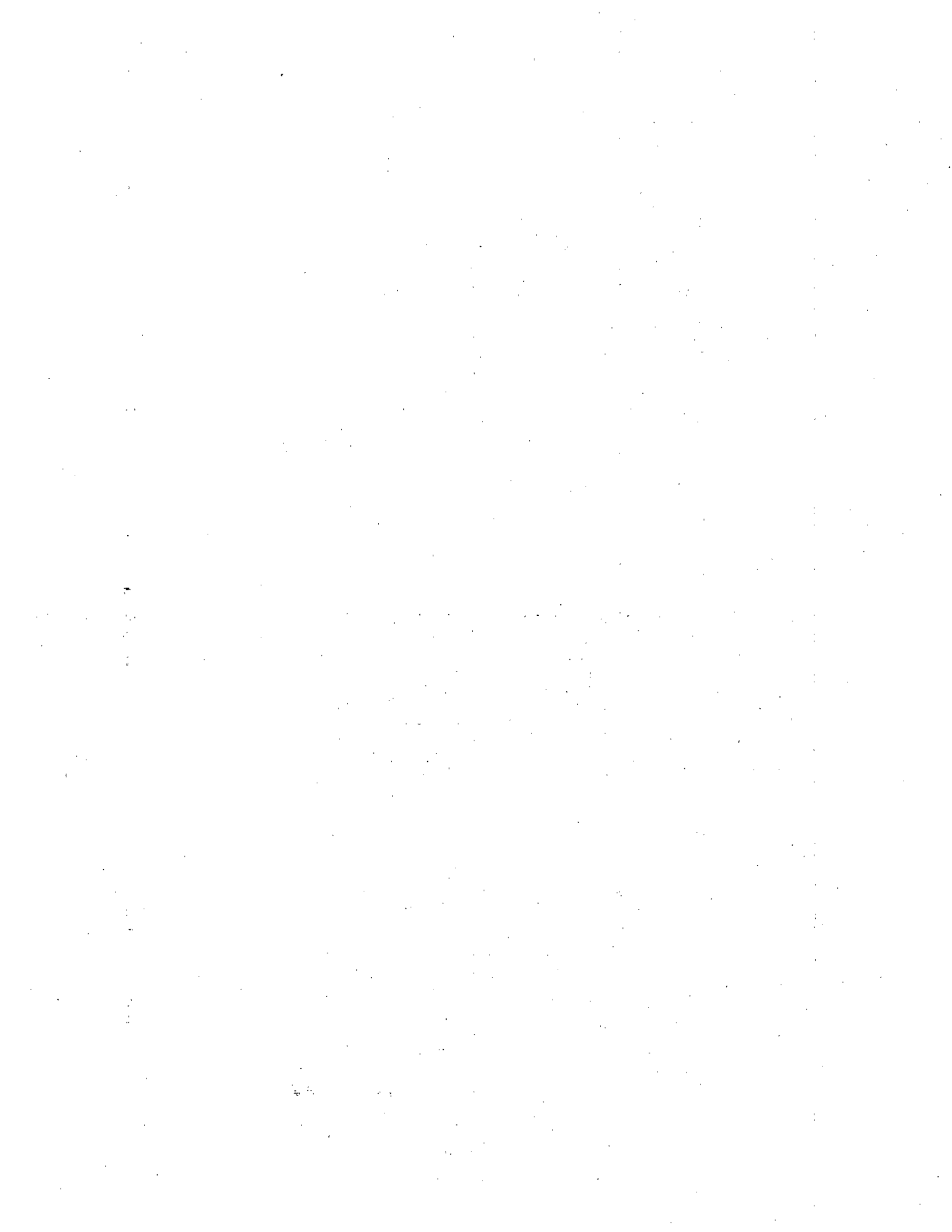


TABLE 7.7. DATA REDUCTION NET ACID CONSUMPTION

I. ACID CONSUMPTION BY CATION ANALYSIS

| Stoichiometric Factors Copper Minerals | | Stoichiometric Factors Gangue Cations | | Acid Consumption Per Unit Copper Produced |
|---|-----------------------------------|--|---------------------|---|
| Copper Mineral | $\delta_c = \frac{gH_2SO_4}{gCu}$ | Cation | gH_2SO_4/g Cation | $Y_{TC} = \frac{gH_2SO_4}{gCu}$ |
| Chrysocolla | 1.54 | Al | 5.44 | $Y_{TC} = \frac{r_c + r_g}{\Delta Cu}$ |
| Malachite | 1.54 | Mg | 4.03 | |
| Azurite | 1.54 | Ca | 2.45 | |
| Tenorite | 1.54 | Fe | 2.22 | |
| Cuprite | 1.54 | (50%Fe ⁺²) | | |
| Brochantite | 1.16 | Na | 2.13 | |
| Atacamite | 1.16 | K | 1.25 | |
| Antlerite | 1.03 | * Presence of Ferrous iron could indicate leaching of sulfide copper | | |

$r_c = \text{gpl } H_2SO_4 \text{ used for Cu}$

$r_g = \text{gpl } H_2SO_4 \text{ used for gangue cation}$

$r_c = \delta_c \Delta Cu$

$r_g = 5.44 \Delta Al + 4.03 \Delta Mg + 2.45 \Delta Ca$
 $+ 2.22 \Delta Fe + 2.13 \Delta Na + 1.25 \Delta K$

II. ACID CONSUMPTION BY FREE ACID ANALYSIS

$$Y_{TA} = \frac{gH_2SO_4}{gCu}$$

$$Y_{TA} = \frac{(\text{gpl Free Acid in}) - (\text{gpl Free Acid out})}{\Delta Cu}$$

- o The cumulative percent of copper recovered from the start of leaching up to each sampling point is represented by F. The recovery curve is obtained by plotting F versus total leaching time t.

For a generic discussion of the procedure used to analyze the copper recovery curve refer to Figure 7.3

TABLE 7.8. CORE LEACH DATA REDUCTION SHEET

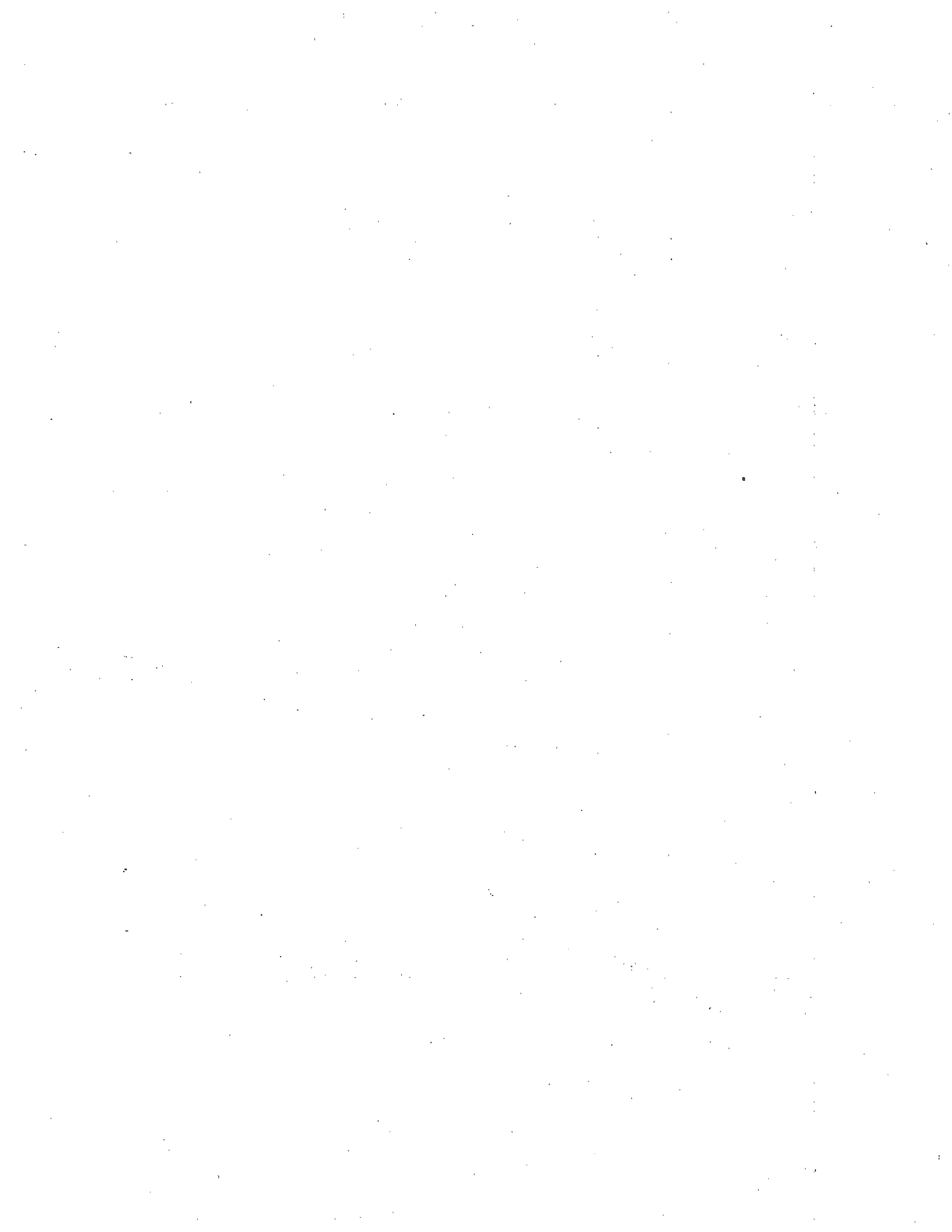
| Total Volume cc | Total Time hr | Relative Permeability k | Cumulative Copper Recovered W grams | Cumulative % Copper Recovered F | V_{TC} Each Sample g/g | V_{TA} Each Sample g/g | $K_s = [Ca][SO_4]$ (gpl) |
|--------------------|------------------|----------------------------|---|---------------------------------------|--------------------------------|--------------------------------|-----------------------------|
| | | | | | | | |
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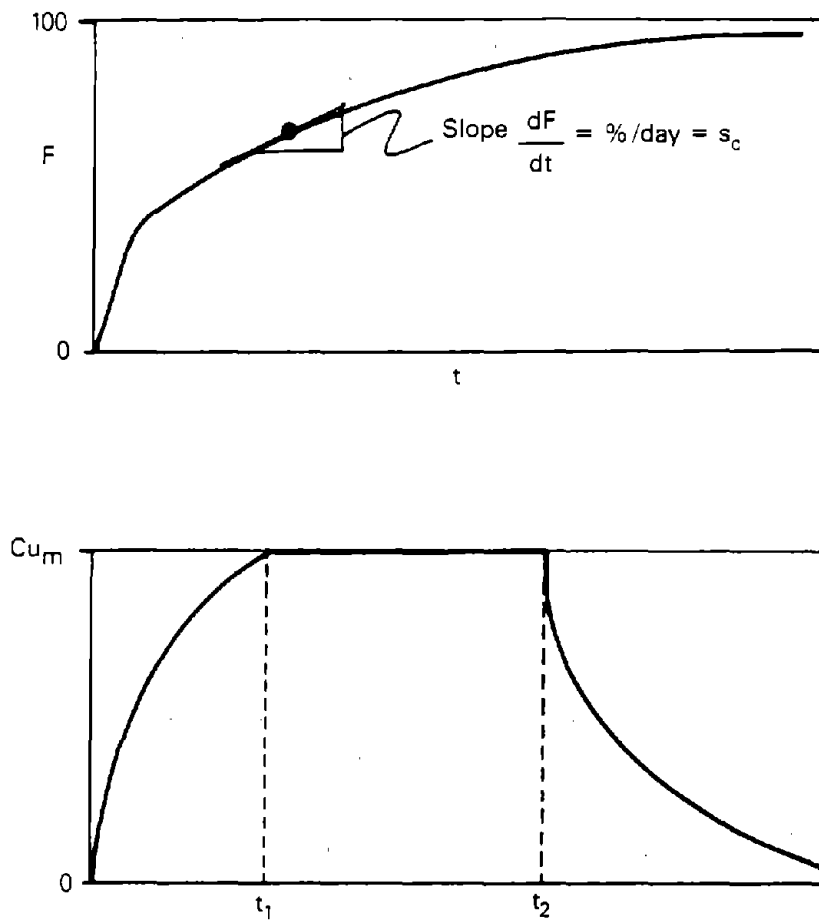
Calculation of k

- o Letters refer to columns in Table 7.6
- o Subscript S refers to each acid sample point, W refers to water baseline
- o
$$k = \frac{[(E \times H) - C]_s}{[(E \times H) - C]_w}$$

Calculation of F

- o i refers to ith sampling point
- o A refers to column A in Table 7.6
- o W_o refers to initial copper weight in core
- o $W = \sum_1 (Ax\Delta Cu)_i \div 1000$
- o $F = (W/W_o) \times 100$





s_c = %/day copper recovery below which well pattern loadings decline

t_{FR} = Well pattern residence time, days

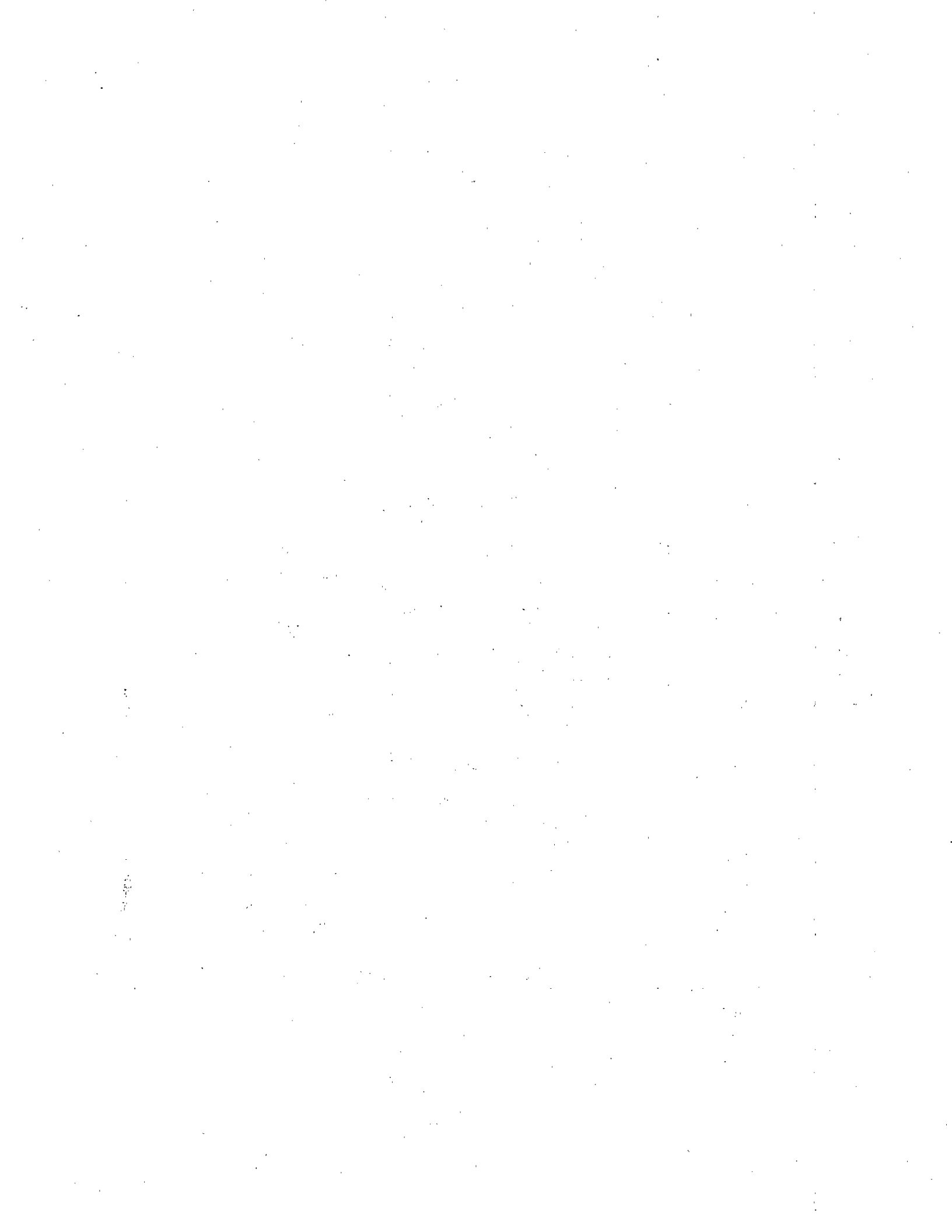
F_c = % initial copper grade

ϕ = % porosity

Cu_m = gpl copper loading in pregnant liquor

$$s_c \geq 3.85 \left(\frac{\phi}{100 - \phi} \right) \left(\frac{Cu_m}{F_c t_{FR}} \right)$$

Figure 7-3. Generic Laboratory Core Leaching Recovery Curve



- o Graphs of % copper recovery and copper loading versus time are drawn.
- o Cu_m represents the maximum copper loading obtained when the residence time is sufficient to achieve effluent pH levels of 2- to-3. For example, assume 40 gpl H_2SO_4 is injected and an initial acid consumption of $4gH_2SO_4/g$ copper is expected. Cu_m would correspond to 10 gpl copper. The time required to first achieve this value (t_{c1}) corresponds to the time required to obtain 1 pore volume displacement, which is the residence time.
- o The copper loading will remain at Cu_m until one of the following occurs at t_{c2} .
 - + 100% of the recoverable copper is achieved.
 - + The rate of copper recovery, the slope of the curve F vs. t ($\frac{\partial F}{\partial t}$), is reduced to a level at which complete acid spending is not achieved in the residence.
 - + The rate of gangue acid consumption is increasing with time, and even though the effluent pH of 2- to-3 is maintained a smaller fraction of the consumed acid is used to react with copper minerals. Should acid consumption by gangue decline with time Cu_m would increase, and the slope of F versus t would also increase with time.
 - + Precipitation of copper minerals in the core is taking place.
- o The value of the fractional copper recovery at which reductions from the maximum wellfield pregnant liquor copper loading would be expected to occur is estimated by finding the value of the % per day slope at which the wellfield residence time is not sufficient to concentrate copper to an undiluted level equal to Cu_m . The value of %/day at which this occurs is expressed in terms of field design levels for gpl Cu_m , % initial copper grade, % porosity, and days well pattern residence, see Figure 7.3. For example, with a residence time of 60 days, a copper loading of 10 gpl, a porosity of 5%, and initial copper grade of 0.6%, the value of the slope of the copper recovery curve at which a loading decline would be estimated is 0.056% per day. The value of F at which s_c equals 0.056% per day would be determined from the core leaching curve. This value of F would correspond to the minimum leach efficiency, E_L .
- o The shape of the curve of F versus t and the time frame to approach 100% recovery are indicative of the mechanism controlling copper recovery. Diffusion limitations to copper

recovery will result in the fractional recovery being proportional to the square root of time. A plot of F versus $(t-t_0)^{1/2}$ would yield a straight line over the time period $t > t_0$, where diffusion is rate limiting. The rate limitation mechanism can range from diffusion control through a porous mineral product layer (SiO_2 resulting from chrysocolla attack by acid) to diffusion of acid from flow fractures to copper minerals along non-flow fractures which connect to flow fractures. The slope of the curve of F versus $(t-t_0)^{1/2}$ is proportional to the square root of the diffusion coefficient divided by the square of the maximum diffusion length $(D/l_c^2)^{1/2}$. Other mechanisms would produce a different relationship between F and t .

Additional analyses of the data that are suggested which involve plotting the following as a function of copper recovery:

- o Y_{TC} and Y_{TA}
- o k
- o $[\text{Ca}][\text{SO}_4]$
- o Gangue cation ratios relative to Na.

7.3 SET II TYPE TESTS-SIGNIFICANT ENVIRONMENTAL PERMITTING

7.3.1 Tracer Testing

The volume of rock and corresponding quantity of copper swept by the injected acid as it moves between injection and production wells and the time required to travel through this volume is a function of a number of geologic and process variables:

- o Heterogeneity of rock permeability and porosity, including directional permeability.
- o Average value of rock porosity.
- o Well spacing, configuration, and density.
- o Flow rate per well module.

A chemical tracer added to the fluid that is circulated through the well pattern provides both a means of quantifying rock heterogeneity and a baseline to make material balances for all reactive chemicals in the fluid. To be effective a tracer must be: non-reactive with the rock

and solvent; not adsorb onto rock or mineral surfaces; added at levels an order of magnitude higher than background levels present in the native in situ water; and compatible with the environment.

Tracer tests can be carried out in a variety of modes of operation. Two examples are: continuous injection at fixed level of concentration or injection of a slug of tracer. For the former, the tracer continually increases at the production well, while in the latter mode of operation, the produced concentration reaches a peak level and then gradually declines. By using a reservoir flow simulator, the rate of tracer rise and the shape of the tracer curve can be related to the volume of rock swept and the porosity of the rock. For examples of the application of reservoir simulators to in situ leaching reference is made to studies by Kabir(69) and Schmidt(70) for in situ uranium leaching.

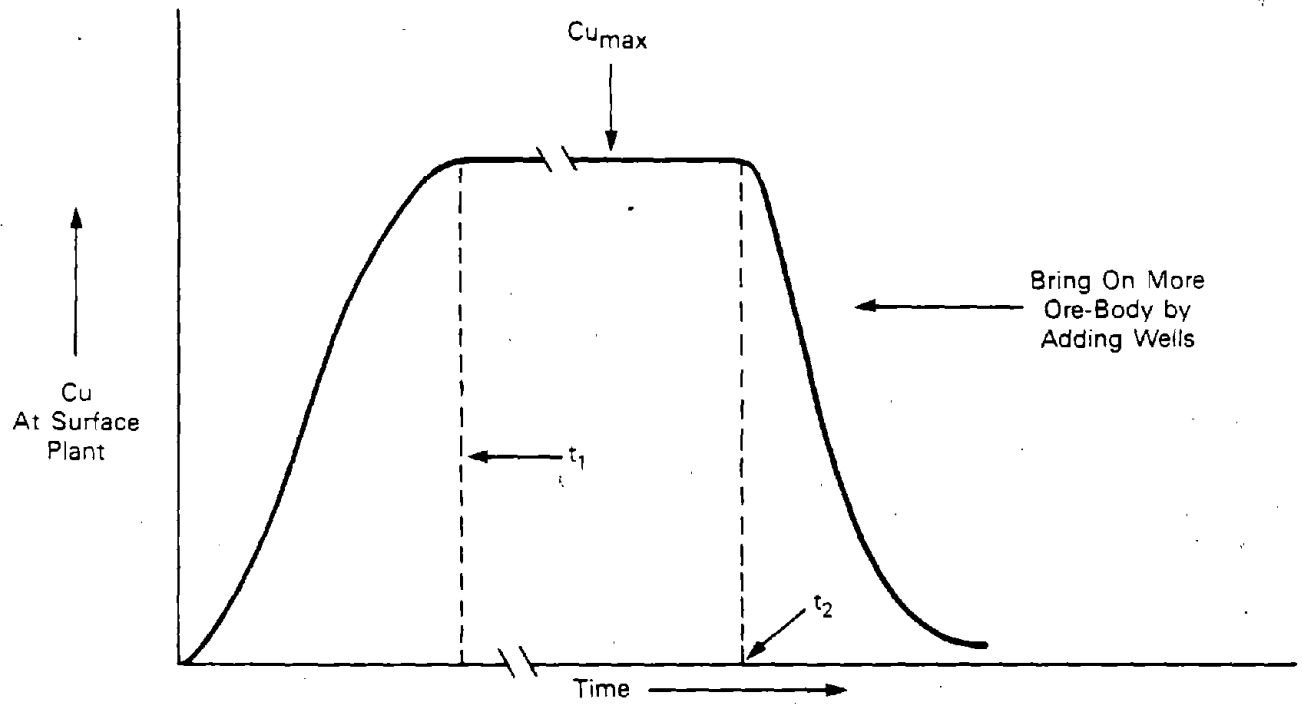
To conduct the tracer test equipment such as mixing tanks, pump, valves, flowlines, and instrumentation are required. The operator must decide to run the test in a "slug" mode or a continuous mode. In either case he must estimate the expected results and procure sufficient reagents. Injection and production rates should be similar to those that will be used for leaching. Chemical tracer requirements will be a function of porosity, well spacing, and the mode of test. Most if not all equipment to be used for leaching will be suitable for the tracer test. However, the operator is cautioned about serious corrosion problems that can result from inadvertently mixing large chloride concentrations with acids. The operator should have the tracer concentration periodically assayed and adjust the concentration as necessary. This may require assaying at the test site. If that is not possible,

quick turn around should be obtained from a laboratory. This is particularly important if several batches must be prepared and storage volume is limited.

When sampling fluids from the production wells the frequency will depend upon the predicted nature of the tracer curve. It is recommended that only about one of every five samples or so be assayed. The remaining samples should be placed in a sample library. Each sample should be large enough for two or more complete assays if required. When looking for breakthrough, when inflection points occur or when concentrations are changing quite rapidly the operator may want to assay more than one of five samples.

The basis for tracer testing is to calibrate the expected rock volume that will be contacted by the solvent during leaching. A concentration time plot for a leaching operation is likely to have the form shown in Figure 7.4. A commercial operation is designed to operate within a specified range of effluent copper concentrations. An initial time period t_1 is required to build-up the concentration in the wellfield. This time is controlled by the well spacing, porosity, well pattern type and density, vertical flow losses, ground water flow and permeability and viscosity variability. The maximum copper concentration is controlled by the injected acid strength and acid consumption of copper and gangue minerals. After a period of time t_2 has elapsed, copper concentrations will decline for one of two reasons.

- o Not all of the fluid traveling between wells contact the same amount of ore. This is illustrated by Figure 7.5. Those fluid elements or streamlines that have the shortest distance to travel, such as through rock volume V_1 , contain the least tonnage of copper, and will be depleted of copper more rapidly than the longer streamlines such as V_2 , even at 100% recovery. The fluid effluent being produced from the longer streamlines V_2 is diluted by the barren solution that must pass through V_1 .



t_1 = Time to build concentration to operation level.

t_2 = Time at which heads begin to decline.

Figure 7-4. Illustration of Wellfield Leach Performance

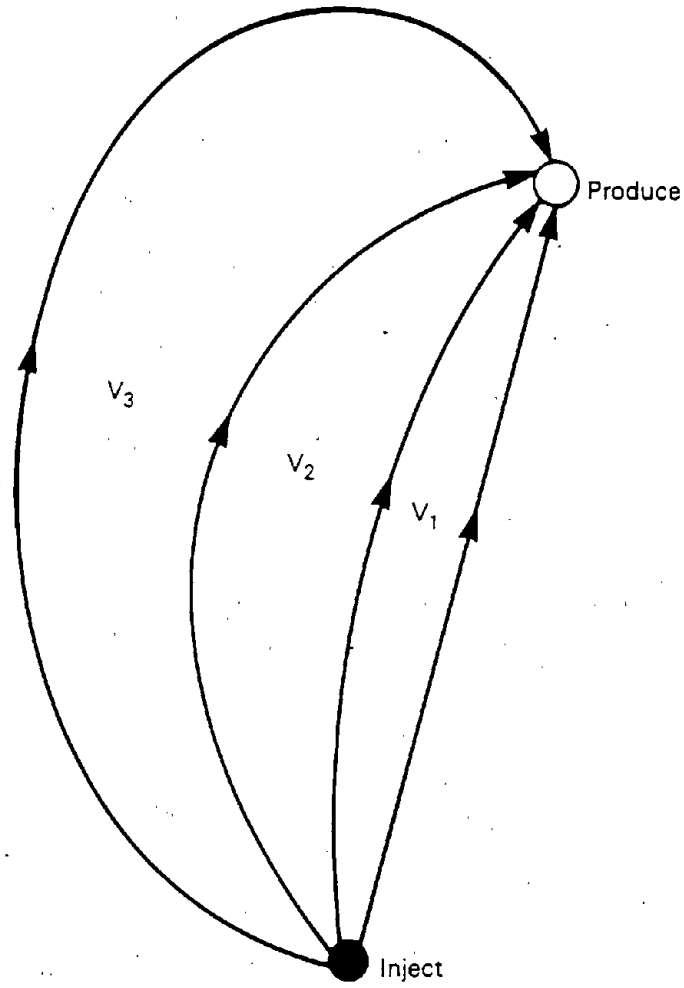


Figure 7-5. View of Inter-Well Fluid Stream Lines

- o The rate of copper leaching in any flow volume may decrease with the amount of copper recovered. In many cases this is associated with the fact that the easiest copper to recover is that closest to the prime flow channels in the fractures of the rock. As this copper is removed the acid must diffuse over longer distances to contact copper, which lowers the effective leaching rate. Acid can no longer completely react in the time it takes fluid to move between wells, resulting in lower copper concentrations. Eventually the copper loadings decline to some level where additional wells must be added in new sections of the ore body to supplement the declining productivity of the initial set of wells.

The degree of heterogeneity and confinement of the flow to the vicinity of the well pattern can be obtained by comparison of the swept volume to that expected for a well pattern of homogeneous properties. The three well patterns that are most likely to be used are a 2-spot (one injector and one producer) and unconfined 5-spot during the pre and pilot phases of testing, and multiple five spots for a commercial operation. The confined 5-spot (equal number of injectors and producers) represents the maximum confinement for a commercial operation. To assist in the design and planning of field tests with regard to estimating the quantity of copper that can be contacted in a period of time, Table 7.9 is provided in which the residence times and relative rock volumes associated with individual streamlines for a 2-spot, single 5-spot, and confined 5-spot pattern. These data were obtained from a two dimensional potential flow calculation to generate a system of streamlines of equal flow that move between injection and production wells. The calculation procedure is described by Parsons(71).

Tracer breakthrough curves for continuous tracer injection for the 2-spot, single 5-spot, and confined 5-spot are shown in Figures 7.6, 7.7, and 7.8 respectively. The dashed line corresponds to plug flow displacement along each streamline, the solid curve corresponds to chemical dispersion in each streamline. The dispersion coefficient is

selected to be proportional to the average velocity in each streamline. Dispersion is associated with micro-scale heterogeneity of flow. Prior field experience indicates that this dispersion can be represented by a dispersivity of 22 feet. The breakthrough time for plug flow can be scaled using equation (7.4), but this scaling only provides an approximation for the dispersion curve. The subscript o corresponds to base conditions listed in Table 7.9.

$$\text{Time} = (\text{Base Time}) \left(\frac{\phi}{\phi_o} \right) (S/S_o)^2 \left(\frac{q_o^1}{q^1} \right) \quad (7.4)$$

7.3.2 Well Pattern Leaching

Leaching tests are conducted to determine the ability to contact the copper mineral with the lixiviant, to determine acid consumption, copper loadings in the pregnant liquor (diluted and with tracer data described elsewhere undiluted), and the nature of the leaching curve. When leaching with sulfuric acid the sulfate anion may be used as a tracer provided that significant quantities of sulfate are not precipitated in the deposit.

To execute the test the lixiviant must be prepared, injected into the deposit through the injection well, and the pregnant liquor removed from the deposit through the production well(s). The lixiviant concentration should be maintained at a constant value and the total fluid production rate should equal the injection rate. In those tests in which the pregnant liquor is stripped of copper and is to be recycled the stripped liquor must be reconstituted before reinjection.

Maintaining constant concentration of the lixiviant is important because interpretation of results are facilitated. Uniform concentration is easily accomplished when lixiviant is batch mixed. When mixing

TABLE 7.9. STREAMLINE RESIDENCE TIMES AND ROCK VOLUMES

- o 141 feet injector-to-producer (200 feet producer-to-producer = S)
- o 5% porosity
- o 0.1 gpm per foot of ore interval
- o 18 streamlines or each streamline has (1/18) of total flow
- o Streamline volume normalized to nominal volume of FIVE-SPOT (S^2) = 40,000 cubic feet per foot of ore interval

| Streamline No. | 2-SPOT | | Single 5-SPOT | | Confined 5-SPOT | |
|----------------|---------------------|------------------------------|---------------------|------------------------------|---------------------|------------------------------|
| | Residence Time Days | Normalized Streamline Volume | Residence Time Days | Normalized Streamline Volume | Residence Time Days | Normalized Streamline Volume |
| 1 | 54 | 0.029 | 108 | 0.058 | 77.0 | 0.041 |
| 2 | 55 | 0.030 | 109 | 0.058 | 77.1 | 0.041 |
| 3 | 58 | 0.031 | 110 | 0.059 | 77.7 | 0.042 |
| 4 | 63 | 0.034 | 112 | 0.060 | 78.3 | 0.042 |
| 5 | 70 | 0.037 | 116 | 0.062 | 79.6 | 0.043 |
| 6 | 79 | 0.042 | 121 | 0.0647 | 81.2 | 0.043 |
| 7 | 93 | 0.050 | 128 | 0.068 | 83.1 | 0.045 |
| 8 | 113 | 0.061 | 136 | 0.073 | 85.6 | 0.046 |
| 9 | 143 | 0.077 | 147 | 0.079 | 88.7 | 0.047 |
| 10 | 189 | 0.10 | 163 | 0.087 | 92.3 | 0.049 |

TABLE 7.9. STREAMLINE RESIDENCE TIMES AND ROCK VOLUMES (Continued)

- o 141 feet injector-to-producer (200 feet producer-to-producer = S)
- o 5% porosity
- o 0.1 gpm per foot of ore interval
- o 18 streamlines or each streamline has (1/18) of total flow
- o Streamline volume normalized to nominal volume of FIVE-SPOT (S^2) = 40,000 cubic feet per foot of ore interval

| Streamline No. | 2-SPOT | | Single 5-SPOT | | Confined 5-SPOT | |
|----------------|---------------------|------------------------------|---------------------|------------------------------|---------------------|------------------------------|
| | Residence Time Days | Normalized Streamline Volume | Residence Time Days | Normalized Streamline Volume | Residence Time Days | Normalized Streamline Volume |
| 11 | 261 | 0.14 | 182 | 0.098 | 96.7 | 0.052 |
| 12 | 386 | 0.21 | 209 | 0.11 | 102 | 0.055 |
| 13 | 617 | 0.33 | 248 | 0.13 | 109 | 0.059 |
| 14 | 1,100 | 0.59 | 307 | 0.16 | 118 | 0.063 |
| 15 | 2,303 | 1.2 | 404 | 0.22 | 129 | 0.069 |
| 16 | 5,258 | 3.3 | 589 | 0.32 | 144 | 0.072 |
| 17 | 28,860 | 15 | 1,325 | 0.55 | 167 | 0.085 |
| 18 | 58,275 | 31 | 2,777 | 1.5 | 207 | 0.11 |

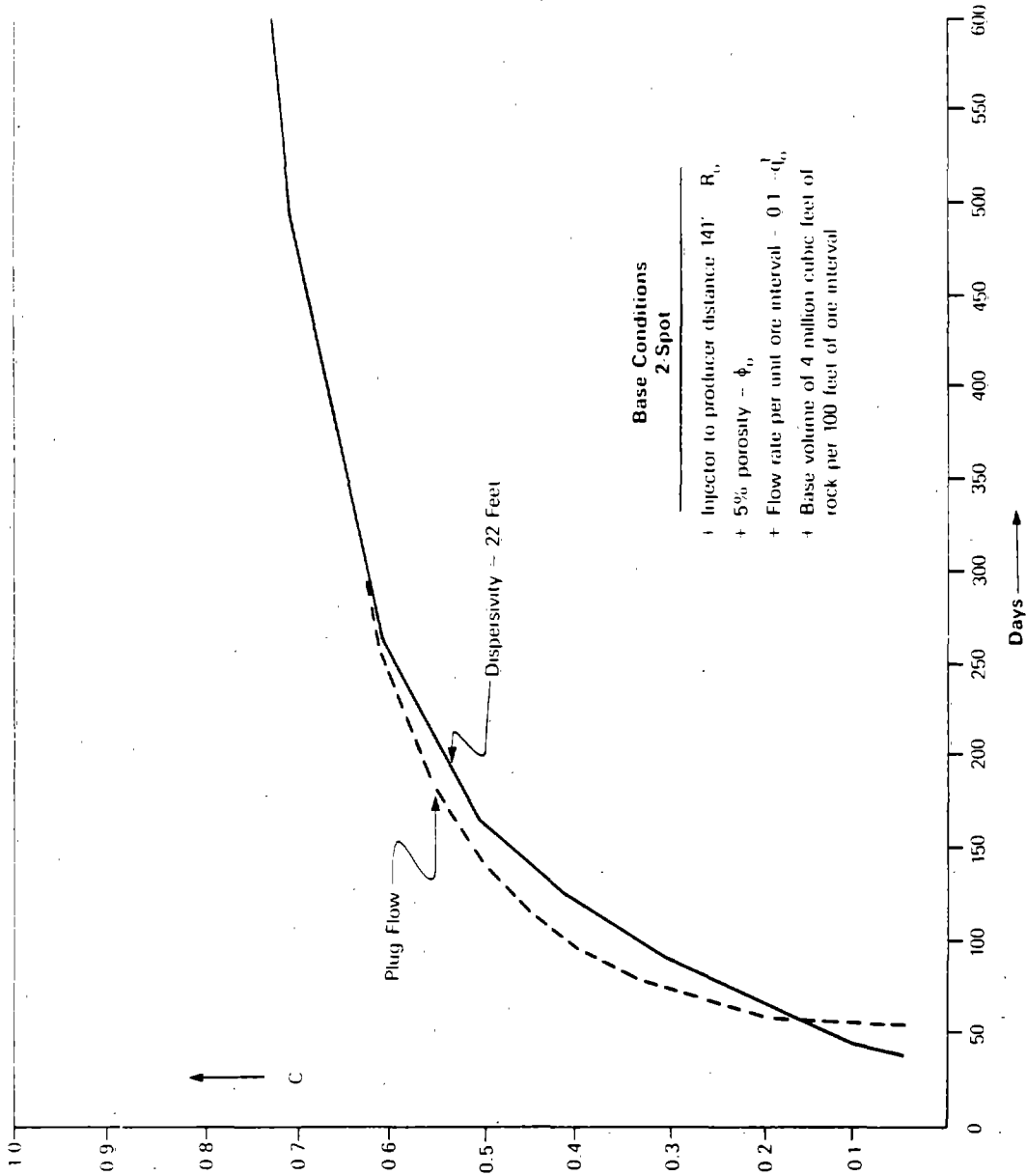
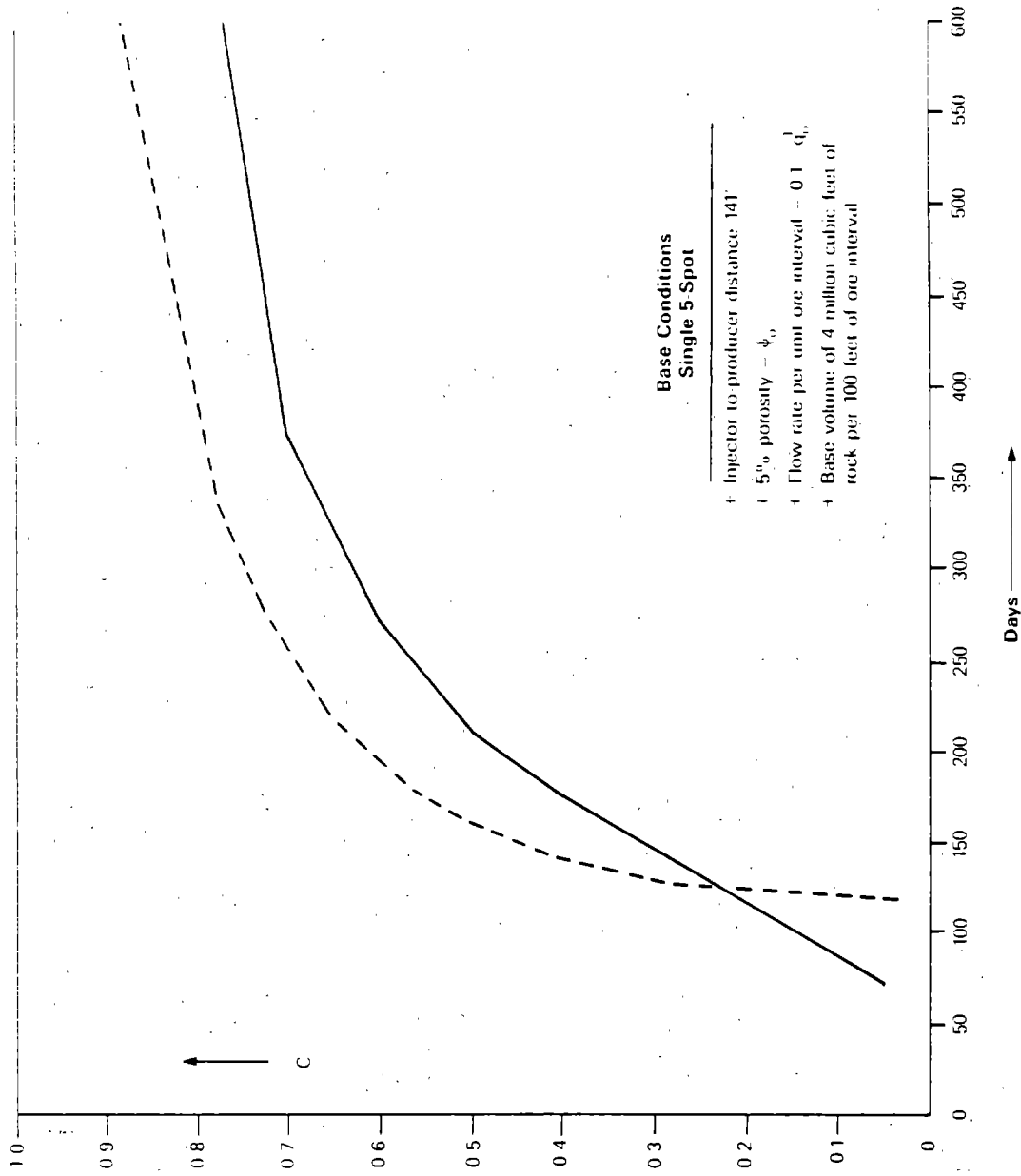
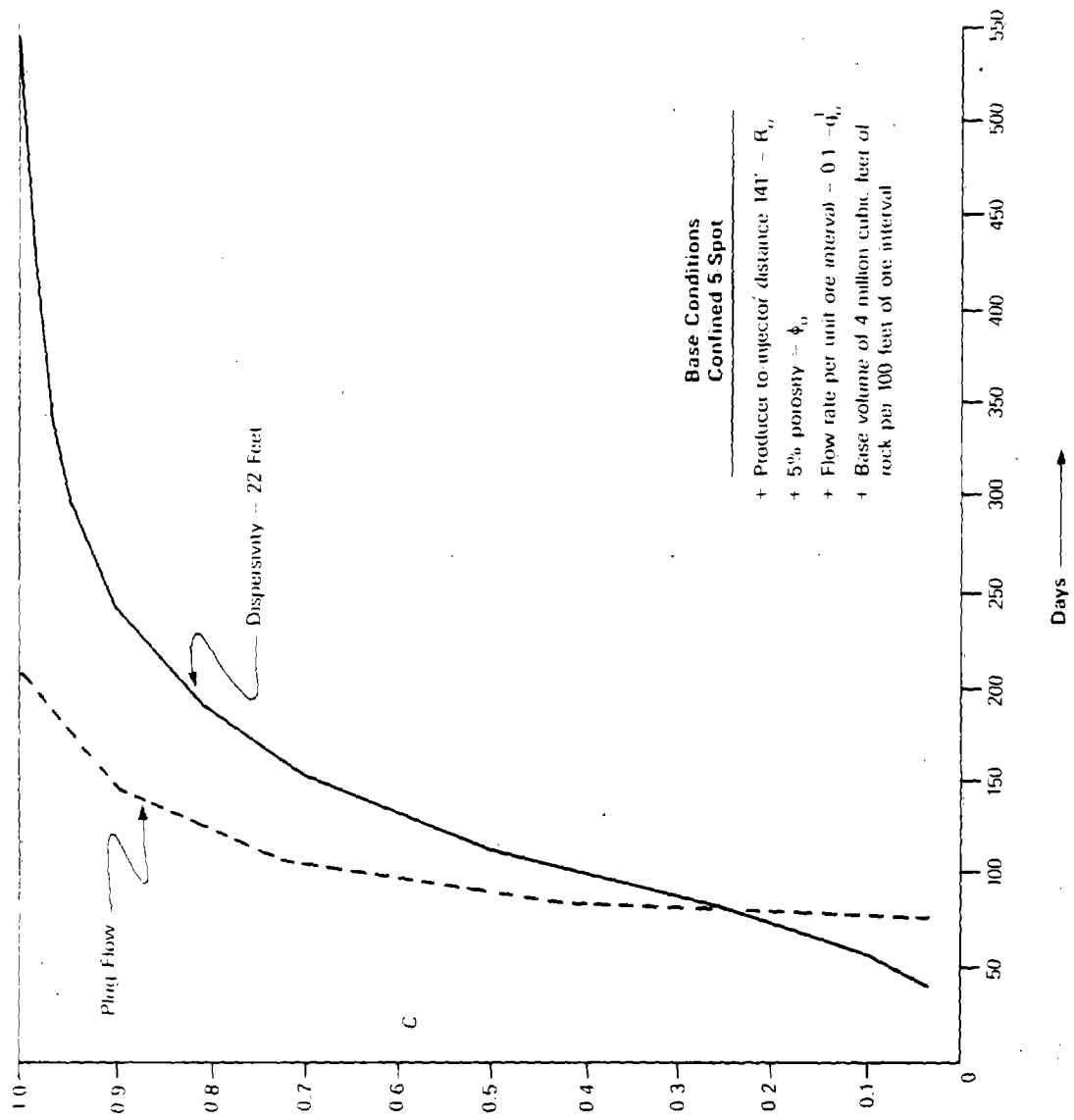


Figure 7-6 Continuous Tracer Injection
2-Spot



**Figure 7-7. Continuous Tracer Injection
Single 5-Spot**



**Figure 7-8. Continuous Tracer Injection
Confined 5-Spot**

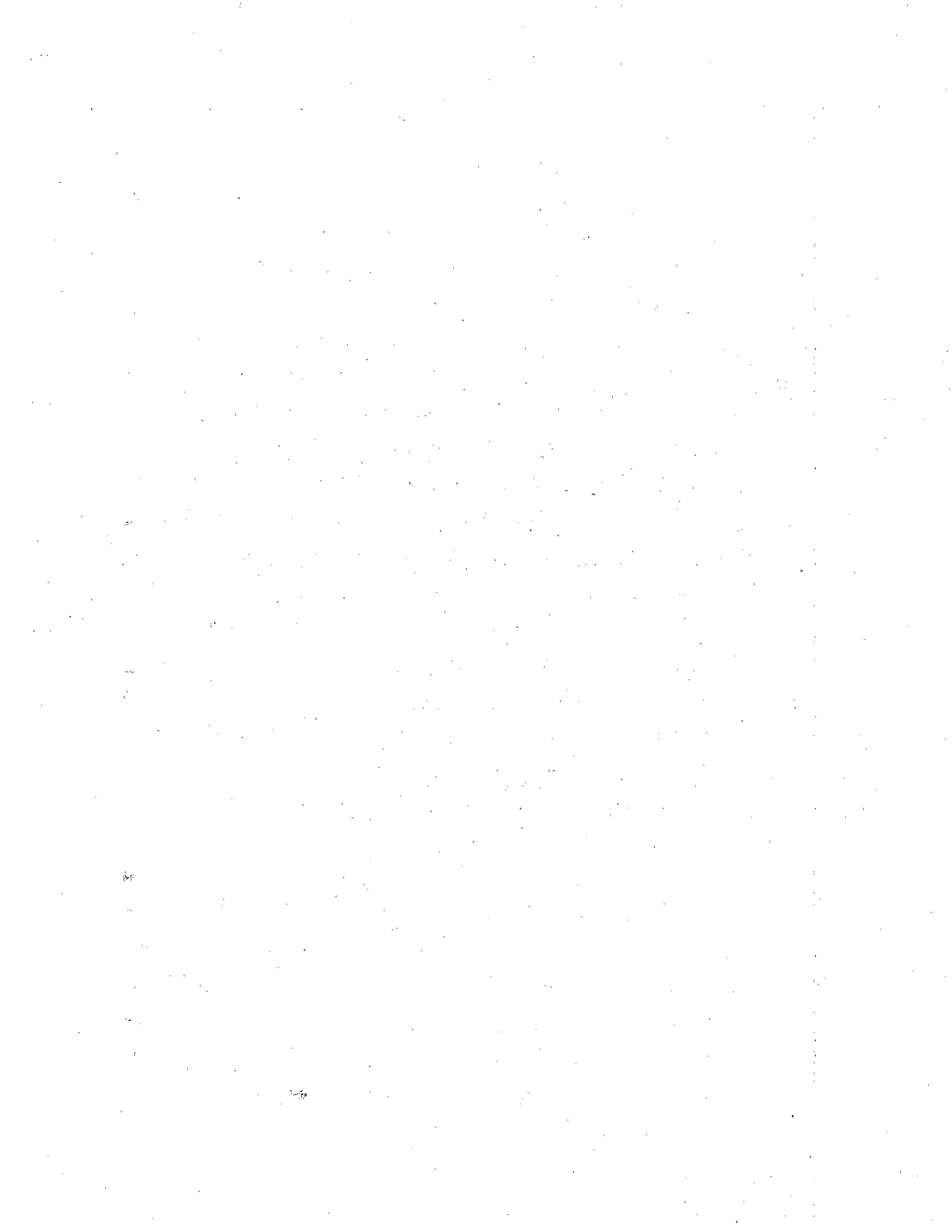


"on line" greater care often must be exercised to maintain uniform concentration. In either procedure samples should be taken frequently and assayed to assure that uniform concentration of lixiviant is being injected. Assaying for acid should be done at the test site.

