Energy Management Training Program

Monograph 3

# Energy Resource Assessment

Alfred Petrick
Petrick Associates
Evergreen, Colorado

prepared for the
Office of Energy -
Agency for International Development

National Center for Analysis
of Energy Systems
Brookhaven National Laboratory
Upton, New York

The Institute for Energy Research
State University of New York at
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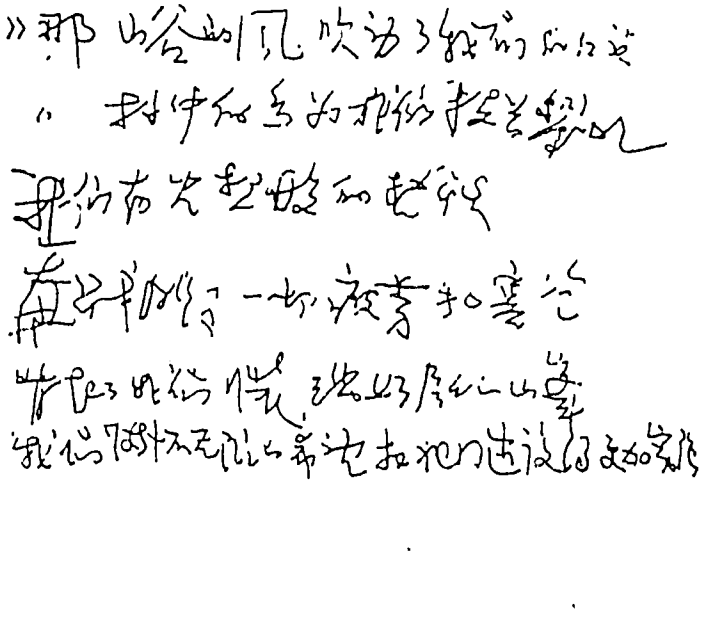
# Exploration Economics



Pictured above is the original of the Chinese delegation's "Song of the Geologist" which they sang on the evening of November 17, 1978, at Pattaya, Thailand, to the great delight of the assembled participants of the III GEOSEA Conference. An exceedingly free translation follows:

"The wind blowing from the valley makes a heartfelt impression,
As early in the morning the birds in the village sing a symbol of sunrise.
With flaming enthusiasm and full of joy,
We forget about the cold and our weariness.
We leave our camp to find the outcrops.
And we have unlimited hope that this will bring more prosperity!"

From the AGID News, Jan. 1979

# EXPLORATION ECONOMICS

## 1. INTRODUCTION

At a recent seminar in exploration economics, an experienced explorationist commented that it seemed that discussions of "exploration economics" usually degenerated into a discussion of the economics of projects already discovered and under development - not really exploration economics. When pressed to recognize the problems of the exploration manager the "economist" is likely to backdown into mathematical games" or to abandon long discussions of what makes a discovery valuable and talk about capital budgeting in general. In this chapter we attempt to deal with this problem - specifically to define a practical "exploration economics" that addressed the subject and its connection with project development economics. The discovery model described by Paul Bailly and others seems to put the work of the economist, geostatistician, exploration manager and other gamblers into the right perspective.

## 2. THE EXPLORATION DISCOVERY MODEL

The mineral discovery model shown in figure 1 breaks the expected value of an exploration discovery into four components: (1) the probability of occurrence of an ore deposit in a given area, (2) the value of the ore deposit which might be discovered, (3) the efficiency of exploration or the probability that the orebody will be detected at reasonable cost (before the money runs out), and (4) the security of land tenure as reflected through past experience, usually past experience with governments but sometimes experience with private property owners.

# A MINERAL DISCOVERY MODEL

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Exploration Problems | Is there a chance that a mineral deposit occurs in this area? | | If a mineral deposit is present, what is the best estimate of its possible value | | If a mineral deposit is present, can it be found with available tools? At what cost? How soon? | | Can we obtain secure rights to explore? If an orebody is found can we hold on to it and harvest the rewards of this discovery? |
| EXPLORATION DISCOVERY MODEL | = PROBABILITY OF OCCURRENCE | X | PRESENT VALUE OF EXPECTED ORE DEPOSITS TO BE DISCOVERED | X | PROBABILITY OF DETECTION / EXPLORATION COSTS | X | SECURITY OF LAND TENURE |
| CONTROLLING ACTIVITIES AND FACTORS | .Selection of regions<br>Selction of areas.<br>Selection of targets.<br>.Continuous evaluation and updating of target concepts<br>-ore deposit models<br>-working hypotheses<br>-genetic hypotheses (?)<br>-genetic theories (?)<br>.Continuous appraisal of exploration program: decision to continue<br>.Previous record of discovery and production. | | .Forecast of:<br>-commodity demand and price.<br>-capital and production costs,<br>-mode of financing<br>-taxation, depletion and depreciation,<br>-land costs.<br>.Evaluation of tonnage, grade and geometry of expected mineral<br>.Economic evaluation of targets. | | .Selection-Scheduling of effective methods and techniques<br>.Efficient application of such methods and techniques.<br>.Translation of planned work into time and expenditure units.<br>.Continuous appraisal. of results in terms of discovery possibility.<br>.Continuous updating methods, scheduling of work.<br>.Transporation Fuel Energy.<br>.Skilled labor, supplies<br>.Health hazards.<br>.Availability of Capital.<br>.Exploration incentives | | .Land laws.<br>.Ownership patterns.<br>.Optioning patterns.<br>.Competition<br>.Strategy and tactics of land acquisition.<br>.Encouragement of free enterprise.<br>.Possibility of expropriation.<br>.Possibility of political unrest.<br>.Honesty in government and employees.<br>.Repatriation of Capital and Profit.<br>.U.S. Government does not prohibit activities by U.S. Cos. and persons.<br>.Tenure jeopardized by other activity of Co. |

## 2.1 Probability of Occurrence

The determination of the probability that an orebody exists still rests on the judgment of experienced geologists after careful study of geologic data from a new region and ore deposit models from producing regions. In practice, a series of regions, areas and targets are ranked by experienced explorationists according to the probability that they contain an economically exploitable orebody. By nature these decisions are a combination of objective and subjective analyses.

### 2.1.1 Department of Energy Model

A number of geostatistical models have been developed that attempt to quantify the factors involved in "geologic favorability".These models help to rank one region versus another region according to favorability of ore deposit occurrence. One ranking system is used to quantify the probability of uranium deposit occurrence in a new area by comparing it to a thoroughly explored "control area" (Hetland, 1977).

The steps followed in the estimation process are:

1. Comparison of characteristics that constitute favorable ground in well-known uranium areas with those of the area to be evaluated. This comparison includes the selection of the control area. For example, evaluation of the (new) East Chaco Canyon area utilizes two segments of the Grants mineral belt as the control area because of similarity in host rocks and geologic environment, a size sufficient to yield meaningful control statistics, and sufficiency of data to evaluate resource base and the favorability criteria.