After injection commences, some time will elapse before pregnant liquor arrives at the production well(s). The time when products arrive is termed the breakthrough time. This breakthrough time is related to porosity and permeability of ore and rate of injection and production. If more than one production well is employed, all producing fluid at the same rate, breakthrough time can provide information about porosity and directional permeability. This information can be used for well pattern layout for the commercial wellfield.

Sampling of produced fluid should be quite frequent during the period of breakthrough and when concentrations of dissolve species are expected to be changing rapidly. At other times during the test, sampling can be less frequent. However assaying of all samples may not be necessary. Initially assays should be conducted to determine the nature of the copper concentration curve. This may be possible by assaying every other sample or perhaps every fifth sample. When the nature of the curve has been established additional samples can be chosen for assay to more precisely identify points of inflection and other portions of the curves. This curve will be useful in predicting expected copper recovery.

Finally samples can be chosen for assaying that provide the suite of cations and anions of interest. In addition to pH and free acid the concentration of the following anions and cations should be made: copper, sulfate, chloride, aluminum, sodium, iron, potassium, calcium,



and magnesium. With these assay data it is possible to determine the acid consumption per pound of copper produced.

The acid consumption may be calculated from the concentrations of cations in solution by assuming:

- o No cations are put into solution by oxidation or reduction reactions
- o All cations in solution are due to reaction with acid
- o Acid consumed by quartz is negligible
- o No precipitation of cations occurs after they have been put into solution.

Given the above assumptions, a simple multiplying factor may be applied to the concentration of each of the metal ions in solution. These are listed in Table 7.7.

7.3.3 Matrix Modification

Movement of fluid from an injection well through a deposit and into a production well is related to the wellbore radius, rock permeability, ore interval exposed in the well, applied differential pressure and distance between the injection and production wells. The term matrix modification as considered for true ISL will refer to well stimulation techniques as opposed to deposit rubbilization. Deposit rubbilization renders the ore zone non-suitable for true ISL.

Stimulation of a well can be defined as the application of a technique which permits the increase of fluid injection or production at a constant applied differential pressure. Well stimulation techniques include wellbore shooting (and variations), hydraulic fracturing, and acidizing. Acidizing techniques have commonly employed hydrochloric acid and more recently hydrofluoric acid or combinations. Deposits

which contain little or no acid soluble minerals in the flow channels are not likely to be effectively stimulated using acid. Drilling a larger hole (increasing the wellbore radius) or underreaming the hole in the ore interval will increase the flow rate. However the equivalent effect of wellbore shooting or hydraulic fracturing is to increase the wellbore radius.

Early in the history of the oil industry, efforts were made to stimulate production. The methods that evolved were of two classes; explosive, and hydraulic.

The process of "shooting" oil and gas wells with explosives to stimulate production originated more than 6 decades ago. During the late 1940's the mechanical process of "hydraulic fracturing" was brought forth and interest in "shooting" declined. In the early 1960's the concept of detonating explosives in hydraulic fractures (explosive fracturing) was developed. Unfortunately, the latter technology was not developed at a rapid rate.

There seem to be two reasons for the rather slow development of explosive fracturing technology. While good records have not been kept or are unavailable, it appears that the cost-benefit ratio for explosive fracturing may be somewhat discouraging. While handling explosives has always been hazardous, a few unfortunate (and in several cases fatal) accidents have obviously retarded the development of this technology.

In contrast to hydraulic fracturing, which is thought to generate a single planar fracture, wellbore shooting is thought to generate multi-directional random fractures. Further, many gas wells, which were completed in the Devonian shale, have been shot and an average 5-fold increase in flow has been reported.

Wellbore shooting evaluated in a number of pretests often creates a significant quantity of rubble in the hole which can be quite difficult and time consuming to remove. Further, methods to control fluid exit out of or entry into the hole should be available. Both of these problems would have to be addressed and suitable solutions found for this technique to be acceptable. Stimulation of wells by introducing liquid explosives into an induced hydraulic fracture and detonating the explosive has been substantially abandoned. Occidental Minerals(14) reported that this technique did more harm than good. A procedure wherein a rocket propellant type of substance is burned in a controlled manner to generate gas which in turn creates fractures has recently been demonstrated. This procedure reportedly eliminates damage to the casing and avoids rubblelization of the formation. However no information is available on any application of this technique for ISL.

Hydraulic fracturing was evaluated at the Kimbley pit project in Nevada and at the Van Dyke and the Blue Bird Mine in Arizona. A patent(15) describes the use of hydraulic fractures to enhance flow rates and convert the flow regime from radial (5-spot) to linear or axial flow.

Theory suggests that induced hydraulic fracture will be horizontal down to a depth of about 1,000 feet below the surface. Further the theory predicts that deeper than 3,000 feet below the surface, the induced fractures will have a vertical orientation. Hence the Oxymin technology should be workable to at least 1,000 feet. At greater depths one should expect the possibility of vertical fractures occurring. To use hydraulic fracturing stimulation in an environment where vertical fractures are likely to occur will result in wellfield design problems. The engineer must be able to predict the azimuth of the vertical

fracture. This azimuth will dictate the orientation of the injection wells in relation to the production wells. A line between injection and production wells should be orthogonal to the azimuth of the induced fractures. Otherwise short circuiting of fluids could occur.

In order to choose a stimulation technique one will want to evaluate the advantages and disadvantages of each. It is likely that this evaluation will point to the choice of hydraulic fracturing. This technique is the most readily applied because many companies are available to provide the service and it has been applied cost effectively in the oil industry for many decades. It is this method that will be discussed below.

Any matrix modification or well stimulation technique should enhance the well's injection or production rate at a given differential pressure. Hence prior to a stimulation test the engineer will have conducted flow or transient tests, described elsewhere, to know the initial flow condition associated with the test well.

The test must be designed to meet the objective or proposed operation at a given site. Therefore the engineer should attempt to anticipate whether the fracture will be horizontal or vertical. In addition one must choose a desired flow rate to be achieved and in conjunction with a specialist decide if a fracturing procedure can be designed to meet the requirements. Design considerations⁽³⁶⁾ include length of the fracture, its width during installation, proppant to be used, width of fracture upon closure on proppant and expected pressure loss in the induced fracture when injecting into or producing from the well.

With these design parameters in mind the engineer in conjunction with a completion specialist can decide upon the well completion technique required for the test. For instance if a high flow capacity horizontal hydraulic fracture is desired the engineer should consider completing the well with a slot abraded through the casing, cement sheath and into the ore zone to be fractured. To keep the fracture open a proppant is used. A choice needs to be made between using multilayers of a smaller diameter proppant or a single layer of a large diameter proppant, or a partial single layer of large diameter proppant spaced apart with a soluble filler material. If on the other hand he should choose a vertical fracture over a lengthy ore intercept the engineer may choose to perforate the well in only a fraction of the ore near the bottom of the intercept and install a fracture in this partially completed interval. Subsequently he can repeat the process sequentially in higher portions of the ore interval until the entire ore intercept is fractured.

For in situ leaching it will be important to know or be able to predict the attitude of an induced fracture, i.e., whether it is horizontal or vertical, whether it is circular or elliptical, and if vertical the azimuth of the fracture. Recent studies (72), (73) indicate that fracture azimuth can be measured during installation. Some measurements are more suitable than others.

Upon completion of the design the engineer will mobilize the various contractors. Their arrival will coincide with finalization of well completion activities. Contractors will deploy their equipment for various measurements. In the case of the service company which will install the fracture it will supply the proppant and fluid additives for

the frac fluid and ready the system for the activity. However the engineer must assure that suitable tanks and process water are available for the activity. It may be necessary to conduct a minifrac to obtain data prior to finalizing the fracture procedure. Data from the minifrac could dictate a change in pad volume and/or injection rate and expected injection pressure. If a slot is required for installation of a horizontal fracture the service company charged with installing the fracture may also be able to install the slot. During installations of the fracture nearby wells should be monitored to detect any evidence related to azimuth of the induced fracture.

The fracture is installed by implementation of the following activities:

1. The service company checks to assure all equipment is functioning properly. This includes the pump truck, the blender (to blend proppant with frac fluid), and the sander (this unit provides the proppant to the blender).
2. The frac fluid is prepared by mixing polymer chemicals with the process water.
3. High-pressure flow lines are connected to the wellhead from the pumper.
4. A pad (non-proppant containing frac fluid) is injected into the zone to break down the formation and to develop a suitable width to the fracture.
5. Fluid with proppant is injected.
6. Upon injecting the volume of frac fluid and proppant required, pumping is terminated. A valve at the wellhead is closed and the well is left shut in until the pressure bleeds off (is dissipated) to the formation.
7. The well can then be serviced as necessary.
8. Other flow tests can be conducted to evaluate the improvement in flow and by monitoring any nearby wells to obtain additional data on fracture attitude.

Analysis of test data will depend on the nature of various measurements that were made before, during, and after installing the fracture. Any flow tests (transient or interference) can be evaluated as discussed elsewhere. However changes in pressure pulse arrival times at nearby wells can be interpreted to indicate fracture attitude.

CHAPTER 8
ECONOMIC ANALYSIS

8.1 DESCRIPTION OF DCF/ROR CALCULATIONS

Discounted cash flow, rate of return (DCF/ROR), or the discounted cashflow return of investment (DCF/ROI) are special versions of the more generic term internal rate of return (IRR). The terms DCF/ROR and DCF/ROI are used interchangeably and refer to the same method. This criterion is commonly employed in the minerals industry (74) for evaluation of different investment options. The more general concept of internal rate of return is discussed in books such as "Managerial Economics: Analysis and Cases" (75). This manual uses the DCF/ROR method. In this method the IRR is such that the sum of all cash inflows is equal to the sum of all cash outflows. The net present value function is used to quantitatively define the method.

$$\begin{aligned}
 PV &= \text{Net Present Value} \\
 &= \frac{RR_1}{(1+i)} + \frac{RR_2}{(1+i)^2} + \frac{RR_3}{(1+i)^3} + \frac{RR_N}{(1+i)^N}
 \end{aligned}
 \tag{8.1}$$

$RR_1, RR_2, RR_3 \dots RR_N$ - Are the actual (inflow-outflow) project cash flows in each project year

i - internal rate of return (IRR)

In the DCF/ROR method a value of i is calculated which makes the net present value PV zero. This value of i is called DCF/ROR. For in situ copper mining this method is used to calculate copper selling price if DCF/ROR is specified or DCF/ROR if copper selling price is specified.

8.2 DESCRIPTION OF COSTS

The net cash flow includes both capital and operating cost elements. All default capital and operating costs are 1986 dollars. Inflation Index parameters INDC and INDM are used in the cash flow program to adjust costs for the surface plant (INDC) and mining (INDM) to account for inflation. The major elements of capital costs are:

- o Surface Plant. This includes the solvent extraction, electro-winning, and leach solution injection pumping and transfer lines. The capital cost of solvent extraction is dependent on the solution flow rate (Q). The capital cost of electrowinning is proportional to annual production capacity (Y). Capital cost of injection pumps is proportional to the pump horsepower. The transfer line cost is dependent on the length of the line and its diameter. A detailed discussion of the plant capital cost is included in Chapter 5.0. Environmental costs related to permitting the operation, installation of the monitoring system, and annual monitoring of the operation are reported under surface plant costs.
- o Wellfield. This includes well costs for drilling, casing, cementing, completions, fracturing, wellheads, and other equipment such as inflation tubing, packers, downhole production pumps. If wells are drilled from underground costs of crosscuts and drifts put in each time a wellfield is developed are included in wellfield capital. Wellfield priming is a start-up cost incurred while acid is being pumped into the orebody and is initially diluted by groundwater. A discussion of wellfield capital costs is included in Chapter 4.0. Environmental costs related to wellfield restoration are included in wellfield costs. Restoration costs are dependent on solution hold-up and are taken as a percentage of wellfield priming costs.
- o Underground Workings. This includes the cost of underground development, if the orebody is accessed from newly developed underground workings. Costs include cutting shafts, raises, drifts and crosscuts, and the costs of support equipment for ventilation, electrical facilities, hoist, headframe, maintenance shop, etc.

For each capital expenditure, the construction may span more than a year. If it does, the actual expenditure in each year is specified. The total project life is equal to the sum of initial plant construction

time and total plant operating time. In order to provide pregnant leach solution to the surface plant, a depleted wellfield is replaced with a new wellfield. This replacement of a wellfield is scheduled within the operating time as many times as necessary. The surface plant is assumed to have a 3 year construction period from engineering to start-up. For an operating time of 20 years the total project life is 23 years.

The operating cost elements are:

- o Revenues. This is the copper selling price multiplied by copper production. Costs such as taxes, depreciation, exploration, property acquisition are not included. As a result the copper selling price should be considered as "pre-tax" copper selling price.
- o Labor. Plant and wellfield labor includes management, administrative, engineering and technical service, maintenance and operations. These costs are considered to depend on the size of plant (annual copper production).
- o Utilities. Electric power is the major utility cost. The main consumers of electric power are electrolytic cells, and injection and production pumps. Water is the other utility used by plant personnel, for cathode washing, and for ore body saturation.
- o Chemicals and Consumables. The raw materials used include extractant, diluent, cobalt sulfate, sulfuric acid, anodes for electrolytic cells, and lime for neutralization of bleed streams. The annual consumption of extractant and diluent depends on the system flow rate; all other materials are consumed in proportion to copper production.
- o Maintenance Materials and Contracts. Wellfield maintenance is contracted out and its cost per year is estimated as percentage of wellfield capital cost. Plant maintenance requirements are estimated as a percentage of surface plant capital costs.
- o Environmental Monitoring. Annual environmental monitoring and reporting is taken as a fixed cost.

8.3 INFORMATION FLOW NETWORK AND LISTING OF ALGORITHMS

Various design and cost algorithms are used to calculate design variables such as injection flow rate, and then to calculate costs.

These algorithms are arranged into a calculation sequence which is described by the information flow network shown in Figure 8-1. The flow network is based on a computer flow diagram convention. Each rectangular box involves a computation for either a design or cost algorithm. Each diamond represents a decision based on either the user's design choice or input/output control. For a typical economic evaluation a set of base values, such as ore body characteristics, will be specified, and a number of evaluations made to rank different design options or sensitivity to a specific parameter. The initial program control logic provides for starting computations with a base case value and then changing the inputs to make multiple evaluations. Algorithms, either design or cost, used in each computational box are listed in Appendices A, B, and C.

There are many input and output variables. A discussion of these different variables by functional groups follows.

8.3.1 Input Parameters

The input parameters fall into the following major groups:

- o Business Related Inputs: this includes parameters such as, annual production rate Y, required ROR or copper selling price, construction and capital expenditure schedules, and plant life.
- o Site Specific Orebody and Wellfield Characteristic Input Parameters: this includes those parameters that must be specified at a selected site in the design of the wells and well pattern.
- o Copper Leaching Input Parameters: this includes those parameters that must be specified at a selected site that relate to pregnant liquor copper loading, acid consumption, and overall copper recovery.
- o Program Control Input Parameters: these input parameters control the printing of output parameters by the computer program.

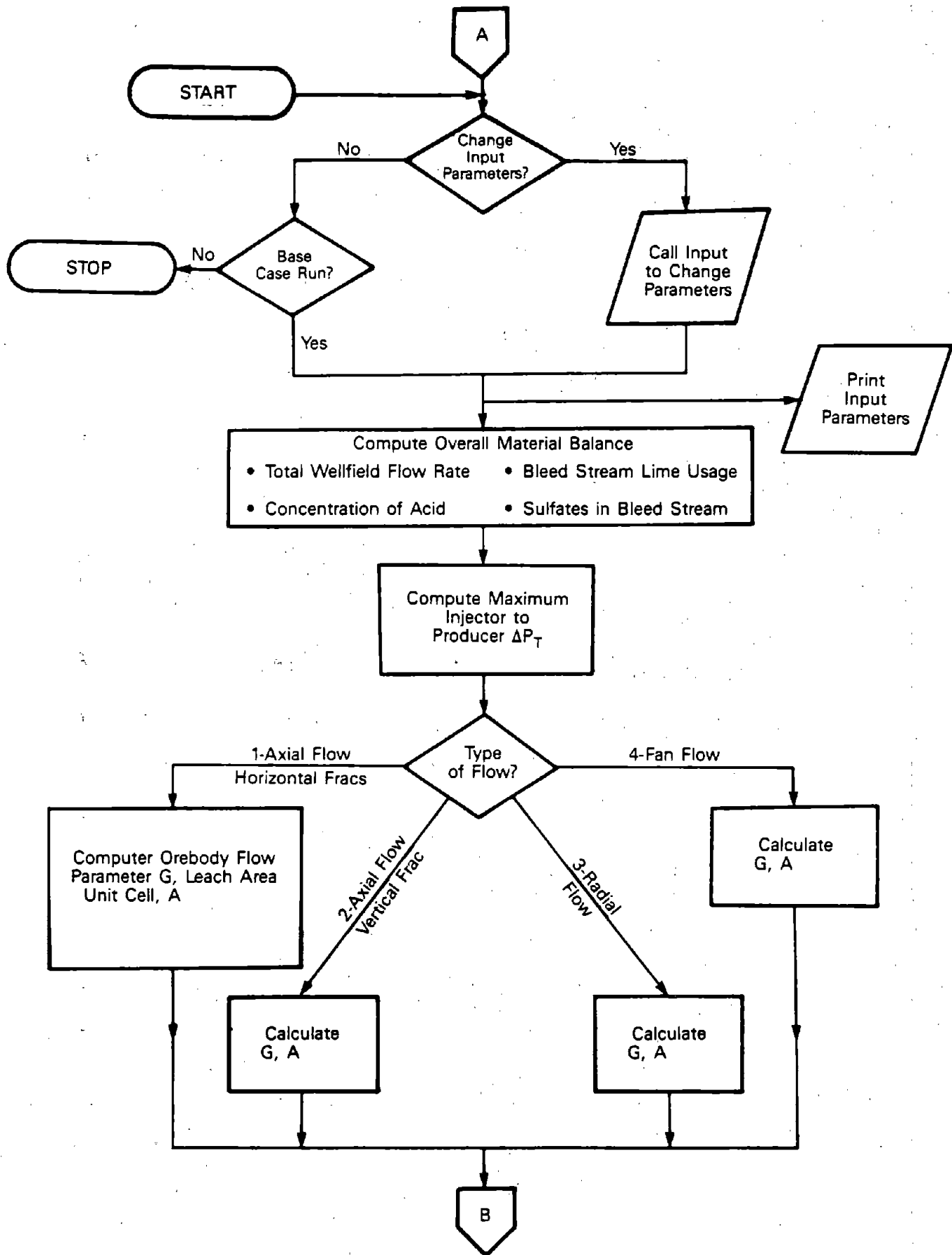


Figure 8-1. Information Flow Network

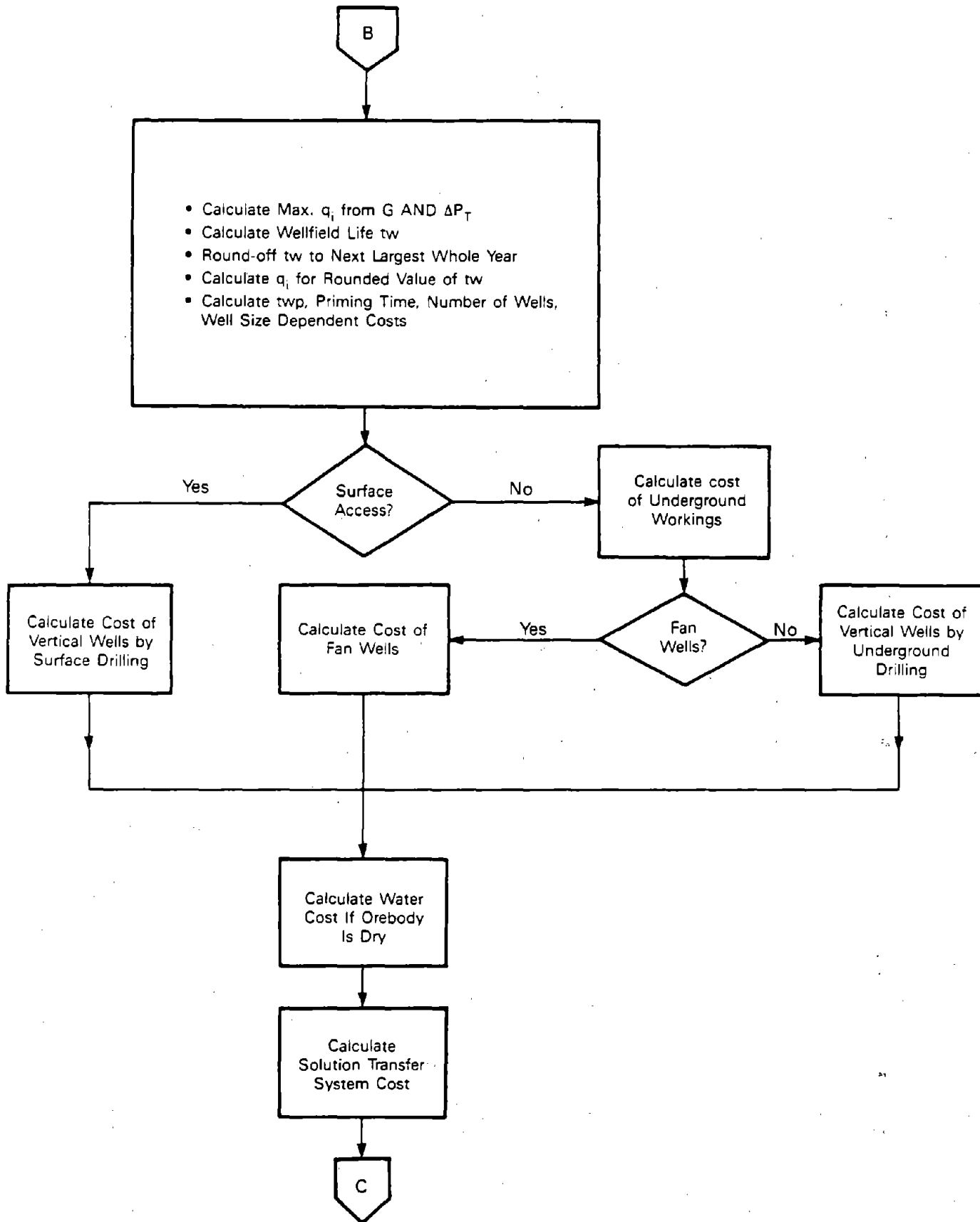


Figure 8-1. Information Flow Network (Continued)

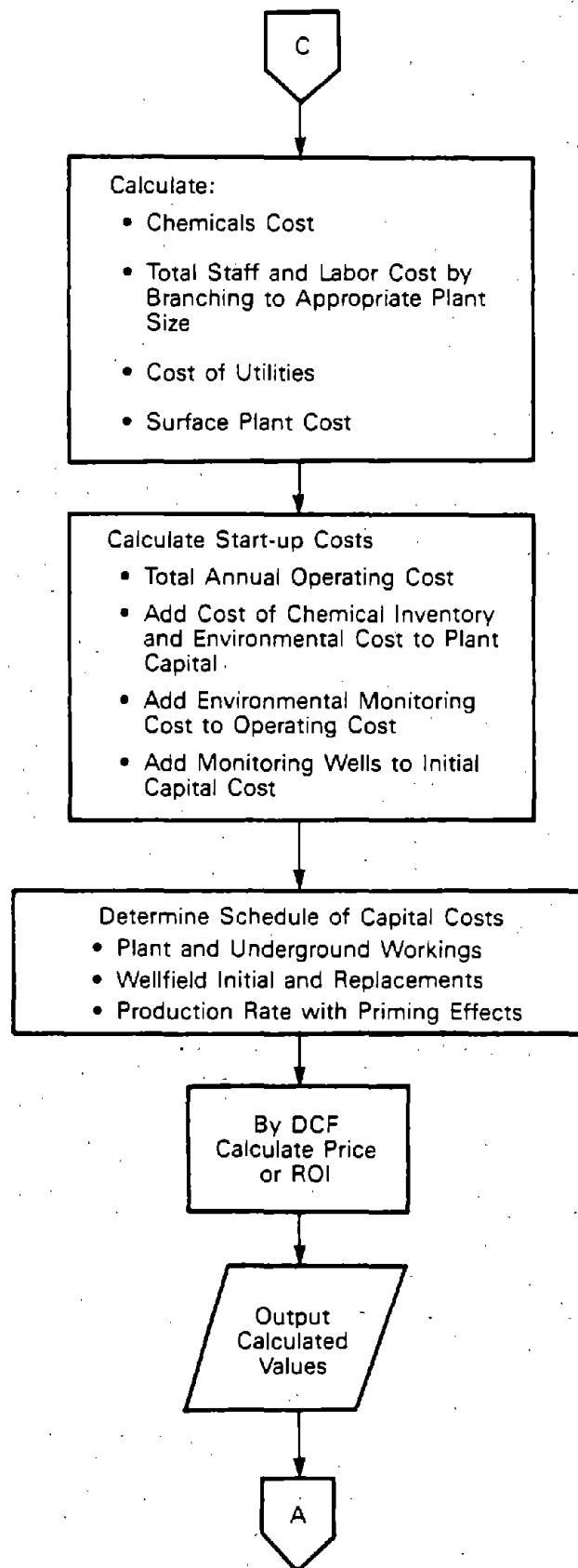


Figure 8-1. Information Flow Network (Continued)

- o Well System Specification and Cost Default Input Parameters: this includes all constants used to convert well system input parameters to output specification and costs.
- o Surface Plant Specification and Cost Default Input Parameters: this includes all constants used to compute surface plant specifications and costs.

All the input parameters are listed in Table 8.1. The notation for each input parameter listed in Table 8.1 and for each output parameter listed in Table 8.2 is defined at the beginning of the IBM program (Section D.2) as comment statements.

8.3.2 Output Parameters

The calculated values include design variables and costs. The design variables include: leach area of unit cell; leach area of wellfield; injection pressure at top of ore zone; total system flow rate; injection flow rate; number of unit cells; wellfield life; wellfield start-up or priming time; injection acid concentration; acid and lime consumption; metal sulfates per year; G, RI and XI factors of flow pattern pressure drop relationship; number of injection and total wells; solution pipeline length; weight of copper in unit cell; fractional copper recovery; number of mine operators; sizes of well hole; casing and tubing; injection and production pump horsepower; size of wellfield solution piping; size of plant to wellfield pipeline; and total number of staff.

The calculated costs include capital costs and operating costs. The capital costs include: wellsite preparation cost; well casing, cementing, drilling, completion, logging, injection and production equipment; cost per fan for fan wells; plant capital; solution transfer



TABLE 8.1 INPUT PARAMETERS

| BUSINESS RELATED | | | |
|---|----------------|------|----------------|
| Y | 25000 TPY | ROI | 20% |
| PRIC | 0.000C/LB. | INDC | 100% |
| INDM | 100% | SCP1 | 0.230 FRACTION |
| SCP2 | 0.250 FRACTION | SCP3 | 0.520 FRACTION |
| SCP4 | 0.000 FRACTION | SCP5 | 0.000 FRACTION |
| SCMI | 0.400 FRACTION | SCM2 | 0.600 FRACTION |
| SCM3 | 0.000 FRACTION | SCM4 | 0.000 FRACTION |
| SCM5 | 0.000 FRACTION | SCW1 | 0.340 FRACTION |
| SCW2 | 0.660 FRACTION | SCW3 | 0.000 FRACTION |
| SCW4 | 0.000 FRACTION | SCW5 | 0.000 FRACTION |
| TP | 20 YEARS | | |
| Site Specific Orebody and Wellfield Characteristics | | | |
| AF | 1 PSI/FT. | D | 1000 FT. |
| H | 300 FT. | GRDO | 1% |
| PERM | 2 MD | PORO | 5% |
| RHOP | 162 LB/CU.FT | WS | 80% |
| DRY | 1 | AW | 0.43 PSI/FT. |
| H1 | 30 FT. | H2 | 60 FT. |
| RW | 0.25 FT. | RA | 8 FT. |
| S2 | 100 FT. | S1 | 100 FT. |
| SR | 0 FT. | SS | 0 FT. |
| THTA | 0.315 RADIAN | SDA | 2,000 FT. |
| STIM | #2 | MINE | #3 |
| WORK | #2 | MACE | #1 |

TABLE 8.1 INPUT PARAMETERS (Continued)

| Copper Leaching | | | |
|--|---------------------------|------|--------------------------|
| CULD | 6 GRAM/L | EFFL | 75% |
| EFFO | 91.2% | EFFP | 100% |
| EFFR | 90% | EFFS | 75% |
| VISC | 1 Centipoise | W7 | 1.540 ton acid/ton Cu |
| W4 | 4.000 ton acid/ ton Cu | WD | 500 FT. |
| Program Control Parameters | | | |
| LSTI | T | LST | T |
| LSTA | T | | |
| Wellfield Component Specification and Cost Constants | | | |
| FACJ | -0.619 FRACTION | RC | 130 FT/HR |
| BA | 2400\$ | BAU | 5000\$ |
| BB | 4\$/CU.FT. | BG | 15\$/CU.FT. |
| BJ | 1.5\$/JET | BL | 800\$/WELL |
| BLU | 1600\$/WELL | BSI | 2000\$/WELL |
| BTI | 1\$/FT | BW | 20\$/FT |
| BWFI | 30\$/FT | BWFP | 10\$/FT |
| BX | 400\$/FT | B1 | 0.560\$/FT |
| B2 | 2045\$/WELL | B3 | 1425\$/WELL |
| B3U | 5000\$/WELL | B4 | 2500\$/WELL |
| B4U | 5600\$/WELL | B5 | 14\$/FT |
| B6 | 5000\$/FRAC | B6U | 10000\$/FRAC |
| B7 | 0.41\$/SQ. FT. | B8 | 2800\$/WELL |
| B8U | 3600\$/WELL | B9 | 235\$/FT |

TABLE 8.1 INPUT PARAMETERS (continued)

| | | | |
|------|--------------|------|---------------|
| B10 | 3135\$/WELL | B10U | 4702\$/WELL |
| B11 | 2.7\$/FT | B12 | 0.1\$/FT |
| B13 | 92\$/HP | B14 | 1811\$/WELL |
| B15 | 5000\$/WELL | CDA | 400\$/FT |
| RW | 0.250FT. | S1 | 100 FT. |
| S2 | 100 FT. | SDA | 2000.000FT. |
| SR | 0 FT. | SS | 0 FT. |
| THTA | 0.315 RADIAN | STIM | #2 |
| WORK | #2 | MACE | #1 |
| MINE | #3 | | |
| CP | 150\$/HP | CPL | 700 KW |
| CR | 1000\$/FT | EE | 200000\$/FT |
| CS | 3000\$/FT | | |
| EM | 2500000\$ | EV | 120000\$ |
| BW1 | 5.41\$/FT | BW2 | 11.9\$/FT |
| BW3 | 1\$/FT | BW4 | 325\$/HP |
| BW5 | 0.000\$/WELL | BW6 | 1100\$/WELL |
| BW7 | 1240\$/WELL | BW8 | 175\$/HR |
| BW9 | 350\$/HR | BW10 | 30FT/HR |
| BW11 | 15\$/FT | BW12 | 33\$/FT |
| BW13 | 7IN | BW14 | 4IN |
| BW15 | 1.92IN | BW16 | 3000\$/PACKER |
| BW17 | 7.35\$/FT | BW18 | 16.17\$/FT |
| BW19 | 3\$/FT | BW20 | 70\$/HP |
| BW21 | 500\$/WELL | BW22 | 1350\$/WELL |
| BW23 | 1240\$/WELL | BW24 | 200\$/HR |

TABLE 8.1 INPUT PARAMETERS (Continued)

| | | | |
|------|-------------|------|---------------|
| BW25 | 400\$/HR | BW26 | 20FT/HR |
| BW27 | 26\$/FT | BW28 | 57.2\$/FT |
| BW29 | 10IN | BW30 | 6IN |
| BW31 | 2.42IN | BS32 | 5000\$/PACKER |
| BW33 | 15.8\$/FT | BS34 | 34.76\$/FT |
| BW35 | 5\$/FT | BW36 | 102\$/HP |
| BW37 | 1000\$/WELL | BW38 | 2500\$/WELL |
| BW39 | 1718\$/FT | BW40 | 250\$/HR |
| BW41 | 500\$/HR | BW42 | 15FT/HR |
| BW43 | 35\$/FT | BW44 | 77\$/FT |
| BW45 | 12IN | BW46 | 8IN |
| BW47 | 4.04IN | BW48 | \$700/PACKER |

Surface Plant Specification and Cost Constants

| | | | |
|-----|--|------|--|
| W1 | 0.015M ³ /GPM/YR | ST | 6000FT. |
| W3 | 0.261KG/TON | W2 | 0.085M ³ /GPM/YR |
| W5 | 0.0650TON ANOD/TON | ETA | 0.7 FRACTION |
| W8 | 0.200 FRACTION | W9 | 0.231TON ACID/ TON CU |
| W12 | 0.571TON CAO/TON | W13 | 2.430TON SO ₄ / TON LIME |
| W15 | 1.360Ton FeSO ₄ / Ton Acid | RHOF | 62.4 LB/CU.FT |
| QS1 | 55 GPM | QS2 | 150 GPM |
| QS3 | 300 GPM | QS4 | 800 GPM |
| QS5 | 1600 GPM | QS6 | 2900 GPM |
| QS7 | 4500 GPM | QS8 | 5700 GPM |
| QS9 | 8000 GPM | QS10 | 10600 GPM |

TABLE 8.1 INPUT PARAMETERS (Continued)

| | | | |
|------------------------------|--------------------------------|------|--------------------------------|
| QW1 | 50 GPM | QW2 | 100 GPM |
| QW3 | 300 GPM | POPO | 32 MEN |
| POP1 | 40 MEN | POP2 | 60 MEN |
| POP3 | 80 MEN | BP1 | 2 IN. |
| BP2 | 12.50\$/FT | BP3 | 3 IN. |
| BP4 | 18.75\$/FT | BP5 | 4 IN. |
| BP6 | 25.00\$/FT | BP7 | 6 IN. |
| BP8 | 37.50\$/FT | BP9 | 8 IN. |
| BP10 | 50.00\$/FT | BP11 | 10 IN. |
| BP12 | 62.50\$/FT | BP13 | 12 IN. |
| BP14 | 65.00\$/FT | BP15 | 14 IN. |
| BP16 | 75.80\$/FT | BP17 | 16 IN. |
| BP18 | 86.67\$/FT | BP19 | 18 IN. |
| BP20 | 97.50\$/FT | CL | 20\$/HR |
| CE | 650\$/TPY | CLP1 | 1750000\$/YR |
| CLPO | 1746000\$/YR | CLP3 | 3500000\$/YR |
| CLP2 | 2625000\$/YR | | |
| CU | 0.05\$/KWHR | CX | 2500\$/GPM |
| C1 | 10000\$/CU.M. | C2 | 300\$/CU.M. |
| C3 | 6.50\$/KG | C4 | 30\$/TON |
| C5 | 185\$/TON | C6 | 50\$/TON |
| C7 | 0.02\$/GALLON | | |
| Environmental Cost Constants | | | |
| CMA | 0.000137\$/ft ² /ft | CMW | 0.000183\$/ft ² /ft |
| EP6 | 462500\$ | EPEM | 80300\$/YR |
| X1 | 5% | | |

TABLE 8.2 OUTPUT PARAMETERS

CALCULATED VALUES,

| | | | |
|-----------|-------------------|----------|------------------------|
| A | 10000.000SQ.FT. | A SUB W | 780,000.000SQ.FT. |
| INJ PRES | 700.000PSI | Q | 1900.000GPM |
| INJ FLOW | 24.359GPM | # CELLS | 78.000# |
| WEL LIFE | 4.000YR | PRIM T | 0.087YR |
| ACID C. | 33.24GRAM/L | LIME CON | 0.308TON/TON |
| ACID CON | 4.539TON/TON | SULFATES | 141083.625TON/YR |
| SULFATES | 6.188TON/TON | G | 604.094FT |
| RI | 16.554FT | XI | 4966.11FT ² |
| INJ WELS | 78.000# | WELLS | 175.000# |
| SOL.PIPE | 34932.703FT | CUWGT | 2308.5 TONS/CELL |
| RECOVERY | 0.506 FRACTION | MINE OPS | 10.000# |
| CASING | 4.000IN | HOLE DIA | 7.000IN |
| INJ TUBE | 1.920IN | PRD TUBE | 1.920IN |
| INJ PUMP | 636.690HP | PRD PUMP | 480.310HP |
| WEL PIPE | 4.000IN | TRS PIPE | 10.000IN |
| PLNT OPS | 92.000# | | |
| SITE PRP | 2400.000\$/WELL | CASING | 18951.154\$/WELL |
| CEMENT | 4844.762\$/WELL | DRILLING | 5833.333\$/WELL |
| FAN WELL | 0.000\$/FAN | COMPLTON | 9300.000\$/WELL |
| LOGGING | 5835.000\$/WELL | INJ EQIP | 10727.000\$/WELL |
| PRD EQIP | 10727.064\$/WELL | UND.WORK | 0.000\$ |
| CHEMICLS | 4072489.25\$/YR | LABOR | 4371000.000\$/YR |
| O & M | 13331525.000\$/YR | PLNT CAP | 24701136.000\$ |
| SOL TRNS | 1343821.125\$ | UND.DEV. | 0.000\$ |
| UTILITYYS | 3058337.25\$/YR | WEL CAP. | 10485404.0\$ |
| EIS & PER | 444500.000\$ | MON WELS | 894692.875\$ |
| ENV.MON. | 80300.000\$/YR | RESTORE | 57935.754\$ |

pumps and piping; total wellfield capital; environmental costs of permitting, monitoring wells, and restoration. The operating costs include: chemicals, labor, utilities, environmental monitoring; surface plant and wellfield maintenance; and total operating cost. Table 8.2 lists output parameters.

8.4 CASH FLOW ANALYSIS

The cash flow analysis consists of scheduling the capital and operating costs over the project life and calculating DCF/ROR or selling price of copper. Once the individual cost elements are calculated the cash flow analysis is initiated. This consists of determining the total project life, which is equal to the total of plant life plus the construction period. The first year of production is the first year following completion of construction. The costs incurred in each year are calculated to meet these schedules. Table 8.3 lists the cash flow summary over the life of the project. The project life is 23 years, including 3 year plant construction. An old wellfield is replaced with new wellfield as the old wellfield is depleted. It is assumed that wellfield construction requires 1 1/2 years. For the example illustrated in Table 8.3 the well life is 4 years. Therefore, wellfield replacements are initiated in year 6, 10, 14, and 18 so that new wellfields are in operation at the start of year 8, 12, 16 and 20.

The total operating costs are incurred from the first year of production (year 4 in Table 8.3) through the end of the last year of project life (year 23). As each wellfield is put into operation, a well priming time is required, during which time acid is pumped into ground but no copper is produced. Full operating costs are incurred during

TABLE 8.3 CASH FLOW SUMMARY

**** PRICE = 53.19 C/LB ****

Discounted Initial Value of Investment = 1376.54\$/ANNUAL

Ton

Annual Operating Costs = 26.66C/LB

CASH FLOWS IN \$(000)

| PRODTN YR | TPY | PLANT CAPITAL | WELL CAPITAL | UNDERGROUND CAPITAL | PLANT O & M | NET CASH FLOW | DISCOUNTED CASH FLOW |
|--------------|-----|------------------|-----------------|------------------------|----------------|------------------|-------------------------|
| 1 | 0 | 5681 | 0 | 0 | 0 | -5681 | -5681 |
| 2 | 0 | 6175 | 3565 | 0 | 0 | -9740 | -8117 |
| 3 | 0 | 12845 | 6920 | 0 | 0 | -19765 | -13726 |
| 4 | 21 | 0 | 0 | 0 | 13332 | 8599 | 4977 |
| 5 | 23 | 0 | 0 | 0 | 13332 | 10925 | 5269 |
| 6 | 23 | 0 | 3585 | 0 | 13332 | 7340 | 2950 |
| 7 | 23 | 0 | 6959 | 0 | 13332 | 3967 | 1328 |
| 8 | 21 | 0 | 0 | 0 | 13332 | 8599 | 2400 |
| 9 | 23 | 0 | 0 | 0 | 13332 | 10925 | 2541 |
| 10 | 23 | 0 | 3585 | 0 | 13332 | 7340 | 1423 |
| 11 | 23 | 0 | 6959 | 0 | 13332 | 3967 | 641 |
| 12 | 21 | 0 | 0 | 0 | 13332 | 8599 | 1157 |
| 13 | 23 | 0 | 0 | 0 | 13332 | 10925 | 1225 |
| 14 | 23 | 0 | 3585 | 0 | 13332 | 7340 | 686 |
| 15 | 23 | 0 | 6959 | 0 | 13332 | 3967 | 309 |
| 16 | 21 | 0 | 0 | 0 | 13332 | 8599 | 558 |
| 17 | 23 | 0 | 0 | 0 | 13332 | 10925 | 591 |
| 18 | 23 | 0 | 3585 | 0 | 13332 | 7340 | 331 |
| 19 | 23 | 0 | 6959 | 0 | 13332 | 3967 | 149 |
| 20 | 21 | 0 | 0 | 0 | 13332 | 8599 | 269 |
| 21 | 23 | 0 | 0 | 0 | 13332 | 10925 | 285 |
| 22 | 23 | 0 | 0 | 0 | 13332 | 10925 | 237 |
| 23 | 23 | 0 | 0 | 0 | 13332 | 10925 | 198 |
| | | | | | | 129515 | 0 |

this time but there is no net production. For the example illustrated in Table 8.3 production in the priming years (4, 8, 12, 16, 20) is 21,000 TPY versus 23,000 TPY in non priming year.

The DCF/ROR method described in Section 8.1 is used to compute copper selling price. (Table 8.3 shows the selling price for an ROR of 20%.) Two other summary numbers, namely annual operating cost (cents per lb copper) and discounted initial value of investment (\$ per annual ton capacity) are also listed.

8.5 OPTIMIZATION OF COMMERCIAL DESIGN AND SENSITIVITY ANALYSIS

For a specific site and plant size, the method outlined in Chapter 9, "Estimation of Best Mining Scenario" can be used to reduce the number of designer choices to be evaluated on the computer. On the other hand, each available option can be evaluated in detail by picking values of appropriate input parameters and evaluating each option on the computer. For example, for each choice of mining access and type of flow pattern, the well spacing can be varied to determine the "optimum" well life. Optimization of design specifications can be carried out by preparing a set of input parameters and conducting a computer run for each change in an input parameter. Results are printed out for each set of runs. Input parameters may have a level of variability or uncertainty associated with them. This is especially true concerning ore body characteristics such as ore grade and permeability. The effect of a known variation in these parameters or the effect of an uncertainty can also be evaluated by conducting a set of runs over the expected range of uncertainty or variability. The economics sensitivity to this variation can then be determined.

Table 8.4 illustrates an example of optimizing well spacing for radial flow geometry. Stimulation via small radius hydrofracturing is also evaluated. Copper selling price at 20% ROI is used to compare different cases. This table illustrates that small radius hydrofracturing is cost effective and the lowest price is almost 12¢/lb less with stimulation than without. The lowest price with stimulation is 52.1¢/lb at a well spacing of 120 ft, while the lowest price for no stimulation is 63.7¢/lb at a well spacing of 100 ft. Figure D-1 is a computer generated graphic illustrating the sensitivity analysis using Lotus 123.*

TABLE 8-4. OPTIMIZATION OF WELL SPACING FOR RADIAL FLOW

| Case No. | Hydraulic Stimulation | Well Spacing feet | Selling Price ¢/lb | Discounted Investment \$/AT | Operating Cost ¢/lb |
|----------|-----------------------|-------------------|--------------------|-----------------------------|---------------------|
| 1 | Yes | 50 | 72.23 | 2550.2 | 26.58 |
| 2 | Yes | 70 | 59.66 | 1780.4 | 26.66 |
| 3 | Yes | 100 | 53.19 | 1376.54 | 26.66 |
| 4 | Yes | 120 | 52.05 | 1282.42 | 26.78 |
| 5 | Yes | 140 | 52.48 | 1258.72 | 27.07 |
| 6 | Yes | 160 | 52.75 | 1233.78 | 27.15 |
| 7 | No | 50 | 76.09 | 2552.38 | 29.67 |
| 8 | No | 70 | 67.03 | 1964.38 | 29.85 |
| 9 | No | 100 | 63.67 | 1691.03 | 29.89 |
| 10 | No | 120 | 64.19 | 1648.74 | 29.91 |
| 11 | No | 140 | 67.24 | 1674.64 | 30.25 |
| 12 | No | 160 | 70.03 | 1694.82 | 30.33 |

*Reference to specific products does not imply endorsement by the Bureau of Mines.

CHAPTER 9

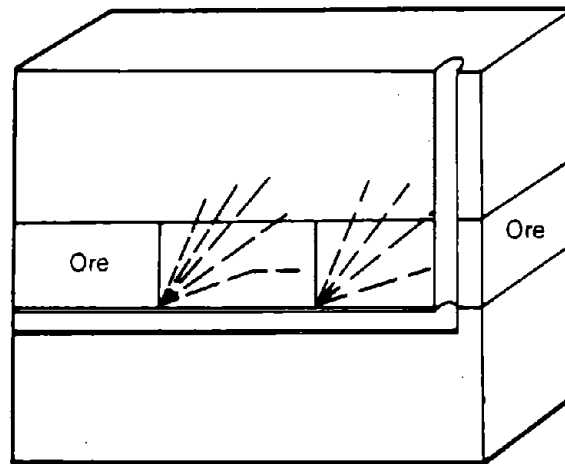
ESTIMATION OF BEST MINING SCENARIO

9.1 APPROACH

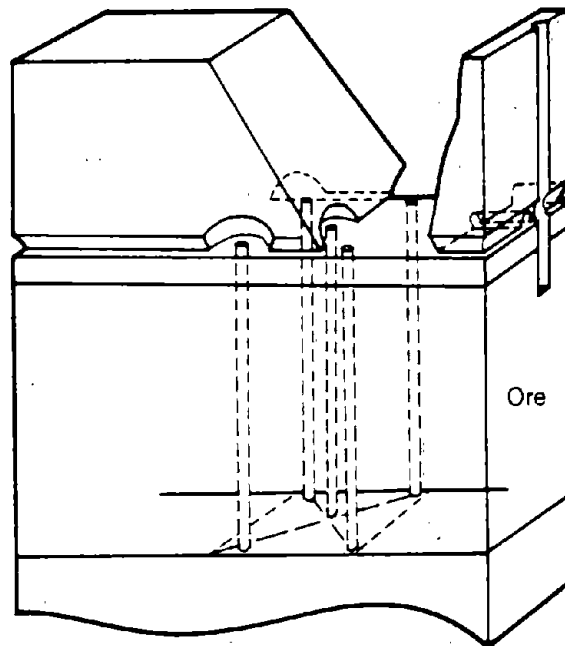
The approach used to estimate which of the 42 possible mining scenarios is most likely to result in the commercial design with the maximum DCF/ROR consists of two steps. The first one involves determining which of the 42 possible mining scenarios is best. The second step involves determining a copper loading to maximize the DCF/ROR. This analysis will provide a mining scenario and copper loading (or system gpm) as a design basis for using the functional design categories to conduct the detail commercial design and economic analysis.

The following analysis is to be used to determine which of the 42 possible mining scenarios is the best:

- o To achieve high copper recovery, the ore zone will have to be saturated, independent of the initial state, otherwise acid contact of copper and fluid communication between injection and production wells cannot be ensured. If unsaturated, water make-up requirements will be specified. Copper leaching and fluid communication require acid to touch the minerals and form a continuous path between injection and production points. This criteria reduces the number of mining scenarios to 21.
- o All other combinations can be reduced to drilling from the surface and drilling from underground workings, with the latter having two sub-classifications, vertical wells and patterns of fanned wells which induce horizontal flow parallel to crosscuts (Figure 9-1). Drilling from the underground substitutes drilling well footage and mining footage for drilling overburden footage, and underground well completion costs for those on the surface. The ratios of these costs for the two underground sub-classifications relative to surface drilling can be expressed analytically as ratios of unit drilling and completion costs and well pattern dimensions, and the ratio of orebody height to depth. Z_v is the cost ratio of vertical wells, Z_f is the cost ratio for fanned wells. The process of obtaining these



Fan Drilling by Underground Access



Vertical Drilling by Underground Access

Figure 9-1. Two Classifications for Underground Drilling

ratios involves developing analytic expressions for both underground and surface deposit access costs by:

- + Developing total costs as the product of total wells, footage drilled and mined per well, and unit drilling and mining costs.
 - + Utilizing equal system flow rates to equate the product of number of wells and gpm per well. This provides equal total production capacity.
 - + Utilizing equal quantities of copper to equate the product of number of wells, well spacing, and ore thickness. This provides equal well life, providing a comparison at equal future investments for wellfield replacement.
 - + Relating the flow rate per well to pressure drops and well pattern geometries and dimensions.
- o When both Z_v and Z_f are greater than one, surface drilling is the best mining scenario. When only Z_v or Z_f is less than one, the best mining scenario is associated with the Z value that is less than one. When both Z_v and Z_f are less than one, the best mining scenario is associated with the lower Z value. If the underground workings are fully developed and meet the required well pattern dimensions the Z values are computed by setting unit mining costs to zero. The above process reduces the best mining scenario to one of three; no matrix modification, hydraulic fracturing, or borehole blasting.
 - o For the well configuration selected determine the flow rate per well (gpm) without matrix modification. Determine whether it is cost effective to increase the gpm per well using hydraulic fracturing or borehole blasting. This results in the best mining scenario.

The following describes the analysis to be used in selecting the copper loading that maximizes DCF/ROR. The present value of surface plant and wellfield costs consists of fixed and flow rate dependent costs. The latter consists of the following components, with costs expressed as \$ per annual ton of production, \$/AT.

- o Surface plant flow rate dependent costs which are proportional to the system flow rate raised to power n , represented as $B_1(Q)^n = AT_{sf}$
- o Well drilling and completion costs which are proportional to the ratio of system flow rate to well flow rate raised to power m , expressed as $B_2(Q/q)^m = AT_{wd}$

- o Well pattern start-up costs which are inversely proportional to total system flow rate, expressed as $B_3/Q = AT_{WH}$
- o The total flow rate dependent costs are the sum of the one time surface plant cost and the present value of all future well drilling and well pattern start-up costs, AT_{TF}
 - + AT_{TF} = total present value flow rate dependent costs
 - + $AT_{TF} = B_1(Q)^n + B_2(Q/q)^m(1+\beta) + (B_3/Q)(1+\beta)$ (9.1)
 - + β = present value factor of all future investments

The value of the gpm that minimizes AT_{TF} results in the maximum value of DCF/ROR. The copper loading is determined by dividing production capacity by Q times 2.19.

9.2 COMPARISON OF SURFACE VERSUS UNDERGROUND DRILLING OF VERTICAL WELLS (Z_V)

For this cost comparison total production capacity, copper loading, number of well modules, and ore volumes are the same for both surface and underground drilling.

o Nomenclature used in this section

- C = unit cost for mining shaft, \$/foot
- C_s = unit cost for mining raise, \$/foot
- V^r = unit cost for mining crosscut, \$/foot
- C_x = unit cost for mining crosscut, \$/foot
- C_{dT} = unit cost for vertical well from surface, \$/foot
- C_{da} = unit cost for mining drift, \$/foot
- C_{ds} = unit cost for well drilling and casing vertical well from surface, \$/foot
- C_{dc} = unit cost for completing vertical wells from surface, \$/foot
- δ_{ds} = ratio of well drilling and casing costs underground to surface
- δ_{dc} = ratio of well completion costs underground to surface
- S = producer to producer spacing, feet
- N_w = total number of wells in production
- N_I = total number injectors in production
- N_P = total number of producers in production
- N_{HC} = number of crosscuts
- D = total depth to bottom of ore interval, feet
- H = total thickness of ore interval, feet
- ϕ_{ds} = fraction of total well costs for surface drilling associated with well drilling and casing.

o Underground Drilling Costs

Costs considered are: initial costs for the shaft and raise to depth (D-H); initial well drilling and casing costs for hole length H; initial well completion costs for hole lengths H; and initial costs for developing drifts and crosscuts. It is assumed that for each series of well modules that two drifts are required, that wells are drilled in an inverted five-spot pattern, and that the number of crosscuts is equal to the sum of the number of injectors and producers in one row of the total five spot pattern, see Figure 9-2.

o Z_v Cost Ratio

The following equations are used to calculate Z_v , the derivation is provided in the following section. For a mining case where the underground workings are initially in place U_2 , U_3 , and U_4 are zero.

$$Z_v = U_1(H/D) + U_2(S/D) + U_3(1-H/D) + U_4 \quad (9.2)$$

$$U_1 = [\phi_{ds} \delta_{ds} + (1 - \phi_{ds}) \delta_{dc}] \quad (9.3)$$

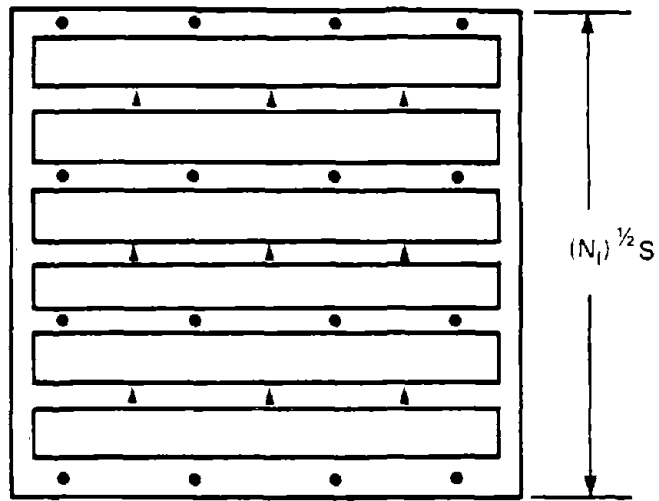
$$U_2 = \left[\frac{V_x}{C_{dT}} \right] \left[1 + \frac{C_{da}}{V_x (N_I)^{1/2}} \right] \quad (9.4)$$

$$U_3 = \frac{[2C_s + C_r]}{[C_{dT}][2N_I]} \quad (9.5)$$

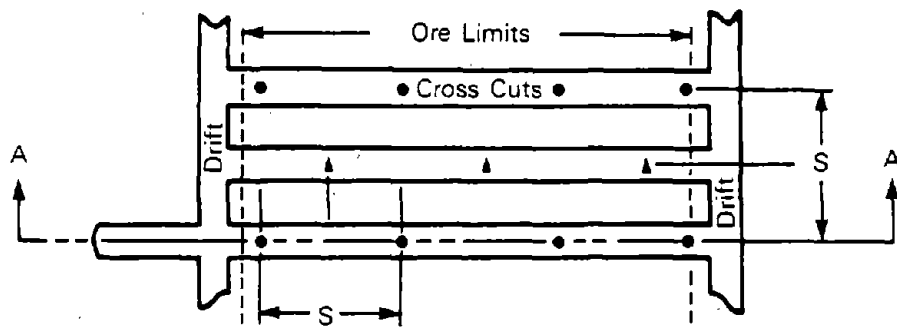
$$U_4 = \frac{2000C_{da}}{2N_I C_{dT} D} \quad (9.6)$$

o The following example illustrates the computation of Z_v .

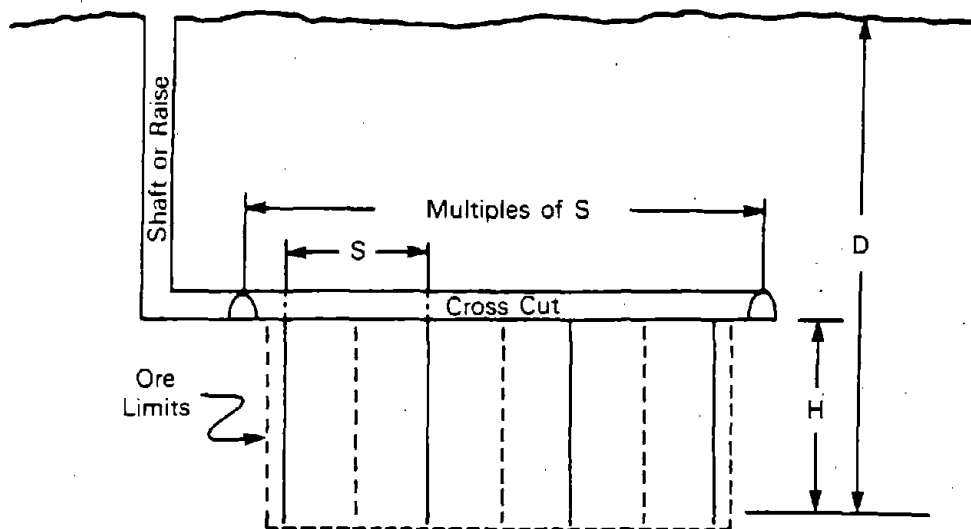
- + No data base exists for drilling and completing large diameter wells in fractured rock from underground workings, but it is likely that unit cost can be expected to exceed 50% of surface drilling, $U_1 \geq 1.5$ for δ_{ds} equal to 1.5.
- + Assume unit crosscut costs and drift costs to be equal and three times unit surface drilling costs (\$300/foot versus \$100/foot). This results in a U_2 value of 3.4 for a 50 injector pattern.
- + Assume unit costs for the shaft to exceed: unit surface drilling costs by 3-to-1, \$3000 per foot versus \$100/foot; and unit raise cost by 3-to-1, \$3,000/ft vs. \$1,000/ft. This results in a U_3 value of 0.7.



Plan View of Pattern



Plan View



Section A-A'

Figure 9-2. Vertical Drilling by Underground Access

- + Assume unit drift costs exceed unit drilling costs by 3-to-1, \$300/ft versus \$100/ft. This results in a value of 60/D for U_4 .
- + For a 1,000 foot deep ore body with a 300 foot ore thickness Z_v is greater than 1 for all values of well spacing.

o Derivation of Z_v

Equations for calculation of underground costs are listed below:

$$\text{\$ for shaft and raise} = (2C_s + C_r)(D-H) \quad (9.7)$$

$$\text{\$ for drilling and casing} = (C_{ds} \delta_{ds})(N_{ws})(H) \quad (9.8)$$

$$\text{\$ for well completion} = (N_w)(C_{dc} \delta_{dc})(H) \quad (9.9)$$

$$\text{\$ for drifts} = (2)(N_I)^{1/2}(S)(C_{da}) + 2000 C_{da} \quad (9.10)$$

$$\text{\$ for crosscuts} = (N_{HC})(N_I)^{1/2}(S)(V_x) \quad (9.11)$$

The cost of surface drilling is listed below:

$$\text{\$ for surface drilling} = (C_{ds} + C_{dc})(D)(N_T) \quad (9.12)$$

Relationships between the number of crosscuts, total wells, and number of injectors (total modules) are listed below:

$$N_w = (N_I) + [(N_I)^{1/2} + 1]^2 \quad (9.13)$$

$$N_{HC} = (N_I)^{1/2} + [(N_I)^{1/2} + 1], \text{ sum of rows of producers and injectors} \quad (9.14)$$

$$\text{For } N_I \gg 1, N_w \approx 2N_I, \text{ and } N_{HC} \approx 2(N_I)^{1/2}.$$

Z_v is obtained by dividing total underground costs by total surface costs, which results in (9.15), with U_1 , U_2 , U_3 , and U_4 given by (9.3) through (9.6).

$$Z_v = U_1(H/D) + U_2(S/D) + U_3(1-H/D) + U_4 \quad (9.15)$$

9.3 COMPARISON OF SURFACE DRILLING VERTICAL WELLS VERSUS UNDERGROUND DRILLING OF FAN PATTERNS (Z_p).

For this cost comparison total production capacity, copper loading and ore volumes are the same for both surface and underground drilling.

o Nomenclature used in this section

- C_s = unit cost for mining shaft, \$/foot
 C_r = unit cost for mining raise, \$/foot
 V_x = unit cost for mining crosscut, \$/foot
 C_{da} = unit cost for mining drift, \$/foot
 C_{dT} = unit cost for drilling, casing, and completing vertical well drilled from the surface, \$/foot
 S = well spacing surface drilling, feet
 D = total well depth, feet
 H = ore thickness, feet
 C_{wf} = unit cost of drilling and casing one well in a fan pattern, \$/foot
 C_{FP} = total pumping cost for fan pattern, \$
 d = separation of fan wells along a crosscut, feet
 h = length of a well in a fan pattern, feet
 N_{HV} = number of vertical units
 N_{IF} = total number of fan units
 N_{HF} = total number of fan patterns in a crosscut
 N_{HC} = number of crosscuts
 N_{TF} = number of wells per fan face
 N_{WS} = total number of surface wells
 N_{IS} = number of injectors surface drilling

o Wellfield Costs For Fan Drilling From the Underground

Costs considered are: initial costs for the shaft and raise to depth D ; initial well drilling and casing costs for fan wells of hole length h ; initial well completion costs pertaining to pumping of all wells; and initial costs for developing drifts and crosscuts, see Figure 9-3.

o Z_F Cost Ratio

The following equations are used to calculate Z_F , the derivation is provided in the next section. For a mining case where the underground workings are initially in place U_3 , U_4 , U_5 , and U_6 , are zero.

$$Z_F = U_5 \left(\frac{h}{D} \right) \left[1 + U_6 + U_7 \left(\frac{H}{h} \right)^{1/2} \right] + U_3 + U_8 + U_4 \quad (9.16)$$

$$U_3 = \frac{[(2C_s + C_r)]}{C_{dT}} \left(\frac{1}{2N_{IS}} \right) \quad (9.17)$$

$$U_4 = \frac{2000C_{da}}{2N_{IS}C_{dT}D} \quad (9.18)$$

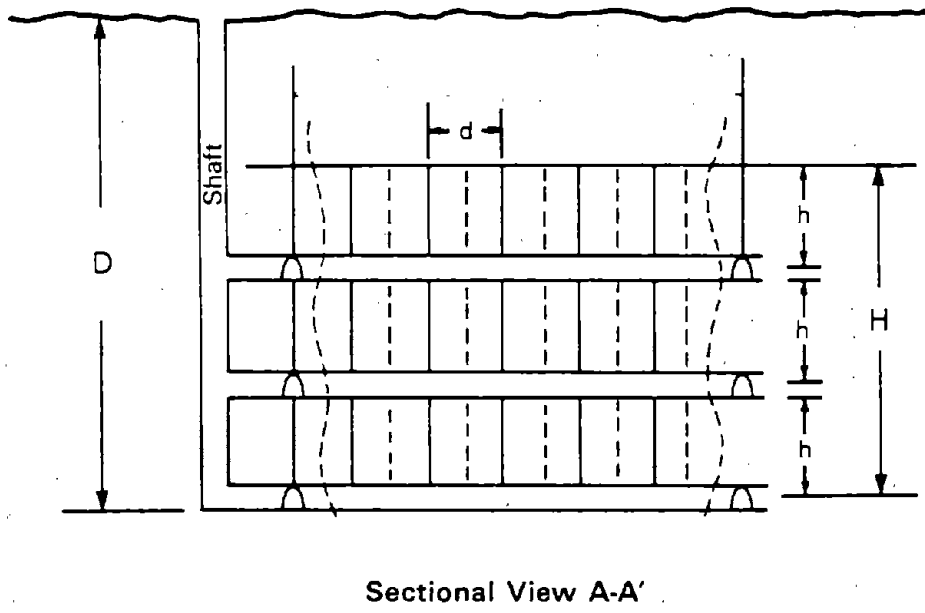
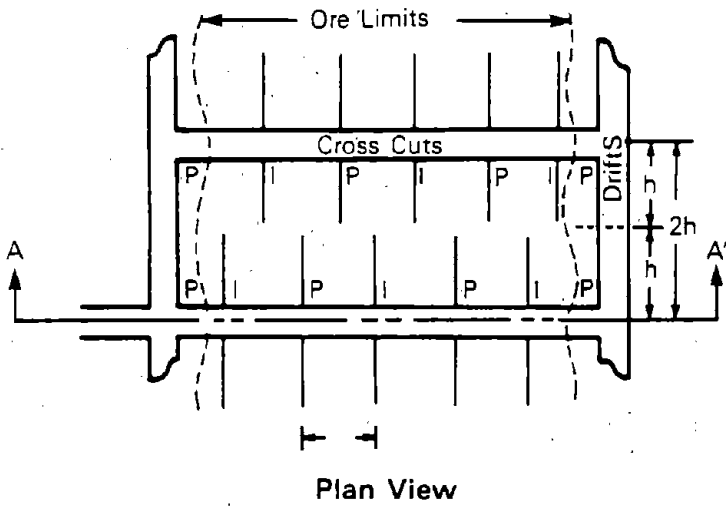


Figure 9-3. Fan Drilling from Underground

$$U_5 = 5.5 \left(\frac{G_{si}}{G_f} \right) \left(\frac{C_{wf}}{C_{dt}} \right) \quad (9.19)$$

$$U_6 = 0.055 \left(\frac{V_x}{C_{wf}} \right) \quad (9.20)$$

$$U_7 = 0.2 \left(\frac{C_{da}}{C_{wf}} \right) \left(\frac{G_f}{G_{si}} \right)^{1/2} \left(\frac{1}{N_{IS}} \right)^{1/2} \quad (9.21)$$

$$U_8 = \phi_2 = \text{fraction of total cost of wells drilled from surface associated with production pumping} \quad (9.22)$$

Based on (G_f/G_{si}) values shown in Table 9.1, Z_f values for each of the three surface drilling well patterns are listed below:

+ Z_{FAH} = Z value for axial flow horizontal fractures

$$Z_{FAH} = 2.85 (S/D)(S/H_c) \left[1 + 0.055 \frac{V_x}{C_{wf}} + 0.28 \frac{C_{da}}{C_{wf}} \frac{(HH_c)^{1/2}}{(N_{IS})^{1/2} S} \right] \left[\frac{C_{wf}}{C_{dt}} \right] + U_3 + U_4 + U_8 \quad (9.23)$$

+ Z_{FAV} = Z value for axial flow vertical fractures

$$Z_{FAV} = 11.5 (H/D) \left[1 + 0.055 \frac{V_x}{C_{wf}} + 1.39 \frac{C_{da}}{C_{wf}} \frac{1}{(N_{SI})^{1/2}} \right] \left[\frac{C_{wf}}{C_{dt}} \right] + U_3 + U_4 + U_8 \quad (9.24)$$

+ Z_{FR} = Z value for radial flow

$$Z_{FR} = 1.49 (H/D) \left[1 + .055 \frac{V_x}{C_{wf}} + 0.38 \frac{C_{da}}{C_{wf}} \frac{1}{(N_{SI})^{1/2}} \right] \left[\frac{C_{wf}}{C_{dt}} \right] + U_3 + U_4 + U_8 \quad (9.25)$$

TABLE 9.1
FOR COMPUTATION OF (G_F/G_{s1})

| Well Pattern | G Factor Well Flow Rates | X Factor Well Life | G_F/G_{s1} Total Flow Rates | G_F/G_{s1} Total Flow Rates Equal Well Lifes $X_F=X_{s1}$ |
|--|--|------------------------------------|---|--|
| Fan Pattern $G_{s1}^{(1)}, X_F^{(1)}$ | $\left(\frac{\pi}{1.63}\right)h$ | $\left(\frac{1.96}{\pi}\right)h^2$ | -- | -- |
| Axial Flow Horizontal Fractures G_{s1}, X_{s1} | $\left(\frac{S^2}{H_c}\right)$ | $H_c H$ | $\left(1.93\right)\left(\frac{h}{S}\right)\left(\frac{H_c}{S}\right)$ | $1.2\left(\frac{h}{H}\right)\left(\frac{h}{S}\right)^2, H_c = 0.62h\left(\frac{h}{H}\right)$ |
| Axial Flow Vertical Fractures $G_{s2}, X_{s1}^{(2)}$ | $4H$ | $\frac{S^2}{4}$ | $0.48\left(\frac{h}{H}\right)$ | $0.48\left(\frac{h}{H}\right), S = 1.58h$ |
| Radial Flow $G_{s3}, X_{s3}^{(3)}$ | $\left(\frac{\pi}{6}\right)\left(\frac{H}{6}\right)$ | $\left(\frac{6}{\pi}\right)S^2$ | $3.68\left(\frac{h}{H}\right)$ | $3.68\left(\frac{h}{H}\right), S = 0.57h$ |

⁽¹⁾ G_F and X_F values correspond to 11 wells per fan face and a (d/h) value of 0.6. In Appendix A, it is shown that this corresponds to the minimum fan module cost per unit of flow rate.

⁽²⁾ For this analysis assume $S_1=S_2=S$

⁽³⁾ For this analysis assume $[\ln(r_e/r_w)-0.619]$ equals 6.

The following example illustrates the computation of Z_f for surface drilling with horizontal fractures.

- + Assume unit crosscut and drift costs are equal, and each is three times unit surface drilling costs, $V_x = C_{da} = 3C_{dT}$.
- + Assume unit costs of fan wells are one fifteenth of unit crosscut costs, $C_{wf} = 0.067V_x$. This also results in $C_{wf} = 0.2C_{dT}$.
- + Assume the sum of unit shaft costs are thirty times the unit cost of surface drilling, $C_s = 30C_{dT}$.
- + Assume unit shaft costs are three times unit raise costs, $C_s = 3C_r$.
- + Assume 50 injectors, $N_{IS} = 50$
- + Assume 10% of the total unit surface drilling costs are associated with production pumping $\phi_2 = 0.1$.
- + For a 1,000 foot deep ore body with 300 foot of ore interval, and a 30 foot separation between horizontal fractures, Z_f is given as:

$$+ Z_{FAH} = 0.86 + 3.45 \times 10^{-5} [S^2 + 31(S)] \quad (9.26)$$

- + For well spacings less than 58 feet Z_f will be less than one.

o Derivation of Z_f

Calculation of costs of underground costs:

$$\text{\$ for shaft and raise} = (2C_s + C_r)(D) \quad (9.27)$$

$$\text{\$ for fan well drilling and completion} = (N_{TF})(N_{IF})(C_{wf})(h) \quad (9.28)$$

$$\text{\$ for crosscut mining} = (N_{IF})(d)(V_x) \quad (9.29)$$

$$\text{\$ for drift mining} = 2(N_{HV})(N_{HC})(2h)(C_{da}) + 2000 C_{da} \quad (9.30)$$

$$\text{\$ for fan well completion pumping} = C_{FP} \quad (9.31)$$

Calculation of surface costs:

$$\text{\$ for surface drilling vertical wells} = (C_{dT})(N_{IS})(2)(D) \quad (9.32)$$

Z_F is obtained by dividing total underground costs by total surface costs.

$$Z_F = U_5^o [1 + U_6^o + U_7^o] + U_3 + U_8^o + U_4 \quad (9.33)$$

$$U_5^o = \left(\frac{N_{IF}}{2N_{IS}} \right) \left(\frac{N_{TF} C_{wf}}{C_{dT}} \right) \left(\frac{h}{D} \right) \quad (9.34)$$

$$U_6^o = \left(\frac{d}{h} \right) \left(\frac{V_x}{N_{TF} C_{wf}} \right) \quad (9.35)$$

$$U_7^o = \left(\frac{N_{HV} N_{HC}}{N_{IF}} \right) \left(\frac{4C_{da}}{N_{TF} C_{wf}} \right) \quad (9.36)$$

$$U_8^o = \frac{C_{FP}}{2N_{IS} C_{dT}} \quad (9.37)$$

The following relationships between parameters contained in U_5^o , U_6^o , U_7^o , and U_8^o are developed:

- + Equal total system flow rates for surface and underground well modules to maintain the same production capacity.

$$\frac{N_{IF}}{N_{IS}} = \frac{G_{si}}{G_F} \quad (9.38)$$

- + Square geometries for surface and underground well patterns.

$$N_{HC} = N_{HF} (d/2h) \quad (9.39)$$

$$N_{HV} = (H/h) \quad (9.40)$$

$$\frac{N_{HV} N_{HC}}{N_{IF}} = \left(\frac{H}{h} \right)^{1/2} \left(\frac{d}{2h} \right)^{1/2} \left[\frac{G_F}{G_{si}} \right]^{1/2} \left[\frac{1}{N_{IS}} \right]^{1/2} \quad (9.41)$$

- + The cost of pumps for lifting the total system flow rate for underground and surface drilling is assumed to be approximately the same.

$$\frac{C_{FP}}{2N_{IS} C_{dT}} = \Phi_2 = \text{fraction of cost of wells associated with production pumping} \quad (9.42)$$

- + For fan drilling use 11 wells per fan face and a fan pattern geometry of (h/d) equal to 1.68. This minimizes the unit cost of a fan module per unit of flow rate obtained.
- + The above results in Z_f expressed as:

$$Z_f = U_5 \left(\frac{h}{D} \right) [1 + U_6 + U_7 (H/h)^{1/2}] + U_3 + U_8 + U_4 \quad (9.43)$$

$U_3, U_4, U_5, U_6, U_7,$ and U_8 are given by (9.17) through (9.22).

9.4 ESTIMATION OF SYSTEM COPPER LOADING TO MAXIMIZE DCF/ROR

As might be expected, the level of copper concentration in the produced solutions and the life of each set of wells have a major impact on project economics. The three major cost areas impacted by the level of effluent copper concentration are: the surface facility (initial cost); wells (initial and future replacement costs); and solution inventory associated with well pattern start-up (initial and future replacement costs).

o Surface Facility

This investment has two components: one related to total production capacity (tons per year), and one related to solution capacity (total gpm). The latter decreases as gpm is reduced. At a fixed level of production capacity (tons per year) the volume of solution continually being handled (total gpm) decreases as the concentration of metal in solution increases. Thus, from the standpoint of surface facility capital it is desirable to achieve a high effluent metal concentration.

o Wells

Total well costs are related to individual well costs, which increase with depth and the number of wells. Since the individual production capacity of a well is proportional to the product of flow rate and metal concentration in solution, it is desirable to have a high metal concentration to achieve a high level of individual well capacity, which in turn keeps the number of wells at a minimum level. The individual well life also impacts cost. The shorter the life the greater the number of future well replacements and costs.

o Wellfield Start-up

The pores of the rock in the well pattern are initially filled with water. Each time a well pattern operation is initiated the solubilized metal is diluted by the pore fluid, requiring at least one exchange of the volume of water in a well pattern (one pore-volume) to attain full production capacity. Prior to this, the cash flow is principally negative. Since the time required to achieve this one-pore volume displacement increases as the total flow rate of the system is reduced, the negative cash flow of start-up will be higher at increased levels of effluent copper concentration, as the product of total gpm and metal concentration is a constant for a given production capacity.

Two of the three major investments (surface facility, and wells) decrease with increasing copper concentration. However, since the negative cash flow associated with start-up is higher for a system designed for high copper concentration (low gpm), it is likely that an optimum concentration exists at which the initial total cash outlay is minimized. Putting it simply, even if it is possible to technically achieve very high metal concentrations, it may not be economically desirable.

Table 9.2 illustrates various options that are available in selecting a wellfield design for a given production capacity. Columns A and B are design options, column C represents the fluid volume associated with start-up or dilution per wellfield module, and columns D, E, F, and G impact both present and future cost expenditures. Factors impacting return on investment: surface plant and well costs increase with system gpm; well startup costs decrease with system gpm; future wellfield investments increase with lower well pattern life; and wellfield start-up costs decrease with lower well pattern life.

The purpose of this analysis is to provide a method of estimating the level of the system flow rate Q or the effluent copper loading [Cu] that minimizes the present value investment. Other design factors must then be considered to determine whether this loading can be achieved. Examples, of these factors are:

- o Effects of acid strength on materials of construction and gangue reactivity.
- o Selection of adequate well pattern residence time to maintain the copper loading at the design level of high fractional copper recovery.

9.4.1 Representation of Flow Rate Dependent Costs

The present value of the flow rate dependent costs is represented by equations (9.43) through (9.48). The derivation follows in Section 9.4.2.

$$AT_{TF} = B_1(Q) + B_2 Q (1+\beta) + B_3 \frac{(1+\beta)}{Q} \quad (9.44)$$

$$B_1 \text{ in 1986 } \$ = 2500/Y \quad (9.45)$$

$$B_2 = \frac{C_w}{Yq_r}, \quad C_w = \text{well costs per well module} \quad (9.46)$$

$$o \quad C_w \text{ for vertical} = 2C_{dT}D \text{ drilling from surface} \quad (9.47)$$

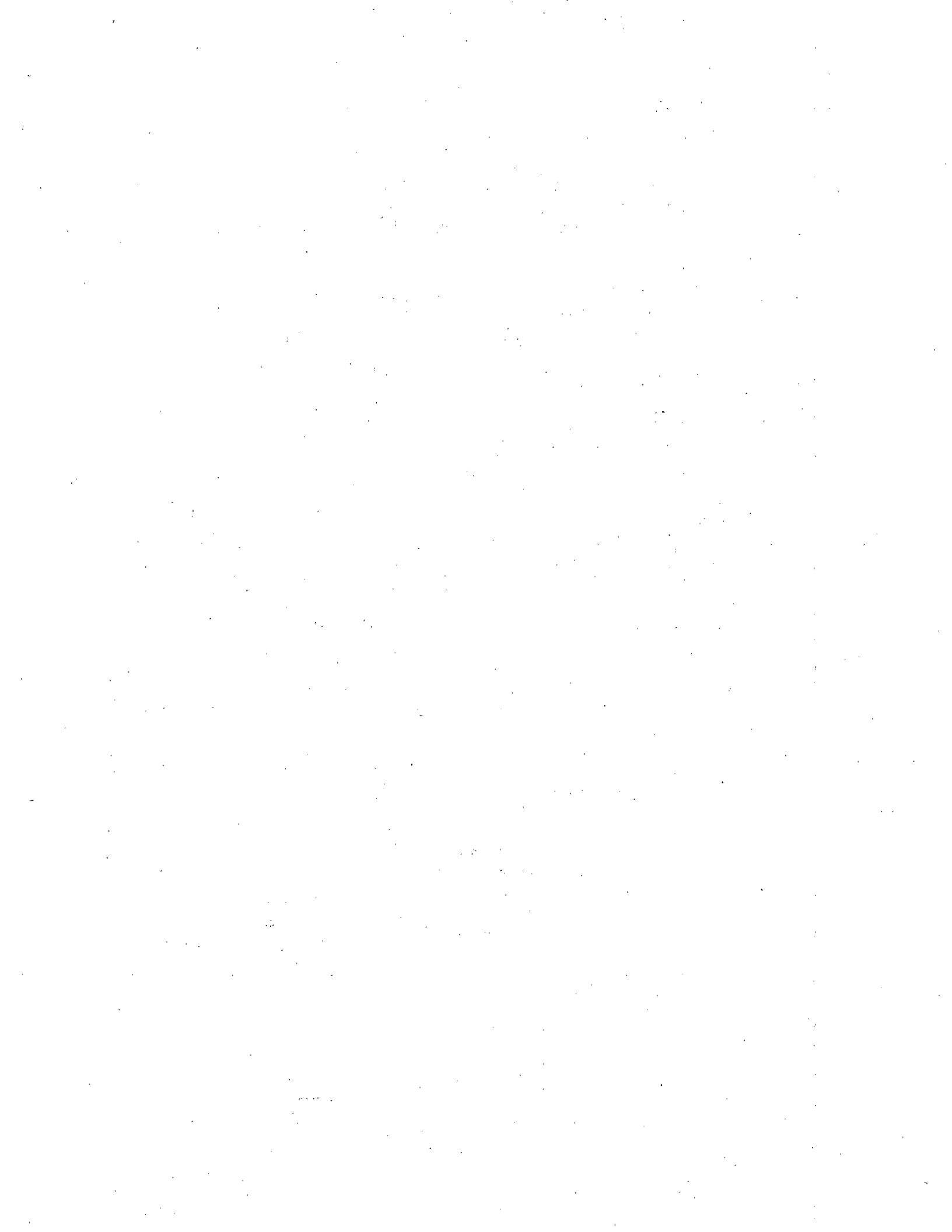


TABLE 9.2

EXAMPLES OF COST TRADE-OFFS ASSOCIATED WITH WELL PATTERN DESIGN OPTIONS

Basis of Design

- o 25,000 tons per year (TPY) copper production
- o 0.5% copper ore
- o 50% copper recovery
- o 5% porosity
- o 20 year mine life

| | A | B | C | D | E | F | G |
|-----------------------------|---------------------------------------|--------------------------------------|--|-------------------------|---------------------------------------|---------------------------------|---|
| | | | | AT _{SF} | AT _{WD} | AT _{WH} | |
| Well Pattern Design Options | Well Pattern Life Years | Pregnant Liquor Copper Loading (g/l) | Gallons Water in One Pore Volume (millions of gallons) | Total GPM Surface Plant | Relative Number of Wells in Operation | Well Pattern Start-up Time Days | Number of Future Well Pattern Additions |
| Primary | Secondary | | | | | | |
| Low Well Life | Minimize Start-Up Costs | 2 | 146 | 5696 | 4x | 18 | 5 |
| | Minimize Surface Plant and Well Costs | 8 | 146 | 1424 | x | 72 | 5 |
| High Well Life | Minimize Start-up Costs | 2 | 243 | 5696 | 4x | 30 | 2 |
| | Minimize Surface Plant and Well Costs | 8 | 243 | 1424 | x | 120 | 2 |

Q = total system flow rate
 q = flow rate per well
 $AT_{SF} = S/AT = B_1 [Q]^n$
 $AT_{WD} = S/AT = B_2 [Q/q]^m$
 $AT_{WH} = S/AT = B_3 [1/Q]$
 AT_{TF} = Present value of flow rate dependent costs = $B_1 [Q]^n + B_2 [Q/q]^m [1 + \beta] + B_3 [1/Q] [1 + \beta]$
 β = Present value factor of future well field replacements



$$o \ C_w \text{ for vertical drilling from underground} = 2[C_{dT} H + SV_x] \quad (9.48)$$

$$o \ C_w \text{ for fan drilling} = (N_{TF})[C_{wf} h + V_x d] \quad (9.49)$$

+ For $V_x = 15 C_{wf}$, and optimum fan pattern costs associated with $N_{TF} = 11$, and $d/h = 0.60$.

$$+ C_w = 110 C_{wf} h \quad (9.50)$$

$$B_3 = 5680 \left(\frac{E_p E_H}{E_s E_L E_R} \right) (YEP_o t_w) \left(\frac{\phi}{100-\phi} \right) \left(\frac{1}{F_c \rho_b} \right) \quad (9.51)$$

For a given deposit access the flow rate per well (q_x) can be calculated based on deposit and wellfield geometry and permeability. For specific values of well life (t_w) and the associated present value factor for well replacements (β), ore grade (F_c), density (ρ_b) and porosity (ϕ), production capacity (Y), unit well costs (C_{dT} or C_{wf}), and efficiency factors (E_p, E_H, E_s, E_L, E_R), T_{TF} can be plotted as a function of Q to identify the value of Q at which T_{TF} is a minimum. The copper loading is then calculated by dividing Y by (2.19)(Q). Table 9.3 lists present value factors (based on 20 year plant life) for 1, 2, 4, 6, and 10 year well life.