2. Delineation of favorable ground (N), measured in linear miles, square miles, or cubic miles. For example, the Westwater Canyon Member underlies the entire East Chaco Canyon area of 797 square miles. Therefore, N=797.

3. Deriviation of a geologic favorability factor (F) from evaluation of applicable criteria. This is the most subjective part of the evaluation. Each criterion in the control area is assigned a numerical rating and the same criteria assigned numerical ratings in the new area. Where information for a specific criterion is lacking in the new area it is omitted in the evaluation. The ratio of total points in the new area to total points in the control area is the index of geologic similarity. For example, the index for the East Chaco area/Grants control area base on the data in Table 1 is 0.8.

Table 1 Ranking of Favorability Criteria

Derivation of Favorability Factor Based on Ranking of Favorability Criteria

| Criterion-Scale | Sandstone-Type Scores: Control Area | Sandstone-Type Scores: E. Chaco Area |
|---|---|---|
| 1. Deposition Environment of Potential Host Rocks 0-20 | 20 | 15 |
| Fluvial - coalasced alluvial fans<br>Fluvial - stream channel and flood plains<br>Marginal marine: deltaic, lagoonal, barrier bar<br>Lacustrine and marine<br>Aeolian and glacial | | |
| In general, order is from most favorable to least favorable; however, highest score in area being appraised would be for whichever environment is most important in gelogically similar area with important deposits. | | |
| 2. Lithology of Potential Host Rocks | | |
| A. Composition 0-10<br>0 is least favorable and 10 is most favorable sedimentary rock based on comparison with similar geologic environments with important deposits. | 10 | 7 |
| B. Sand - Shale Ratios 0-15<br>0 is least favorable and 15 is most favorable ratio based on comparison with similar geologic environments with important deposits. | 15 | 12 |
| C. Sandstone Thickness 0-15<br>0 is least favorable and 15 is most favorable thickness based on comparison with similar geologic environments with important deposits. | 15 | 15 |
| D. Grain Stress 0-15<br>0 is least favorable and 15 is most favorable grain size based on composition with similar geologic environments with important deposits. | 15 | 8 |

Table 1 (continued)

| Criterion-Scale | Scores Control Area | Scores E. Chaco Area |
|---|---|---|
| E. Favorable Permeability Relationship 0-15<br>Score on basis of comparison with similar geologic environments with important deposits. | 15 | 8 |
| F. Reductant 0-40<br>Score high for reductant (carbonaceous trash or $H_2S$ and low for little or no reductant. | 40 | 30 |
| G. Tuffaceous Content in Overlying or Interbedded Sediments 0-30 (pre-erosion)<br>Score high for abundant, altered or unaltered, tuffs and low for tuffaceous content minor or absent. | 30 | 30 |
| 3. Source Area of Host Rocks 0-20<br>Score high for predominately granitic rocks and low for no granitic rocks in provenance. | 20 | 20 |
| 4. Alteration | | |
| A. Anomalous Iron Staining (limonite-hematite) | | |
| (1) Outcrops 0-20<br>0 is no anomalous iron staining in outcrops and 20 is abundant staining in outcrops based on comparison with similar geologic environments with important deposits. | No outcrops | |
| (2) At depth 0-20<br>0 is potential host sediment completely oxidized or oxidized to great apparent depths and 20 is potential host sediments oxidized at outcrops and to shallow depths only. | 20 | 20 |
| (3) Bleaching 0-20<br>Score on basis of important in similar geologic environments with deposits. | Unknown | |
| (4) Calcification 0-15<br>Score on basis of importance in similar geologic environments with deposits. | Unknown | |

Table 1 (continued)

| Criterion-Scale | Scores: Control Area | Scores: E. Chaco Area |
|---|---|---|
| B. Reduced Beds (bleaching) in Thick Red Bed Sequences 0-20<br>Score on basis of importance in similar geologic environments with deposits. | Not Applicable | |
| C. Pyrite Content in Unoxidized Zone 0-15<br>Score on basis of abundance in area being appraised relative to abundance in similar geologic environments with important deposits. | 15 | 10 |
| **Structure** | | |
| A. Dip of Beds 0-25<br>Score high for gentle dips and high for steep dips. | 25 | 25 |
| B. Significant Unconformity of Erosional Surface Subjacent or Superjacent to Section Containing Favorable Host Rocks 0-25<br>Score high for widespread unconformity or erosional surface and low for no unconformity or erosional surface. | 25 | 25 |
| C. Structural Terraces or Flattening of Dip 0-25 | Not Applicable | |
| D. Faulting or Graben Structures 0-20<br>Score on basis of importance in similar geologic environments with deposits. | 10 | 10 |

Table 1 (continued)

| Criterion-Scale | Scores: Control Area | Scores: E. Chaco Area |
|---|---|---|
| 6. Regional Tectonic Environments 0-20 | | |
| Intracratonic basins on forelands of foldbelts | 20 | 20 |
| Intrafoldbelt basins | | |
| Geosynclinal margins | | |
| Continental platforms | | |
| Shields | | |
| Geosynclines | | |
| Order is from most favorable to least favorable; however, certain exceptions exist as in the Texas Coastal Plain where the most important regional environment is a geosynclinal margin. Also in the Rocky Mtn. Province, the most important environment for Tertiary deposits is intrafoldbelt basins. In area being appraised, score highest for environment that is most important in the geological situation. | | |
| 7. Age of Potential Host Rocks 0-20 | | |
| Triassic, Jurassic, Tertiary | 20 | 20 |
| Cretaceous | | |
| Permian | | |
| Pennsylvanian | | |
| Other | | |
| Order is from most favorable to least favorable; however, exceptions include Black Hills (Cretaceous) Anadarko Basin (Permian), etc. In area being appraised, score highest for host rock age that is most important in similar geologic environments with important deposits. | | |

8. Geophysical Surveys

A. Ground and Air Radiometric Surveys 0-50 — Not Applicable
Score high for numerous strong anomalies; score low for no anomalies.

B. Radiometric Anomalies in Oil and Water Wells 0-40 — 40 — 10

See 8A

9. Geochemical Surveys

A. U in Waters 0-30 — Unknown

See 8A

B. U in Potential Host Rocks 0-20 — Unknown

See 8A

C. U in Soils 0-10 — Not Applicable

See 8A

10. Character of Mineralization

A. Persistence of Mineralization 0-30 — Unknown
High score for demonstrated significant lateral and/or vertical continuity; low score for uranium mineralization restricted to shallow depths or to small podlike occurrences.

B. Distribution Patterns 0-25 — Unknown
Score high for known deposits in established or inferred trends or other predictable patterns; score low for no recognized trends.

Table 1 (continued)

| Criterion-Scale | Scores: Control Area | Scores: E. Chaco Area |
|---|---|---|
| 11. U Deposits | | |
| A. Size (Reserves and Production); enter appropriate Roman numeral in scoring column) | | |
| Large deposits; Over 5,000 T. $U_3O_8$ (I) | Unknown | |
| Medium deposits: 1,000-5,000 T. $U_3O_8$ (II) | | |
| Occurrences and small deposits: 1,000 T. $U_3O_8$ (III) | | |
| Mineral occurrences (IV) | | |
| No mineral occurrences | | |
| Total score for geologic, geophysical and geochemical criteria | 355 | 285 |

$$\text{FAVORABILITY FACTOR} = \frac{285}{355} = 0.80$$

In addition it was necessary to make allowances for sparsity of data in the East Chaco Canyon area. Department of Energy geologists estimated that only about 40% of the area will have the proper combination of geologic characteristics necessary for uranium deposition. Thus the "fudge factor" is 0.4 and the favorability factor is:

$$F = 0.8 \times 0.4 = 0.3$$

4. Determination of the percent of unexplored ( or undrilled) favorable ground (U). In East Chaco Canyon this was estimated to be 95%, thus U=.95.

5. Application of the mineralization factor (T) measured in tons of U308 per square mile or other appropriate measure based on knowledge of the control area. In the example, East Chaco area this was determined by dividing the total resources (tons U308) in the control area by the square miles of explored ground in the control area. The result was:

$$T = 295{,}000 \text{ tons} / 1283 \text{ sq. miles} = 230 \text{ tons/sq. miles}$$

6. Substitution for variables in the equation:

$$\text{Potential} = N \times F \times U \times T = 797 \times .3 \times .95 \times 230 = 52{,}243 \text{ tons}$$

7. The result is further modified for differences in mining and processing cost between the control area and the new area. For example, deposits average 1000 feet deep in the Grants control area, 3000 to 5000 feet deep in the East Chaco Canyon Area. This analysis yields cut-off grade estimates which in turn yield potential tonnages in various cost categories.

### 2.1.2 Harris Models

DeVerle Harris has done extensive work in the development of geostatistical models of mineral endowment. The fundamental approach is to relate mineral occurrence to physical features such as geology, geochemical concentration, geophysical responses, or metal or mine density per unit area or volume. These relationships are studied in regions of known deposits, then extrapolated in a region likely to yield new discoveries. The addition of economic considerations in these models allows extrapolation to resources which are subeconomic under current conditions but that might become economic in the future (Harris, 1975).

### 2.1.3 Torries Model

Thomas F. Torries developed a probabilistic model of the availability of deomestically produced $U_3O_8$ in the United States (Torries, 1975). Quantities of uranium available in various production costs categories are classified according to probability of occurrence where such probabilities are partially defined by the Delphi technique which relies on subjective assessments by experts. Subjective assessments of the physical characteristics of uranium deposits are converted by Torries into economic terms using discounted cash flow models.

## 2.2 Present Value of Expected Deposits

The second component of the mineral discovery model is the net present value of the discovery. It is identical with the development model except that at the point of development some exploration costs are sunk and therefore not considered except for their effect on taxes. The question posed by the explorationist is usually "Is the expected present value of the discovery sufficient to justify an exploration budget over several years at a level adequate to have a high probability that new deposits will be discovered.

Since the probability of occurrence, discovery and land tenure are included in other parts of the model, this component concentrates on all factors that determine net present value. These range from technical factors such as metallurgical recovery, mining method, and the geometry of the orebody to market factors of supply, demand and price to financial factors that affect taxation and cash flows. The problem is identical to the development model except that the orebody is an expectation rather than a reality. Implied is work in the selection of commodities whose demand is expected to be strong relative to supplies in the future. The tonnage, grade and geometry of the expected mineral discovery must be consistent with realistic geologic appraisals on the one hand and with economic requirements on the other hand.

## 2.3 Exploration Efficiency

The third component of the mineral discovery model implies that there are specific exploration techniques that make most efficient use of exploration dollars. These techniques vary with commodity and with region but are built into the exploration manager's decisions. A simple example will serve to illustrate. In a recent exploration project an adit was used to explore a narrow vein in the hopes that it would intersect other veins and result in the discovery of a deposit of economic interest. The cost of driving the adit was so expensive that it depleted all financial reserves without a

significant discovery. Utilization of one or two drill holes would have provided more information than that obtained from the adit and further investigation into the likelihood of discovery and the size of the likely discovery would have indicated that the probability of an economic size orebody was very small.

The process of efficient exploration is the daily fare of the exploration manager. Aside from actual experience the best approach to date has been to simulate the day to day decisions of the exploration manager through the use of models. These models seed a region with ore deposits then challenge those who play the game to discover the deposit in the shortest possible time with the expenditure of the smallest amount of money.

In 1969, the CONSAD Research Corporation (Byrne, et al, 1969) developed such a model for the U.S. Bureau of Mines, Department of the Interior. The concept behind the model was that exploration was an investment that involved sequential decision-making and that an optimum program of exploration could be developed by simulating the exploration effort.

In 1978, the Charles Rivers Associates (Charles River Associates, 1978) developed a similar model for the National Science Foundation. The CRA model involves (1) a description of what is in the ground and how it is distributed; (2) an explanation of the decisions of where to look and how much exploration effort to expend; (3) an estimation of the discovery value when exploration effort has been applied to a given endowment; (4) an exploration of the development decision and development timing once a deposit has been discovered; and (5) a determination of the amount to extract and the market price over a specified time period, given the set of existing producing properties. These five components are referred to as endowment, exploration, discovery, development, and market clearing.

## 2.4 Security of Land Tenure

The need for the exploration manager to be concerned with land tenure is obvious. All of the efforts to search, discover and develop are for nothing if access to the deposit is blocked or if proceeds from the discovery are expropriated. Some of the most recent comments on the subject relate to the land withdrawals in the United States and similar loss of prime exploration land around the world.

In 1974, Gary Bennethum and L. Courtland Lee of the Department of the Interior wrote an article entitled "Is Our Account Overdrawn?" questioning withdrawals of public land in the United States from operation of mineral laws. The authors write "with increasing awareness of the importance of mineral resources to the vitality and security of an industrial nation, considerable attention is focusing on the availability of these resources on public land. There is a general feeling, particularly in the mining community, that following a half decade of acute interest in the environment coupled with governmental shortsightedness of the unique problems associated with development of mineral resources, the mineral disposal laws have been made all but meaningless by piecemeal withdrawal, both legislative and administrative, on increasing amounts of land."