Table 9.3. Present Value Factors

| % Return on Investment | Well life Years | Number of Wellfield Replacements | Present Value Factor β | $(1+\beta)$ | $t_w(1+\beta)$ |
|------------------------|-----------------|----------------------------------|------------------------------|-------------|----------------|
| 15 | 1 | 19 | 6.2 | 7.2 | 7.2 |
| | 2 | 9 | 2.9 | 3.9 | 7.8 |
| | 4 | 4 | 1.2 | 2.2 | 8.8 |
| | 6 | 3 | 0.7 | 1.7 | 10.2 |
| | 10 | 2 | 0.3 | 1.3 | 13.0 |
| 25 | 1 | 19 | 3.9 | 4.9 | 4.9 |
| | 2 | 9 | 1.8 | 2.8 | 5.6 |
| | 4 | 4 | 0.7 | 1.7 | 7.2 |
| | 6 | 3 | 0.4 | 1.4 | 8.4 |
| | 10 | 2 | 0.1 | 1.1 | 11.0 |

An alternative to the above method of locating the optimum for the system flow rate is to: differentiate (9.44) with respect to Q; equate the derivative to zero; and solve for the value of Q at which the derivative is zero. The optimum copper loading $[Cu]_M$, (9.52), is obtained by substituting for the relationship between $[Cu]_M$ and Y and Q_m .

$$[Cu]_M = 0.077 \left[\frac{\left[2500 + \frac{C_w(1+\beta)}{q_I} \right] \left[\frac{100-\phi}{\phi} \right] \left[\frac{F_c E_s E_L E_R}{E_P E_H} \right]^{1/2}}{[EP_o t_w (1+\beta)]} \right] \quad (9.52)$$

As an example calculation an optimum copper loading of 15 gpl is calculated for the following values of the parameters on the right hand side of (9.52).

$$C_w = 2 \times \$100/\text{foot} \times 1000 \text{ feet} = \$200,000$$

$$q_I = 25 \text{ gpm}$$

$$\phi = 5\%$$

$$F_c = 0.5\%$$

$$E_P = 95\%, E_H = 100\%$$

$$E_s = 75\%, E_L = 75\%, E_R = 85\% \text{ (equivalent to 48\% copper recovery)}$$

$$t_w = 4 \text{ year well life}$$

$$\beta = 1.2, 15\% \text{ return on investment}$$

$$EP_o = 35\$/\text{lb copper, operating expense}$$

As noted in (9.52), the optimum copper loading is related to C_w/q_I , the well module cost per gpm. The cost and flow algorithms can be used to determine which combination of flow geometry and matrix modification minimizes this ratio. This will result in the minimum capital investment.

9.4.2 Derivation of Flow Rate Dependent Costs

The present value of the flow rate dependent costs are estimated as follows:

- o The surface plant cost (T_{SF}) is obtained by summing all the flow rate dependent costs corresponding to surface plant cost algorithms and dividing by the production capacity Y .

$$AT_{SF} = B_1(Q), \quad n = 1 \text{ for this analysis} \quad (9.53)$$

$$B_1 \text{ in 1986\$} = 2500/Y \quad (9.54)$$

- o The well costs are equal to the cost per well module (C_w) multiplied by the number of well modules (N_I). The total number of well modules equals the total system flow rate (Q) divided by the flow rate per injector (q_I). The total present value of well investments equals the total well costs divided by the production capacity (Y) multiplied by one plus the present value factor of future investments.

$$+ \text{ \$ for wells} = C_w N_I \quad (9.55)$$

$$+ N_I = Q/q_I \quad (9.56)$$

$$+ AT_{WD} = \frac{C_w (1 + \beta) Q}{Yq_I} \quad (9.57)$$

$$+ B_2 = \frac{C_w}{Yq_I} \quad (9.58)$$

- o Expressions for estimating the dollars per well module (C_w) are provided in terms of unit costs and ore body and wellfield dimensions for: surface drilling vertical wells; underground drilling vertical wells; and underground drilling for wells.

- + For surface drilling vertical wells it is assumed that one module contains two wells and the cost per well equals the product of the cost per foot of depth (C_{dT}) times the depth (D).

$$C_w = 2C_{dT}D \quad (9.59)$$

- + For drilling vertical wells from the underground it is assumed that one module contains two wells, and that the module costs include drilling vertical wells over a distance equal to the ore interval and mining costs for crosscuts. The unit cost of

vertical drilling from the underground is assumed to be equal to the unit cost for surface drilling (C_{dT}) multiplied by a factor ($\delta_{dT} > 1$) which reflects the increased cost of drilling large diameter holes from the underground.

$$- \$ \text{ for wells} = 2C_{dT} \delta_{dT} H \quad (9.60)$$

$$- \$ \text{ for crosscut} = 2V_x S \quad (9.61)$$

$$- C_w = 2[C_{dT} \delta_{dT} H + V_x S] \quad (9.62)$$

+ For drilling fan pattern wells from the underground it is assumed that one fan module contains the total wells per fan surface, and that module costs include drilling the wells and mining the cross cut

$$- \$ \text{ for wells} = N_{TF} C_{wf} h \quad (9.63)$$

$$- \$ \text{ for cross cut} = V_x d \quad (9.64)$$

$$- C_w = N_{TF} C_{wf} h + V_x d \quad (9.65)$$

o The hold-up costs associated with wellfield start-up are calculated by multiplying the time required to attain a one pore volume displacement of well pattern fluids (t_{WH}), by the total operating expense incurred over time t_{WH} , by the % of this time allocated to negative cash flow (E_H).

+ The hold-up time t_{WH} equals the total well pattern fluid volume in the pores divided by the system flow rate. V_w is the total well pattern volume

$$t_{WH} \text{ in years} = 1.42 \times 10^{-7} V_w (\phi/Q) \quad (9.66)$$

+ The total system well pattern volume (V_w) is related to production capacity (Y), well life (t_w), ore grade (F_c), and copper recovery ($E_s E_L E_R$)

$$V_w = \frac{2 \times 10^{11} Y t_w E_p}{E_s E_L E_R \rho_b (100 - \phi) F_c} \quad (9.67)$$

+ The total negative cash flow dollars are related to the hold-up time (t_{WH}), the operating cost per pound of copper (EP_o), and the % of the hold-up time (E_H) allocated to negative cash flow:

$$\$ \text{ negative cash flow} = 0.2 t_{WH} EP_o E_H Y \quad (9.68)$$

+ The total present value of the hold-up costs equals equation (9.68) divided by the production capacity Y multiplied by one plus the present value factor of future investments

$$- AT_{WH} = 5680 \left(\frac{E_P E_H}{E_S E_L E_R} \right) \left(\frac{Y t_w E P_o}{F_c \rho_b} \right) \left(\frac{\phi}{100-\phi} \right) \left[\frac{(1+\beta)}{Q} \right] \quad (9.69)$$

$$- AT_{WH} = B_3 (1+\beta)/Q \quad (9.70)$$

$$- B_3 = 5680 \left(\frac{E_P E_H}{E_S E_L E_R} \right) \left(\frac{Y t_w E P_o}{F_c \rho_b} \right) \left(\frac{\phi}{100-\phi} \right) \quad (9.71)$$

CHAPTER 10

WORKSHEET AND EXAMPLE CALCULATION
(BASED ON BASE CASE IN CHAPTER 8)

10.1 ASSUMED ORE BODY CHARACTERISTICS

- o Bottom of ore body 1,000 feet below the surface
+ $D = 1000'$
- o Top of ore body 700 feet below the surface
+ $D-H = 700'$
+ $H = 300'$
- o Average ore grade 1%
+ $F_c = 1\%$
- o Ore density 162 lb/ft³
+ $\rho_b = 162 \text{ lb/ft}^3$
- o Average ore permeability 2 md
+ $k = 2 \text{ md}$
- o Assume 1 centipoise viscosity
+ $\mu = 1 \text{ cp}$
- o Average ore porosity 5%
+ $\phi = 5\%$
- o Water gradient is 0.43 psi/ft
+ $a_w = 0.43 \text{ psi/ft}$
- o Fracture gradient is 1 psi/ft
+ $a_f = 1 \text{ psi/ft}$
- o Total ore reserves 250 million tons of rock
+ $T = 250 \times 10^6 \text{ tons}$
- o Copper mineralization is chrysocolla
+ $W_7 = 1.54 \text{ lb acid/lb copper}$
- o Gangue consumption 4 lb acid/lb copper
+ $W_4 = 4 \text{ lb/lb}$
- o Initial ore saturation is 80%
+ $s_w = 80\%$
+ Type i

10.2 ASSUMED DESIGN BASIS

- o Production rate of 25,000 TPY cathode
+ $Y = 25,000 \text{ tons per on stream year}$

- o Net copper loading increase per solvent pass through the ore 6 gpl copper
 - + $[C_u]_d = 6$ gpl copper
- o On stream plant operating time per year 333 days
 - + $E_p = 91.2\%$
- o Negative cash flow time based on wellfield start-up is one pore volume
 - + $E_H = 100\%$
- o Sweep efficiency per wellfield is 75%
 - + $E_s = 75\%$
- o Leach efficiency per wellfield is 75%
 - + $E_L = 75\%$
- o Solution recovery per wellfield is 90%
 - + $E_R = 90\%$
- o Plant life is 20 years
 - + $t_p = 20$ years
- o Deposit access is by surface drilling

In Chapter 9 it is shown that for the example ore body characteristics best mining scenario is likely to be surface drilling.

+ Type 1

- o Matrix modification and radial flow
 - + Type B
 - + $r_w = 8$ ft
- o Assume a 100 foot well spacing
 - + $S = 100$ feet

10.3 ASSUMED LEVELS OF SX/EW PROCESS PARAMETERS

- o $W_1 = 0.015$ m³ extractant/gpm/year
- o $W_2 = 0.085$ m³ diluent/gpm/year
- o $W_3 = 0.261$ Kg cobalt sulfate/ton cathode
- o $W_5 = 0.065$ ton anode/ton cathode
- o $W_8 = 0.2$ fraction
- o $W_9 = 0.231$ ton acid/ton cathode
- o $W_{12} = 0.571$ ton CaO/ton acid
- o $W_{13} = 2.43$ ton gypsum/ton CaO

- o $W_{15} = 1.36$ ton sulfate/ton acid (assume ferric sulfate)
- o $C_1 = 10,000$ $\$/m^3$ extractant
- o $C_2 = 300$ $\$/m^3$ diluent
- o $C_3 = 6.5$ $\$/Kg$ cobalt sulfate
- o $C_4 = 30$ $\$/ton$ acid
- o $C_5 = 185$ $\$/ton$ anode
- o $C_6 = 50$ $\$/ton$ C_aO
- o $C_7 = 0.02$ $\$/gallon$ water
- o $C_x = 2,500$ $\$/gpm$
- o $C_E = 650$ $\$/TPY$
- o $\eta = 70\%$ HP efficiency
- o $\eta_p = 70\%$ HP efficiency
- o $C_P = 150$ $\$/HP$
- o $x_1 = 5\%$ % of wellfield start-up costs applied for restoration
- o $C_{\bullet 1} = \$0.05/Kwhr$
- o $\alpha_9 = 2,333$ Kwhr/ton cathode
- o $\alpha_{10} = 6559.5$ Kwhr/HP-year

10.4 ASSUMED LEVELS OF ENVIRONMENTAL COST FACTORS

- o $EP_6 =$ initial permitting costs = \$444,500
- o Monitoring well installation
 - $C_{MA} = 1.37 \times 10^{-4}$ $\$/ft^2/ft$
 - $C_{MW} = 0.0917$ $\$/ft^2$
- o $EP_{EM} =$ annual monitoring cost = \$80,300
- o $x_1 = 1\%$ wellfield restoration cost, % wellfield hold-up cost

10.5 WELLFIELD SPECIFICATIONS

- o Equation numbers refer to source of calculation in the text. The flow regime for radial flow is subscript i equal to 3.
- o Total system flow rate

$$Q = \frac{0.456 \times 25,000}{6} = 1,900 \text{ gpm} \quad (C.1)$$

- o Flow rate per well

$$+ \Delta P_r = 1 \times (1,000 - 300) = 700 \text{ psi} \quad (\text{A.3})$$

$$+ G_3 = \frac{\pi \times 300}{\left[\ln \left(\frac{100}{8\sqrt{2}} \right) - .619 \right]} = 604.1 \quad (\text{A.6})$$

$$+ q_r = 3.34 \times 10^{-5} \times 2 \times 700 \times 604.1 = 28.25 \text{ gpm} \quad (\text{A.1})$$

- o Number of well units

$$N_r = \left[\frac{1,900 \times 1}{3.34 \times 10^{-5} \times 2 \times 700} \right] \left[\frac{1}{604.1} \right] = 67.3 \quad (\text{A.10})$$

Round off to $N_r = 67$

- o Total number of wells

$$N_w = 67 + \left(\sqrt{67 + 1} \right)^2 = 151.4 \quad (\text{A.11})$$

Round off to 151

+ For fan wells use (A.12)

- o Wellfield life

$$t_w = [4.06 \times 10^4][5551][3.08 \times 10^{-12}][3183][1.56] \quad (\text{A.16})$$

$$= 3.45 \text{ years}$$

Round off t_w to 4 years

The round off to higher whole year assures that maximum injection flow rate calculated above will not be exceeded.

+ Round off t_w to 4 years

+ Round off N_r to 78 to match new well life

$$N_r = \frac{4}{3.45} \times 67.3 = 78$$

+ Recalculating q_r for $N_r = 78$

$$q_r = \frac{1900}{78} = 24.36 \text{ gpm}$$

- o Plan area of the wellfield

$$A_w = [4.06 \times 10^4][10.6][1.56] = 671,361 \text{ ft}^2 \quad (\text{A.21})$$

- + Rounding off wellfield area for round off in wellfield life

$$A_w = 671,361 \times \frac{4}{3.45} = 780,000 \text{ ft}^2$$

- o Total wellfield leach area over plant life

$$A_{wt} = \frac{(25,000) 2 \times 10^{11} \times 20 \times 91.2}{(75 \times 75 \times 90 \times 1) (95) 162(300)} \quad (\text{A.28})$$

$$= 3.902 \text{ million ft}^2$$

- o Wellfield Residence Time

$$t_{wh} = 1.42 \times 10^{-9} \times 7.8 \times 10^5 \times 300 \times 5 \times \left[\frac{100}{1900} \right] \quad (\text{A.26})$$

$$= 0.087 \text{ years}$$

- o Number of wellfield replacements

$$N_{wr} = 20/4 - 1 = 4 \quad (\text{A.29})$$

Replacements in years 4, 8, 12, and 16 of operation

- o Wellfield water make-up requirements

$$GA = 7.48 \times 10^{-4} \times 7.8 \times 10^5 \times 300 \times 5(100-80) \quad (\text{A.27})$$

$$= 17.5 \times 10^6 \text{ gal}$$

10.6 WELL COST - \$57,891/INJECTOR, \$57,938/PRODUCER

- o Surface drilling

- + For vertical wells drilled from underground use calculation sequence in sections B.1 [(B.1), (B.2), (B.4), (B.6)] and B.3 [(B.35) through (B.56)]

- + For fan wells used calculation sequence in sections B.1 [(B.1), (B.3), (B.5), (B.7)] and B.4 [(B.58) through (B.59)]

- o Drill site development

$$C_A = \$2,400 \quad (\text{B.1})$$

o Well equipment (use Table B.2)

+ Production well recovery pump

$$- q_p = \frac{1900}{97} = 19.6 \text{ gpm} \quad (\text{B.10})$$

- well size is 4 inches

$$- \text{HP}_L = 3.61 \times 10^{-4} \times 19.6 \times (1,000 - 300) = 4.96 \text{ HP} \quad (\text{B.11})$$

$$- C_{RP} = 4.96(325 + 92) + 0 + (1,000-300)(1+.1) + 1,100 + 1811 = \$5,745 \quad (\text{B.12})$$

+ Tubing (use Table B.3)

$$C_{TP} = 5.41(1,000-300) = \$3,787 \quad (\text{B.13})$$

+ Packer (use Table B.4) for injection well

$$C_{PP} = 3,000 + (1,000-300) = \$3,700 \quad (\text{B.14})$$

+ Wellhead (use Table B.5)

$$C_{PW} = \$1,240 \quad (\text{B.15})$$

+ Injection well flow meter

$$C_{PM} = \$2,000 \quad (\text{C.16})$$

+ Total equipment cost injection well

$$C_{WEI} = \$3,787 + \$3,700 + \$1,240 + \$2,000 = \$10,727 \quad (\text{B.17})$$

+ Total equipment cost production well

$$C_{WEP} = \$5,745 + \$3,787 + \$1,240 = \$10,772 \quad (\text{B.18})$$

o Well drilling cost (use Table B.7)

$$C_d = 1,000(175/30) = \$5,833 \quad (\text{B.20})$$

o Well casing cost (use Table B.6)

$$C_c = 1,000(15 + 175/130 = 0.56) + 2045 = \$18,951 \quad (\text{B.19})$$

o Well cementing (use Table B.7)

$$C_{cm} = \left(\frac{\pi \times 1,000}{576} \right) (49 - 16)(15 + 4) + 1,425 = \$4,845 \quad (\text{B.21})$$

- o Well completion

- + Assume perforated completion

- + $C_p = 6(300) + 800 = \$2,600 = C_{cp}$ (B.24)

- o Well stimulation

- + Assume short radius hydraulic fracture

- + $C_{hs} = 2,500 + 14(300) = \$6,700 = C_{hm}$ (B.28)

- o Well logging

- + $C_{wl} = 3,135 + 2.7(1,000) = \$5,835$ (B.31)

- o Total injection well cost

- + $C_{ewi} = \$2,400 + \$10,772 + \$5,833 + \$18,951 + \$4,845$ (B.32)
 - + $\quad + \$2,600 + \$6,700 + \$5,835 = \$57,891$

- o Total production well cost

- + $C_{ewp} = \$2,400 + \$10,772 + \$5,833 + \$18,951 + \$4,845$ (B.33)
 - + $\quad + \$2,600 + \$6,700 + \$5,835 = \$57,938$

10.7 WELLFIELD COSTS

- o Wellfield well costs

- + $EW_w = 78(57,891) + 97(57,938) = \$10,135,404$ (B.34)

- + For vertical wells from underground (B.57)

- + For fan wells (B.60)

- o Wellfield water make-up costs

- + $EP_{ww} = 17.5 \times 10^6 \times 0.02 = \$350,000$ (B.62)

- o Total initial wellfield cost

- + $EW = \$10,135,404 + \$350,000 = \$10,485,404$ (B.64)

- + For vertical wells from underground (B.66)

- + For fan wells (B.68)

- o Wellfield restoration cost

- + $EP_{ws} = (5/100)(0.087)(13,371,330) = \$58,165$ (B.63)

- o Wellfield replacement cost

$$EW_{RP} = \$10,485,404 + \$58,165 = \$10,543,570 \quad (\text{B.65})$$

- + For vertical wells from underground (B.67)

- + For fan wells (B.69)

- o Lost copper production during start-up

$$T_{LH} = 0.087 \times 25,000 = 2,175 \text{ tons cathode} \quad (\text{B.61})$$

10.8 SURFACE FACILITIES SPECIFICATIONS AND COSTS

- o Overall material balance

- + Plant flow rate

$$Q = 0.456 \left(\frac{25,000}{6} \right) = 1,900 \text{ gpm} \quad (\text{C.1})$$

- + Acid injection concentration - gpl

$$[H_2SO_4] = [6](1.54 + 4) = 33.2 \quad (\text{C.2})$$

- + Unit total acid consumption - ton/ton copper

$$W_{10} = 4 + 1.54 \times 0.2 + 0.23 = 4.54 \quad (\text{C.3})$$

- + Unit lime consumption - ton/ton copper

$$W_6 = 0.571(1.54 \times 0.2 + 0.231) = 0.31 \quad (\text{C.4})$$

- + Solids content of bleed stream - ton sulfate/ton Cu

$$W_{14} = 2.43 \times 0.31 + 1.36 \times 4 = 6.19 \quad (\text{C.5})$$

- o Solution transfer

- + Wellfield/plant piping

From Table C.2 for 1,900 gpm use 10 inch nominal pipe diameter.

- o Interconnecting wellfield piping

- + Flow rate per injector row, 5-spot

$$q_{10} = (1,900 \times 24.36)^{1/2} = 215 \text{ gpm} \quad (\text{C.9})$$

- + From Table C.2 for 215 gpm use 4 inch nominal pipe diameter

- + Fan pattern use (C.10)

- o Pipe length

- + 5-spot pattern

- + $L_{TW} = 2 \times 100[2(78) + 2(78)^{1/2} + 1] = 34,932$ feet (C.12)

- + Fan pattern use (C.13)

- o Maximum surface pressure

$$P_{IS} = \left(\frac{1}{.43} - 1 \right) (1,000 - 300) = 928 \text{ feet of head} \quad (C.14)$$

- o Maximum lifting pressure

$$P_{PL} = 1000 - 300 \text{ feet} = 700 \text{ feet of head} \quad (C.15)$$

- o Horsepower for injection pumping

$$HP_I = 0.0252 \times 928(1,900/70) = 635 \text{ HP} \quad (C.16)$$

- o Horsepower for production pumping

$$HP_P = 0.0252 \times 700(1,900/70) = 479 \text{ HP} \quad (C.17)$$

- o Capital cost - \$22,559,475

- + SX/EW plant

$$EP_1 = 2,500 \times 1,900 + 650 \times 25,000 = \$21 \text{ million} \quad (C.18)$$

- + Injection pumps

$$EP_2 = 150 \times 637 = \$95,550 \quad (C.19)$$

- + Production pumps

- Included in well costs for vertical wells

- For fan wells (C.20)

- + Wellfield interconnecting piping

- From Table C.2 C_{PLW} equals \$25

$$EP_4 = 25 \times 34,932 = \$873,300 \quad (C.21)$$

- + Wellfield/plant piping

- From Table C.2 $C_{PLT} = \$62.5/\text{foot}$
 - Assume L_{TT} equals 6,000 feet

$$EP_5 = 62.5(6,000) = \$375,000 \quad (C.22)$$

+ Environmental Permitting

$$EP_6 = \$462,500 \quad (C.23)$$

+ Monitoring well

$$EP_7 = (1.37 \times 10^{-4} \times 1000 + 1.83 \times 10^{-4} \times 500)3.902 \quad (C.24)$$

$$\times 10^6 = \$894,692$$

+ Start-up cost of consumables

$$EP_8 = \$4,072,490/4 = \$1,018,120 \quad (C.25)$$

+ Total capital cost

$$EP_T = \$21,000,000 + \$95,550 + \$873,300 + \$375,000 \quad (C.26)$$

$$+ \$462,500 + \$894,690 + \$1,018,120 = \$24,701,178$$

o Staffing

$$ST = 2.4(25,000/1,000) + 32 = 92 \quad (C.31)$$

o Annual operating costs - \$13,697,259

+ Salaries

$$EP_1 = 1.746 \times 10^6 + 105 \times 25,000 = \$4,371,000 \quad (C.34)$$

+ Consumables

$$- EP_{c1} = (10,000 \times 0.015 + 300 \times 0.085)1,900 \quad (C.36)$$

$$= \$333,450$$

$$- EP_{c2} = (0.261 \times 6.5 + 30 \times 4.54 + 185 \times 0.065)25,000 \quad (C.37)$$

$$+ (50 \times 0.31)25,000 = \$4,135,540$$

$$- EP_c = (EP_{c1} + EP_{c2}) \left(\frac{91.2}{100} \right) = \$4,072,490 \quad (C.38)$$

+ Utilities

- Electricity

$$EP_E = 0.05[6,552.5(637 + 480) + 2,333 \quad (C.39)$$

$$\times 25,000] \left[\frac{91.2}{100} \right] = \$2,993,373$$

- Water

$$EP_W = 0.02[18,250 \times 92 + 68 \times 25,000 \times 0.912] \quad (C.40)$$

$$= \$64,588$$

- Total utilities
 $EP_u = \$3,057,960$
- + Contract maintenance
 - Surface plant
 $EP_{MS} = 0.03 \times 24,701,160 = \$741,040$ (C.41)
 - Wellfield, surface access
 $EP_{MW} = 0.1 \times 10,485,404 = \$1,048,540$ (C.42)
 - Total maintenance
 $EP_M = \$1,789,580$
- + Environmental monitoring
 $EP_{EM} = \$80,300$ (C.44)
- + Total annual operating cost
 $EP_o = \$4,371,000 + 4,072,490 + 3,057,960 + 1,789,580 + 80,300 = \$13,371,330$ (C.45)

10.9 SUMMARY OF CASH FLOW

- o Total initial capital investment - $\$35,186,564 = \$1407.5/AT$
- + Surface facilities
 $EP_T = \$24,701,178 = \$988.1/AT$ (C.26)
- + Wellfield wells
 $EW = \$10,485,404 = \$419.4/AT$ (B.34)
- o Plant construction requires three years
- o Wellfield construction requires 18 months
- o Annual operating cost each year, beginning 4th year
 $EP_o = \$13,371,330 = 26.7¢/lb$ copper (C.45)
- o Wellfield replacement well costs, including restoration cost
 - + $EW_{RP} = \$10,543,570 = \$421.7/AT$ (B.65)
 - + Incurred in year 6,7; 10,11; 14,15; 18,19
 - + 1/3 in year 6, 2/3 in year 7; etc. for others

- o Wellfield operating expenses for start-up and shut-down
 - + Lost production of 2,175 tons cathode in year (B.61)
4, 8, 12, 16, 20
 - + Restoration costs of \$58,165 in year 7, 11, 15, (B.63)
19, 23
- o Copper production for 333 day operating year
 - + Year of wellfield start-up (4, 8, 12, 16, 20)
- $25,000 \times (333/365) - 2,175 = 20,633$ tons cathode
 - + Year 2,4,6,8,10,12,14,16,18,20
- $25,000 \times (333/365) = 22,808$ tons cathode



CHAPTER 11
SUMMARY AND CONCLUSIONS

This design manual has been prepared to provide the user with a set of procedures to design a commercial facility for in situ leaching of a copper oxide deposit. Equations and algorithms have been developed and are included in this document which will permit the user to evaluate some 42 scenarios of ISL. These algorithms permit costing of the installation and operation of the facility and preparation of a cash-flow sheet in order to conduct an economic analysis for the project.

The text provides the user with an understanding of the concept of true in situ leaching and provides a discussion of all pertinent parameters associated with design and costing of wells, wellfield, surface facilities, and associated offsites. It discusses deposit characterization and procedures for obtaining deposit information. Because the ISL process is inter-disciplinary, the reference list includes many books, articles, reports, patents, and other documents which the user will find useful. These references include government, petroleum and mining engineering, metallurgical publications, newspaper articles, and patents.

The manual discusses the status of Federal, State, local agency regulations and requirements pertaining to the permit application process for an ISL copper operation in Arizona. Cost estimates for permitting and monitoring, are provided.

Site specific tests for obtaining the input data required to conduct a commercial design are described and discussed.

A computer model has been prepared and coded which integrates component specifications and costs with a DCF/ROR cash flow calculation. This model permits the user to make inputs which are converted to design elements and costs and generates outputs one of which is a pre-tax copper selling price.

A worksheet illustrating the use of the manual is provided in which design specifications and component costing are shown for an example ore body.

APPENDIX A

ALGORITHMS FOR WELLFIELD PERFORMANCE SPECIFICATIONS

A.1 SUMMARY OF ALGORITHMS

The algorithms used to calculate individual well flow rates, the number of wells, the operating life of a well pattern, the area of a wellfield, the wellfield fluid hold-up or residence time, the wellfield water make-up requirements, and the number of wellfield replacements are expressed as combinations of groupings of input parameters common to each well pattern type, and groupings of input parameters that are specific to a given well pattern type. Input parameters and parameters from other sections are listed in Table A.1.

A.1.1 Flow Rates Per Pattern

The flow rate per pattern is given by:

$$q_T = \left[\frac{C_o k \Delta P_T}{\mu} \right] G_i \quad (A.1)$$

$$C_o = 3.34 \times 10^{-5}, \left(\frac{\text{gpm}}{\text{ft}} \right) \left(\frac{\text{Cp}}{\text{md-psi}} \right) \quad (A.2)$$

$$\Delta P_T \leq a_f (D-H) \quad (A.3)$$

G_i geometric flow factor values for the four well pattern types are:

$$\circ \begin{array}{l} G_1 \text{ value for axial flow} \\ \text{horizontal fractures} \end{array} = \frac{S^2}{H_c} \quad (A.4)$$

$$\circ \begin{array}{l} G_2 \text{ value for axial flow} \\ \text{vertical fractures} \end{array} = \left(\frac{4HS_2}{S_1} \right) \quad (A.5)$$

TABLE A.1. WELL PATTERN PERFORMANCE SPECIFICATIONS
PARAMETER DIRECTORY

| <u>Input Parameter</u> | <u>Parameter From Other Section</u> |
|---|---|
| * μ = 1 centipoise | Q from C.1 |
| * r_w = 0.25 feet for 5-spot, 0.167 feet for fan well | |
| * H_c = 30 feet | |
| * h = 100 feet | |
| * d = 60 feet | |
| * E_s = 75% | |
| * E_L = 75% or from laboratory data | |
| * E_R = 90% | |
| * E_p = 91.2% | |
| * ρ_b = 162 lb/ft ³ | |
| * E_H = 100% | |
| * t_p = 20 years | |
| * a_f = between 0.7 and 1.0 psi/foot | |
| * θ = 1/10 radians | |
| π | |
| D = site specific | |
| H = site specific | |
| S = site specific | |
| S_2 = site specific | |
| S_1 = site specific | |
| Y = site specific | |
| k = site specific | |
| s_w = site specific | |
| F_c = site specific | |

* Recommended or typical values

$$o \quad G_3 \text{ value for radial flow} = \frac{\pi H}{\left[\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619 \right]} \quad (\text{A.6})$$

For the case of wellbore enlargement by small hydrofractures or borehole blasting, less than 10% of ore in stimulated zone $r_w = r_{ws} < 0.126S$ (A.7)

$$o \quad G_4 \text{ value for fan flow} = \frac{\left[\frac{\pi h}{2} \right] \left[\frac{1}{\left(\frac{d}{h} \right) \left(\frac{\pi}{4} \right) + \frac{\Theta}{\pi} \ln \left[\frac{h\Theta}{4r_w} \right]} \right]} \quad (\text{A.8})$$

+ For the combination of (d/h) and (Θ/π) that maximizes the flow rate per module per unit cost of the module, (Θ/π) = 1/10, or 11 wells per fan face, and (d/h) = 0.6

+ Drilling a fan well over 100 feet long is not practical

$$+ \quad G_4 = 192, \text{ for } r_w = 0.167 \text{ and } h = 100 \text{ feet} \quad (\text{A.9})$$

A.1.2 Number of Wells and Well Units

The number of well units is given by:

$$N_I = \left[\frac{Q_u}{C_o k \Delta P_T} \right] \left[\frac{1}{G_i} \right] \quad (\text{A.10})$$

The number of wells is given by (A.11) for G_1, G_2, G_3 (5-spot):

$$N_w = N_I + \left[\sqrt{N_I} + 1 \right]^2 \quad (\text{A.11})$$

The number of wells is given by (A.12) for G_4 (fan pattern):

$$N_w = N_I N_{TF} \quad (\text{A.12})$$

$$N_{HV} = \text{number of vertical units} = H/h \quad (\text{A.13})$$

$$N_{HC} = \text{number of cross cuts per vertical unit} = (N_I)^{1/2} \left(\frac{d}{2H} \right)^{1/2} \quad (\text{A.14})$$

$$N_{HF} = \text{number of fans per cross cut} = (N_I)^{1/2} \left(\frac{2h^2}{dH} \right)^{1/2} \quad (\text{A.15})$$

A.1.3 Wellfield Life

Well pattern life is expressed by:

$$t_w = \left[\frac{Q\mu}{C_o k \Delta P_t} \right] \left[\frac{E_s E_L E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{11} \times Y} \right] [X_i] \quad (\text{A.16})$$

- o X_1 = for axial flow from horizontal fractures

$$X_1 = H_c H \quad (\text{A.17})$$

- o X_2 = value for axial flow in vertical fractures

$$X_2 = S_1^2 / 4 \quad (\text{A.18})$$

- o X_3 = value for radial flow

$$X_3 = \frac{S^2}{\pi} \left[\ln \left(\frac{S}{\sqrt{2r_w}} \right) - .619 \right] \quad (\text{A.19})$$

- o X_4 = value for fan flow

$$X_4 = \left[\frac{4hd}{\pi} \right] \left[\left(\frac{d}{h} \right) \left(\frac{\pi}{4} \right) + \left(\frac{\theta}{\pi} \right) \ln \left(\frac{h\theta}{4r_w} \right) \right] \quad (\text{A.20})$$

$$X_4 = 6237, \text{ for } h = 100 \text{ feet } d = 60 \text{ ft see page 58 and minimum cost fan module}$$

A.1.4 Wellfield Plan Area

The wellfield area (A_w) is given by:

$$A_w = \left[\frac{Q\mu}{C_o k \Delta P_T} \right] [R_i] \quad (\text{A.21})$$

- o R_1 = value for axial flow horizontal fractures

$$R_1 = H_c \quad (A.22)$$

- o R_2 = value for flow between vertical fractures

$$R_2 = \left[\frac{S_1^2}{4H} \right] \quad (A.23)$$

- o R_3 = value for radial flow

$$R_3 = \frac{S^2}{\pi H} \left[\ln \left(\frac{S}{\sqrt{2r_w}} \right) - .619 \right] \quad (A.24)$$

- o R_4 = value for fan pattern flow

$$R_4 = \left[\frac{4dh}{\pi H} \right] \left[\frac{d\pi}{h4} + \frac{\Theta}{\pi} \ln \left(\frac{h\Theta}{4r_w} \right) \right] \quad (A.25)$$

$$R_4 = \frac{6237}{H}, \text{ for } h = 100 \text{ feet } d = 60 \text{ feet see page 59 and minimum cost fan module}$$

A.1.5 Wellfield Residence Time

This is the time required to displace one pore volume of well pattern fluid.

$$t_{wH} = 1.42 \times 10^{-9} [A_w H \phi] \left[\frac{E_H}{Q} \right] \quad (A.26)$$

A.1.6 Wellfield Water Make-up Requirements

This is the gallons of water required to saturate the well pattern pore volume.

$$GA = 7.48 \times 10^{-4} (A_w H \phi) (100 - s_w) \quad (A.27)$$

A.1.7 Total Wellfield Plan Area For Plant Life

$$A_{WT} = \left[\frac{2 \times 10^{11} \times Y t_P}{(100 - \phi) \rho_b H} \right] \left[\frac{E_P}{E_S E_L E_R F_C} \right] \quad (A.28)$$

A.1.8 Number of Wellfield Replacements

The number of wellfield replacements equals the plant life divided by the well life minus one.

$$N_{WR} = (t_P / t_W) - 1 \quad (A.29)$$

A.2 AXIAL FLOW HORIZONTAL FRACTURES

Basic assumptions include: five spot pattern; fractures overlap completely; ΔP in fractures is negligible; and no fluid loss from pattern.

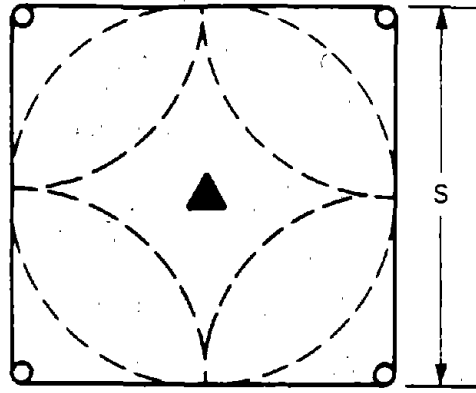
The flow rate is calculated using Darcy's law for linear flow between two equipotential planes separated by distance H_c over an area S^2 , see Figure A-1.

$$q_I = \left[\frac{C_o k \Delta P_T}{u} \right] \left[\frac{S^2}{H_c} \right] \quad (A.30)$$

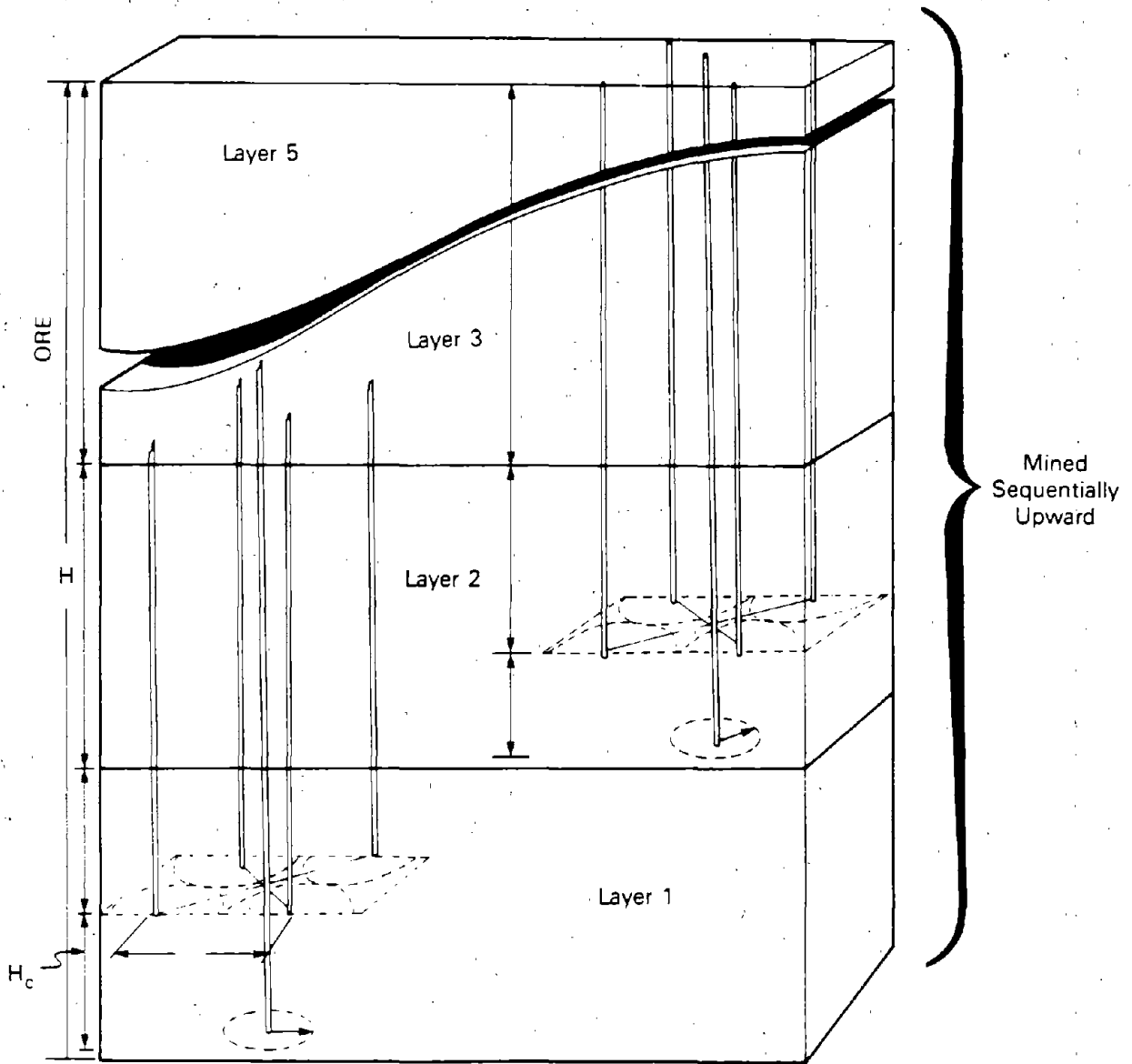
The number of patterns in operation is given by the system flow rate divided by the injection rate per well.

$$N_I = Q / q_I \quad (A.31)$$

Since the total ore thickness (H) is normally much greater than the distance between fractures, the method of leaching between fractures can be repeated vertically in a given 5-spot pattern in increments of H_c in thickness.



Plan View
Horizontal Fractures



Vertical View
Horizontal Fractures

Figure A-1. Axial Flow Horizontal Fractures

Let N_v = Number of vertical intervals to be leached in a five spot
(average over whole deposit)

$$N_v = H/H_c \quad (A.32)$$

The wellfield surface area is calculated as the product of the area per well module and the total number of modules.

$$A_w = \left(\frac{Q}{q_I} \right) S^2 = \left[\frac{Qu}{C_o k \Delta P_T} \right] [H_c] \quad (A.33)$$

The life of a well module (t_w) can be calculated from the on stream production time (E_p % on stream) and a material balance between copper in the ground and total copper to be produced over the well life.

$$\frac{Y t_w E_p}{100} = \frac{H A_w E_L E_s E_R (100/\phi) \rho_b F_c}{2 \times 10^{13}} \quad (A.34)$$

Solving for t_w after substituting for A_w :

$$t_w = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\frac{E_L E_s E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{13} \times Y} \right] [H_c] \quad (A.35)$$

The total number of wells in a square five spot are related to the number of injection wells by (A.36).

$$N_w = N_I + \left(\sqrt{N_I} + 1 \right)^2 \quad (A.36)$$

This relationship also provides an adequate representation for non-symmetric five spot geometries, see Figure A-2.