Thomas Walthier, exploration manager with St. Joe Minerals Corporation, carried the Bennethum-Lee analysis a step further by observing that throughout the world, governments are placing increasingly severe restrictions on mineral exploration.

The conclusions of the preceding analyses are controversial and there are different

opinions as to the effect. They do illustrate the concern of the explorationist for adequate land in order to increase the probabilities of occurrence and discovery.

### 2.5 Sequential Nature of Exploration

Another extremely important characteristic of exploration decision making is the sequential nature of the exploration process itself. These mineral exploration-development stages are summarized in another chart prepared by Paul Bailly showing the changes in tax status, level of risk, capital expenditures, possibilities of project financing, and possibilities of joint ventures while moving from reconnaisance to production.

MINERAL EXPLORATION - DEVELOPMENT STAGES

| | RECONNAISSANCE<br>Detection of land tracts with characteristics indicative of possible presence of mineral deposit (exploration targets) | TARGET EXPLORATION*<br>Three-dimensional investigation to determine probability of outlining a profitable deposit. Each step ends with a get-off/on decision. | DEPOSIT DEVELOPMENT<br>Detailed sampling and metallurgical tests. Definitive Feasability Study. Each step ends with a get-off/on decison. | MINE DEVELOPMENT<br>Equipping the mine for production. |
|---|---|---|---|---|
| U.S. Tax Status | Exploration | Exploration/Development* | Development | Development |
| LEVEL OF RISK | VERY HIGH | HIGH | MODERATE | LOW |
| CAPITAL EXPENDITURES | VERY SMALL<br>-few $1000's to $100,000 if air-ground geophysics required | SMALL TO LARGE<br>-may take 3 or 4 decision steps<br>-$100,000 to $800,000 for each step | LARGE TO VERY LARGE<br>-may require several steps<br>-$300,000 to $3,000,000 each step | LARGE TO VERY LARGE<br>-several million $ to several 100 million $ |
| Possibility of PROJECT FINANCING | NIL | NIL | NONE<br>(Possible along the way if deposit extremely attractive.) | YES<br>(If deposit exceptionally attractive.) |
| Possibility of JOINT VENTURE | VERY LIMITED<br>NONE<br>NO | LIMITED<br>(unless very attractive)<br>NONE<br>NO | GOOD<br>LIMITED<br>NOT LIKELY | EXCELLENT<br>GOOD<br>(especially if deposit attractive)<br>QUITE POSSIBLE |

*In Development Tax Status, after enough reserves found to reasonably justify minimum-size commercial operation.

This chart highlights some important characteristics of exploration, for example, it is most likely that project financing during the early exploration phases must come from equity capital within the exploration firm. While the capital expenditures are small relative to the very large expenditures made during development they are nevertheless extremely important because so many of them lead to failure and they must be repeated for a long enough time to achieve success. If there is any single factor most characteristic of exploration it is probably the very high level of risk involved in this investment expenditure, thus our evaluations must make maximum use of risk analysis.

## 2.6 Exploration Budgeting

The exploration budget and the periodic of sorting of projects to eliminate the least promising and expedite the most promising is the core of practical exploration management. A format for an exploration budget follows with some examples of the type of analysis in the various sections.

### FORMAT FOR THE NARRATIVE, STRATEGIC, AND FINANCIAL SECTION OF A 5-YEAR BUDGET

1.1 Highlights
1.2 Premises
1.3 Objectives
1.4 Strategies
1.5 Action Plans
1.6 Issues
1.7 Alternatives and Contingencies

2.1 Incoming Sales by Business Entity or Market Category
2.2 Income
2.3 Quantification of Assumptions. To allow management to review the financial impact of management decisions and future trends. Consider the major premises, objectives, actioin plans, and other "assumptions" that have been used. Assumptions can be related to product lines, geographic areas, changes in laws or other major events. Estimate the total dollar impact of assumptions.

2.4 Key Operating Strategies
2.5 Anticipated Shortage of Energy, Raw Materials, or Supplies
2.6 Footnotes on the Results of Operation

3.1 Capital Expenditures. The prime objective of this section is to justify capital expenditures

Property Plant and Equipment
1. Maintenance of existing equipment
2. Enviornmental and pollution control
3. Incremental capital
4. Cost reduction potential
5. New profit potential
6. Development
7. Exploration

Acquisitions and Other Assets
8. Research and development
9. Investment
10. Acquisitions

Within the ten categories abide by the following requirements.

Highlights

1.1 Financial Highlights
1.2 Premises
General
Financial evaluation
Commodity analysis e.g. copper supply, demand, price forecast
Appendix 1 U.S. production capacity and cost of discoveries
Appendix 2 U.S. future demand and supply
Other commodities e.g., nickel, gold, uranium
Mineral exploration development planning stage
1.3 Objective
1.4 Strategies
1.5 Action plans
Mine development projects and detailed plans
1.6 Issues
1.7 Alternatives and contingencies

Result of Operations

2.1 Income by sale and entity (business area or market categories)
2.2 Income
2.3 Quantification of assumptions
2.4 Key operating strategies
2.5 Anticipated shortages of energy or other materials
2.6 Results of operations

Capital Expenditures

3.1 Capital expenditure summary
3.1a Capital expenditure details
3.2 Capital commitments summary
3.2a Capital commitment detail
3.3 Asset disposals
3.4 Capital expenditure/disposal footnotes

Funds Flow and Financing
4.1 Funds flow and financial consolidation
4.2 Analysis of other sources
4.2a Details
4.3 Inter-company transactions
4.4 Funds flow footnotes

Examples of the premises, objectives, strategies, and action plans sections of the 5-year budget are the following:

This is the budget for an exploration group financed by a large oil company with gross revenues of the order of $6 billion and earnings after taxes of $500 million. Total capital expenditures average $1 billion. Their debt to equity ratio is 0.6 to 1. The company has strength in oil exploration, both domestic and foreign as well as production in oil and petrochemicals.

The company desires to get into the metal mining business in stable countries by 1980. They are interested in large mines, big volume metal commodities traded internationally.

The company plans to spend $4 million per year on exploration and has set up an organization with one manager, four staff professionals, three regional managers and twnety-five geologists.

## OBJECTIVES

1. The overall objective of the company is to create new and valuable assets.

2. A secondary objective of the company is to run a productive and profitable mining operation as a result of discovery, acquisition and development of mineral reserves.

3. An objective of the company is to find new reserves through exploration discoveries.

## PREMISES

1. The industrialized economies of the world will continue healthy with recessions but not paralysis through government or other actions. Economic cycles will be of short duration. Environmental controls will become more balanced as feedback develops from existing policies.

2. Within the United States the efforts to change the 1872 mining law will be successful and a general federal mineral permit lease law will be enacted. Opposition to changes in the law will lose effrectiveness. Probably the new lease law will not slow development expenditures. The United States now produces 90% of mineral production under private leasing and a reasonable public leasing system would not be more detrimental.

3. In the United States effective pressures will change the depletion allowance for metals and this will be compensated for by increasing prices. Changes in the depletion allowance will probably take the form of enforcing use of the depletion allowance for creation of new assets through exploration. This approach could be beneficial for companies oriented toward exploration.

4. In Australia all investments will come under stricter governmental regulations. New laws will set new ground rules. The government will ease back on restrictions as exploration activity drops appreciably. There will probably be no significant change in government attitudes over 3 years. All governments in Australia have indicated that investors have a right to expect a reasonable return on their investment. Controls on importation of funds will continue and a tight money situation will remain. The public will be unable to invest in speculative exploration activity because of the tight money situation. Therefore, most exploration will be done by foreign multi-national groups. Successful companies will be those with the staff of professionals that can cope with the local conditions. There will be a continuation of takeover controls by private national groups and government.

5. Developing countries will continue pressure for construction of treatment and processing plants within their countries. Locally generated capital will remain very scarce. There will be pressure for more local private and government participation. Participation in general will consist of a free ride during exploration and early development of properties. Service contracts for metals development will probably be used by some governments.

6. The trend toward nationalization of the minerals industries will continue and spread. The lesson of Chile may moderate future governmental action.

7. There will be no major war.

8. Mineral exporting developing countries will continue with plans for price and production control. Cartels other than oil will have limited success. Successful and longlasting control of price require (1) a high percent of control well production, (2) a low elasticity of demand, (3) low elasticity in substitution, (4) a low elasticity of supply in the importing countries, (5) cohesion within the group attempting cartelization.

9. The real danger in commodity supply for the industrial countries is in requirements for a metal commodity where there is one or a few exporting producers and no satisfactory substitutes. An example is chromium form South Africa and Zambia, tungsten from China or palladium in the U.S.S.R.

10. Trends in metal consumption will remain stable which means 3 to 7% annual growth for nonferrous metals with wide short-term swings. The average profit of established metals producers will remain the same. This indicates a 9 to 17% return on investment, continually adjusted for rising inflation.

11. Increasing demand will allow exploitation of lower grade deposits.

12. There will be a stable relationship between price and cost but with wide swings over the short term.

13. Exploration costs are rising rapidly and will continue to rise. The effectiveness of exploration dollars varies with the generation of exploration. The first generation of exploration is surface exploration of outcrops. The second generation is geological mapping, instrumentation, geochemical, geophysical and airborne surveys. The second stage results in a substanial increase in reserves. The third generation of exploration allows predictions about mineral provinces and occurrences. This method has not produced much reserves but may produce more in the future. In the first generation costs are negligible and in the second generation high. In the last 20 years the effectiveness of the exploration dollar has declined by a third.

14. In copper the average investment to equip a copper deposit for production is 100 times the discovery cost. The average value of production derived from the deposit is about 30 times discovery costs.

15. For each 1000 prospects, 100 will be worthy of field exploration, 10 will be worthy of physical investigation, and 1 will be a mineral deposit.

16. For a medium to large size deposit the time lapse from interception of the deposit to determining that development is justified will be 1 to 5 years averaging 2.5

years. The time from start of development to production will be 1 to 7 years with an average of 3.5 years including 6 months to 1 year for environmental impact studies. The payout period based on 100% equity will be 4 to 7 years.

17. For small deposits amenable to high profit operation, the period of exploration, development, and payout will be 1/2 to 1/3 of the medium to large size deposits.

18. There will be no large bonanza discoveries by others which would be so huge, rich and low cost that there would be drastic changes in supply and prices.

19. Remote sensing will remain a mapping, not a mineral detection tool. New discoveries will continue to require insistent physical presence of competent persons in the field.

20. The U.S. will continue self-sufficient in copper unless older smelters are forced to close because of their air quality standards. Mine production will follow in parallel with demand at 4 to 4 1/2% annual increase.

21. There will be no disruptive strikes in the copper industry.

22. The recycling of scrap will continue as a significant source of copper supply.

23. The two long-term factors related to copper supply include (1) Japanese production in excess of consumption is 20,000 tons per month and this will end up in international markets, (2) there is a possibility for substantial copper production from ocean nodules. Each ocean nodule mining unit is capable of 60 million pounds per year. Elsewhere in the world conditions for copper supply are stable.

24. Copper mines will continue difficult to find and to finance. Typical deposits for copper are in the 50 to 5 million ton range, require capital investments of $50 to $700 million and generate cash flows of $15 to $150 million annually. They produce valuable byproducts of gold, silver, platinum, palladium, selenium, and tellurium.

25. Small blast and leach in-situ deposits of copper that were ignored in the past now have the potential to be brought into production quickly at low cost with high profitability.

26. The LME price for copper will rise slowly. Price controls on copper ran until April, 1974. Thereafter prices rose rapidly and after 1974 they declined and were slow to recover.

27. The flotation technique applies to the bulk of U.S. copper production. Leaching applies to only a small portion of copper deposits. Leaching techniques apply only to some oxide and sulphide deposits in the U.S.

28. The required investment in the domestic copper industry of the United States was $490 million in 1975, expected to be $652 million in 1979, $855 million in 1985, $1.1 billion by 1992 and $1.5 billion by the year 2000.

29. In the nickel industry consumption will rise at 6 to 7% average annual growth. INCO will limit its production in the future to the optimal level. Many new projects will be postponed.

30. Growth for the company will occur only when certain critical factors are favorable. These include (1) existence of a favorable geologic environment, (2) technical skills available, (3) skilled tradesmen available, (4) there is sufficient transportation facilities, (5) there is adequate energy at a reasonable price, (6) there is continuity of sufficient risk capital for each stage of exploration and (7) when there are acceptable and favorable mining and tax laws.

## PREMISES FOR FINANCIAL EVALUATION

1. Initially financial evaluations are hypotheses constructed from collective experience. They describe what is likely to be discovered — the target. It is necessary to have established procedures and techniques to value targets. This includes standards for estimating costs which are constantly revised and changed through reading the literature, discussions with consultants (on a no-charge basis), discussions with representatives of suppliers, requests for quotations and visits to operating properties.

2. Investment costs require escalation annually. In 1972 escalation was 5%. In the 1973-74 period, the annual rate of escalation went from 5% to 7% to 8% and then 10% annually plus a contingency factor. Recent rates of inflation indicate escalation rates of 12 to 15 percent and higher are justified.

3. The standard contingency factor is 15%. Different rates apply to different situations up to 40% depending on reliability of computations.

4. The cost of money in the mid-1970's was 15% but it is increasing rapidly with the runaway inflation of the late 70's and early 1980's.