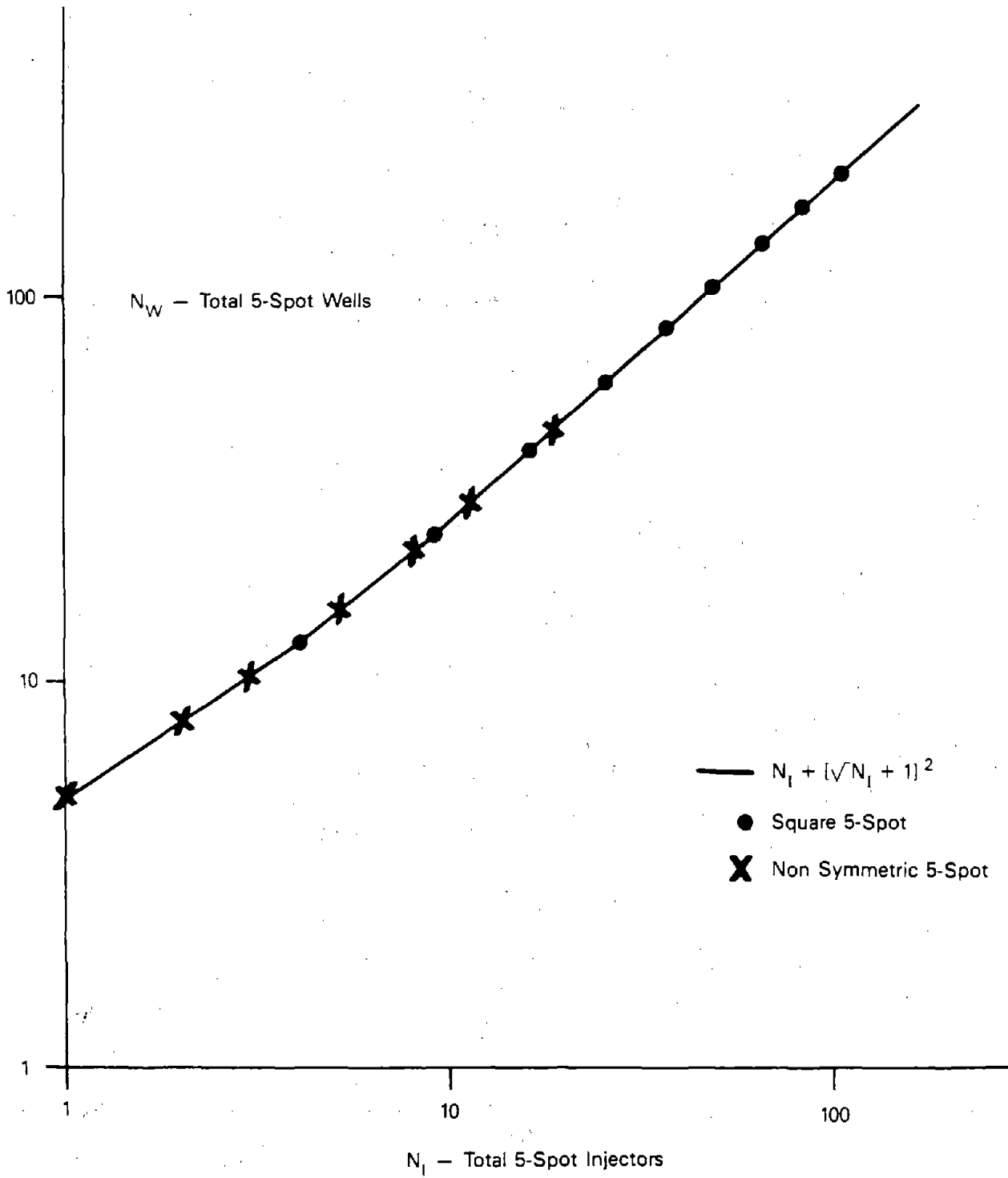


Figure A-2. Total Wells Versus Number of Injectors 5-Spot

A.3 AXIAL FLOW VERTICAL FRACTURES

In this case a square pattern is likely not to provide the maximum flow rate. A rectangular geometry for the well pattern is considered with dimensions S_1 and S_2 . S_2 is the spacing along the fractures, S_1 is the spacing perpendicular to the fractures. The flow rate is calculated using Darcy's Law for flow between equipotential planes separated by S_1 with flow normal to area (S_2H), see Figure A-3. Basic assumptions are: fractures form vertically and parallel; no ΔP in fractures; no fluid loss from pattern; and the pattern is a staggered line drive.

$$q_I = 2 \left[\frac{C_o k \Delta P_I}{u} \right] \left[\frac{2S_2 H}{S} \right] \quad (A.37)$$

$$q_I = \left[\frac{C_o k \Delta P_I}{u} \right] \left[\frac{4HS_2}{S_1} \right] \quad (A.38)$$

The number of well patterns is calculated by dividing the total system flow rate by the flow rate per injector.

$$N_I = \left[\frac{Qu}{C_o k \Delta P_I} \right] \left[\frac{S_1}{4HS_2} \right] \quad (A.39)$$

The total number of wells is calculated using (A.36).

The total wellfield plan area is calculated as the product of the area of one well module ($S_1 S_2$) and the total number of modules [Q/q_I].

$$A_w = [S_1 S_2] [Q/q_I] \quad (A.40)$$

$$A_w = \left[\frac{Qu}{C_o k \Delta P_I} \right] \left[\frac{S_1^2}{4H} \right] \quad (A.41)$$

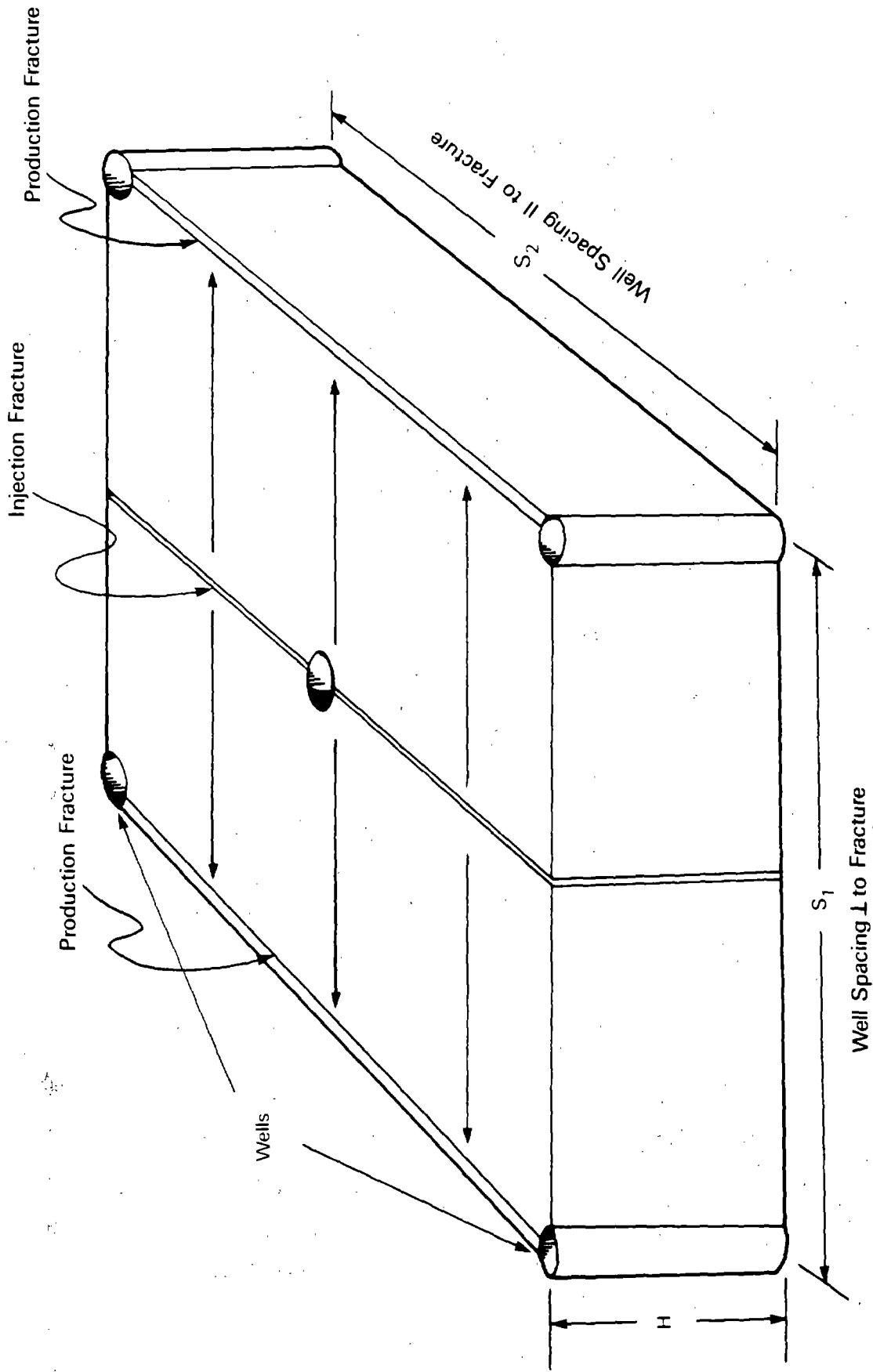


Figure A-3. Axial Flow Vertical Fracture

The procedure for calculating the life of the well module is the same as that used in section A.2, and is based on a material balance between copper produced and copper initially in place in the deposit within one well module.

$$(Yt_w) (E_p/100) = \frac{H A_w E_L E_s E_R (100-\phi) \rho_b F_c}{2 \times 10^{13}} \quad (\text{A.42})$$

Substituting for A_w :

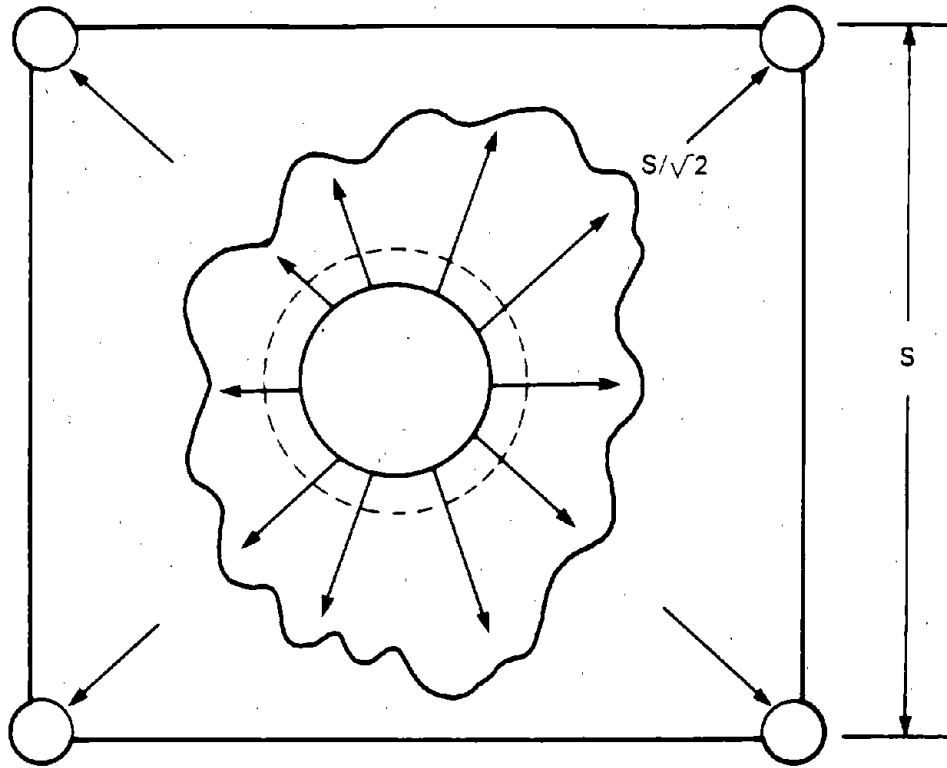
$$t_w = \left[\frac{Qu}{C_o k \Delta P_r} \right] \left[\frac{E_L E_s E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{11} \times Y} \right] \left[\frac{S_1^2}{4} \right] \quad (\text{A.43})$$

A.4 RADIAL FLOW

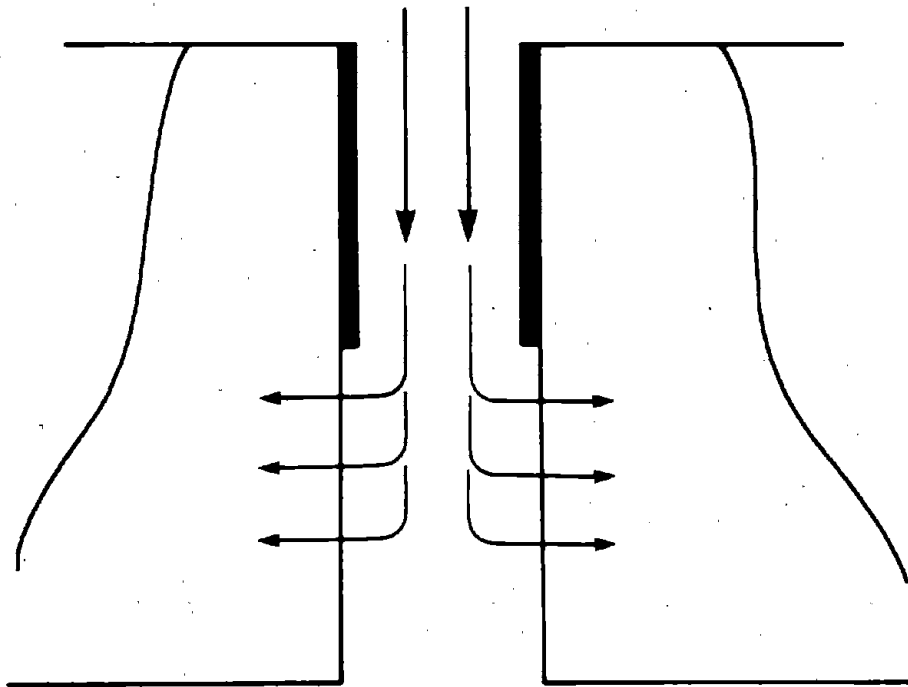
The flow rate is calculated by applying Darcy's Law to radial flow in a confined five spot, see Figure A-4. Basic assumptions are steady state and a confined five spot pattern.

$$q_r = \left[\frac{C_o k \Delta P_r}{u} \right] \left(\frac{\pi H}{\ln \left(\frac{S}{\sqrt{2} r_w} \right) - 0.619} \right) \quad (\text{A.44})$$

The flow in a radial pattern may be improved by stimulation, which can take the form of short propped hydraulic fractures (any orientation). Alternatively, borehole blasting may be used to obtain a rubblelized and a highly fractured zone around the wellbore. The increase in flow rate is accounted for by assuming infinite permeability from r_w to r_{ws} (the stimulated radius). The value of r_w used in (A.44) is r_{ws} . It is understood that r_{ws} is less than 12.6% of S to ensure that the stimulated zone contains less than 10% of the copper in the wellfield.



Vertical View
Radial Flow



Plan View
Radial Flow

Figure A-4. Radial Flow

For a fixed value of r_{ws} the well spacing S should be greater than 7.9 times r_{ws} .

The number of required injection units is $N_I = Q/q_I$, or:

$$N_I = Q/q_I = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\frac{\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619}{\pi H} \right] \quad (A.45)$$

The total number of wells are obtained from (A.36).

The area of all well modules (A_w) is calculated by taking the product of the number of well modules (N_I) and the area per module (S^2).

$$A_w = N_I S^2 \quad (A.46)$$

Substituting for N_I from (A.44):

$$A_w = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619 \right] \left[\frac{S^2}{\pi H} \right] \quad (A.47)$$

The well life is calculated by making a material balance between produced copper and copper initially in place.

$$(Y t_w)(E_p/100) = (A_w H)(E_L E_S E_R F_c) \left(\frac{(100-\phi) \rho_b}{2 \times 10^{13}} \right) \quad (A.48)$$

Solving for t_w and substituting for A_w :

$$t_w = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\frac{E_L E_S E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{13} \times Y} \right] \left[\frac{S^2}{\pi} \right] \left[\ln \left(\frac{S}{\sqrt{2} r_w} \right) - .619 \right] \quad (A.49)$$

A.5 FAN PATTERN

Fan patterns are drilled from underground crosscuts, see Figure A-5. In this pattern fluid injected along wells on one face (A) is made to flow to a second face (B) where it is collected by another set of wells. The total pressure drop can be divided into three components:

- o Radial flow in the injection drill hole from the wellbore radius to some effective drainage radius r_o , with associated pressure drop ΔP_1 .
- o Linear flow, straight line between fan faces, with associated pressure drop ΔP_2 .
- o Radial flow into the production drill hole from a drainage radius r_o to the wellbore r_w , with associated pressure drop ΔP_1 .

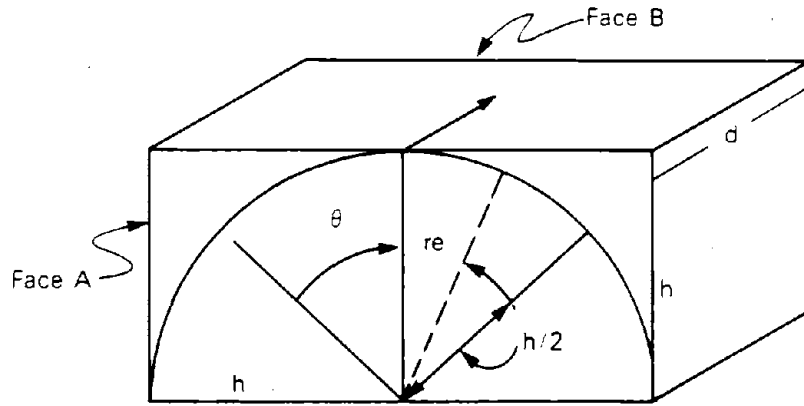
It is assumed that the fan patterns are repeated (joined together) many times, thus the flow rate between fans is $q_f/2$.

Nomenclature used to describe fan flow is listed below:

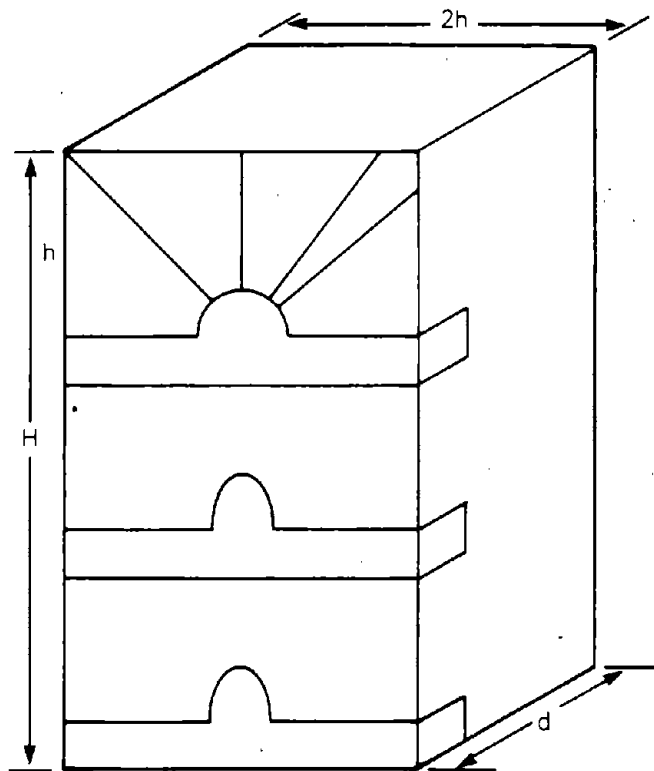
- o q_f = Flow rate per fan
- o q_{dh} = Flow rate per drill hole
- o Θ = Angle between drill holes in fan pattern
- o h = Length of each well
- o d = Distance between fan faces

The radial flow rate at injection and production pressure drop (ΔP_1) is given by:

$$q_{dh} = \frac{C_o 2 \pi k h \Delta P_1}{u \ln(r_o/r_w)} \quad (A.50)$$



One Fan Module



**Vertical Stacking
of Fan Modules**

Figure A-5. Fan Pattern Flow

For flow between fans at pressure drop ΔP_2 , where the flow is divided between fans is:

$$q_f/2 = \frac{C_o 2h^2 k \Delta P_2}{u d} \quad (\text{A.51})$$

$$\pi/\Theta = \text{number of flow sectors per face} \quad (\text{A.52})$$

$$\frac{q_f}{2} = (\pi/\Theta) (q_{dh}) \quad (\text{A.53})$$

$$q_{dh} = \frac{q_f \Theta}{2\pi} \quad (\text{A.54})$$

Substituting for q_{dh} in the radial flow equation (A.50):

$$q_f = \frac{2(\pi)^2 C_o kh \Delta P_1}{\Theta u \ln(r_e/r_w)} \quad (\text{A.55})$$

Summing the three pressure drops to obtain an expression between total pressure drop (ΔP_T) and well module flow rate (q_f):

$$\Delta P_T = 2\Delta P_1 + \Delta P_2 \quad (\text{A.56})$$

$$\Delta P_T = \frac{q_f \Theta u \ln(r_e/r_w)}{2\pi^2 C_o kh} + \frac{q_f u d}{C_o (2h)^2 k} \quad (\text{A.57})$$

$$\Delta P_T = \left[\frac{q_f u}{C_o \pi kh} \right] \left[\frac{\Theta}{\pi} \ln(r_e/r_w) + \frac{\pi d}{4h} \right] \quad (\text{A.58})$$

It is assumed that the drainage radius r_e is equal to half the arc length between wells at half the well distance:

$$r_e = \left(\frac{h}{2} \right) \left(\frac{\Theta}{2} \right) \quad (\text{A.59})$$

$$q_f = \left[\frac{C_o k \Delta P_T}{\mu} \right] \left[\frac{\pi h}{2} \right] \left[\frac{1}{\frac{\pi d}{4h} + \frac{\Theta}{\pi} \ln \left(\frac{h\Theta}{4r_w} \right)} \right] \quad (\text{A.60})$$

The number of vertical units is given by:

$$N_{HV} = H/h \quad (\text{A.61})$$

The number of fan patterns needed for development is:

$$N_I = Q/q_f \quad (\text{A.62})$$

$$N_I = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\frac{2}{\pi h} \right] \left[\left(\frac{d}{h} \right) \left(\frac{\pi}{4} \right) + \frac{\Theta}{\pi} \ln \left(\frac{h\Theta}{4r_w} \right) \right] \quad (\text{A.63})$$

It is assumed that the area of the crosscut is square, such that the total distance between crosscuts equals the total distance along a crosscut. This provides the following relationship between the number of crosscuts (N_{HC}) and the number of fan units per crosscut (N_{HF}).

$$(N_{HC}) (2h) = (N_{HF}) (d) \quad (\text{A.64})$$

$$N_{HF} = N_{HC} (2h/d) \quad (\text{A.65})$$

The number of crosscuts (N_{HC}) is obtained by equating the total number of units (N_I) to the product of the number of vertical units (N_{HV}), the number of crosscuts (N_{HC}), and the number of fans per crosscut (N_{HF}).

$$N_I = (N_{HV}) (N_{HC}) (N_{HF}) \quad (\text{A.66})$$

From (A.66), (A.61), and (A.65):

$$N_{HC} = (N_I)^{1/2} \left(\frac{d}{2H} \right)^{1/2} \quad (\text{A.67})$$

From (A.63) and (A.66):

$$N_{HF} = (N_I)^{1/2} \left(\frac{2h^2}{dH} \right)^{1/2} \quad (A.68)$$

The well module plan area (A_w) is calculated by multiplying the area per module ($2dh$) by the number of modules per layer $N_I \left(\frac{h}{H} \right)$.

$$A_w = \left[\frac{Qu}{C_o K \Delta P_T} \right] \left[\frac{4dh}{\pi H} \right] \left[(d/h)(\pi/4) + (\Theta/\pi) \ln \left(\frac{h\Theta}{4r_w} \right) \right] \quad (A.69)$$

The well life is calculated by making a material balance between produced and in-place copper recovery.

$$(Yt_w)(E_p/100) = \left[A_w H \right] \left[E_s E_L E_R F_c \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{13}} \right] \quad (A.70)$$

Solving for t_w and substituting for A_w from (A.68):

$$t_w = \left[\frac{Qu}{C_o k \Delta P_T} \right] \left[\frac{E_s E_L E_R F_c}{E_p} \right] \left[\frac{(100-\phi) \rho_b}{2 \times 10^{11} \times Y} \right] \left[\frac{4hd}{\pi} \right] \left[\left(\frac{\pi d}{4h} \right) + \left(\frac{\Theta}{\pi} \right) \ln \left(\frac{h\Theta}{4r_w} \right) \right] \quad (A.71)$$

The following discussion addresses the cost optimization of the flow rate per module q_f with regard to the number of wells per fan face and the separation of fan faces. The flow rate can be increased by either increasing the number of wells per module (decreasing Θ), which also increases the cost of the module, or by reducing d . The latter requires more modules per cross cut, which also increases cost. A minimum cross cut cost per unit flow rate is sought.

V_x = cost to excavate crosscut, \$/foot

C_{wf} = cost to drill and complete one fan well, \$/foot

M = unit cost of mining and wells per unit flow rate

$$\text{Mining and well costs} = \frac{[C_{wf} h(\pi/\Theta + 1) + V_x d]}{d} \quad \text{per foot of cross cut} \quad (\text{A.72})$$

$$M_o = \frac{2V_x \mu}{\pi h C_o k \Delta P_T} \quad (\text{A.73})$$

$$b_1 = C_{wf} / V_x \quad (\text{A.74})$$

$$x = h/d \quad (\text{A.75})$$

$$y = \Theta/\pi \quad (\text{A.76})$$

$$b_2 = \frac{\pi h}{4r_w} \quad (\text{A.77})$$

$$M = (M_o) [b_1 x (1/y + 1) + 1] \left[y \ln(b_2 y) + \frac{\pi}{4x} \right] \quad (\text{A.78})$$

A parametric analysis of M divided by M_o was conducted to identify optimum values of x and y at a cost ratio of 15-to-1 (V_x divided by C_{wf}). This data is summarized in the Table A.2 below and plotted in Figure A.6, which indicates an optimum at Θ/π equal to 10 (11 wells per face) and d equal to 60 feet. In addition, the value of M/M_o is not very sensitive to changes in Θ and d around the optimum values.

TABLE A.2. PARAMETRIC ANALYSIS TO OPTIMIZE FAN DESIGN

$h = 100$ feet
 $r_w = 0.167$ feet

$V_x = \$300/\text{foot}$
 $C_{wf}^x = \$20/\text{foot}$

| Θ | y | $d = 30'$ | $d = 40'$ | $d = 50'$ | $d = 60'$ | $d = 70'$ | $d = 80'$ |
|----------|-------|-----------|-----------|-----------|-----------|-----------|-----------|
| $\pi/6$ | 0.165 | 2.45 | 2.25 | 2.16 | 2.12 | 2.12 | 2.14 |
| $\pi/8$ | 9.124 | 2.23 | 2.06 | 1.96 | 1.96 | 1.96 | 1.99 |
| $\pi/9$ | 0.108 | 2.16 | 2.00 | 1.94 | 1.92 | 1.93 | 1.95 |
| $\pi/10$ | 0.099 | 2.13 | 1.98 | 1.92 | 1.91 | 1.91 | 1.94 |
| $\pi/12$ | 0.083 | 2.10 | 1.96 | 1.91 | 1.80 | 1.92 | 1.95 |
| $\pi/15$ | 0.067 | 2.12 | 1.99 | 1.95 | 1.95 | 1.97 | 2.00 |
| $\pi/20$ | 0.051 | 2.22 | 2.11 | 2.08 | 2.08 | 2.11 | 2.15 |

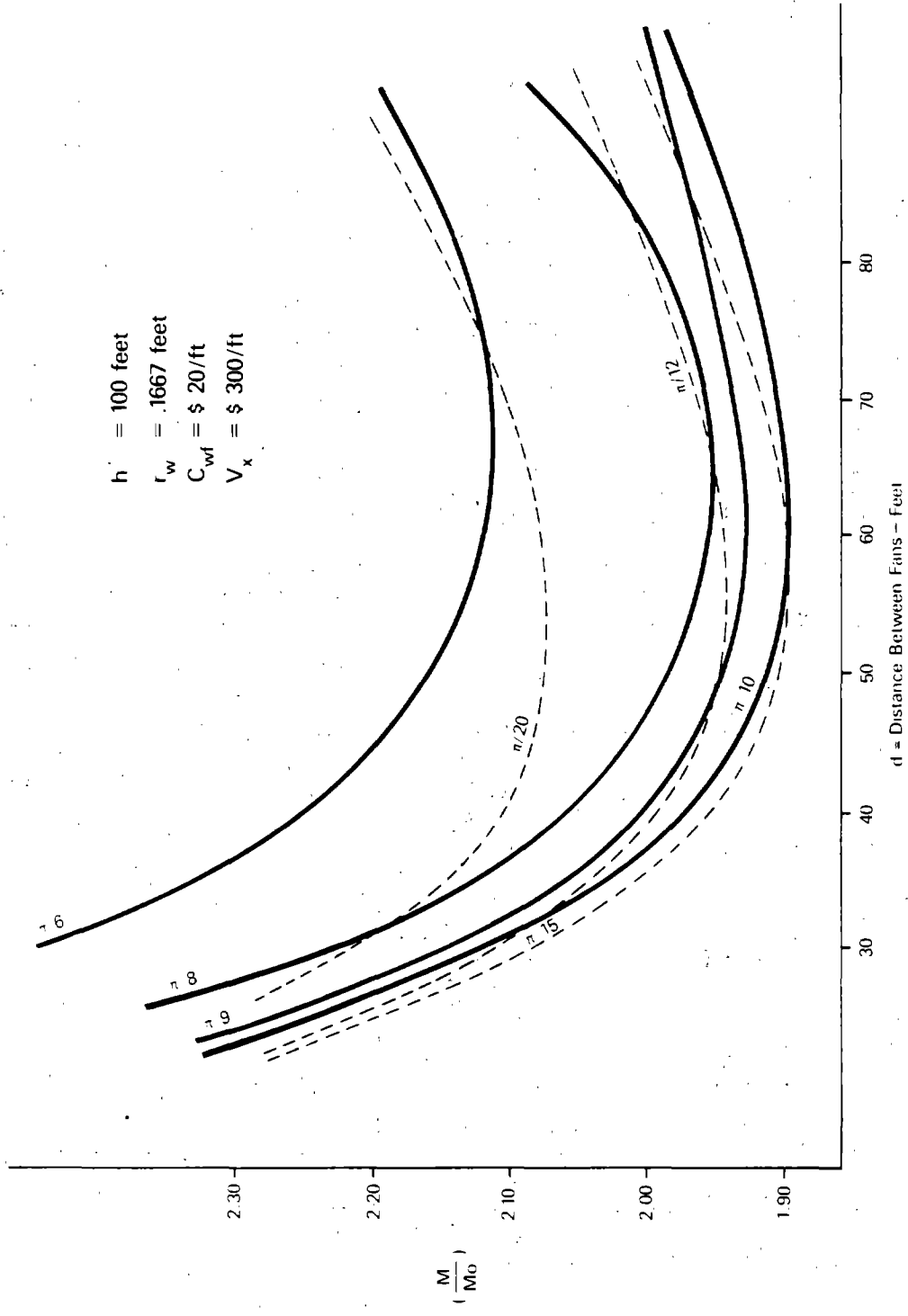


Figure A-6. Minimizing Fan Costs

APPENDIX B. ALGORITHMS FOR COSTING SUB-SURFACE COMPONENTS

The cost data base used to develop all sub-surface cost algorithms is summarized in this section. These algorithms are categorized by: costing of underground development (shafts, raises, drifts, and crosscuts); costing of vertical wells drilled from the surface; costing of vertical wells drilled from the underground; costing of fan wells; and costing of wellfields. Table B.1 lists input parameters used in this section and those obtained from other sections.

B.1 UNDERGROUND WORKINGS

- o Mine plant for underground workings

$$EM = \$2,500,000 \quad (B.1)$$

- o Shaft, raise, drift access development vertical wells

- + 2 shafts
- + 1 raise
- + 2,000 feet of drift = DR

$$ES_A = (2C_s + C_r)(D-H) + DR C_{da} \quad (B.2)$$

- o Shaft, raise, drift access development for fan wells

- + 2 shafts
- + 1 raise
- + 2000 feet of drift = DR

$$ES_A = (2C_s + C_r) D + DR C_{da} \quad (B.3)$$

- o Wellfield crosscut costs - \$

This cost is incurred each time a new wellfield is added

- + Vertical wells

$$EW_c = [2(Q/q_r) + (Q/q_r)^{1/2}]SV_x \quad (B.4)$$

- + Fan pattern

$$EW_c = (Q/q_r)dV_x \quad (B.5)$$

Table B.1 Sub-Surface Facility Parameter Directory

| <u>Input parameter</u> | <u>Parameter from other section</u> |
|---|-------------------------------------|
| *C _s = \$3000/ft | Q from C.1 |
| *C _r = \$1000/ft | q _i from A.1 |
| *C _{da} = \$300/ft | *d from A.1, 60 feet |
| *V _x = \$300/ft | *N _{TF} from A.1, 11 wells |
| *C _A = \$2400 | t _{WH} from A.1 |
| Y = site specific | A _w from A.1 |
| *C _{wfI} = \$30/ft | |
| *C _{wfP} = \$10/ft | |
| D = site specific | |
| H = site specific | |
| S = site specific | |
| S ₂ = site specific | |
| s _w = site specific | |
| φ = site specific | |
| *h = 100 feet | |
| *M _x , B _{xq} , B _{RPW} , B _{RPC} see Table B.2 | *R _{CS} = 130 ft/hr |
| *B _t see Table B.3 | *B _{RCs} = \$1425/well |
| *B _K , B _I see Table B.4 | *B _{PS} = \$800/well |
| *B _h see Table B.5 | *B _{EXS} = \$2800/well |
| *B _c see Table B.6 | *B _{SRS} = \$2500/well |
| *B _d , R _d , B _w , d _c , d _H see Table B.7 | *B _{LRS} = \$5000/frac |
| *B _g between \$10/ft ³ and \$20/ft ³ | *B _{FWL} = \$3135/well |
| *C ₇ = 2¢/gallon | *B _{FCU} = \$5000 |
| x ₁ = 5% | *B _{EXU} = \$3600 |
| *B _{SRU} = \$5600/well | *DR = 2000 ft |
| *B _{WLT} = \$0.1/ft | *B _{WC} = \$2045/well |
| *B _{PI} = \$1811/PUMP | *C _{AU} = \$5000/well |

*Recommended or typical values

o Wellfield drift costs - \$

This cost is incurred each time a new wellfield is added

+ Vertical wells

$$EW_d = 2(Q/q_T)^{1/2} SC_{da} \quad (B.6)$$

+ Fan pattern

$$EW_d = 4(Q/q_T) \left(\frac{d}{2H} \right)^{1/2} HC_{da} \quad (B.7)$$

B.2 VERTICAL WELL DRILLED FROM THE SURFACE

o Drill site development - \$/well

$$C_A = \$2400 \quad (B.8)$$

o Well equipment costs - \$/well

+ Recovery pump cost - data for constants are listed in Table B.2.

$$- N_p = [N_I^{1/2} + 1]^2 \quad (B.9)$$

$$- q_p = Q/N_p \quad (B.10)$$

$$- HP_L = 3.61 \times 10^{-4} q_p (D-H) \quad (B.11)$$

$$- C_{RP} = (HP_L)(M_x + 92) + B_{xq} + (D-H)(B_{RPW} + B_{WLT}) \\ + B_{RPC} + B_{PI} \quad (B.12)$$

+ Tubing cost - Data for constants are listed in Table B.3

$$C_{TP} = B_t (D-H) \quad (B.13)$$

+ Packer cost - Data for constants are listed in Table B.4

$$C_{PP} = B_k + B_I (D-H) \quad (B.14)$$

+ Wellhead cost - Data for constants are listed in Table B.5

$$C_{PW} = B_h \quad (B.15)$$

+ Injection well flow meter

$$C_{PM} = \$2,000 \quad (B.16)$$

TABLE B.2. DOWNHOLE PUMP COSTS COMPONENT COSTS

| Well Size (in) | M_x | B_{xq} | B_{spw} Electric Cable \$/FT | B_{spc} Electric Controls (\$) | Approx. Flowrate Range (gpm) |
|----------------|-------|----------|--------------------------------------|--|------------------------------|
| 4 | 325 | 0 | 1 | 1100 | 0 - 55 |
| 6 | 70 | 500 | 3 | 1300 | 50 - 100 |
| 8 | 102 | 1000 | 5 | 2500 | 100 - 300 |

TABLE B.3. TUBING SPECIFICATIONS AND COSTS

| Nominal O.D. (in) | Max O.D. (in) | I.D. (in) | Internal Press. (psi) | Tensile Rating (lb) | B_t Approx. Cost/FT (\$) | Flowrate Range (gpm) | Friction Loss Per 100' (psi) |
|-------------------|---------------|-----------|-----------------------|---------------------|-------------------------------|----------------------|------------------------------|
| 2 3/8 | 3.8 | 1.92 | 2500 | 17,000 | 5.41 | 0-55 | 0-2.3 |
| 2 7/8 | 4.6 | 2.42 | 2500 | 21,200 | 7.35 | 50-100 | 0.9-2.5 |
| 4 1/2 | 7.3 | 4.04 | 2500 | 48,000 | 15.80 | 100-300 | 0.3-2.7 |

TABLE B.4. PACKER SPECIFICATIONS AND COSTS

| Casing Size, I.D. (in) | Packer I.D. (in) | Uninflated O.D. (in) | Differential Pressure Rating (psi) | B_p Packer Cost. (\$) 316ss | B_i Inflation Tube Cost (\$/ft) |
|------------------------|------------------|----------------------|------------------------------------|-------------------------------------|--------------------------------------|
| 4" | 1.25 | 3.5 | 2000+ | 3000 | 1.00 |
| 6" | 2.0 | 5.25 | 2000 | 5000 | 1.00 |
| 8" | 2.5 | 6.5 | 2000 | 7000 | 1.00 |

TABLE B.5 WELLHEAD SPECIFICATION AND COSTS

| Well Casing Size (in) | B_{CH} Casing Head (\$) | | B_{WH} Wellhead Equip. \$ | | B_n Total \$ |
|-----------------------|---------------------------|---|-----------------------------|---|----------------|
| 4 | 540 | + | 700 | = | 1,240 |
| 6 | 540 | + | 700 | = | 1,240 |
| 8 | 712 | + | 1,000 | = | 1,712 |

TABLE B.6. WELL CASING COSTS

| Casing Well Size (in) | B_C Casing Cost (\$/Ft) | B_B Centralizers (\$/ft) | B_F Float Valve (\$) | | B_S Float Shoe (\$) | | B_{CC} Conductor Casing (\$) | | B_P Pup Joints (\$) | | B_{WC} Total Fixed Cost (\$)/Well |
|-----------------------|---------------------------|----------------------------|------------------------|---|-----------------------|---|--------------------------------|---|-----------------------|---|-------------------------------------|
| 4 | 15.00 | 0.56 | 180.00 | + | 265.00 | + | 200.00 | + | 1,400.00 | = | 2,045 |
| 6 | 26.00 | 0.56 | 180.00 | + | 265.00 | + | 200.00 | + | 1,400.00 | = | 2,045 |
| 8 | 35.00 | 0.56 | 180.00 | + | 265.00 | + | 200.00 | + | 1,400.00 | = | 2,045 |

TABLE B.7. DRILLING COSTS

| Casing Size (in) | d_c Hole Size (in) | B_d (\$/hr) | | R_d (ft/hr) | | B_v (\$/ft) |
|------------------|----------------------|---------------|--|---------------|--|---------------|
| 4 | 7 | 175 | | 30 | | 15 |
| 6 | 10 | 200 | | 20 | | 32 |
| 8 | 12 | 250 | | 15 | | 45 |

+ Total injection well equipment cost - \$

$$C_{WEI} = C_{TP} + C_{PP} + C_{PW} + C_{PM} \quad (B.17)$$

+ Total production well cost - \$

$$C_{WEP} = C_{RP} + C_{TP} + C_{PW} \quad (B.18)$$

o Well casing costs - \$

$$C_c = D \left(B_c + \frac{B_d}{R_{CS}} + B_B \right) + B_{WC} \quad (B.19)$$

Constant B_c and B_{WC} from Table B.6, B_d from Table B.7

o Well drilling costs - \$

Constants obtained from Table B.7

$$C_d = \frac{DB_d}{R_d} \quad (B.20)$$

o Well cementing costs - \$

d_H and d_c obtained from Table B.7

$$C_{CM} = \frac{\pi D}{576} (d_H^2 - d_c^2)(B_G + 4) + B_{FCS} \quad (B.21)$$

o Well completions - \$

+ Choose one of the below items for use as C_{CP}

+ C_{CP} = completion cost (B.22)

+ $C_{CP} = 0$ for large radius horizontal fracture

+ Screened constants B_d from Table B.7

$$C_{SC} = H(B_W + B_d/R_{CS}) \quad (B.23)$$

+ Perforated

$$C_P = 6H + B_{PS} \quad (B.24)$$

o Well stimulation - \$

Choose one of the below items for use as C_{MM}

+ C_{MM} = matrix modification cost (B.25)

+ No modification
 $C_{MM} = 0$ (B.26)

+ Explosive stimulation
 $C_{EX} = B_{EXS} + 235H$ (B.27)

+ Short-radius hydraulic fracture
 $C_{HS} = B_{SRS} + 14H$ (B.28)

+ Horizontal hydraulic fracture
 $C_{HC} = \left[B_{LRS} + 0.41S^2 \right] \left[\frac{H}{2H_c} + \frac{N_p}{N_w} \right]$ (B.29)

+ Vertical hydraulic fracture
 $C_{HV} = B_{LRS} + 0.41S_2H$ (B.30)

o Well logging - \$

$$C_{WL} = B_{FWL} + 2.7D$$
 (B.31)

o Total injection well cost - \$

$$C_{EWI} = (B.8) + (B.17) + (B.19) + (B.20) + (B.21) + (B.22) + (B.25) + (B.31)$$
 (B.32)

o Total production well cost - \$

$$C_{EWP} = (B.8) + (B.18) + (B.19) + (B.20) + (B.21) + (B.22) + (B.25) + (B.31)$$
 (B.33)

o Total cost of wellfield wells - \$

$$EW_w = (Q/q_I)C_{EWI} + [(Q/q_I)^{1/2} + 1]^2 C_{EWP}$$
 (B.34)

B.3 VERTICAL WELL DRILLED FROM UNDERGROUND

o Drill site development - \$/well

$$C_{AU} = 5,000$$
 (B.35)

o Well equipment costs - \$/well

+ Recovery pumps

$$C_{RP} = (B.12)$$
 (B.36)

+ Tubing costs - \$/well

$$C_{TP} = 2.2 (B.13)$$
 (B.37)

+ Packer costs - \$/well

$$C_{PP} = (B.14) \quad (B.38)$$

+ Wellhead costs - \$/well

$$C_{PW} = (B.15) \quad (B.39)$$

+ Injection well flow meter - \$/well

$$C_{PM} = (B.16) \quad (B.40)$$

+ Total injection well equipment cost - \$/well

$$C_{WEI} = C_{TP} + C_{PP} + C_{PW} + C_{PM} \quad (B.41)$$

+ Total production well equipment cost - \$/well

$$C_{WEP} = C_{RP} + C_{TP} + C_{PW} \quad (B.42)$$

o Well casing costs - \$/well

$$C_c = H \left[2.2 B_c + \frac{2B_d}{R_{CS}} + B_B \right] + B_{WC} \quad (B.43)$$

o Well drilling costs - \$/well

$$C_d = 2 \left(\frac{B_d H}{R_d} \right) + C_{AU} \quad (B.44)$$

o Well cementing costs - \$/well

$$C_{CM} = \frac{\pi H}{576} (d_H^2 - d_c^2) (B_G + 4) + B_{FCU} \quad (B.45)$$

o Well completion costs - \$/well

Choose one of the below items for use as C_{CP}

$$C_{CP} = \text{well completion cost} \quad (B.46)$$

+ Screened

$$C_{SC} = H \left(B_W + \frac{2B_d}{R_{CS}} \right) \quad (B.47)$$

+ Perforated

$$C_P = 6H + 2B_{LS} \quad (B.48)$$

o Well stimulation - \$/well

Choose one item below as C_{MM}

$$+ C_{MM} = \text{matrix modification cost} \quad (\text{B.49})$$

$$C_{MM} = 0, \text{ no modification}$$

$$+ C_{ex} = B_{EXU} + 235H \quad (\text{B.50})$$

+ Short-radius hydraulic fracture

$$C_{HS} = B_{SRU} + 14H \quad (\text{B.51})$$

+ Horizontal hydraulic fracture

$$C_{HC} = \left[2B_{LRS} + 0.41S^2 \right] \left[\frac{H}{2H_c} + \frac{N_p}{N_w} \right] \quad (\text{B.52})$$

+ Vertical hydraulic fracture

$$C_{HV} = 2B_{LRS} + 0.41S_2H \quad (\text{B.53})$$

o Well logging - \$/well

$$C_{WL} = 1.5 B_{LS} + 2.7H \quad (\text{B.54})$$

o Total injection well cost - \$/well

$$C_{WEI} = (\text{B.35}) + (\text{B.41}) + (\text{B.43}) + (\text{B.44}) + (\text{B.45}) + (\text{B.46}) + (\text{B.49}) + (\text{B.54}) \quad (\text{B.55})$$

o Total production well costs - \$/well

$$C_{WEP} = (\text{B.35}) + (\text{B.42}) + (\text{B.43}) + (\text{B.44}) + (\text{B.45}) + (\text{B.46}) + (\text{B.49}) + (\text{B.54}) \quad (\text{B.56})$$

o Total cost of Wellfield wells - \$

$$EW_w = (Q/q_I)C_{WEI} + [(Q/q_I)^{1/2} + 1]^2 C_{WEP} \quad (\text{B.57})$$

B.4 FAN WELLS

o Injection well costs per fan - \$

$$C_{EWI} = \left(\frac{N_{TF}}{2} \right) (C_{WEI})h \quad (\text{B.58})$$

o Production well costs per fan - \$

$$C_{EWP} = \left(\frac{N_{TF}}{2} \right) (C_{WEP})h \quad (\text{B.59})$$

- o Total well cost for fan costs - \$

$$EW_W = [C_{EWI} + C_{EWP}][Q/q_I] \quad (B.60)$$

B.5 WELLFIELD COSTS

- o Wellfield Start-up and Shut-Down Costs

- + Wellfield start-up - tons lost cathode production

$$T_{LH} = t_{WH} Y \quad (B.61)$$

- + Wellfield water make-up - R

$$EP_{WW} = 7.48 \times 10^{-4} A_w H \phi (100 - s_w) C_7 \quad (B.62)$$

- + Wellfield restoration - \$

$$EP_{WS} = (x_1/100) t_{WH} EP_o \quad (B.63)$$

- o Total Wellfield Cost Vertical Wells Drilled from the Surface

- + Initial wellfield cost

$$EW = (B.34) + (B.62) \quad (B.64)$$

- + Replacement + wellfield cost

$$EW_{RP} = (B.63) + (B.64) \quad (B.65)$$

- o Total Wellfield Cost Vertical Wells Drilled from Underground

- + Initial wellfield cost

$$EW = (B.1) + (B.2) + (B.4) + (B.6) + (B.57) + (B.62) \quad (B.66)$$

- + Replacement Wellfield Cost

$$EW_{RP} = (B.4) + (B.6) + (B.57) + (B.62) + (B.63) \quad (B.67)$$

- o Total Wellfield Cost Fan Wells

- + Initial Wellfield Cost

$$EW = (B.1) + (B.3) + (B.5) + (B.7) + (B.60) + (B.62) \quad (B.68)$$

- + Replacement Wellfield Cost

$$EW_{RP} = (B.5) + (B.7) + (B.60) + (B.62) + (B.63) \quad (B.69)$$

APPENDIX C
ALGORITHMS FOR SURFACE FACILITY
SPECIFICATIONS AND COSTS

The following is a summary of all algorithms used to size and cost surface facility equipment and operations. Table C.1 lists all input parameters and those parameters calculated in other sections. Table C.2 lists values of surface facility process design parameters recommended for use.