5. The most difficult element in financial evaluation is projection of price and operating costs. The premise is that they will escalate in parallel. Therefore no escalation of costs or price is included in the evaluation model.

   A recent price is <u>not</u> used. The current level may be high or low in relation to a reasonable assumption for projection. Prices are reviewed quarterly and revised when necessary. The approach is to judge whether current price is abnormally high or low because of some transitory factors. It is not a projection of a price series.

   For short-lived projects, short-term fluctuations and price are significant and must be considered. A recent short-term copper project involved fantastic changes in the price level from 58¢ per pound to $1.50 per pound and back down to 85¢ per pound. Projections used in the evaluation included a price assumption of 53¢. The basic assumption is that the trend in prices and costs will be parallel. There is no conclusive evidence but comparisons of prices and costs indicates the idea has some validity. Therefore we assume a normal price and we use current operating costs without escalation. We hope the result is a reasonablly accurate projection of the operating possibility for 5 to 30 year periods. This type of analysis probably tends toward understatement of profitability.

   Some producers do build escalation assumptions into their analyses. Others attempt to hold cost constant and escalate a "real" price. The latter factors out inflation common to both price and cost and attempts to model whether prices will go up slightly faster or slower than costs.

6. In evaluating reconnaissance economic "models" they should indicate a minimum $4

million annual cash flow and a rate of return of more than 20% over 15 years after all interest and taxes.

7. In the mid-1970's, target exploration projects in preliminary and order of magnitude evaluations required a minimum annual cash flow of $1 million over 15 years and a 20% rate of return in the United States and Australia. A rate of 25% was required in riskier countries.

8. In the mid-1970's in definitive estimates the company requires at least $1 million annual cash flow, and a 20% rate of return or a $500,000 annual cash flow for a bonanza deposit with a rate of return greater than 25%. Outside of the United States and Australia rates of return required are higher.

9. The company will not engage in service contracts without a profit center in the United States.

## STRATEGIES

1. Favorable exploration projects will be selected and work accelerated.

2. Continue reconnaissance under all circumstances because projects may fail even down to the final feasibility study. In any event orebodies will have to be replaced indefinitely in the future.

3. The company will acquire and/or operate mining properties and go into joint ventures with specific partners.

4. All projects are constantly monitored as priorities change.

5. U.S. projects which meet only minimum expectations at the end of the target exploration stage are marketed.

6. In foreign countries the company seeks partners for all successful projects.

7. The selection of countries for exploration will be based on the following considerations: (1) geologically favorable conditions, (2) secure investment and property rights, (3) taxation allows acceptable rate of return, (4) the import of capital and repatriation of profits are possible, (5) requirements for local participation in the project are reasonable, (6) requirements to conduct processing in the host country does not render the project infeasible, (7) the investment climate permits financing, (8) the U.S. government does not prohibit operations, (9) other aspects of company operations are not jeopardized by the new investment.

## ACTION PLANS

This section details the specific actions to be taken on project alternatives. These include one major property at the decision point of whether or not to operate, another project at the level of detail drilling and metallurgical tests and involves consideratain of joint venture partners.

This section details additional staff requirements for each project, capital expenditures and cumulative capital expenditures and the various activities required in connection with each project. This includes land acquisition, exploration drilling, metallurgical testing, target feasibility studies, requesting bids for equipment, obtaining

operating permits and developing marketing plans.

### 2.7 Ranking Procedures

Some exploration groups attack the problem of choosing projects by review of all data and independent ranking of all projects by management personnel. These rankings combined objective and subjective elements of expected value and probability through the judgment of qualified individuals. Two to 60 projects may be ranked with the judgment of senior people being given more weight than others.

Table 2 is a summary of the top 30 projects out of 47 projects independently ranked by four individuals in a major exploration group. While there is an indication of strong agreement on some projects, the further down the list one goes the wider the variation in opinions.

Table 2 Independent Rankings of Annual Budget Proposals

| Project | Average | Evaluator Rankings #1 | #2 | #3 | #4 |
|---|---|---|---|---|---|
| 1 | 1.00 | 1 | 1 | 1 | 1 |
| 2 | 3.50 | 3 | 4 | 2 | 5 |
| 3 | 5.75 | 11 | 2 | 3 | 7 |
| 4 | 6.75 | 5 | 7 | 13 | 2 |
| 5 | 9.50 | 7 | 3 | 17 | 11 |
| 6 | 9.50 | 9 | 10 | 15 | 4 |
| 7 | 10.75 | 2 | 16 | 4 | 21 |
| 8 | 13.00 | 23 | 17 | 6 | 6 |
| 9 | 13.25 | 26 | 5 | 8 | 14 |
| 10 | 13.25 | 10 | 8 | 22 | 13 |
| 11 | 14.00 | 18 | 15 | 20 | 3 |
| 12 | 14.00 | 6 | 35 | 5 | 10 |
| 13 | 16.00 | 14 | 11 | 19 | 20 |
| 14 | 16.75 | 20 | 28 | 11 | 8 |
| 15 | 16.75 | 12 | 34 | 12 | 9 |
| 16 | 17.50 | 44* | 7 | 7 | 12 |
| 17 | 20.00 | 13 | 18 | 27 | 22 |
| 18 | 20.50 | 8 | 26 | 23 | 25 |
| 19 | 21.75 | 21 | 6 | 24 | 36 |
| 20 | 21.75 | 25 | 38 | 9 | 15 |
| 21 | 22.00 | 15 | 20 | 32 | 17 |
| 22 | 22.50 | 22 | 21 | 10 | 37 |
| 23 | 23.00 | 19 | 13 | 28 | 32 |
| 24 | 23.25 | 16 | 24 | 19 | 24 |
| 25 | 24.75 | 18* | 14 | 37 | 30 |
| 26 | 25.250 | 29 | 12 | 34 | 26 |
| 27 | 25.25 | 30 | 23 | 30 | 18 |
| 28 | 25.25 | 15* | 7 * | 39 | 40 |
| 29 | 25.75 | 27 | 29 | 14 | 33 |
| 30 | 25.75 | 4 | 33 | 25 | 41 |

## 3. GAMBLER'S RUIN

In his Jackling lecture of 1960, Lewis B. Slichter reminded the mining industry that

"prospecting is certainly the world's biggest and best gambling business. It is a game where the chips cost many thousands and where many millions, even billions, can be won. An attractive feature of this gamble is the fact that the players are free to rig the odds as favorably as possible. Only the limited bounty of nature, the restrictions of the laws of the land, the competition from other players, the limited sagacity of the player himself - only these, and other factors, restrict the possibilities for large winnings. The fact that prospecting is a gambling business, reminds us at once of the elementary rule known as the "law of gambler's ruin"...."This rule

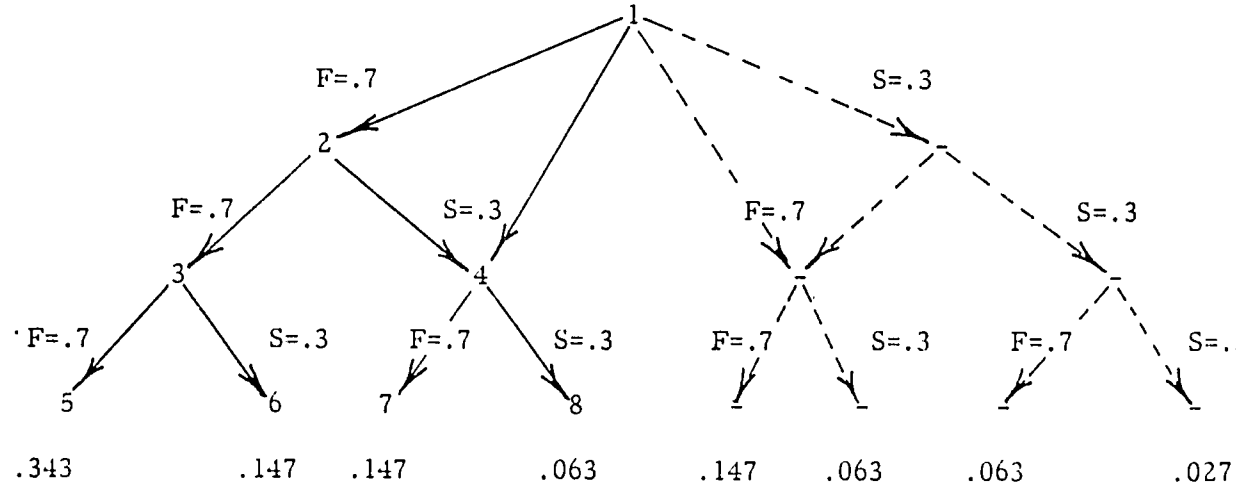
expresses the rather serious chance of going broke and the odds for success are small, merely by a normal run of bad luck regardless of the long-run expectations of gain. The only sure way of avoiding this special risk of gambler's ruin is to have enough capital, and the will to continue to play many times and thus ride out the inevitable runs of bad luck."

The facts of gambler's ruin are that given a stated (average) probability of success in a single venture, and the willingness to state the cost of an average single venture, for example the cost of following up an average "prospect" the amount of money necessary to assure a reasonable probability of success is a mathematical calculation. We have programmed the gambler's ruin calculation in a program called GAMBLR.FCL that request data on the average cost to follow up a geologic lead and the user's subjective or objective estimate of the probability of finding an orebody in the region. The latter is a combination of the probability of occurrence and the probability of finding the orebody if it exists.

The calculations of GAMBLR.FCL are shown diagramatically in figure 1. In this example each individual prospect is assumed to have a 30% chance of success and a 70% chance of failure. Starting from point 1, a single failure leads us to point 2 where the gambler has another chance to realize the odds. A second failure from point 2 leads us to point 3. The chances of arriving at point 5 is the product of the probabilities:. probabilities: 0.7 x 0.7 or 0.343. Similarly the probability of two failures and one success is 0.147 arriving at point 6. The probability of one failure followed by one success and another failure is 0.147 at point 7 and the probability of a failure and two successes arriving at point 8 is 0.063.

$P_s$ = 0.3 = probability of success

$P_f$ = 0.7 = probability of failure




| OUTCOMES | POSSIBLE WAYS | PROBABILITY | TOTAL PROBABILITY |
|---|---|---|---|
| FFF | 1 | .343 | .343 |
| FFS | 3 | .147 | .441 |
| FSS | 3 | .063 | .189 |
| SSS | 1 | .027 | .027 |
| 8 | | 1.0 | |

for any outcome:

$$P = C^n_r * P * (1-P_s)^{n-r}$$

Where $C = \frac{N!}{R!(N-R)!}$ (Zero factorial= 0! = 1)

FIGURE 1 THE BINOMIAL DISTRIBUTIONS

The significance is that when the probability of success are low it may be necessary to spend a large amount of money over a long period of time in order to fully exploit the odds of an expected discovery. Some calcuations with "GAMBLR.FCL" serve to illustrate this point.

### First Case

```
WHAT IS THE ESTIMATED PROBABILITY OF SUCCESS FOR A SINGLE VENTURE (%)  ?     1
HOW MUCH DO YOU PLAN TO BUDGET IN TOTAL FOR EXPLORATION ($000)   ?     2000
WHAT IS THE ESTIMATED COST PER PROSPECT INVESTIGATION ($000)     ?     50
WHAT IS THE PRESENT VALUE OF YOUR EXPECTED DISCOVERY ($000)   ?     50000
YOUR PROBABILITY OF GAMBLER'S RUIN IS     66.9%

THE EXPECTED VALUE OF THIS PROJECT ($000) IS      16550.
```

### Second Case

```
WHAT IS THE ESTIMATED PROBABILITY OF SUCCESS FOR A SINGLE VENTURE (%)   ?     1
HOW MUCH DO YOU PLAN TO BUDGET IN TOTAL FOR EXPLORATION ($000)   ?     20000
WHAT IS THE ESTIMATED COST PER PROSPECT INVESTIGATION ($000)   ?     50
WHAT IS THE PRESENT VALUE OF YOUR EXPECTED DISCOVERY ($000)   ?     50000
YOUR PROBABILITY OF GAMBLER'S RUIN IS    13.4%

THE EXPECTED VALUE OF THIS PROJECT ($000) IS         43300
```

The first case indicates that with an estimated probability of success of only 1% and a planned exploration budget of $2 million where the average prospect investigation is expected to cost $50,000, the probability that all the money will be spent without a single discovery is 66.9% and the expected value of a $50 million discovery is only $16,550,000.

In the second case with an estimated probability of success of 1 out of 100 or 1%, and a planned exploration budget of $20 million with a cost of $100,000 per investigation the probability of gambler's ruin is 13.4% and the expected value of a $50 million discovery is $43,300,000.