C.1 OVERALL MATERIAL BALANCE

- o System flow rate - gpm

$$Q = 0.456 \frac{Y}{[\text{Cu}]_d} \quad (\text{C.1})$$

- o Sulfuric acid injection concentration - gpl

$$[\text{H}_2\text{SO}_4] = [\text{Cu}]_d [W_7 + W_4] \quad (\text{C.2})$$

- o Sulfuric acid consumption in surface plant and sub-surface - ton acid/ton copper

$$W_{10} = W_4 + W_7 W_8 + W_9 \quad (\text{C.3})$$

- o Lime consumption - ton lime/ton acid

$$W_6 = W_{12} (W_7 W_8 + W_9) \quad (\text{C.4})$$

- o Solids content of bleed stream - ton sulfate/ton copper

$$W_{14} = W_{13} W_6 + W_{15} W_4 \quad (\text{C.5})$$

C.2 SPECIFICATIONS, SOLUTION TRANSFER

- o Plant/wellfield pipe diameter - in

$$+ \text{Friction gradient} = 0.06 \text{ ft/ft} \quad (\text{C.6})$$

$$+ d_s = 0.413 (Q)^{.4} \quad (\text{C.7})$$

- + d_s is rounded off based on data in Table C.2

TABLE C.1. SURFACE FACILITY PARAMETER DIRECTORY

| <u>Input Parameter</u> | | <u>Parameter From Other Section</u> |
|------------------------|---------------|-------------------------------------|
| Y | W_1 | q_i from A.1 |
| $[Cu]_d$ | W_2 | d from A.1 |
| H | W_3 | A_w from A.1 |
| D | W_4 | A_{WT} from A.1 |
| S | W_7 | EW from B.5 |
| h | W_8 | |
| a_f | W_9 | |
| a_w | W_{12} | |
| s_w | W_{13} | |
| ϕ | W_{15} | |
| E_p | α_{10} | |
| C_E | α_9 | |
| C_x | C_{ma} | |
| C_1 | C_{mw} | |
| C_2 | L_{TT} | |
| C_3 | HP_m | |
| C_4 | | |
| C_5 | | |
| C_6 | | |
| C_p | | |
| C_{PLT} | | |
| C_{PLW} | | |

TABLE C.2. RECOMMENDED VALUES
SURFACE FACILITY PROCESS DESIGN PARAMETERS

| | | |
|------------|--|---|
| W_1 | = 0.015 m ³ extractant/gpm/year | |
| W_2 | = 0.085 m ³ diluent/gpm/year | |
| W_3 | = 0.261 Kg cobalt sulfate/ton cathode | |
| W_4 | = 4 ton acid/ton gangue | |
| W_5 | = 0.065 ton anode/ton cathode | |
| W_7 | = 1.54 ton acid/ton copper | |
| W_8 | = 0.2 fraction | |
| W_9 | = 0.231 ton acid/ton cathode | |
| W_{12} | = 0.571 ton CaO/ton acid | |
| W_{13} | = 2.43 ton gypsum/ton CaO | |
| W_{15} | = 1.36 ton sulfate/ton acid (assume ferric) | |
| C_x | = 2500 \$/gpm | C_{HP} = 150 \$/HP |
| C_E | = 650 \$/TPY | C_{e1} = 0.05 ¢/Kwhr |
| C_1 | = 10,000 \$/m ³ extractant | C_5 = 185 \$/ton anode |
| C_2 | = 300 \$/m ³ diluent | C_6 = 50 \$/ton CaO |
| C_3 | = 6.5 \$/Kg cobalt sulfate | C_7 = 0.02 \$/gallon water |
| C_4 | = 30 \$/ton acid | C_{PLT} (from next section Table C.2) |
| HP_m | = 700 hP | C_{PLW} (from next section Table C.2) |
| α_9 | = 2333.3 kwhr/ton cathode | α_{10} = 6552.5 Kwhr/hP-year |
| C_{MA} | = 1.37×10^{-4} \$/ft ² /ft | C_{MW} = 1.83×10^{-4} \$/ft ² /ft |

TABLE C.2 (continued)
 SIZING PIPE FOR FRICTION GRADIENT < 0.06 FT/FT

| d_s or d_t Nominal Pipe Diameter (in) | Flow Rate (gpm) | Cost of pipeline (\$/ft) | | C_{PLW} or C_{PLT} Average |
|---|--------------------|--------------------------|------------|--------------------------------------|
| | | Injection | Production | |
| 2 | 0 - 50 | | | a |
| 3 | 50 - 150 | | | a |
| 4 | 150 - 300 | 12.00 | 38.00 | 25.00 |
| 6 | 300 - 800 | | | a |
| 8 | 800 - 1600 | | | a |
| 10 | 1600 - 2900 | | | a |
| 12 | 2900 - 4500 | | | a |
| 14 | 4500 - 5700 | | | a |
| 16 | 5700 - 8000 | | | a |
| 18 | 8000 - 10,600 | 75.00 | 120.00 | 97.50 |

For intermediate values of C_{PLW} or C_{PLT} (a) scale proportionally by diameter

INJECTION PUMP COST ALGORITHM BASED ON:

- o \$97,612 for 250 gpm 600hp pump
This is equivalent to \$162.70/hp
- o \$205,000 for 1000 gpm 1500 hp pump
This is equivalent to \$136.70/hp
- o Use average of \$150/hp for unit cost

o Interconnecting pipe diameter

+ Friction gradient = 0.06 ft/ft (C.8)

+ Flow rate per row of patterns, gpm

- $q_{I_o} = [Qq_I]^{1/2}$, 5-spot (C.9)

- $q_{I_o} = [Qq_I]^{1/2} \left[\frac{2h^2}{Hd} \right]^{1/2}$, fan pattern (C.10)

+ Pipe diameter, in

- $d_T = 0.413(q_{I_o})^{0.4}$ (C.11)

- d_T is rounded off based on data in Table C.2

o Pipe length per row of well pattern - feet

+ $L_{TW} = 2S[2(Q/q_I) + 2(Q/q_I)^{1/2} + 1]$, 5-spot (C.12)

+ $L_{TW} = 2d(Q/q_I) + 4(Q/q_I)^{1/2} \left(\frac{dH}{2} \right)^{1/2}$, fan pattern (C.13)

o Maximum surface injection pressure - feet of head

$$P_{IS} = \left(\frac{a_f}{a_w} - 1 \right) (D-H) \quad (C.14)$$

o Maximum lifting pressure - feet of head

$$P_{PL} = (D-H) \quad (C.15)$$

o Horsepower for injection pumps - hp

$$HP_I = 0.0252 P_{IS} (Q/n) \quad (C.16)$$

o Horsepower for production pumping - hp

$$HP_P = 0.0252 P_{PL} (Q/n) \quad (C.17)$$

C.3 CAPITAL COSTS

o Sx/Ew - \$

$$EP_1 = C_x Q + C_E Y \quad (C.18)$$

o Pump Costs - \$

+ Injection pumps

$$EP_2 = C_{HP} HP_I \quad (C.19)$$

- + Production pumps fan pattern

$$EP_3 = C_{HP} HP_p \quad (C.20)$$

- o Wellfield interconnecting piping costs - \$

$$EP_4 = C_{PLW} L_{TW} \quad (C.21)$$

- o Surface plant to wellfield piping costs - \$

$$EP_5 = C_{PLT} L_{TT} \quad (C.22)$$

- o Environmental Permitting Costs - \$

$$EP_6 = \$444,500 \quad (C.23)$$

- o Monitoring well costs - \$

$$EP_7 = C_{ms} A_{WT} D + C_{mw} A_{WT} WD \quad (C.24)$$

- o Start-up cost of consumables

$$+ EP_8 = \frac{EP_c}{4}, \quad (C.25)$$

- + see (C.38) for EP_c

- o Total Capital Costs - \$

$$+ EP_T = EP_1 + EP_2 + EP_4 + EP_5 + EP_6 + EP_7 + EP_8, \text{ 5-spot} \quad (C.26)$$

$$+ EP_T = (C.26) + (C.20), \text{ fan pattern} \quad (C.27)$$

C.4 UTILITY REQUIREMENTS

- o Electricity - Kwhr

$$K_{whr} = \alpha_{10} (HP_I + HP_m) + \alpha_9 Y \quad (C.28)$$

- o Water

- + Personnel requirements 50 gal/man/day
- + Process usage 0.034 gal/lb cathode
- + Wellfield saturation - gallons

$$GA = 7.48 \times 10^{-4} A_w H \phi (1-s_w) \quad (C.29)$$

- o Fuel

- + None

C.5 STAFFING TOTAL SURFACE FACILITY

Staffing is a function of plant size. Use equations below to interpolate for intermediate values.

o Small plant 12,500 TPY

$$ST = 3.2(Y/1000) + 22 \quad (C.30)$$

o Medium plant 25,000 TPY

$$ST = 2.4(Y/1000) + 32 \quad (C.31)$$

o Large plant 50,000 TPY

$$ST = 1.6(Y/1000) + 32 \quad (C.32)$$

C.6 OPERATING COSTS

o Salaries - \$/year

$$+ EP_1 = 1,746,000 + 140Y, \text{ small plant} \quad (C.33)$$

$$+ EP_1 = 1,746,000 + 105Y, \text{ medium plant} \quad (C.34)$$

$$+ EP_1 = 1,746,000 + 70Y, \text{ large plant} \quad (C.35)$$

o Consumables - \$/year

$$+ EP_{c1} = (C_1W_1 + C_2W_2)Q \quad (C.36)$$

$$+ EP_{c2} = (C_3W_3 + C_4W_{10} + C_5W_5 + C_6W_6)Y \quad (C.37)$$

$$+ EP_c = (EP_{c1} + EP_{c2})(E_p/100) \quad (C.38)$$

o Utilities - \$/year

+ Electricity

$$EP_E = C_{e1} [\alpha_{10}(HP_I + HP_P) + \alpha_9 Y] \left[\frac{E_p}{100} \right] \quad (C.39)$$

+ Water for the plant

$$EP_w = C_7 [18,250 \times ST + 68Y(E_p/100)] \quad (C.40)$$

+ Fuel (none)

o Contract maintenance - \$/year

+ Surface plant

$$EP_{MS} = 0.03EP_T \quad (C.41)$$

+ Wellfield, surface access

$$EP_{MW} = 0.1EW \quad (C.42)$$

+ Wellfield, underground access

$$EP_{MW} = 0.15EW \quad (C.43)$$

o Environmental monitoring - \$/year

$$EP_{EM} = \$80,300 \quad (C.44)$$

o Total annual operating cost - \$/year

$$EP_o = EP_1 + EP_c + EP_E + EP_w + EP_{MS} + EP_{MW} + EP_{EM} \quad (C.45)$$

APPENDIX D. COMPUTER PROGRAM

D.1 USER GUIDE

Various algorithms developed in this manual are combined into a computer program for the design and economic analysis of an in situ mining operation. This program was written and compiled on an IBM PC AT using an IBM Professional Fortran compiler. Minimum hardware requirements for operating the executable Fortran program GENERIC.EXE on an IBM Personal Computer include 360 K memory and an 8087 or 80287 math coprocessor. An executable version of the program that will not require a math coprocessor can be obtained using some of the other available Fortran compilers. The source code for the program is provided in GENERIC.FOR.

The basic method of analysis, organization of different algorithms and input data set was discussed in Chapter 8. This section describes the mechanics of conducting the analysis. A listing of the program is included in the appendix and a diskette containing the program, executable modules, input data set and example output is enclosed.

The diskette contains the files as described below.

| <u>File</u> | <u>Description</u> |
|-------------|----------------------------------|
| COMMAND.COM | DOS 3.1 commands |
| GENERIC.FOR | Fortran program source codes |
| GENERIC.EXE | Fortran compiled executable file |
| SUMMARY | Program output file |
| PRINTFIL | Program output file |

Execution of the program is menu driven. A copy of all menu screens is included in this appendix in Section D.2. The user responds to screen prompts using keyboard input. An optional brief tutorial can

be printed to the screen at the initial screen prompt. Input of values for site specific parameters is requested at the second screen. The option to set these values by reading an external data file is provided, as is the option to write the values used for a given run to an external file. The second screen prompts the user to enter a number corresponding to the category of site specific parameters to be input. A specific input parameter is then assigned a value by entering the parameters name followed by the desired value. After the entering of each new value the screen resets and displays all parameters and their corresponding values, including the new value just entered. All parameters are set using real values (F10.0 format) except for the Program Control Parameters which require a logical format (.TRUE. or .FALSE.).

The program outputs a detailed set of calculated values to file PRINTFIL and SUMMARY consisting of: parameters changed for each run (called case # in output); main result either ROR or selling price, and total investment required and annual operating cost. SUMMARY can be reorganized using graphics programs such as Lotus 123 into summary table (summary.wk1 file on diskette) and summary graph (summary.pic). The sensitivity analysis of the example problem manipulated by Lotus 123 is included as examples on diskette.

D.2 MENU DRIVEN SCREENS

Welcome to the Generic In Situ Copper Mine Design Manual Program

Written by SAIC:
Science Applications International Corporation

under contract J0267001
for the Bureau of Mines
U.S. Department of the Interior

Last updated : APRIL 2, 1987.

This program is menu driven, but you will need the Generic In Situ Copper Mine Design Manual in order to run this program efficiently. If you would like a brief explanation on how to use this program enter Y, Else,

Hit Enter key to continue.

Initial Discussion After SAIC Welcome

The computations performed by this program develop commercial design specifications and a DCF/ROR cash flow analysis for a true in situ copper mining operation at a selected site.

A commercial design involves three areas of design specifications and costs: wells and wellfields that can be accessed from the surface or from underground workings; surface facilities for acid make-up and handling copper leach solutions (SX/EW); and environmental permitting, monitoring, and restoration.

The program contains all required algorithms to conduct the integrated system design when the input parameters are specified.

The input parameters are grouped into categories: (1) Business Related; (2) Site Specific Orebody and Wellfield Characteristics; (3) Copper Leaching; (4) Program Control; (5) Well System Specification and Cost Default Values; (6) Surface Plant Specification and Cost Default Values; (7) Environmental Cost Default Values.

- Categories (1), (2), and (3) contain those input parameters that the user must select to define and conduct a specific mining scenario.

- Category (4) contains the input parameters that the user must specify to control the print out of output data.

- Categories (5), (6), and (7) contain those input parameters that correspond to design specification and cost constants that convert a specific mining scenario into capital and operating costs. These should only be changed by the user after developing new constants by an independent analysis.

The input parameters required to conduct a specific mining scenario are listed below by category.

- Business Related (Category 1)

| | |
|------|----------------|
| INDC | SCP1 thru SCP5 |
| INDM | SCM1 thru SCM5 |
| PRIC | SCW1 thru SCW5 |
| ROI | TP |
| Y | |

- Site Specific Orebody and Wellfield Characteristic (Category 2)

| | | | |
|------|------|------|------|
| AF | RA | RHOP | DRY |
| D | RW | WS | WORK |
| H | S1 | H1 | H2 |
| GRDO | S2 | MACE | PORO |
| PERM | STIM | MINE | |

- Copper Leaching

| | |
|------|------|
| CULD | EFFR |
| EFFL | EFFS |
| EFFO | W4 |
| EFFP | W7 |
| VISC | PLNT |

- Program Control

LSTI
LSTA
LST

To assign new values to specific parameters, enter the menu driven screen containing that parameter and type in the variable's four character name followed by the new value. (Note: all parameter name entries must consist of four characters or the parameter's full name

followed by enough spaces to fill a four character entry.)

The comment section lists all input parameters. For Categories (1), (2), (3), and (4) typical values or ranges are specified for some parameters, for others no value or range is specified because it is so broad. For Categories (5), (6), and (7) default values for all constants are provided.

Note the following with regard to surface versus underground drilling of wells.

- Large diameter vertical wells can be drilled from the surface or from underground. Designs are provided for three well sizes, the well size being determined by the well flow rate; 0-50gpm the smallest size; 50-100gpm the intermediate size; and 100-300gpm the largest size. Algorithms contained in the program select which well size is to be used.
- Fan wells are drilled from underground workings along crosscuts.
- Underground wellfields require shafts, raises, drifts, crosscuts, and supporting mine plant facilities.

The surface versus underground option is executed using input parameter WORK.

For large diameter vertical wells, four well pattern design options can be selected.

- Radial flow no stimulation
- Radial flow short radius hydrotrac
- Axial flow large radius horizontal hydrotrac
- Axial flow large radius vertical hydrotrac

For fan well matrix modification is not an option. The flow regime and method of completion is selected using input parameters MINE and STIM.

Note the following with regard to the business related input parameters:

- Either select as input the rate of return (ROR) or the copper selling price (PRIC). Selection of one parameter then results in the calculation of the other. If the ROR is selected as an input parameter, then input zero for PRIC.
- To account for inflation an inflation index for mining (INDM) and plant (INDC) capital costs are provided. A value of 100% is equivalent to current cost, no inflation.

- The parameters SCP1 through SCP5, SCW1 through SCW5, and SCM1 through SCM5 provided the option of scheduling capital cost expenditures over a five year time frame. In the default mode for surface plant construction a total time of 3 years for installation of the surface plant is used, with 0.23 of the total capital in the first year (SCP1=0.23), 0.25 in the second year (SCP2=0.25), 0.52 in the third year (SCP3=.052). This requires setting SCP4 and SCP5 equal to zero. In the default mode for well system capital an 18 month installation is used, with 0.40 of the total capital in the first year (SCW1=0.4) and 0.60 in the second year (SCW2=0.6). This requires SCW3, SCW4, and SCW5 to be 0.

INPUT PHASE

- | | |
|--------------------------------------|------------------------------------|
| 1. Business Related Variables | 6. Surface Plant and Cost Inputs |
| 2. Orebody and Wellfield Char. | 7. Environment and Cost Parameters |
| 3. Copper Leaching Inputs | 8. READ a Saved Data File |
| 4. Program Control Parameters | 9. SAVE Data to File |
| 5. Well System Spec. and Cost Inputs | 0. Quit Input & Go Calculate |

TYPE in Option Number and Hit the Enter Key

Business Related Input Parameters

| | | | |
|------|-----------|------|------------|
| INDC | 100.000 % | INDM | 100.000 % |
| ROI | 20.000 % | PRIC | 0.000 c/LB |
| SCM1 | 0.400 | SCM2 | 0.600 |
| SCM3 | 0.000 | SCM4 | 0.000 |
| SCM5 | 0.000 | SCP1 | 0.230 |
| SCP2 | 0.250 | SCP3 | 0.520 |
| SCP4 | 0.000 | SCP5 | 0.000 |
| SCW1 | 0.340 | SCW2 | 0.660 |
| SCW3 | 0.000 | SCW4 | 0.000 |
| SCW5 | 0.000 | TP | 20.000 YRS |

Y 25000.000 TPY

TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Site Specific Orebody and Wellfield Characteristic Parameters

| | | | |
|------|------------------|------|-------------|
| AF | 1.000 PSI/FT | D | 1000.000 FT |
| DRY | 1.000 | GRDO | 1.000 % |
| H | 300.000 FT | H1 | 30.000 FT |
| H2 | 60.000 FT | MACE | 1.000 |
| MINE | 3.000 | PERM | 2.000 M.D. |
| PORO | 5.000 % | RA | 8.000 FT |
| RHOP | 162.000 LB/CU.FT | RW | 0.250 FT |
| S1 | 100.000 FT | S2 | 100.000 FT |
| SDA | 2000.000 FT | SR | 0.000 FT |

| | | | |
|------|--------------|------|------------|
| SS | 0.000 FT | STIM | 2.000 |
| THTA | 0.315 RADIAN | WORK | 2.000 |
| WS | 80.000 % | WD | 500.000 FT |

Type U or D to move UP or DOWN a screen in this category
 TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Copper Leaching Input Parameters

| | | | |
|------|----------------|------|----------------|
| CULD | 6.000 GRAM/L | EFFL | 75.000 % |
| EFFO | 91.200 % | EFFP | 100.000 % |
| EFFR | 90.000 % | EFFS | 75.000 % |
| PLNT | 2.000 | VISC | 1.000 CENTI P |
| W4 | 4.000 T ACID/T | W7 | 1.540 T ACID/F |

TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Program Control Parameters

| | |
|------|---|
| LSTI | T |
| LSTA | T |
| LST | T |

TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Well System Spec. and Cost Input Parameters

| | | | |
|------|--------------------|------|------------------|
| AW | 0.430 PSI/FT | B1 | 0.560 \$/FT |
| B2 | 2045.000 \$/WELL | B3 | 1425.000 \$/WELL |
| B4 | 2500.000 \$/WELL | B5 | 14.000 \$/FT |
| B6 | 5000.000 \$/FRAC | B7 | 0.410 \$/SQ. FT. |
| B8 | 2800.000 \$/WELL | B9 | 235.000 \$/FT |
| B10 | 3135.000 \$/WELL | B11 | 2.700 \$/FT |
| B12 | 0.100 \$/FT | B13 | 92.000 \$/HP |
| B14 | 1811.000 \$/WELL | B15 | 5000.000 \$/WELL |
| B3U | 5000.000 \$/WELL | B4U | 5600.000 \$/WELL |
| B6U | 10000.000 \$/FRAC | B8U | 3600.000 \$/WELL |
| B10U | 4702.500 \$/WELL | BA | 2400.000 \$ |
| BAU | 5000.000 \$ | BB | 4.000 \$/CU. FT. |
| BG | 15.000 \$/CU. FT. | BJ | 1.500 \$/JET |
| BL | 800.000 \$/WELL | BLU | 1600.000 \$/WELL |
| BSI | 2000.000 \$/WELL | BTI | 1.000 \$/FT |
| BW | 20.000 \$/FT | BW1 | 5.410 \$/FT |
| BW2 | 11.900 \$/FT | BW3 | 1.000 \$/FT |
| BW4 | 325.000 \$/HP | BW5 | 0.000 \$/WELL |
| BW6 | 1100.000 \$/WELL | BW7 | 1240.000 \$/WELL |
| BW8 | 175.000 \$/HR | BW9 | 350.000 \$/HR |
| BW10 | 30.000 FT/HR | BW11 | 15.000 \$/FT |
| BW12 | 33.000 \$/FT | BW13 | 7.000 IN |
| BW14 | 4.000 IN | BW15 | 1.920 IN |
| BW16 | 3000.000 \$/PACKER | BW17 | 7.350 \$/FT |
| BW18 | 16.170 \$/FT | BW19 | 3.000 \$/FT |
| BW20 | 70.000 \$/HP | BW21 | 500.000 \$/WELL |
| BW22 | 1350.000 \$/WELL | BW23 | 1240.000 \$/WELL |

| | | | |
|------|--------------------|------|------------------|
| BW24 | 200.000 \$/HR | BW25 | 400.000 \$/HR |
| BW26 | 20.000 FT/HR | BW27 | 26.000 \$/FT |
| BW28 | 57.200 \$/FT | BW29 | 10.000 IN |
| BW30 | 6.000 IN | BW31 | 2.420 IN |
| BW32 | 5000.000 \$/PACKER | BW33 | 15.800 \$/FT |
| BW34 | 34.760 \$/FT | BW35 | 5.000 \$/FT |
| BW36 | 102.000 \$/HP | BW37 | 1000.000 \$/WELL |
| BW38 | 2500.000 \$/WELL | BW39 | 1718.000 \$/WELL |
| BW40 | 250.000 \$/HR | BW41 | 500.000 \$/HR |
| BW42 | 15.000 FT/HR | BW43 | 35.000 \$/FT |
| BW44 | 77.000 \$/FT | BW45 | 12.000 IN |
| BW46 | 8.000 IN | BW47 | 4.040 IN |
| BW48 | 7000.000 \$/PACKER | BWFI | 30.000 \$/FT |
| BWFP | 10.000 \$/FT | BX | 400.000 \$/FT |
| CDA | 400.000 \$/FT | CP | 150.000 \$/HP |
| CPL | 700.000 KW | CR | 1000.000 \$/FT |
| CS | 3000.000 \$/FT | EE | 200000.000 \$ |
| EM | 2500000.000 \$ | EV | 120000.000 \$ |
| FACJ | -0.619 | RC | 130.000 FT/HR |

Type U or D to move UP or DOWN a screen in this category
 TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Surface Plant and Cost Input Parameters

| | | | |
|-----|----------|-----|--------------|
| BP1 | 2.000 IN | BP2 | 12.500 \$/FT |
| BP3 | 3.000 IN | BP4 | 18.750 \$/FT |
| BP5 | 4.000 IN | BP6 | 25.000 \$/FT |
| BP7 | 6.000 IN | BP8 | 37.500 \$/FT |

| | | | |
|------|--------------------|------|-------------------|
| BP9 | 8.000 IN | BP10 | 50.000 \$/FT |
| BP11 | 10.000 IN | BP12 | 62.500 \$/FT |
| BP13 | 12.000 IN | BP14 | 65.000 \$/FT |
| BP15 | 14.000 IN | BP16 | 75.800 \$/FT |
| BP17 | 16.000 IN | BP18 | 86.670 \$/FT |
| BP19 | 18.000 IN | BP20 | 97.500 \$/FT |
| C1 | 10000.000 \$/CU.M. | C2 | 300.000 \$/CU.M. |
| C3 | 6.500 \$/KG | C4 | 30.000 \$/TON |
| C5 | 185.000 \$/TON | C6 | 50.000 \$/TON |
| C7 | 0.020 \$/GALLON | CE | 650.000 \$/TPY |
| CL | 20.000 \$/HR | CLP0 | 1746000.000 \$/YR |
| CLP1 | 1750000.000 \$/YR | CLP2 | 2625000.000 \$/YR |
| CLP3 | 3500000.000 \$/YR | CU | 0.050 \$/KWHR |
| CX | 2500.000 \$/GPM | ETA | 0.700 FRACTION |
| POPO | 32.000 MEN | POP1 | 40.000 MEN |
| POP2 | 60.000 MEN | POP3 | 80.000 MEN |
| QS1 | 55.000 GPM | QS2 | 150.000 GPM |
| QS3 | 300.000 GPM | QS4 | 800.000 GPM |
| QS5 | 1600.000 GPM | QS6 | 2900.000 GPM |
| QS7 | 4500.000 GPM | QS8 | 5700.000 GPM |
| QS9 | 8000.000 GPM | QS10 | 10600.000 GPM |
| QW1 | 50.000 GPM | QW2 | 100.000 GPM |
| QW3 | 300.000 GPM | RHOF | 62.400 LB/CU.FT |

| | | | |
|-----|----------------|-----|----------------|
| ST | 6000.000 FT | W1 | 0.015 M/GPM/YR |
| W2 | 0.085 M/GPM/YR | W3 | 0.261 KG/TON |
| W5 | 0.065 T ANOD/T | W8 | 0.200 |
| W9 | 0.231 T ACID/T | W12 | 0.571 T CAO/T |
| W13 | 2.430 SO4/LIME | W15 | 1.360 FESO4/AC |

Type U or D to move UP or DOWN a screen in this category
 TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

Environmental and Cost Input Parameters

| | | | |
|-----|-------------------|------|-------------------|
| CMA | 0.00014 \$/SQFTFT | CMW | 0.00018 \$/SQFTFT |
| EP6 | 462500.00000 \$ | EP6M | 80300.00000 \$/YR |
| X1 | 5.00000 % | | |

TYPE in Variable NAME and New Value, or Hit the Enter Key for menu

D.3 COMPUTER PROGRAM GENERIC DESIGN

This program is intended to support the analysis of the economics of an in-situ copper mining project.

*** INPUT PARAMETERS ***

BUSINESS RELATED:

1 INDC - Inflation Index for Plant Construction Cost, % (100 for no inflation)
 1 INDM - Inflation Index for Mining Construction Cost, % (100 for no inflation)
 1 FRIC - Copper Selling Price, c/lb (No range specified)
 1 ROI - Rate of Return (ROR), % (No range specified)
 1 SCM1 thru SCM5 - Annual Fraction of Capital Expenditure of underground workings applied for each year over a five year installation schedule (Values to be specified by user)
 1 SCP1 thru SCP5 - Annual Fraction of Capital Expenditure for Surface plant applied each year over five year installation schedule (values to be specified by user)
 1 SCW1 thru SCW5 - Annual Fraction of Capital Expenditure for each wellfield applied each year over a five year installation schedule (Values to be specified by user)
 1 TP - Plant Life, years (< 20)
 1 Y - Copper production, tons/on-stream year (2500 to 50,000 range)

SITE SPECIFIC OREBODY AND WELLFIELD CHARACTERISTICS:

2 AF - Fracture gradient, psi/ft, 0.7 to 2 range
 2 D - Depth to the bottom of ore zone, ft. < 3000
 2 DRY - Initial State of Ore Body Saturation
 1 Unsaturated
 2 Saturated
 2 GRDO - Ore Grade, %, 0.3 to 2 1/2 range
 2 H - Thickness of ore zone, ft. (No range specified)
 2 H1 - Vertical leach interval for horizontal fractures and for fan flow pattern, ft. (No range specified)
 2 H2 - Distance along crosscut between faces, ft. (No range specified)
 2 MACE - Type of Mining Access
 1 Surface
 2 Underground
 2 MINE - Wellfield flow pattern used in leaching,
 1 Axial flow with horizontal fractures
 2 Axial flow with vertical fractures
 3 Radial flow
 4 Fan flow
 2 PERM - Permeability of orezone, md (No range specified)
 2 PORO - Porosity, %, < 25
 2 RA - Effective wellbore radius, ft, 8
 2 RHOP - Particle Density, lb/cubic ft, 162
 2 RW - Wellbore radius prior to stimulation, ft. (< 0.25)
 2 S1 - Well Spacing, square pattern radial flow, horizontal fracture axial flow, or well spacing perpendicular to vertical fracture, ft. (No range specified)
 2 S2 - Well spacing parallel to vertical fracture with axial flow, ft. (No range specified)
 2 SDA - Drift footage underground access, ft. (2000 Default)
 2 SR - Raise footage underground access, ft. SET default to zero to use default value given by algorithm.

C 2 SS - Shaft footage underground access, ft. SET value to
 C 2 zero to use default value given by algorithm.
 C 2 STIM - Type of well completion and stimulation
 C 2 0 screened well completion, no stimulation
 C 2 1 perforated well completion, no stimulation
 C 2 2 small radius hydrofrac and perforated completion
 C 2 3 Large radius vertical frac and perforated completion
 C 2 4 Large radius horizontal frac and slotted completion
 C 2 5 small radius explosive fracture and perforated completion
 C 2 THTA - Fan angle, rad. (0.315 for OPTIMUM UNIT FAN COST)
 C 2 WD - Static Water Table, ft, (no range specified)
 C 2 WORK - Status of Mine Access
 C 2 1 Existing
 C 2 2 Non Existing
 C 2 WS - Orebody Water Saturation, %, 0 to 100 range

COPPER LEACHING:

C 3 CULD - Copper loading, gpl, 2 to 20 range
 C 3 EFFL - Leach Efficiency, % (75 Default)
 C 3 EFFO - Plant onstream Efficiency, % (91.2 Default)
 C 3 EFFF - Priming Efficiency, % (100 Default)
 C 3 EFFR - Recovery Efficiency, % (90 Default)
 C 3 EFFS - Sweep Efficiency, % (75 Default)
 C 3 PLNT - Status of Surface Plant
 C 3 1 Existing
 C 3 2 Not Existing
 C 3 VISC - Lixiviant viscosity, cp (1 Default)
 C 3 W4 - Acid consumption by gangue material, ton acid/ton cu.
 C 3 (4 Default)
 C 3 W7 - Acid consumption by copper minerals, ton acid/ton Cu. -
 C 3 (1.54 Default)

PROGRAM CONTROL:

C 4 LSTI - Control of Print Out of Calculated Variables
 C True, Calculated values printed out
 C False, No print out
 C 4 LSTA - Control of Print Out of Annual Cash Flow by Elements
 C True, Print out
 C False, No print out
 C 4 LST - Control of Print Out of All Input Parameters
 C True, Print out
 C False, No print out

WELL SYSTEM SPECIFICATION AND COST:

C 5 AW - Hydrostatic gradient in well tubing, psi/ft (0.43 Default)
 C 5 B1 - Depth dependant constant in casing cost, \$/ft (0.56 Default)
 C 5 B2 - Constant in casing cost, \$/well (2045 Default)
 C 5 B3 - Constant in cementing cost for surface access, \$/well
 C 5 (1425 Default)
 C 5 B4 - Constant in small radius Hydrofrac, \$/well (2500 Default)
 C 5 B5 - Height dependant hydrofrac cost, \$/ft (14 Default)
 C 5 B6 - Constant in large radius hydrofrac, \$/fracture (5000 Default)
 C 5 B7 - Area dependant constant in large radius hydrofrac, \$/sq.ft.
 C 5 (0.41 Default)
 C 5 B8 - Constant in high explosive stimulation, \$/well (2800 Default)
 C 5 access, \$/Well (3600 Default)
 C 5 B9 - Height dependant constant in high explosive stimulation, \$/ft
 C 5 (235 Default)

| | | | |
|---|---|------|--|
| C | 5 | B10 | - Cost of logging set-up surface drilling, \$/well (3135 Default) |
| C | 5 | B11 | - Depth dependant cost of well logging, \$/ft (2.7 Default) |
| C | 5 | B12 | - Depth dependant cost constant in production equipment, \$/ft (0.1 Default) |
| C | 5 | B13 | - Constant in Cost of production pump, \$/hp (92 Default) |
| C | 5 | B14 | - Constant in production equipment cost, \$/well (1811 Default) |
| C | 5 | B15 | - Constant in underground cost of drilling, \$/well (5000 Default) |
| C | 5 | B3U | - Constant in cementing cost for underground access, \$/well (5000 Default) |
| C | 5 | B4U | - Constant in small radius hydrofrac by underground access, \$/well (5600 Default) |
| C | 5 | B6U | - Constant in large radius hydrofrac via underground access, \$/fracture (10000 Default) |
| C | 5 | B8U | - Constant in high explosive stimulation via underground |
| C | 5 | B10U | - Cost of logging set-up via underground access, \$/well (4702.50 Default) |
| C | 5 | BA | - Cost of preparing surface drillsite, \$/well (2400 Default) |
| C | 5 | BAU | - Cost of preparing underground drillsite, \$/well (5000 Default) |
| C | 5 | BB | - Cost of cement blending, \$/cubic ft. (4 Default) |
| C | 5 | BG | - Cost of cement, \$/cubic ft. (15 Default) |
| C | 5 | BJ | - Cost of jet for perforated completion, \$/jet (1.5 Default) |
| C | 5 | BL | - Cost of logging for perforated completion \$/well (800 Default) |
| C | 5 | BLU | - Cost of logging for underground drilled wells, \$/well (1600 Default) |
| C | 5 | BSI | - Cost injection well flow meter, \$/well (2000 Default) |
| C | 5 | BTI | - Unit cost of inflation tubing, \$/ft (1 Default) |
| C | 5 | BW | - Unit cost well screen, \$/ft (20 Default) |
| C | 5 | BW1 | - Cost of tubing for small well, \$/ft (5.41 Default) |
| C | 5 | BW2 | - Cost of tubing via underground access for small well, \$/ft (11.9 Default) |
| C | 5 | BW3 | - Cost of production pump wire for small well, \$/ft (1 Default) |
| C | 5 | BW4 | - Horsepower dependant cost of pump for small well, \$/hp (325 Default) |
| C | 5 | BW5 | - Constant in production equipment cost for small well, \$/well (0 Default) |
| C | 5 | BW6 | - Constant in production equipment cost for small well, \$/well (1100 Default) |
| C | 5 | BW7 | - Wellhead cost for small well, \$/well (1240 Default) |
| C | 5 | BW8 | - Surface drilling small rig cost, \$/hr (175 Default) |
| C | 5 | BW9 | - Underground small rig cost, \$/hr (350 Default) |
| C | 5 | BW10 | - Small well drilling rate, ft/hr (30 Default) |
| C | 5 | BW11 | - Cost of small casing, \$/ft (15 Default) |
| C | 5 | BW12 | - cost of small underground casing, \$/ft (33 Default) |
| C | 5 | BW13 | - Small well hole diameter, in (7 Default) |
| C | 5 | BW14 | - Small well casing diameter, in (4 Default) |
| C | 5 | BW15 | - Small well tubing diameter, in (1.92 Default) |
| C | 5 | BW16 | - Small well packer cost, \$/packer (3000 Default) |
| C | 5 | BW17 | - Medium well tubing cost, \$/ft (7.35 Default) |
| C | 5 | BW18 | - Medium well underground tubing cost, \$/ft (16.17 Default) |
| C | 5 | BW19 | - Medium well production pump wire, \$/ft (3 Default) |
| C | 5 | BW20 | - Medium well horsepower dependant cost of pump, \$/hp (70 Default) |
| C | 5 | BW21 | - Medium well constant in production equipment, \$/well (500 Default) |
| C | 5 | BW22 | - Medium well constant in production equipment, \$/well (1350 Default) |
| C | 5 | BW23 | - Medium well wellhead cost, \$/well (1240 Default) |
| C | 5 | BW24 | - Medium well surface drilling rig cost, \$/hr (200 Default) |
| C | 5 | BW25 | - Medium well underground drilling rig cost, \$/hr (400 Default) |

C 5 BW26 - Medium well drilling rate, ft/hr (20 Default)
 C 5 BW27 - Medium well casing cost, \$/ft (26 Default)
 C 5 BW28 - Medium well underground casing cost, \$/ft (57.2 Default)
 C 5 BW29 - Medium well hole diameter, in (10 Default)
 C 5 BW30 - Medium well casing diameter, in (6 Default)
 C 5 BW31 - Medium well tubing diameter, in (2.42 Default)
 C 5 BW32 - Medium well packer cost, \$/packer (5000 Default)
 C 5 BW33 - Large well tubing cost, \$/ft (15.8 Default)
 C 5 BW34 - Large well underground tubing cost, \$/ft (34.76 Default)
 C 5 BW35 - Large well production pump wire cost, \$/ft (5 Default)
 C 5 BW36 - Large well horsepower dependant cost, \$/hp (102 Default)
 C 5 BW37 - Large well constant in production equipment cost, \$/well
 (1000 Default)
 C 5 BW38 - Large well constant in production equipment cost, \$/well
 (2500 Default)
 C 5 BW39 - Large well wellhead cost, \$/well (1718 Default)
 C 5 BW40 - Large well surface drilling rig cost, \$/hr (250 Default)
 C 5 BW41 - Large well underground drill rig cost, \$/hr (500 Default)
 C 5 BW42 - Large well drilling rate, ft/hr (15 Default)
 C 5 BW43 - Large well casing cost, \$/ft (35 Default)
 C 5 BW44 - Large well underground casing cost, \$/ft (77 Default)
 C 5 BW45 - Large well hole diameter, in (12 Default)
 C 5 BW46 - Large well casing diameter, in (8 Default)
 C 5 BW47 - Large well tubing diameter, in (4.04 Default)
 C 5 BW48 - Large well packer cost, \$/packer (7000 Default)
 C 5 BWFI - Cost per ft of injection fan wells, \$/ft (30 Default)
 C 5 BWFP - Cost per ft of production fan wells, \$/ft (10 Default)
 C 5 BX - Unit cost for crosscut, \$/ft (400 Default)
 C 5 CDA - Unit cost of drift, \$/ft (400 Default)
 C 5 CP - Unit cost of injection pumping system, \$/hp (150 Default)
 C 5 CPL - Electric load of underground mineplant, KW (700 Default)
 C 5 CR - Unit cost of raise, \$/ft (1000 Default)
 C 5 CS - Unit cost of shaft, \$/ft (3000 Default)
 C 5 EE - Capital cost of underground electrical installation, \$
 (200000 Default)
 C 5 EM - Capital cost of underground mineplant, \$ (2500000 Default)
 C 5 EV - Capital cost of underground ventilation system, \$
 (120000 Default)
 C 5 FACJ - Constant in radial flow equation. (-0.619 Default)
 C 5 RC - Rate casing set-up, ft/hr (130 Default)

SURFACE PLANT SPECIFICATION AND COST DEFAULT:

C 6 BP1 - First line size, in (2 Default)
 C 6 BP2 - Cost of line for line size BP1, \$/ft (12.50 Default)
 C 6 BP3 - Second line size, in (3 Default)
 C 6 BP4 - Cost of line for line size BP3, \$/ft (18.75 Default)
 C 6 BP5 - Third line size, in (4 Default)
 C 6 BP6 - Cost of line for BP5 line size, \$/ft (25 Default)
 C 6 BP7 - Fourth line size, in (6 Default)
 C 6 BP8 - Cost of line for BP7 line size, \$/ft (37.50 Default)
 C 6 BP9 - Fifth line size, in (8 Default)
 C 6 BP10 - Cost of line for BP9 line size, \$/ft (50.00 Default)
 C 6 BP11 - Sixth line size, in (10 Default)
 C 6 BP12 - Cost of line for BP11 line size, \$/ft (62.50 Default)
 C 6 BP13 - Seventh line size, in (12 Default)
 C 6 BP14 - Cost of line for BP13 line size, \$/ft (65.00 Default)
 C 6 BP15 - Eighth line size, in (14 Default)
 C 6 BP16 - Cost of line for BP15 line size, \$/ft (75.80 Default)
 C 6 BP17 - Ninth line size, in (16 Default)

| | | | |
|---|---|------|---|
| C | 6 | BP18 | - Cost of line for BP17 line size , \$/ft (86.67 Default) |
| C | 6 | BP19 | - Tenth line size, in (18 Default) |
| C | 6 | BP20 | - Cost of line for BP19 line size, \$/ft (97.50 Default) |
| C | 6 | C1 | - Unit cost of extractant, \$/cubic meter (10000 Default) |
| C | 6 | C2 | - Unit cost of diluent, \$/cubic meter (300 Default) |
| C | 6 | C3 | - Unit cost of cobalt sulfate, \$/kg (6.5 Default) |
| C | 6 | C4 | - Cost of acid, \$/ton (30 Default) |
| C | 6 | C5 | - Cost of anode, \$/ton (185 Default) |
| C | 6 | C6 | - Cost of lime, \$/ton (50 Default) |
| C | 6 | C7 | - Cost of water, \$/gallon (0.02 Default) |
| C | 6 | CE | - Copper production dependant Surface plant cost, \$/ton per year (650 Default) |
| C | 6 | CL | - Labor cost, \$/hr (20 Default) |
| C | 6 | CLP0 | - Cost of base staff(for POP0), \$/yr (1746000 Default) |
| C | 6 | CLP1 | - Cost of additional staff for small plant, \$/yr (1750000 Default) |
| C | 6 | CLP2 | - Cost of additional staff for medium plant, \$/yr (2625000 Default) |
| C | 6 | CLP3 | - Cost of additional staff for large plant, \$/yr (3500000 Default) |
| C | 6 | CU | - Unit cost of electricity, \$/KWhr (0.05 Default) |
| C | 6 | CX | - Flow rate dependant surface plant cost, \$/gpm (2500 Default) |
| C | 6 | ETA | - Pump Efficiency, fraction (.7 Default) |
| C | 6 | POPO | - Base level support staff, men (32 Default) |
| C | 6 | POP1 | - Additional staff for a 12500 tpy plant, men (40 Default) |
| C | 6 | POP2 | - Additional staff for a 25000 tpy plant, men (60 Default) |
| C | 6 | POP3 | - Additional staff for a 50000 tpy plant, men (80 Default) |
| C | 6 | QS1 | - Maximum flow rate thru 2 inch solution transfer line, gpm (55 Default) |
| C | 6 | QS2 | - Maximum flow rate thru 3 inch line, gpm (150 Default) |
| C | 6 | QS3 | - Maximum flow rate thru 4 inch line, gpm (300 Default) |
| C | 6 | QS4 | - Maximum flow rate thru 6 inch line, gpm (300 Default) |
| C | 6 | QS5 | - Maximum flow rate thru 8 inch line, gpm (1600 Default) |
| C | 6 | QS6 | - Maximum flow rate thru 10 inch line, gpm (2900 Default) |
| C | 6 | QS7 | - Maximum flow rate thru 12 inch line, gpm (4500 Default) |
| C | 6 | QS8 | - Maximum flow rate thru 14 inch line, gpm (5700 Default) |
| C | 6 | QS9 | - Maximum flow rate thru 16 inch line, gpm (8000 Default) |
| C | 6 | QS10 | - Maximum flow rate thru 18 inch line, gpm (10600 Default) |
| C | 6 | QW1 | - Maximum flow rate thru smallest size well, gpm (50 Default) |
| C | 6 | QW2 | - Maximum flow rate thru medium size well, gpm (100 Default) |
| C | 6 | QW3 | - Maximum flow rate thru largest size well, gpm (300 Default) |
| C | 6 | RHOF | - Lixiviant density, lb/cubic ft (62.4 Default) |
| C | 6 | ST | - Length of plant to wellfield piping, ft. (6000 Default) |
| C | 6 | W1 | - Usage of extractant, cu.m/(year gpm) (0.015 Default) |
| C | 6 | W2 | - Usage of diluent, cu.m/(year gpm) (0.085 Default) |
| C | 6 | W3 | - Usage of cobalt sulfate, kg/ton copper cathode (0.261 Default) |
| C | 6 | W5 | - Anode usage, ton anode/ton cathode (0.065 Default) |
| C | 6 | W8 | - Fractional bleed stream to remove accumulation of gangue material from lixiviant. (0.2 Default) |
| C | 6 | W9 | - Acid demand by electrolytic bleed, ton acid/ton cathode (.231 Default) |
| C | 6 | W12 | - Lime, acid stoichiometry, ton CaO/ton acid (.571 Default) |
| C | 6 | W13 | - Gypsum, lime stoichiometry, ton gypsum/ton lime. (2.43 Default) |
| C | 6 | W15 | - FESO4, acid stoichiometry, ton sulfate/ton acid (1.36 Default) |

ENVIRONMENT COST DEFAULT:

C 7 CMA - Constant in monitoring well cost, \$/sq.ft./ft
 C 7 [0.000137 Default]
 C 7 CMW - Constant in monitoring well cost, \$/sq.ft./ft
 C 7 (0.000183 Default)
 C 7 EP6 - Cost of initial environmental permitting, \$ (462500 Default)
 C 7 EP6M - Annual cost of environmental monitoring, \$/yr (80300 Default)
 C 7 X1 - Wellfield restoration cost as % of wellfield priming
 C 7 cost, % (3 Default)

*** OUTPUT PARAMETERS ***

WELL SYSTEM:

C 8 A - Leach area of unit cell, sq. ft.
 C 8 ASUBW - Area of wellfield, sq.ft.
 C 8 CASING - Cost of casing, \$/well
 C 8 CASING - Casing diameter, in
 C 8 CEMENT - Cost of cementing, \$/well
 C 8 COMPLON - Cost of completion and stimulation, \$/well
 C 8 CUWGT - Total weight of copper in unit cell, ton
 C 8 DRILLING - Cost of drilling, \$/well
 C 8 FAN WELL - Cost per fan, \$/fan
 C 8 G - Geometric flow factor, ft
 C 8 HOLE DIA - Well hole diameter, in
 C 8 INJ EQIP - Cost of injection equipment, \$/well
 C 8 INJ FLOW - Injection flow rate, gpm
 C 8 INJ PRES - Injection pressure at top of orezone, psi
 C 8 INJ TUBE - Injection tubing diameter, in
 C 8 INJ WELS - Number of injection wells
 C 8 LOGGING - Cost of well logging, \$/well
 C 8 PRD EQIP - Cost of production equipment, \$/well
 C 8 PRD TUBE - Production tubing diameter, in
 C 8 PRIM T - Time for one PORE volume, year
 C 8 Q - Total system flowrate, gpm
 C 8 RECOVERY - Fraction of underground copper recovered.
 C 8 Ri - Flow pattern geometric factor, ft
 C 8 SITE PRP - Cost of drillsite preparation, \$/well
 C 8 UND.DEV - Total cost of underground facilities, \$
 C 8 UND.WORK - Capital cost of underground workings, \$
 C 8 WEL CAP - Total wellfield capital cost, \$
 C 8 WEL LIFE - Wellfield life, years
 C 8 WELLS - Total number of wells
 C 8 Xi - Flow pattern geometric factor, ft(2)
 C 8 * cells - Number of unit cells

SURFACE PLANT:

C 9 ACID CON - Acid consumption, ton acid/ton copper
 C 9 ACID C. - Acid concentration, gpl
 C 9 CHEMCLS - Annual cost of chemical and consumables, \$/yr
 C 9 INJ PUMP - Injection pump power requirement, hp
 C 9 LABOR - Annual cost of labor, \$/yr
 C 9 LIME CON - Lime consumption, ton lime/ton copper
 C 9 MINE OPS - Number of mine/wellfield operators
 C 9 O & M - Annual total operating and maintenance cost, \$/yr
 C 9 PLNT CAP - Total surface facility capital cost, \$
 C 9 PLNT OPS - Total size of plant staff
 C 9 PRD PUMP - Production pump power requirement, hp

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```
C WHERE NECESSARY.
C
C
C DATE OF LAST COMPUTER PROGRAM REVISION (UPDATE).
C
C UPDATE=' APRIL 11, 1988
C
C Start off the program with a welcome
C
9000 CONTINUE
WRITE (*,2000) UPDATE
2000 FORMAT (//10X,'Welcome to the Generic In Situ Copper Mine ',
1 'Design Manual Program',//,10X,'Written by SAIC:',/,
2 10X,'Science Applications International Corporation',//,
3 10X,'under contract J0267001',/,
4 10X,'for the Bureau of Mines',/,
5 10X,'U.S. Department of the Interior',//,
6 10X,'Last updated : ',A18,///,
7 10X,'This program is menu driven, but you will need the',/,
8 10X,'Generic In Situ Copper Mine Design Manual',/,
9 10X,'in order to run this program efficiently.',/,
A 10X,'If you would like a brief explanation on how',/,
B 10X,'to use this program enter Y, Else',//,
C 10X,'Hit Enter key to continue.')
READ (*,2020,ERR=9000) AK

C
C Write Initial Discussion.
C
C IF (AK .NE. 'Y') GO TO 50
C
C READ THE TUTORIAL FILE AND PRINT NLINES (NUMBER OF LINES)
C TO THE SCREEN AT A TIME.
C
C NLINES = 11
C CALL TUTORIAL(NLINES)
50 CONTINUE

C
C Initialize files
C
OPEN(7,FILE='PRINTFIL')
REWIND 7
OPEN(8,FILE='SUMMARY')
REWIND 8
ICASE =0

C
C LOOP FOR A NUMBER OF EVALUATIONS
C
100 CONTINUE
ICASE=ICASE+1
C Initialize variables
DO 3060 I =1,31
3060 VAL0(I)=0.0
DO 3061 I = 1,22
3061 VAL1(I)= 0.0

C
C *****
C Check if there are any more cases to be run.
C *****
C
IF (ICASE .EQ. 1) GO TO 110
```

```

9001 CONTINUE
      WRITE (*,2010)
2010 FORMAT (//,' Do you want to run any more cases(Y/N)?',/)
      READ (*,2020,ERR=9001) IYN
2020 FORMAT (A1)
      IF (IYN .EQ. No) GO TO 900
110  WRITE (*,6100) CHAR(12),UPDATE,ICASE
      WRITE (7,6100) CHAR(12),UPDATE,ICASE
      WRITE(8,6101) ICASE
C
C Subroutine INPUT identifies input parameter and changes its value.
C
      CALL INPUT
C
C Initialize integer constants. These values were read in as real
C number in SUBROUTINE INPUT.
C
      TP = NINT(ATP)
      DRY = NINT(ADRY)
      STIM = NINT(ASTIM)
      MACE = NINT(AMACE)
      MINE = NINT(AMINE)
      WORK = NINT(AWORK)
      PLNT = NINT(APLNT)
      IF (STIM .EQ. 2 .OR. STIM .EQ. 5) THEN
        IF (MINE .NE. 4) RRW = RA
      ELSE
        RRW = RW
      ENDIF
C
C Write parameter values used for a specific run to output.
C
      WRITE(7,6700)
      WRITE(7,6220) (IVA1(I),VA1(I),VAR1(I),I=1,21)
      WRITE(7,*) ' '
      WRITE(7,*) '           Site Specific Orebody and Wellfield'
      WRITE(7,*) '           Characteristics'
      WRITE(7,6220) (IVA2(I),VA2(I),VAR2(I),I=1,24)
      WRITE(7,*) ' '
      WRITE(7,*) '           Copper Leaching'
      WRITE(7,6220) (IVA3(I),VA3(I),VAR3(I),I=1,10)
      WRITE(7,*) ' '
      WRITE(7,*) '           Program Control'
      WRITE(7,6900) (IVA4(I),VAL4(I),I=1,3)
      WRITE(7,*) ' '
      WRITE(7,*) '           Well System Specification and Cost'
      WRITE(7,6220) (IVA5(I),VA5(I),VAR5(I),I=1,92)
      WRITE(7,*) ' '
      WRITE(7,*) '           Surface Plant Specifiacion and Cost Default'
      WRITE(7,6220) (IVA6(I),VA6(I),VAR6(I),I=1,64)
      WRITE(7,*) ' '
      WRITE(7,*) '           Environment Cost Default'
      WRITE(7,6221) (IVA7(I),VA7(I),VAR7(I),I=1,5)
      IF (TP.LE.0) GO TO 900
C
C COMPUTE INTERNAL CONSTANTS.
C
      PRODCY = Y *EFFECT/100.
      PRDDAY = Y/365.0
C
C Compute total wellfield flow rate,acid concentration,consumption of
C acid and lime, and waste generation.

```

```

C
C relevant nomenclature :
C Y = Annual on-stream production rate tons/onstream year
C CULD = Copper loading grams/liter
C ALPHA1 = Units conversion factor appropriate
C Q = Wellfield total flow rate gal/min
C
C Q = ALPHA1*Y/CULD
C CH2SO4 = CULD*(W4+W7)
C W10 = W4+W7+W8+W9
C W6 = W12*(W7+W8-W9)
C W14 = W13*W6-W15*W4
C W11 = W14*Y*EFFO/100.
C
C Calculate pressures and pressure drops across production and injection wells.
C
C relevant nomenclature :
C D = Depth to bottom of ore zone. ft
C H = Ore zone thickness ft
C AF = Fracture gradient psi/ft
C PRESI = Pressure at top of ore zone at injection well psi
C DPT = Injector to producer pressure drop psi
C
C Injection pressure is calculated at maximum limited by fracturing.
C Production pressure at atmospheric.
C
C PRESI = AF*(D-H)
C DPT = PRESI
C
C Branch to appropriate mining method to calculate geometric factors G and A.
C
C MINE defines type of flow system used for mining.
C MINE = 1, Axial flow with horizontal fractures.
C 2, Axial flow with vertical fractures.
C 3, Radial flow.
C 4, Fan flow, only available with underground access.
C
C GO TO (3001,3002,3003,3004),MINE
C WRITE (7,7001)
C GO TO 900
C
C Axial flow, horizontal fractures.
C Nomenclature:
C S1 = Horizontal distance along one side of square ft.
C H1 = Vertical height of leach interval ft.
C G = Effective flow area per unit length of flow path. ft.
C A = Leach area of unit cell square ft.
C
C 3001 CONTINUE
C A = S1*S1
C G = A/H1
C SW = S1
C SWW = S1
C GO TO 3005
C
C Axial flow, vertical fractures.
C Nomenclature :
C S1 = Producer to producer distance perpendicular ft.

```

```

C          to fracture.
C          S2 = Producer to producer distance parallel
C          to fracture.
C
C          3002 CONTINUE
C          G = 4*H*S2/S1
C          A = S1*S2
C          SW = (S1+S2)/2.
C          SWW = SW
C          GO TO 3005
C
C Radial flow pattern.
C Nomenclature :
C   S1      = Producer to producer distance.          ft.
C   RW      = Well radius.                             ft.
C   RA      = Well radius after stimulation.           ft.
C   RE      = Drainage radius.                         ft.
C   FACJ    = Constant in radial flow equation.       -
C   IF (STIM .EQ. 2 .OR. STIM .EQ. 5) RRW = RA
C
C          3003 CONTINUE
C          RE = S1/SQRT(2.)
C          G = PI*H/(ALOG(RE/RRW)+FACJ)
C          A = S1*S1
C          SW = S1
C          SWW = S1
C          GO TO 3005
C
C Fan flow pattern.
C Nomenclature :
C   H1      = Height of leach unit in fan flow.       ft.
C   H2      = Horizontal length of leach unit in fan flow. ft.
C   THTA    = Angle between wells in fan flow.        rad.
C   RW      = Radius of well.                         ft.
C
C          3004 CONTINUE
C          G = PI/2.*H1/(PI/4.*H2/H1+THTA/PI*ALOG(THTA*H1/(4.*RW)))
C          A = 2.*H1*H2
C          3005 CONTINUE
C
C Calculate wellfield life and number of unit cells in operation at one time.
C Nomenclature :
C   QI      = Injection well flow rate.                gpm.
C   NT      = Number of unit cells in operation.       -
C   TW      = Well life                               years.
C   NWELLS = Number of wells in operation.           -
C   TWPRM   = Time required to prime the wellfield.   years.
C   EFFF    = Percent of pore volume to be filled-up
C             by acid solution for priming.
C   CUWGT   = Weight of copper in unit cell.          tons.
C   RCOVRY  = Fraction of copper recovered.           fraction.
C   NPROD   = Number of production wells.
C   DRY     = Initial condition of orebody-
C             1 for unsaturated orebody.
C             2 for saturated orebody.
C
C          IF (MINE .EQ. 4) THEN
C            EZ = H1/H
C          ELSE

```

```

EZ = 1
ENDIF
QI = ALPHA2*PERM*DPT*G/VISC
RNT = Q/QI
CUWGT = EZ*A*H*RHOP*(1.-PORO/100.)*GRDO*5.E-6
RCOVRY= EFFS/100.*EFFL/100.*EFFR/100.
TWO =RNT*CUWGT*RCOVRY/Y*100./EFFO
AWT = EZ*A*RNT*FLOAT(TP)/TWO
TL = INT(TWO)+1
TW = FLOAT(TL)
X = Q/QI*FLOAT(TL)/TWO
NT = NINT(X)
RNT = FLOAT(NT)
SQRNT = SQRT(RNT)
QI = Q/RNT
AWF = EZ*A*RNT
RI = EZ*A/G
XI = EZ*A*H/G
RPROD= (1.+SQRT(RNT))**2.
NPROD= NINT(RPROD)
RINJ = FLOAT(NT)
RPROD = FLOAT(NPROD)
QP = Q/RPROD
NWELLS=NT+NPROD
IF(MINE.EQ.4)GO TO 3075

```

```

C
C Look-Up well size dependant factors for vertical wells.
C

```

```

DO 3077 I =1,3
IF(QI.GT.QW(I))GO TO 3077.
DH = BWV(13,I)
DC = BWV(14,I)
DI = BWV(15,I)
DP = DI
BT = BWV(1,I)
BTU = BWV(2,I)
BRW = BWV(3,I)
BRH = BWV(4,I)
BRX = BWV(5,I)
BRC = BWV(6,I)
BH = BWV(7,I)
BD = BWV(8,I)
BDU = BWV(9,I)
R = BWV(10,I)
BC = BWV(11,I)
BCU = BWV(12,I)
BK = BWV(16,I)
GO TO 3078
3077 CONTINUE
3078 CONTINUE
SW = 2.*SW*(2.*RNT+2.*SQRNT+1)
GO TO 3076
3075 CONTINUE
C AWF =AWF*H1/H
C RI =RI*H1/H
C XI =XI*H1/H
NWELLS = NT*(NINT(PI/THTA)+1)
NFACE = NWELLS/NT
SW = 2.*H2*RNT+4.*SQRNT*SQRT(H1*H2/2)
3076 CONTINUE

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```

R WELL = FLOAT(NWELLS)
TWP = ALPHA3*EFFP*PORO*EZ*A*H/QI
C
C Branch for type of mining access to orebody underground or surface.
C
C MACE = 1 for surface access.
C MACE = 2 for underground access.
C
C IF (MACE .EQ. 1) GO TO 3007
C
C **** MINING BY UNDERGROUND ACCESS ****
C
C Calculate underground development costs.
C
C Nomenclature :
C CS = Cost per foot of shaft. $/ft.
C SS = Footage of shaft. ft.
C CR = Cost per foot of raise. $/ft.
C SR = Footage of raise. ft.
C CDA = Cost per foot of adit or drift. $/ft.
C SDA = Footage of adit or drift. ft.
C EA = Capital expenses for access to orebody by $
C underground working.
C EV = Ventilation capital cost for underground working. $
C EM = Capital expenses for supporting surface $
C facilities including headframe,hoist,maintenance
C shops,etc.
C EE = Capital expenses for electrical facilities. $
C ET = Total capital expenses for underground workings. $
C
C HPM =CPL
C IF(SS.GT.0.)GO TO 4000
C SDE = D
C IF(MINE.NE.4)SDE = D-H
C SS = 2.*SDE
C SR = SDE
C 4000 CONTINUE
C EA = CS*SS + CR*SR + CDA*SDA
C ET = EA + EV + EM + EE
C IF(WORK .EQ. 1) ET=0.
C
C Branch for fanwell pattern.
C Note MINE =4 for fanwell pattern.
C
C IF ( MINE.EQ.4) GO TO 3006
C
C Calculate costs for vertically drilled wells via underground access.
C Costs formulae are same as for surface access drilling of vertical
C wells but values of cost constants may be different.If a constant has
C a different value U is added on the end for underground access.
C
C CA = BAU
C CD = BDU*H/R+B15
C CC = H*(BCU+BDU/RC+B1)+B2
C CCM = H*PI*(DH**2-DC**2)/ALPHA4*(BG+BB)+B3U
C GO TO (3018,3019,3020,3021,3022),STIM
C
C Screened well completion.
C
C CW = H*(BW+BDU/RC)

```

```

      GO TO 3023
3018 CONTINUE
C
C   Perforated well completion.
C
      CW = H*4.*BJ+BLU
      GO TO 3023
3019 CONTINUE
C
C   Well completion by small radius hydrofrac.
C
      CW = B4U+B5*H-4.*H*BJ-BLU
      GO TO 3023
3020 CONTINUE
C
C   Well completion by large radius vertical hydrofrac.
C
      CW = B6U +B7*S2*H-4.*H*BJ-BLU
      GO TO 3023
3021 CONTINUE
C
C   Well completion by large radius horizontal hydrofrac.
C
      NV = NINT(H/H1)
      NPF = NV/2+1
      NIF = NV+1-NPF
      FRACTN = (RPROD*FLOAT(NPF)-RINJ*FLOAT(NIF))/(RPROD+RINJ)
      CW = (B6U+B7*S1*S1)*FRACTN
      GO TO 3023
3022 CONTINUE
C   Well completion by explosive fracturing.
      CW = B8U+B9*H
3023 CONTINUE
C
C   Calculate wellfield capital expenses.
C
      CWL = B10U+B11*H
      CWEI = BH +BK + H*(BTU+BTI)+BSI
      HPP = ALPHA7*Q*(D-H)*RHOF/ETA
      CWEP = H*(BTU+BRW+B12)+ALPHAS*QP*(D-H)*(BRH+B13)+
1      BRX+BRC+BH+B14
      CDE = SWW*BX*(2.*RNT+SQRNT)+2.*SWW*SQRNT*CDA
      EW = (RINJ+RPROD)*(CA+CD+CC+CCM+CW+CWL)+
1      RINJ*CWEI+RPROD*CWEP+CDE
      GO TO 3015
C
C   Calculate cost of fanwell pattern.
C
C   Nomenclature:
C   BX      = Cost per foot of crosscut           $/ft.
C   BP      = Piping cost for fanwell pattern     $/ft.
C   CF      = Capital cost per fanwells unit cell $/cell.
C   EW      = Wellfield capital cost incurrrred eachtime $
C
3006 CONTINUE
      CDE = RNT*H2*BX+4.*SQRNT*SQRT(H2/2./H)*H*CDA
      CWEI = 0.
      CWEP = 0.
      CEWI = NFACE*0.5*BWFI*H1
      CEWP = NFACE*0.5*BWFP*H1

```

CF = NFACE*0.5*(BWFI+BWFP)*H1
 HPP = ALPHA7*Q*(D-H)*RHO/ETA
 EW = CDE + (CEWP + CEWI)*RNT
 GO TO 3015

3007 CONTINUE
 ET = 0.0
 HPM = 0.0

***** MINING BY SURFACE ACCESS *****

Calculate cost of vertically drilled wells from surface access.

Nomenclature :

| | | |
|--------|---|------------|
| BA | = Earthmoving cost per drillsite | \$/sq. ft. |
| BD | = Drilling rig hourly cost | \$/hr. |
| R | = Average drilling rate. | ft/hr. |
| RC | = Casing & Screen setting rate | ft/hr. |
| BC | = Casing cost. | \$/ft. |
| CC | = Casing cost per well. | \$/well. |
| CD | = Drilling cost per well. | \$/well. |
| CA | = Drilling site development. | \$/well. |
| CCM | = Cementing cost per well. | \$/well. |
| BG | = Grout (cement) cost. | \$/cu. ft. |
| BB | = Cement blending and pumping cost. | |
| DH | = Drilled hole diameter | in. |
| DC | = Casing diameter. | in. |
| CW | = Well completion | \$/well. |
| STIM | = Type of stimulation and well completion. | |
| | 0 for screened or open hole. | |
| | 1 for perforated completion. | |
| | 2 for small radius stimulation by hydrofrac. | |
| | 3 for large radius stimulation by vertical hydrofrac. | |
| | 4 for large radius stimulation by horizontal hydrofrac. | |
| | 5 for explosive stimulation. | |
| BW | = Cost of well screen. | \$/ft. |
| BJ | = Cost of perforations. | \$/jet. |
| BL | = Cost of logging set-up. | \$/well. |
| CWL | = Cost of well logging. | \$/well. |
| CWEI | = Cost of injection well equipment. | \$/well. |
| CWEP | = Cost of production well equipment. | \$/well. |
| BH | = Wellhead cost. | \$/well. |
| BK | = Packer cost. | \$/well. |
| BRH | = Cost per hp of recovery pump. | \$/hp. |
| BT | = Cost of tubing. | \$/ft. |
| BTI | = Cost of inflation tube | \$/ft. |
| BRW | = Cost of recovery pump wire cable. | \$/ft. |
| BSIG | = Cost of recovery pump controls. | \$/pump. |
| B1-B16 | = Constants in cost equations. | |

CA = BA
 CD = BD*D/R
 CC = D*(BC+BD/RC+B1)+B2
 CCM = D*PI*(DH**2-DC**2)/ALPHA4*(BG+BB)+B3
 GO TO (3008,3009,3010,3011,3012),STIM

WELL COMPLETION IS SCREENED OR OPEN HOLE

CW = H*(BW+BD/RC)
 GO TO 3013
 3008 CONTINUE

```

C
C WELL COMPLETION - PERFORATED
C
  CW = H*4*BJ+BL
  GO TO 3013
3009 CONTINUE
C
C WELL COMPLETION - STIMULATION BY SMALL RADIUS HYDROFRAC.
C
  CW = B4+B5*H+4.*H*BJ+BL
  GO TO 3013
3010 CONTINUE
C
C WELL COMPLETION - STIMULATION BY LARGE RADIUS VERTICAL HYDROFRAC.
C
  CW = B6+B7*S2*H+4.*H*BJ+BL
  GO TO 3013
3011 CONTINUE
C
C WELL COMPLETION - STIMULATION BY LARGE RADIUS HORIZONTAL HYDROFRAC.
C
  NV = NINT(H/H1)
  NPF = NV/2 +1
  NIF = NV+1-NPF
  FRACTN = (RPROD*FLOAT(NPF)+RINJ*FLOAT(NIF))/(RPROD+RINJ)
  CW = (B6 + B7*S1*S1)*FRACTN
  GO TO 3013
3012 CONTINUE
C
C WELL COMPLETION - STIMULATION BY EXPLOSIVES.
C
  CW = B8 + B9*H
3013 CONTINUE
  CWL = B10 + B11 *D
  CWEI = BH+BK+(D-H)*(BT+BTI)+BSI
  HPP = ALPHA7*Q*(D-H)*RHOF/ETA
  CWEP=(D-H)*(BT+BRW+B12)+ALPHA5*QP*(D-H)*(BRH+B13)+
1   BRX+BRC+BH+B14
  EW = (RINJ+RPROD)*(CA+CD+CC+CCM+CW+CWL) +
1   RINJ*CWEI + RPROD*CWEP
3015 CONTINUE
C
C If initially orebody is dry add cost to wet it.
C
  IF (DRY .EQ. 2) GO TO 3100
  WATER = 7.48*EZ*A*H*RNT*(PORO/100.)*(1.-WS/100.)
  EW = EW + WATER*C7
3100 CONTINUE
C
C *** Wellfield capital cost calculation complete ***
C
C Calculate solution transfer system cost.
C
  DPIT = DPT/AW-(D-H)
  HPI = ALPHA7*Q*DPIT*RHOF/ETA
C
C Table look-up for solution transfer pipeline size.
C
  QSS = SQRT(Q*QI)
  DO 3080 I =1,10

```

```

IF(QSS.GT.QS(I))GO TO 3080
CP1 = BP(2,I)
DP1 = BP(1,I)
GO TO 3081
3080 CONTINUE
3081 CONTINUE
DO 3082 I =1,10
IF(Q.GT.QS(I))GO TO 3082
DP2 =BP(1,I)
CP2 =BP(2,I)
GO TO 3083
3082 CONTINUE
3083 CONTINUE
ES = CP *HPI + CP1*SW + CP2*ST
IF(MINE.EQ.4)ES=ES+CP*HPP
C
C Solution transfer system cost calculated,calculate operating costs.
C Add appropriate start-up costs to capital estimates
C
RMOP =10.
EC = ((C1*W1+C2*W2)*Q-(C1*W3-C4*W10-CS*W5+C6*W6)*Y)*EFO/100.
EL = 0.
RPOP = POPO
EL = EL + CLP0
IF(Y.GT.12500.)GO TO 3200
EL = EL+CLP1
RPOP = RPOP + POP1
GO TO 3230
3200 CONTINUE
IF(Y.GT.25000.)GO TO 3210
CLP = CLP1*(25000.-Y)/12500. +CLP2*(Y-12500.)/12500.
APOP = POP1*(25000.-Y)/12500. +POP2*(Y-12500.)/12500.
RPOP = RPOP+APOP
EL = EL + CLP
GO TO 3230
3210 CONTINUE
IF(Y.GT.50000.)GO TO 3220
CLP = CLP2*(50000.-Y)/25000. + CLP3*(Y-25000.)/25000.
APOP = POP2*(50000.-Y)/25000.+POP3*(Y-25000.)/25000.
RPOP = RPOP+APOP
EL = EL + CLP
GO TO 3230
3220 EL = EL + CLP3+70.*Y
RPOP = RPOP + POP3+1.6*(Y-50)
3230 CONTINUE
EU = CU*(ALPH10*(HPI+HPP+HPM)+ALPHA9*Y)*EFO/100.
EU = EU + C7*(18250.*RPOP+68.*Y*(EFO/100.))
C
C SURFACE PLANT
C
EP = CX*Q+CE*Y
IF(PLNT .EQ. 1) EP =0.
EP = EP + ES + EC/4.
C
C Use inflation indices to correct costs to year of interest.
C
EP = EP * INDC/100.
EW = EW *INDM/100.
C
C Total annual operating costs.

```



```

305  CONTINUE
C
C  FIND FIRST YEAR OF OPERATION
C
      N=AMAXO(LASTE, LASTW)
      N1=N-TW3
      TPROD=AMAXO(N1, LASTP)+1
C
C  FIND FIRST YEAR OF CONSTRUCTION
C
      ISTCON=TPROD-LASTP
      IEND=TPROD-1
      IX=ISTCON-1
      DO 306 I =ISTCON, IEND
306  CAP(I)=EP*SCP(I-IX)
C
C  FIND TOTAL PROJECT LIFE
C
      NYRS=TPROD+TP-1
C
C  DERIVE WELL SCENERIO
C
      IREPL =0
      JRPL =0
C
C  EWE4 is restoration cost. It is expended everytime a wellfield is replaced.
C
      EWE4=0.
      ISWELL=TPROD-LASTW
      IPROD=TPROD+TW4-1
      IX=ISWELL-1
329  CONTINUE
      DO 330 I=ISWELL, IEND
330  WCAP(I)=WCAP(I)+SCW(I-IX)*(EW-EWE4)
      JRPL = JRPL+1
      IRPL(JRPL)=IEND+1
      IF(IREPL.GT.0) GO TO 3065
      IREPL = 1
      EWE4 = E4
3065 CONTINUE
      ISWELL=ISWELL-TW4
      IEND=IEND-TW4
      IX=ISWELL-1
      IF(IPROD.GE.NYRS)GO TO 335
      IPROD=IPROD+TW4
      GO TO 329
335  CONTINUE
C
C  WELL EXPENSES
C
      IWEXP=TPROD-LASTE
      IPRD=TPROD+TW4
      IX=IWEXP-1
      IEND=TPROD-1
396  CONTINUE
      DO 397 I=IWEXP, IEND
397  WEXP(I)=WEXP(I)+SCM(I-IX)*ET
398  CONTINUE
C
500  CONTINUE

```

```

C
C GENERATE PRODUCTION AND PLANT O & M
C
  JRPL = 1
  DO 525 I=TPROD,NYRS
  PROD(I)=PRODT
  IF (IRPL(JRPL).NE.I) GO TO 3701
  JRPL = JRPL+1
  PROD(I)=PROD(I)-TWP*Y
3701 CONTINUE
  OMP(I)=OMP(I)-EO
525 CONTINUE
C
C AGGREGATE CASH FLOWS INTO SUBTOTALS
C
  DO 600 I=1,NYRS
  OMT(I)=OMP(I)+WEXP(I)
600 CONTINUE
C
C ***** COMPUTE PRICE OF COPPER *****
C
  IF(FNDMOD.EQ.1)GO TO 700
  DENOM=1.
  RATE=1./(1.+ROI/100.)
  TFUNDS=0.
  TPRODS=0.
  DO 650 I=1,NYRS
  TFUNDS=TFUNDS+(CAP(I)+WCAP(I)+OMT(I))*DENOM
  TPRODS=TPRODS+PROD(I)* DENOM
  DENOM=DENOM*RATE
650 CONTINUE
C
  PRDTON = TFUNDS/ TPRODS
  PRICE = PRDTON /20.
C
  IF(.NOT. LSTA) GO TO 825
C
C COMPUTE ANNUAL CASH FLOW
C
700 CONTINUE
  PRDTON = 20.* PRICE
  TACF=0.
  DO 750 I= 1,NYRS
  ACF(I)=(PRDTON*PROD(I)-OMT(I)-CAP(I)-WCAP(I))
  TACF = TACF +ACF(I)
750 CONTINUE
C
  IF(FNDMOD.NE.1) GO TO 775
C
C ***** COMPUTE ROI *****
C
  ROI =ROIFCN (ACF,NYRS)
C
  IF(.NOT.LSTA) GO TO 825
775 CONTINUE
C
C COMPUTE DISCOUNTED CASH FLOW
C
  DENOM = 1.
  RATE=1./(1.+ROI/100.)

```

```

TDCF=0.
PRINCE =0.
DO 800 I=1,NYRS
DCF(I) = ACF(I)* DENOM
PRINCE = PRINCE + (CAP(I)-WCAP(I)+WEXP(I))*DENOM/Y
TDCF=TDCF+DCF(I)
DENOM=DENOM*RATE
800 CONTINUE
825 CONTINUE
C
C IF(LSTI) WRITE CALCULATED VALUES.
C
IF(.NOT.LSTI) GO TO 850
WRITE (7,6200) CHAR(12)
WRITE (7,6210) (VAR8(1,I),VAL0(I),VAR8(2,I),I=1,31)
WRITE (7,6210) (VAR9(1,I),VAL1(I),VAR9(2,I),I=1,22)
850 CONTINUE
WRITE(7,6500) CHAR(12),OPMODE(1,FNDMOD),OPMODE(2,FNDMOD),
1 RESULT(FNDMOD),UNITS(FNDMOD)
WRITE(*,6500) CHAR(12),OPMODE(1,FNDMOD),OPMODE(2,FNDMOD),
1 RESULT(FNDMOD),UNITS(FNDMOD)
WRITE(8,6501)RESULT(FNDMOD),UNITS(FNDMOD)
OPERAT = EO/Y/20.
WRITE(7,6600)PRINCE,OPERAT
WRITE(8,6601)PRINCE,OPERAT
RESULT(FNDMOD) = 0.
C
IF(.NOT.LSTA) GO TO 875
WRITE(7,6300) (I,PROD(I),CAP(I),WCAP(I),WEXP(I),OMP(I),
1 ACF(I),DCF(I),I=1,NYRS)
WRITE(7,6650) TACF,TDCF
875 CONTINUE
C
890 CONTINUE
C
GO TO 100
C
900 CONTINUE
- STOP
6100 FORMAT(A1,/,/,
1 20X,'COPPER IN-SITU MINING ECONOMIC EVALUATION',/,
2 30X,A19,/,/,30X,'CASE #',I3,/)
6101 FORMAT(/,'CASE #',I3)
6200 FORMAT (A1,/,/20X,'CALCULATED VALUES',/)
6210 FORMAT (12X,A8,F15.5,1X,A8,10X,A8,F15.5,1X,A8/)
6220 FORMAT(12X,A4,F15.5,1X,A8,10X,A4,F15.5,1X,A8/)
6221 FORMAT(12X,A4,F15.5,1X,A8,10X,A4,F15.5,1X,A8/)
6300 FORMAT(/,35X,'CASH FLOWS IN $(000)',/,
1 4X,'PRODTN',5X,'PLANT',6X,'WELL',3X,'UNDERGROUND',1X,
2 'PLANT',7X,'NET',2X,'DISCOUNTED'/1X,'YR',4X,'TPY',
3 3X,'CAPITAL',3X,'CAPITAL',3X,'CAPITAL',5X,'O & M',1X,
4 'CASH FLOW',2X,'CASH FLOW'/
5 ,(I3,F7.0,-3P5F10.0,-3PF11.0))
6500 FORMAT(A1,/,15X,'**** ',2A4,' = ',F12.2,' ',A4,' ****',/)
6501 FORMAT(F12.2,A4)
6601 FORMAT(2F12.2)
6600 FORMAT(/15X,'DISCOUNTED INITIAL VALUE OF INVESTMENT =',
1 F12.2,1X,'$/Annual Ton'//,15X,
2 'Annual Operating Costs = ',F12.2,1X,'C/LB',/)
6650 FORMAT (50X,'-----', '-----',/)

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```

1 50X,-3PF10.0,-3PF11.0)
6700 FORMAT(/30X,' INPUT PARAMETERS '//20X,'BUSINESS RELATED'//)
6800 FORMAT(/12X,'INTEGERS'/12X,A4,I2,A8,A4,I2,A8,A4,I2,A8//)
6900 FORMAT(12X,'LOGICAL VARIABLES'/(12X,A4,L7,8X))
7001 FORMAT (12X,'INCORRECT MINING PATTERN SPECIFIED')
7011 FORMAT(3I2)
END
BLOCK DATA L1

```

```

C
C Business Related Variables
C

```

```

REAL*8 VAR1(21),VAR,VAR2
COMMON/INPUT1/VA(216)
COMMON/NAME1/IVA(219)
COMMON/NAME2/VAR(216)
DIMENSION IVA1(21),VA1(21)
EQUIVALENCE(VAR1(1),VAR(1)),(IVA(1),IVA1(1)),(VA1(1),VA(1))
DATA IVA1/4HINDC,4HINDM,3HROI,4HPRIC,4HSCM1,4HSCM2,4HSCM3,
1 4HSCM4,4HSCM5,4HSCP1,4HSCP2,4HSCP3,4HSCP4,4HSCP5,4HSCW1,
2 4HSCW2,4HSCW3,4HSCW4,4HSCW5,2HTP,1HY/
DATA VA1/100.0,100.0,20.0,0.0,0.4,0.6,0.0,0.0,0.0,0.23,0.25,0.52,
1 0.0,0.0,0.34,0.66,0.0,0.0,0.0,0.0,0.0,20.0,25000.0/
DATA VAR1/2*1H%,1H%,4Hc/LB,15*1H ,3HYRS,3HTPY/
END
BLOCK DATA L2

```

```

C
C Site Specific Orebody and Wellfield Variables.
C

```

```

COMMON/INPUT1/VA1(21),VA2(24),VA3(10),VA5(92),VA6(64),
1 VA7(5)
COMMON/NAME1/IVA1(21),IVA2(24),IVA3(10),IVA4(3),IVA5(92),IVA6(64),
1 IV7(5)
REAL*8 VARR,VAR1,VAR2,VAR3,VAR5,VAR6,VAR7
COMMON/NAME2/VAR1(21),VAR2(24),VAR3(10),VAR5(92),VAR6(64),
1 VAR7(5),VARR(2,53)
DATA IVA2/2HAF,1HD,3HDY,4HGRDO,1HH,2HH1,2HH2,4HMACE,4HMINE,
1 4HPERM,4HPORO,2HRA,4HRHOP,2HRW,2HS1,2HS2,3HSDA,2HSR,2HSS,4HSTIM,
2 4HTHTA,4HWOR,2HWS,2HWD/
DATA VA2/1.0,1000.0,1.0,1.0,300.0,30.,60.,1.0,3.0,2.0,5.0,8.0,
1 162.0,0.25,100.0,100.0,2000.0,0.0,0.0,2.0,0.315,2.0,80.0,500.0/
DATA VAR2/6HPSI/FT,2HFT,1H ,1H%,3*2HFT,2*1H ,4HM.D.,1H%,2HFT,
1 8HLB/CU.FT,6*2HFT,1H ,6HRADIAN,1H ,1H%,2HFT/
END
BLOCK DATA L3

```

```

C
C Copper Leaching Variables.
C

```

```

COMMON/INPUT1/VA1(21),VA2(24),VA3(10),VA5(92),VA6(64),
1 VA7(5)
COMMON/NAME1/IVA1(21),IVA2(24),IVA3(10),IVA4(3),IVA5(92),IVA6(64),
1 IV7(5)
REAL*8 VARR,VAR1,VAR2,VAR3,VAR5,VAR6,VAR7
COMMON/NAME2/VAR1(21),VAR2(24),VAR3(10),VAR5(92),VAR6(64),
1 VAR7(5),VARR(2,53)
DATA IVA3/4HCULD,4HEFFL,4HEFFO,4HEFFP,4HEFFR,4HEFFS,4HPLNT,
1 4HVISC,2HW4,2HW7/
DATA VA3/6.0,75.0,91.2,100.0,90.0,75.0,2.0,1.0,4.0,1.54/
DATA VAR3/6HGRAM/L,5*1H%,1H ,7HCENTI P,2*8HT ACID/T/
END
BLOCK DATA L4

```

C
C Program Control Variables.
C

```
LOGICAL LSTI, LSTA, LST, VAL4
REAL*8 VARR, VAR1, VAR2, VAR3, VAR5, VAR6, VAR7
COMMON/INPUT1/VA1(21), VA2(24), VA3(10), VA5(92), VA6(64),
1 VA7(5)
COMMON/INPUT2/ VAL4(3)
COMMON/NAME1/IVA1(21), IVA2(24), IVA3(10), IVA4(3), IVA5(92), IVA6(64),
1 IV7(5)
COMMON/NAME2/VAR1(21), VAR2(24), VAR3(10), VAR5(92), VAR6(64),
1 VAR7(5), VARR(2, 53)
DATA IVA4/4HLSTI, 4HLSTA, 3HLST/
DATA VAL4/3*.TRUE./
END
BLOCK DATA L5
```

C
C Well system specification and cost inputs.
C

```
REAL*8 VARR, VAR1, VAR2, VAR3, VAR5, VAR6, VAR7
COMMON/INPUT1/VA1(21), VA2(24), VA3(10), VA5(92), VA6(64),
1 VA7(5)
COMMON/NAME1/IVA1(21), IVA2(24), IVA3(10), IVA4(3), IVA5(92), IVA6(64),
1 IV7(5)
COMMON/NAME2/VAR1(21), VAR2(24), VAR3(10), VAR5(92), VAR6(64),
1 VAR7(5), VARR(2, 53)
DATA IVAS/2HAW, 2HB1, 2HB2, 2HB3, 2HB4, 2HB5, 2HB6, 2HB7, 2HB8, 2HB9, 3HB10,
1 3HB11, 3HB12, 3HB13, 3HB14, 3HB15, 3HB3U, 3HB4U, 3HB6U, 3HB8U, 4HB10U,
2 2HBA, 3HBAU, 2HBB, 2HBC, 2HBJ, 2HBL, 3HBLU, 3HBSI, 3HBTI, 2HBW, 3HBW1,
3 3HBW2, 3HBW3, 3HBW4, 3HBW5, 3HBW6, 3HBW7, 3HBW8, 3HBW9, 4HBW10, 4HBW11,
4 4HBW12, 4HBW13, 4HBW14, 4HBW15, 4HBW16, 4HBW17, 4HBW18, 4HBW19, 4HBW20,
5 4HBW21, 4HBW22, 4HBW23, 4HBW24, 4HBW25, 4HBW26, 4HBW27, 4HBW28, 4HBW29,
6 4HBW30, 4HBW31, 4HBW32, 4HBW33, 4HBW34, 4HBW35, 4HBW36, 4HBW37, 4HBW38,
7 4HBW39, 4HBW40, 4HBW41, 4HBW42, 4HBW43, 4HBW44, 4HBW45, 4HBW46, 4HBW47,
8 4HBW48, 4HBWFI, 4HBWFP, 2HBX, 3HCDA, 2HCP, 3HCPL, 2HCR, 2HCS, 2HEE, 2HEM,
9 2HEV, 4HFACJ, 2HRC/
DATA VAS/.43, 0.56, 2045.0, 1425.0, 2500.0, 14.0, 5000.0, 0.41, 2800.0,
1 235.0, 3135.0, 2.7, 0.1, 92.0, 1811.0, 5000.0, 5000.0, 5600.0, 10000.0,
2 3600.0, 4702.5, 2400.0, 5000.0, 470.15, 1.5, 800.0, 1600.0, 2000.0,
3 1.0, 20.0, 5.41, 11.9, 1.0, 325.0, 0.0, 1100.0, 1240.0, 175.0, 350.0,
4 30.0, 15.0, 33.0, 7.0, 4.0, 1.92, 3000.0, 7.35, 16.17, 3.0, 70.0, 500.0,
5 1350.0, 1240.0, 200.0, 400.0, 20.0, 26.0, 57.2, 10.0, 6.0, 2.42, 5000.0,
6 15.8, 34.76, 5.0, 102.0, 1000.0, 2500.0, 1718.0, 250.0, 500.0, 15.0,
7 35.0, 77.0, 12.0, 8.0, 4.04, 7000.0, 30.0, 10.0, 400.0, 400.0, 150.0,
8 700.0, 1000.0, 3000.0, 200000.0, 2500000.0, 120000.0, -0.619, 130.0/
DATA VARS/6HPSI/FT, 4HS/FT, 3*6HS/WELL, 4HS/FT, 6HS/FRAC, 8HS/SQ. FT.,
1 6HS/WELL, 4HS/FT, 6HS/WELL, 2*4HS/FT, 4HS/HP, 4*6HS/WELL, 6HS/FRAC,
2 2*6HS/WELL, 2*1HS, 2*8HS/CU. FT., 5HS/JET, 3*6HS/WELL, 4HS/FT,
3 4*4HS/FT, 4HS/HP, 3*6HS/WELL, 2*4HS/HR, 5HFT/HR, 2*4HS/FT, 3*2HIN,
4 8HS/PACKER, 3*4HS/FT, 4HS/HP, 3*6HS/WELL, 2*4HS/HR, 5HFT/HR, 2*4HS/FT,
5 3*2HIN, 8HS/PACKER, 3*4HS/FT, 4HS/HP, 3*6HS/WELL, 2*4HS/HR, 5HFT/HR,
6 2*4HS/FT, 3*2HIN, 8HS/PACKER, 4*4HS/FT, 4HS/HP, 2HKW, 2*4HS/FT, 3*1HS,
7 1H, 5HFT/HR/
END
BLOCK DATA L6
```

C
C Surface plant and cost inputs.
C

```
REAL*8 VARR, VAR1, VAR2, VAR3, VAR5, VAR6, VAR7
COMMON/INPUT1/VA1(21), VA2(24), VA3(10), VA5(92), VA6(64),
```

```

1 VA7(5)
COMMON/NAME1/IVA1(21), IVA2(24), IVA3(10), IVA4(3), IVA5(92), IVA6(64),
1 IV7(5)
COMMON/NAME2/VAR1(21), VAR2(24), VAR3(10), VAR5(92), VAR6(64),
1 VAR7(5), VARR(2, 53)
DATA IVA6/3HBP1, 3HBP2, 3HBP3, 3HBP4, 3HBP5, 3HBP6, 3HBP7,
1 3HBP8, 3HBP9, 4HBP10, 4HBP11, 4HBP12, 4HBP13, 4HBP14, 4HBP15,
2 4HBP16, 4HBP17, 4HBP18, 4HBP19, 4HBP20, 2HC1, 2HC2, 2HC3, 2HC4, 2HC5,
3 2HC6, 2HC7, 2HCE, 2HCL, 4HCLP0, 4HCLP1, 4HCLP2, 4HCLP3, 2HCU, 2HCX,
4 3HETA, 4HPOPO, 4HPOP1, 4HPOP2, 4HPOP3, 3HQS1, 3HQS2, 3HQS3,
5 3HQS4, 3HQS5, 3HQS6, 3HQS7, 3HQS8, 3HQS9, 4HQS10, 3HQP1, 3HQP2, 3HQP3,
6 4HRHOF, 2HST, 2HW1, 2HW2, 2HW3, 2HW5, 2HW8, 2HW9, 3HW12, 3HW13, 3HW15/
DATA VA6/2.0, 12.5, 3.0, 18.75, 4.0, 25.0, 6.0, 37.5, 8.0, 50.0, 10.0, 62.5,
1 12.0, 65.0, 14.0, 75.8, 16.0, 86.67, 18.0, 97.5, 10000.0, 300.0, 6.5, 30.0,
2 185.0, 50.0, 0.02, 650.0, 20.0, 1746000.0, 1750000.0, 2625000.0,
3 3500000.0, 0.05, 2500.0, 0.7, 32.0, 40.0, 60.0, 80.0, 55.0, 150.0, 300.0,
4 800.0, 1600.0, 2900.0, 4500.0, 5700.0, 8000.0, 10600.0, 50.0, 100.0,
5 300.0, 62.4, 6000.0, 0.015, 0.085, 0.261, 0.065, 0.2, 0.231, 0.571, 2.43,
6 1.36/
DATA VAR6/2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN,
1 4HS/FT, 2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN, 4HS/FT, 2HIN,
1 4HS/FT, 2*7HS/CU.M., 4HS/KG, 3*5HS/TON,
2 8HS/GALLON, 5HS/TPY, 4HS/HR, 4*4HS/YR, 6HS/KWHR, 5HS/GPM, 8HFRACTION,
3 4*3HMEM, 13*3HGPM, 8HLB/CU.FT, 2HFT, 2*8HM/GPM/YR, 6HKG/TON,
4 8HT ANOD/T, 1H ,8HT ACID/T, 7HT CAO/T, 8HS04/LIME, 8HFES04/AC/
END
BLOCK DATA L7

```

```

C
C Environment and cost parameters.
C

```

```

REAL*8 VARR, VAR1, VAR2, VAR3, VAR5, VAR6, VAR7
COMMON/INPUT1/VA1(21), VA2(24), VA3(10), VA5(92), VA6(64),
1 VA7(5)
COMMON/NAME1/IVA1(21), IVA2(24), IVA3(10), IVA4(3), IVA5(92), IVA6(64),
1 IVA7(5)
COMMON/NAME2/VAR1(21), VAR2(24), VAR3(10), VAR5(92), VAR6(64),
1 VAR7(5), VARR(2, 53)
DATA IVA7/3HMA, 3HMAW, 3HEP6, 4HEPEM, 2HX1/
DATA VA7/1.37E-4, 1.83E-4, 462500.0, 80300.0, 5.0/
DATA VAR7/8HS/SQFTFT, 8HS/SQFTFT, 1HS, 4HS/YR, 1H$/
END
BLOCK DATA L8

```

```

C
C ** OUTPUT VARIABLES **
C

```

```

REAL*8 VARR, VAR8, VAR9
COMMON/NAME2/VARR(216), VAR8(2, 31), VAR9(2, 22)
DATA VAR8/1HA, 6HSQ.FT., 7HA SUB W, 6HSQ.FT., 8HINJ PRES,
1 3HPSI, 1HQ, 3HGPM, 8HINJ FLOW, 3HGPM, 7H# CELLS, 1H#, 8HWEL LIFE, 2HYR,
2 6HPRIM T, 2HYR, 7HACID C., 6HGRAM/L, 8HLIME CON, 7HTON/TON, 8HACID CON,
3 7HTON/TON, 8HSULFATES, 6HTON/YR, 8HSULFATES, 7HTON/TON, 1HG, 1H ,2HRI,
4 1H ,2HXI, 1H ,8HWEL MODS, 1H#, 5HWELLS, 1H#, 8HSOL PIPE, 2HFT, 5HCWGT,
5 3HTON, 8HRECOVERY, 5HFRACTION, 8HMINE OPS, 1H#, 6HCASING, 2HIN, 8HOLE DIA,
6 2HIN, 8HINJ TUBE, 2HIN, 8HPRD TUBE, 2HIN, 8HINJ PUMP, 2HHP, 8HPRD PUMP,
7 2HHP, 8HWEL PIPE, 2HIN, 8HTRS PIPE, 2HIN, 8HPLNT OPS, 1H#/
DATA VAR9/8HSITE PRP, 6HS/WELL, 6HCASING, 6HS/WELL, 6HCEMENT, 6HS/WELL,
1 8HDRILLING, 6HS/WELL, 8HFAN WELL, 5HS/FAN, 8HCOMPLTON, 6HS/WELL,
2 7HLOGGING, 6HS/WELL, 8HINJ EQIP, 6HS/WELL, 8HPRD EQIP, 6HS/WELL,
3 8HUND.WORK, 1HS, 8HCHEMICLS, 4HS/YR, 5HLABOR, 4HS/YR, 5HO & M, 4HS/YR,
4 8HPLNT CAP, 1HS, 8HSOL TRNS, 1HS, 8HUND.DEV., 1HS, 8HUTILITYYS, 4HS/YR,

```

```

5 8HWEL CAP.,1HS,8HEIS &PER,1HS,8HMON WELS,1HS,8HENV.MON.,4HS/YR,
6 7HRESTORE,1HS/
END
SUBROUTINE INPUT
LOGICAL VAL4, VAL4P, FLXT
REAL*8 VAR1,VAR2,VAR3,VAR5,VAR6,VAR7,VARR
CHARACTER*20 Filename, Temp
COMMON/INPUT1/ VAL(21),VA2(24),VA3(10),VA5(92),VA6(64),VA7(5)
COMMON/INPUT2/ VAL4(3)
COMMON/NAME1/ IVA1(21), IVA2(24), IVA3(10), IVA4(3),
1 IVA5(92), IVA6(64), IVA7(5)
COMMON/NAME2/ VAR1(21), VAR2(24), VAR3(10),
1 VAR5(92), VAR6(64), VAR7(5), VARR(2,53)
DATA ICD, ICU / 1HD, 1HU /
DATA Iyes,No /1HY, 1HN/, Iblank/1H /
C
C Write Main Input Menu to Screen
C
10 WRITE(*,7000)
7000 FORMAT (//,10X,'INPUT PHASE',//,
1 5X,'1. Business Related Variables',T45,
2 '6. Surface Plant and Cost Inputs',//,
3 5X,'2. Orebody and Wellfield Char.',T45,
4 '7. Environment and Cost Parameters',//,
5 5X,'3. Copper Leaching Inputs',T45,
6 '8. READ a Saved Data File',//,
7 5X,'4. Program Control Parameters',T45,
8 '9. SAVE Data to File',//,
9 5X,'5. Well System Spec. and Cost Inputs',T45,
A '0. Quit Input & Go Calculate',/////,
B 10X,'TYPE in Option Number and Hit the Enter Key',/////))
READ (*,7001,ERR=10) Key
7001 FORMAT (I1)
IF (Key .LT. 0 .OR. Key .GT. 9) GO TO 10
GO TO (300,110,120,130,140,150,160,170,180,190), Key+1
C
C Key = 1 : Business Related Input Parameters
C
9003 CONTINUE
110 WRITE (*,7010)
7010 FORMAT (/, ' Business Related Input Parameters',/)
WRITE (*,7002) (IVAL(I),VAL(I),VAR1(I),I=1,21)
7002 FORMAT (10X, A4, F15.6, 1X, A8, 10X, A4, F15.6, 1X, A8,/)
WRITE (*,7003)
7003 FORMAT (' TYPE in Variable NAME and New Value, or Hit the Enter',
1 ' Key for menu',/)
READ (*,7004,ERR=9003) JVAR, VALP
7004 FORMAT (A4,F15.0)
IF (JVAR .EQ. Iblank) GO TO 10
DO 111 I = 1, 21
IF (IVAL(I) .EQ. JVAR) GO TO 112
111 CONTINUE
WRITE (*,7005)
7005 FORMAT (/, ' Variable NAME Not Found...Please try again.',/)
GO TO 110
112 VAL(I) = VALP
GO TO 110
C
C Key = 2 : Site Specific Orebody and Wellfield Characteristics
C Input Parameters

```

```

C
9004 CONTINUE
120 Iscreen = 1
123 WRITE (*,7020)
7020 FORMAT (/, ' Site Specific Orebody and Wellfield Characteristic',
1 ' Parameters',/)
MAX = 24
M1 = (Iscreen -1) * 18 + 1
M2 = MINO (M1+17, MAX)
IF ((M2-M1) .LT. 14) M1=M2-17
WRITE (*,7002) (IVA2(I),VA2(I),VAR2(I),I=M1,M2)
WRITE (*,7021)
7021 FORMAT (' Type U or D to move UP or DOWN a screen in this ',
1 ' category')
WRITE (*,7003)
READ (*,7004,ERR=9007) JVAR, VALP
IF (JVAR .EQ. Iblank) GO TO 10
IF (JVAR .EQ. ICU) THEN
  Iscreen = Iscreen - 1
  IF (Iscreen .LE. 0) Iscreen = 1
  GO TO 123
ENDIF
IF (JVAR .EQ. ICD .AND. VALP .EQ. 0.0) THEN
  IF (M2 .EQ. MAX) THEN
    WRITE (*,7022)
7022 FORMAT (' No more screens in this category')
    GO TO 123
  ENDIF
  Iscreen = Iscreen + 1
  GO TO 123
ENDIF
DO 121 I = M1, M2
IF (IVA2(I) .EQ. JVAR) GO TO 122
121 CONTINUE
WRITE (*,7005)
GO TO 123
122 VA2(I) = VALP
GO TO 123

```

```

C -
C Key = 3 : Copper Leaching Input Parameters
C

```

```

9005 CONTINUE
130 WRITE (*,7030)
7030 FORMAT (/, ' Copper Leaching Input Parameters',/)
WRITE (*,7002) (IVA3(I),VA3(I),VAR3(I),I=1,10)
DO 133 I=1,10
WRITE (*,7042)
133 CONTINUE
WRITE (*,7003)
READ (*,7004,ERR=9005) JVAR, VALP
IF (JVAR .EQ. Iblank) GO TO 10
DO 131 I = 1, 10
IF (IVA3(I) .EQ. JVAR) GO TO 132
131 CONTINUE
WRITE (*,7005)
GO TO 130
132 VA3(I) = VALP
GO TO 130

```

```

C
C Key = 4 : Program Control Parameters

```

```

C
9006 CONTINUE
  140 WRITE (*,7040)
7040 FORMAT (/, ' Program Control Parameters',/)
  WRITE (*,7041) (IVA4(I),VAL4(I),I=1,3)
7041 FORMAT(12X,A4,10X,L7,/)
  DO 143 I=1,14
  WRITE (*,7042)
7042 FORMAT(' ')
  143 CONTINUE
  WRITE (*,7003)
  READ (*,7044,ERR=9006) Temp
7044 FORMAT(A20)
  IF (LEN (Temp) .EQ. 0) GO TO 10
  IF (Temp(1:1) .EQ. ' ') GO TO 10
  READ (Temp,7043,ERR=145,IOSTAT=IOS) JVAR
7043 FORMAT (A4)
  IF (JVAR .EQ. Iblank) GO TO 10
  READ (Temp,7045,ERR=145,IOSTAT=IOS) VAL4P
7045 FORMAT (4X,L10)
  DO 141 I = 1,3
  IF (IVA4(I) .EQ. JVAR) GO TO 142
  141 CONTINUE
  WRITE (*,7005)
  GO TO 140
  142 VAL4(I) = VAL4P
  GO TO 140
  145 WRITE(*,7046) IOS
7046 FORMAT (5X,'Error #',I5,'in READING data.')
  GO TO 140

```

```

C
C   Key = 5 : Well System Specification and Cost Default
C             Input Parameters
C

```

```

9007 CONTINUE
  150 Iscreen = 1
  153 WRITE (*,7050)
7050 FORMAT (/, ' Well System Spec. and Cost Input Parameters',/)
  MAX = 92
  M1 = (Iscreen - 1) * 18 + 1
  M2 = MIN0 (M1+17, MAX)
  IF ((M2-M1) .LT. 14) M1 = M2-17
  WRITE (*,7002) (IVAS(I),VA5(I),VAR5(I),I=M1,M2)
  WRITE (*,7021)
  WRITE (*,7003)
  READ (*,7004,ERR=9007) JVAR, VALP
  IF (JVAR .EQ. Iblank) GO TO 10
  IF (JVAR .EQ. ICU) THEN
    Iscreen = Iscreen - 1
    IF (Iscreen .LE. 0) Iscreen = 1
    GO TO 153
  ENDIF
  IF (JVAR .EQ. ICD) THEN
    IF (M2 .EQ. MAX) THEN
      WRITE (*,7022)
      GO TO 153
    ENDIF
    Iscreen = Iscreen + 1
    GO TO 153
  ENDIF

```

```

DO 151 I = M1, M2
IF (IVAS(I) .EQ. JVAR) GO TO 152
151 CONTINUE
WRITE (*,7005)
GO TO 153
152 VAS(I) = VALP
GO TO 153

```

```

C
C   Key = 6 : Surface Plant Specifications and Cost Default Input
C   Parameters
C

```

```

9008 CONTINUE
160 Iscreen = 1
163 WRITE (*,7060)
7060 FORMAT(/,' Surface Plant and Cost Input Parameters',/)
MAX = 64
M1 = (Iscreen - 1) * 18 + 1
M2 = MIN0 (M1+17, MAX)
IF((M2-M1) .LT. 14) M1 = M2-17
WRITE (*,7002) (IVA6(I),VA6(I),VAR6(I),I=M1,M2)
WRITE (*,7021)
WRITE (*,7003)
READ (*,7004,ERR=9008) JVAR, VALP
IF (JVAR .EQ. Iblank) GO TO 10
IF (JVAR .EQ. ICU) THEN
  Iscreen = Iscreen - 1
  IF (Iscreen .LE. 0) Iscreen = 1
  GO TO 163
ENDIF
IF (JVAR .EQ. ICD) THEN
  IF (M2 .EQ. MAX) THEN
    WRITE (*,7022)
    GO TO 163
  ENDIF
  Iscreen = Iscreen + 1
  GO TO 163
ENDIF
DO 161 I = M1, M2
IF (IVA6(I) .EQ. JVAR) GO TO 162
161 CONTINUE
WRITE (*,7005)
GO TO 163
162 VA6(I) = VALP
GO TO 163

```

```

C
C   Key = 7 : Environment and Cost Default Input Parameters
C

```

```

9009 CONTINUE
170 WRITE (*,7070)
7070 FORMAT (/,' Environmental and Cost Input Parameters',/)
WRITE (*,7072) (IVA7(I),VA7(I),VAR7(I),I=1,5)
7072 FORMAT (10X, A4, F15.5, 1X, A8, 10X, A4, F15.5, 1X, A8,/)
DO 173 I=1,16
WRITE (*,7042)
173 CONTINUE
WRITE (*,7003)
READ (*,7004,ERR=9009) JVAR,VALP
IF (JVAR .EQ. Iblank) GO TO 10
DO 171 I = 1, 5
IF (IVA7(I) .EQ. JVAR) GO TO 172

```

```

171 CONTINUE
    WRITE (*,7005)
    GO TO 170
172 VA7(I) = VALP
    GO TO 170
175 WRITE (*,7075) IOS
7075 FORMAT (5X,'Error #',I5,' in READING data')
    GO TO 170

```

```

C
C Key = 8 : Read a SAVED Data File
C

```

```

9010 CONTINUE
180 WRITE (*,7080)
7080 FORMAT (/, ' Read a SAVED Data File',///, ' File Name?')
    READ (*,7081,ERR=9010) Filename
7081 FORMAT (A20)
    IF (LEN(Filename) .EQ. 0) GO TO 10
    IF (Filename .EQ. ' ') GO TO 10
    INQUIRE (FILE=Filename, EXIST=FLXT, ERR=182, IOSTAT=IOS)
    IF (FLXT) GO TO 181
    WRITE (*,7082)
7082 FORMAT (/, ' File does NOT exist...please try again')
    GO TO 180
181 OPEN (1,FILE=Filename, ERR=182, IOSTAT=IOS)
    READ (1,7083) (VA1(I),I=1,21)
    READ (1,7083) (VA2(I),I=1,24)
    READ (1,7083) (VA3(I),I=1,10)
    READ (1,7084) (VAL4(I),I=1,3)
    READ (1,7083) (VA5(I),I=1,92)
    READ (1,7083) (VA6(I),I=1,64)
    READ (1,7083) (VA7(I),I=1,5)
7083 FORMAT (4(6X,F14.0))
7084 FORMAT (3(6X,L7))
7085 FORMAT (4(6X,F10.0,6X),/,3(6X,F10.0,6X))
    CLOSE (1)
    WRITE (7,7086) Filename
7086 FORMAT (5X,'Data READ from file ',A20)
    GO TO 10
182 WRITE (*,7087) IOS
7087 FORMAT (/, ' ERROR #',I5,' in INQUIRE or OPEN Read File')
    GO TO 180

```

```

C
C Key = 9 : SAVE Data in File
C

```

```

190 WRITE (*,7090)
7090 FORMAT (/, ' SAVE Data into File',///, ' File Name?')
    READ (*,7081) Filename
    IF (LEN(Filename) .EQ. 0) GO TO 10
    IF (Filename .EQ. ' ') GO TO 10
    INQUIRE (FILE=Filename, EXIST=FLXT, ERR=193, IOSTAT=IOS)
    IF (.NOT. FLXT) GO TO 192
191 WRITE (*,7091)
7091 FORMAT (/, ' File EXISTS, Do you want to Overwrite it?')
    READ (*,7092) IYN
7092 FORMAT (A1)
    IF (IYN .EQ. No) GO TO 190
    IF (IYN .NE. Iyes) GO TO 191
192 OPEN (1,FILE=Filename, ERR=193, IOSTAT=IOS)
    WRITE (1,7093) (IVA1(I), VA1(I), I=1,21)
    WRITE (1,7093) (IVA2(I), VA2(I), I=1,24)

```

```

WRITE (1,7093) (IVA3(I), VA3(I), I=1,10)
WRITE (1,7094) (IVA4(I), VAL4(I), I=1,3)
WRITE (1,7093) (IVA5(I), VA5(I), I=1,92)
WRITE (1,7093) (IVA6(I), VA6(I), I=1,64)
WRITE (1,7093) (IVA7(I), VA7(I), I=1,5)
7093 FORMAT (4(A6,F14.6))
7094 FORMAT (3(A6,L7))
7095 FORMAT (4(A6,F10.2,6X),/,3(A6,F10.2,6X))
CLOSE (1)
WRITE (*,7096) Filename
7096 FORMAT (5X,'Data SAVED in file ',A20)
GO TO 10
193 WRITE (*,7097) IOS
7097 FORMAT (/, ' ERROR #',I5, ' in INQUIRE or OPEN Write File',/)
GO TO 190
300 RETURN
END
FUNCTION ROIFCN (STREAM,NYEARS)
DIMENSION STREAM(1)
DATA START/.0095/,DELMIN/.00005/,EPSILON/.0001/

```

C

```

ROIFCN=0.
CUM = STREAM(1)
DO 10 I =2,NYEARS
CUM=CUM+STREAM(I)
10 CONTINUE
IF (CUM.LE.0.) GO TO 60
R1 =0.
E=START
IF(CUM.LT.0.) E=-E
20 CONTINUE
E=2.*E
IF(ABS(E).GT.5) GO TO 60
PVTRY = PVFCN(STREAM,E,NYEARS)
IF ((PVTRY*CUM).GT.0.) GO TO 20
30 CONTINUE
R2=E
40 CONTINUE
E= (R1+R2)/2.
PVTRY =PVFCN(STREAM,E,NYEARS)
IF (ABS(PVTRY).LT.EPSILON) GO TO 50
IF(ABS(R2-R1).LT.DELMIN) GO TO 50
IF((PVTRY*CUM).LT.0.) GO TO 30
R1 =E
GO TO 40
50 CONTINUE
ROIFCN=E*100
60 CONTINUE
RETURN
END
FUNCTION PVFCN (STREAM,DCRATE,NYEARS)
DIMENSION STREAM(1)
RATE=1.+DCRATE
FACTOR = RATE
PVFCN= STREAM(1)
DO 10 I =2,NYEARS
PVFCN =PVFCN + STREAM(I)/FACTOR
FACTOR =FACTOR *RATE
10 CONTINUE
RETURN

```

```
END
SUBROUTINE TUTORIAL(NLINES)
CHARACTER*80 ALINE,AK*1
OPEN(4,FILE='TUTOR.TXT',STATUS='OLD')
REWIND(4)
1 CONTINUE
DO 2 I=1,NLINES
  READ(4,9,ERR=100,END=5,IOSTAT=IOS) ALINE
  WRITE(*,10) ALINE
2 CONTINUE
WRITE(*,11)
READ(*,12) AK
IF (AK .EQ. 'E') GO TO 5
GO TO 1
100 WRITE(*,13) IOS
5 CONTINUE
CLOSE(4)
RETURN
9 FORMAT(A70)
10 FORMAT(10X,A80)
11 FORMAT(//,15X,'HIT RETURN TO CONTINUE OR E TO END TUTORIAL.')
```

```
12 FORMAT(A1)
13 FORMAT(10X,'ERROR READING TUTORIAL FILE.',I5)
END
```

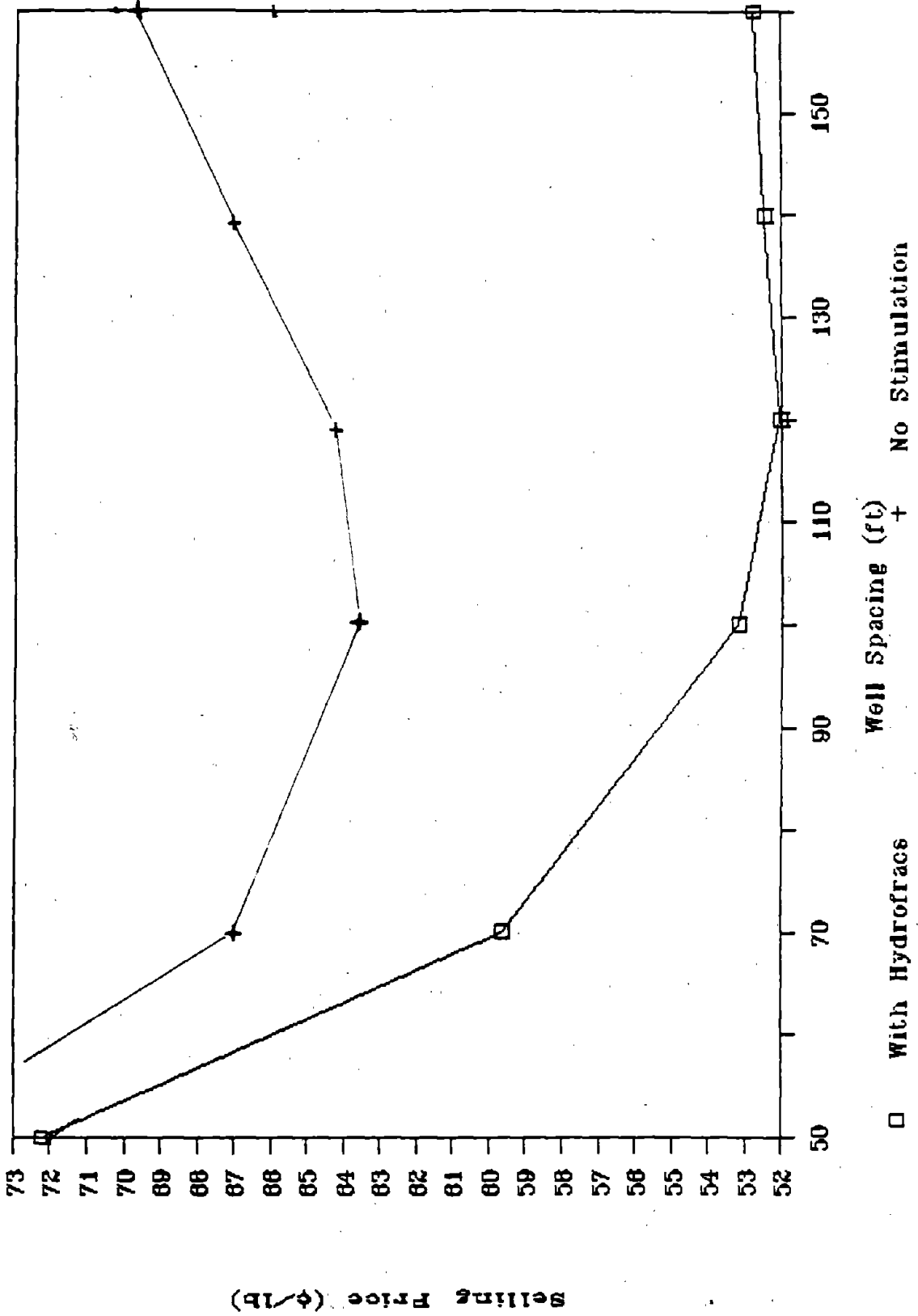


Figure D-1. Example Sensitivity Analysis

APPENDIX E. NOMENCLATURE

- a_f = fracture gradient, psi/ft
 a_w = water gradient, psi/ft
 A_w = wellfield plan area, ft²
 A_{WT} = Total wellfield area over plant life, ft²
 AT_{SF} = SX flow rate dependent costs, \$/AT
 AT_{TF} = total present value flow rate dependent costs, \$/AT
 AT_{WD} = wellfield cost, \$/AT
 AT_{WH} = wellfield start-up cost, \$/AT
 b = volume expansion factor, fraction
 B_B = unit cost centralizers, \$/ft
 B_C = unit cost casing vertical well, \$/ft
 B_D = surface drilling rig hourly rate, \$/hr
 B_{EXS} = fixed charge explosive stimulation surface drilling, \$/well
 B_{EXU} = fixed charge explosive stimulation underground drilling, \$/well
 B_{FCS} = fixed cost cementing surface drilling, \$/well
 B_{FCU} = fixed cost cementing underground drilling, \$/well
 B_{FWL} = fixed cost logging surface drilling, \$/well
 B_G = cement grout cost, \$/ft³
 B_h = wellhead cost, \$/wellhead
 B_I = inflation tubing cost, \$/ft
 B_k = packer component cost, \$/packer
 B_{LRS} = fixed cost large radius hydrofrac surface drilling, \$/frac
 B_{LS} = fixed cost logging surface drilling, \$/well
 B_{PI} = fixed cost vertical well production pump, \$/pump

- B_{PS} = fixed cost perforating surface drilling, \$/well
 B_{RPC} = production pump component cost, \$/pump
 B_{RPW} = production pump component cost, \$/ft
 B_{SRS} = fixed cost short radius hydrofrac surface drilling, \$/well
 B_{SRU} = fixed cost short radius hydrofrac underground drilling,
 \$/well

 B_t = unit cost of tubing, \$/ft
 B_w = unit cost of well screen, \$/ft
 B_{WC} = fixed cost casing, \$/well
 B_{WLT} = unit cost water level tubing vertical well production pump,
 \$/ft

 B_{xq} = production pump component cost, \$/pump
 C_1 = unit cost copper selective extractant, $\$/m^3$
 C_2 = unit cost of organic diluent, $\$/m^3$
 C_3 = unit cost of cobalt sulfate, $\$/Kg$
 C_4 = unit cost of sulfuric acid, $\$/ton$
 C_5 = unit cost of anode, $\$/ton$
 C_6 = unit cost of lime, $\$/ton$
 C_7 = unit cost of water, $\$/gallon$
 C_A = vertical well drill site development cost, \$/well
 C_C = vertical well casing cost, \$/well
 C_{CM} = vertical well cementing cost, \$/well
 C_{CP} = vertical well completion cost, \$
 C_d = vertical well drilling cost, \$/well
 C_{da} = unit cost of drift, \$/ft
 C_{dc} = average unit cost vertical well completion of, \$/ft
 C_{ds} = average unit cost vertical well drilling and casing, \$/ft

- C_{dt} = average unit vertical well cost, \$/ft
 C_{EWI} = injection well cost per fan, \$/fan
 C_{EWF} = total well costs per fan, \$/fan
 C_{EWP} = production well costs per fan, \$/fan
 C_E = unit capital cost electrowinning, \$/ton per year
 C_{ex} = cost per well explosive stimulation, \$/well
 C_{el} = unit cost of electricity, \$/Kwhr
 C_{HC} = cost per vertical well large radius hydrofrac, \$/well
 C_{HP} = unit cost of pumps, \$/HP
 C_{HS} = cost per vertical well short radius hydrofrac, \$/well
 C_{MA} = unit cost monitoring wells, \$/ft²/ft
 C_{MM} = vertical well matrix modification cost, \$/well
 C_{MW} = unit cost monitoring well, \$/ft²/ft
 C_P = perforation cost vertical well, \$/well
 C_{PP} = packer cost per vertical well, \$/well
 C_{PW} = wellhead cost vertical well, \$/well
 C_{Pfl} = cost per vertical well fluid level measurement, \$/well
 C_{PLT} = unit cost surface piping, \$/ft
 C_{PLW} = unit cost wellfield piping, \$/ft
 C_{PM} = cost per vertical well injection flow meter, \$/well
 C_r = unit cost mining raise, \$/ft
 C_{RP} = cost per vertical well for pump, \$/well
 C_s = unit cost mining shaft, \$/ft
 C_{sc} = cost per well of screened completion, \$/well
 C_{TP} = vertical well tubing cost, \$/well
 C_{WEI} = total vertical injection well equipment cost, \$/well
 C_{WEP} = total vertical production well equipment cost, \$/well

- C_{wfi} = unit cost of fan injection well, \$/ft
 C_{wfp} = unit cost of fan production well, \$/ft
 C_{wf} = average unit cost of fan well, \$/ft
 C_{wl} = vertical well logging cost, \$/well
 C_w = cost of one well module, \$
 C_{wm} = annual wellfield maintenance cost, \$/yr
 C_x = flow rate dependent plant capital cost factor, \$/gpm
 d = distance between fan faces, ft
 d_c = vertical well casing diameter, in
 d_h = vertical well hole diameter, in
 d_s = diameter plant/wellfield piping, in
 d_t = diameter interconnecting wellfield piping, in
 D = depth to bottom of ore zone, ft
 DR = drift footage for mine access, ft
 E_c = overall recoverable copper, %
 E_h = pore volume adjustment factor, %
 E_L = leach efficiency, %
 E_p = plant onstream time, %
 E_r = recovery efficiency, %
 E_s = sweep efficiency, %
 EA = total underground access cost, \$
 EE = mine plant electrical equipment costs, \$
 EM = total underground mine plant cost, \$
 EP_1 = total cost SX/EW plant, \$
 EP_2 = total cost injection pumps, \$
 EP_3 = total cost fan production pumps, \$
 EP_4 = total cost wellfield interconnecting piping, \$

- EP_5 = total cost plant/wellfield piping, \$
 EP_6 = plant permitting cost, \$
 EP_7 = monitoring system cost, \$
 EP_8 = cost of consumables for start-up, \$
 EP_{C1} = annual flow rate dependent consumables cost, \$/yr
 EP_{C2} = annual production rate dependent consumables cost, \$/yr
 EP_C = total annual cost consumables, \$/yr
 EP_E = total annual cost electricity, \$/yr
 EP_1 = annual labor cost, \$/yr
 EP_M = annual contract maintenance cost, \$/yr
 EP_{MS} = surface plant annual cost contract maintenance, \$/yr
 EP_{MW} = wellfield, annual cost contract maintenance, \$/yr
 EP_{EM} = annual cost environmental monitoring, \$/yr
 EP_O = total annual operating cost, \$/yr
 EP_T = cost surface facilities, \$
 EP_U = annual utility cost, \$/yr
 EP_W = annual cost of water, \$/yr
 EP_{WS} = wellfield restoration cost, \$
 EP_{WW} = wellfield water make-up cost, \$
 ES = underground access development cost, \$
 EV = mine plant ventilation cost, \$
 EW = total initial wellfield cost, \$
 EW_C = wellfield crosscut costs, \$
 EW_D = wellfield drift costs, \$
 EW_{RP} = replacement wellfield cost, \$
 EW_W = wellfield well cost, \$
 G_1 = axial flow horizontal fracture flow rate factor, ft

- G_2 = axial flow vertical fracture flow rate factor, ft
 G_3 = radial flow flow rate factor, ft
 G_4 = fan pattern flow rate factor, ft
 GA = volume to saturate wellfield, gallon
 h = height of fan unit and length of fan well, ft
 H = ore body thickness, ft
 H_C = distance between vertical well horizontal fracs, ft
 HP_I = wellfield injection pump horsepower, hp
 HP_L = fan wellfield production pump horsepower, hp
 HP_M = mine plant horsepower, hp
 HP_P = vertical well production pump horsepower, hp
 i = rate of return, %
 j = wellflow flow rate transient test, barrels per day
 k = rock permeability, md
 L_{TT} = total length plant/wellfield piping, ft
 L_{TW} = total length wellfield interconnecting piping, ft
 M_x = unit component cost factor vertical well production pump, \$/hp
 N_{HC} = number of crosscuts per vertical unit
 N_{HF} = number of fans per crosscut
 N_{HV} = number of vertical units
 N_I = number of injection wells, also patterns
 N_{IF} = number of fan patterns
 N_{IS} = number of surface patterns
 N_P = number of vertical well producers
 N_{TF} = number of wells per fan face
 N_{WR} = number of wellfield replacements

- N_w = total number of wellfield wells
 P_I = injection pressure top of ore interval, psi
 P_{Is} = surface injection pressure, psi
 PV = net present value, \$
 ΔP_T = injection/production pressure drop, psi
 P_{1hr} = one hour transient pressure, psi
 P_w = bottom hole static pressure, psi
 Q = system flow rate, gpm
 q_I = injector or well module flow rate, gpm
 q_p = vertical production well flow rate, gpm
 q_{ro} = flow rate per row of well pattern, gpm
 q_f = flow rate per fan, gpm
 q_{dh} = flow rate per fan drillhole, gpm
 q_l = well flow rate per foot of ore interval, gpm/ft
 r_e = drainage radius, ft
 r_w = effective wellbore radius, ft
 R_1 = horizontal fracture area factor, ft
 R_2 = vertical fracture area factor, ft
 R_3 = radial flow area factor, ft
 R_4 = fan pattern area factor, ft
 R_{cs} = casing set rate surface drilling, ft/hr
 R_d = vertical well drilling rate, ft/hr
 s_w = initial orebody water saturation, %
 S = vertical well spacing, square area, ft
 S_1 = distance between large vertical fractures, ft
 S_2 = well spacing parallel to vertical fractures, ft
 S_M = minimum economic well spacing, ft

- S_o = well spacing for tracer testing, ft
 ST = total staff for plant
 t_p = plant life, yr
 t_w = wellfield life, yr
 t_{WH} = time to prime wellfield, yr
 T_{LH} = production loss in start-up, tons
 V_x = unit cost of mining crosscut, \$/ft
 W_1 = SX extractant usage, m³/gpm/yr
 W_2 = diluent usage, m³/gpm/yr
 W_3 = cobalt sulfate usage, Kg/ton copper
 W_4 = sulfuric acid usage by gangue, ton acid/ton copper
 W_5 = anode usage, ton anode/ton copper
 W_6 = lime usage, ton lime/ton copper
 W_7 = sulfuric acid usage for copper, ton acid/ton copper
 W_8 = bleed stream fraction
 W_9 = electrowinning bleed, ton acid/ton copper
 W_{10} = net acid consumption, ton acid/ton copper
 W_{12} = lime/acid stoichiometry, ton lime/ton acid
 W_{13} = gypsum/lime stoichiometry, ton gypsum/ton lime
 W_{14} = total metal sulfates produced, ton sulfates/ton copper
 W_{15} = ferric/acid stoichiometry, ton ferric/ton acid
 WD = water table depth below surface, ft
 x_1 = wellfield restoration cost factor, %
 X_1 = horizontal fracture life factor, ft²
 X_2 = vertical fracture life factor, ft²
 X_3 = radial flow life factor, ft²
 X_4 = well pattern life factor, ft²

- Y = copper cathode production rate, ton/yr
 Z_F = cost ratio vertical surface wells versus fan wells
 Z_V = cost ratio vertical wells surface versus underground
 α_3 = electrical usage per unit weight cathode, Kwhr/ton cathode
 α_{10} = conversion factor, Kwhr/hp-yr
 β = net present value factor
 δ_{ds} = ratio well drilling/casing cost vertical wells underground versus surface
 δ_{dc} = ratio well completion cost vertical wells underground versus surface
 Θ = angle between fan wells, radians
 ϕ = porosity, %
 Φ_{ds} = fraction of total vertical well cost for drilling and casing
 μ = fluid viscosity, centipoise
 ρ_b = ore particle density, lb/ft³
 η = pump efficiency, fraction
 $[Cu]_d$ = net copper concentration pick-up from orebody, gpl
 $[H_2SO_4]$ = total injected acid concentration, gpl
 $[Cu]_m$ = optimum copper loading, gpl

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