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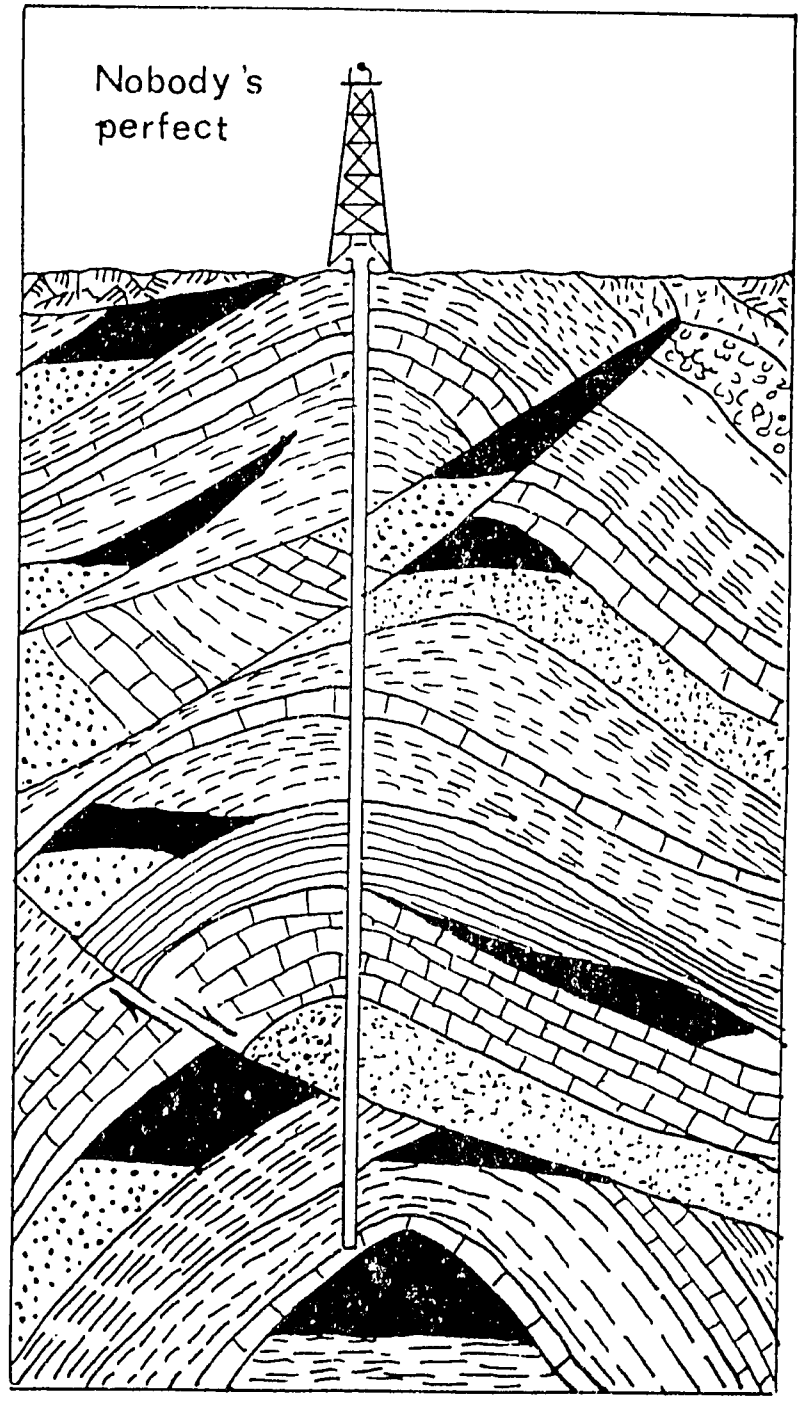
# PETROLEUM EVALUATION FUNDAMENTALS




From DECISION ANALYSIS FOR PETROLEUM EXPLORATION
By Paul D. Newendorp, p 500

# PETROLEUM EVALUATION FUNDAMENTALS

## 1. INTRODUCTION

This chapter summarizes the economic evaluation of a hypothetical wildcat well in Colorado.

There are seven steps in defining the expected profitability of an oil producing project. These are:

(1) Estimate the oil reserves in place. This is a volumetric analysis designed to estimate the porosity of the rock and the space occupied by oil, water and gas in the pore space.

(2) Determine the rate of recovery from the formation which will depend on reserves and the energy in the formation to drive the oil.

(3) Estimate the capital and operating costs of the project assuming if successful and if it results in failure - a "dry hole". This requires study of the physical characteristics of the oil field in order to make engineering assumptions for a technical analysis, then utilization of the engineering assumptions to prepare the financial evaluation.

(4) Estimate the cash flow stream expected from the prospect if it is successful. This requires forecasts of future prices and costs, taxes, and government regulations in order to develop the operating cash flows of the project. The specific development agreement specifies how the investment and operating cash flows are to be divided among the joint venture partners.

(5) Define the technical risks involved in the investment. This often requires subjective estimates of the probabilities involved.

(6) Define the economic risks involved in the investment. This often requires subjective estimates of future prices, costs, tax regimes, and political or legal variables that affect timing or cash flows.

(7) Calculate the present value and rate of return of the investment. Utilize "risk adjusted" as a basis for recommending action.

## 2. THE COLORADO WILDCAT PROSPECT - 1976

This hypothetical wildcat oil prospect is assumed in the state of Colorado where 640 acres are involved in the oil play. The initial proposal is to drill three test wells at the high point on the anticline structure and to run ten miles of seismic line to gain further information on the anticlinal stratigraphic trap. A step by step listing of basic data, well profitability, project profitability and risk analysis follows. The risk analysis in this chapter is further developed in the chapter on expected value.

### 2.1 Basic Data

(1) Type of trap: Anticline

Previous data indicates the shape and size of the expected oil trap. These come in a large variety of shapes and types but the anticline is representative of a large number of oil fields.

(2) Objective geologic formation: Miocene

Geologic cross sections indicate the probable producing formations and their age. In addition physical characteristics of this formation are available. It is a muddy sandstone with certain physical characteristics that affect production.

(3) Depth: 7000 ft. total depth to producing formation

(4) Average net pay: 7 ft

This is the expected portion of the formation expected to be porous and to contain oil.

(5) Average porosity: 20%

This is the pore space in the rock which may contain oil, gas or water.

(6) Average water saturation: (30%)

This is the expected water occupying pore space in the rock.

(7) Average formation volume factor: 1.20

This factor relates the expected volume of the hydrocarbons at the surface to the volume underground. Oil at depth is subjected to approximately 0.434 pounds per square inch per foot of depth. Thus at a depth of 10,000 ft. the rock would be subjected to 4,340 pounds per square inch hydrostatic head. A barrel of oil coming to the surface may come from a temperature of 160° F and a pressure of 3,000 pounds per square inch to atmospheric temperature of 60° F and a pressure of 15 pounds per square inch. When the oil comes to the surface the gas comes out of solution and the barrel shrinks as a result. The formation volume factor measures this difference. A volume factor of 1.2 indicates that the volume at the surface will be 1/1.2 or 83% of the oil underground. The smaller the formation volume factor, the less energy to drive the oil to the surface but the more oil you have underground.

(8) Average initial or solution Gas Oil Ratio (GOR): 354 standard cubic feet per barrel (scf/Bbls.)

This ratio measures the amount of gas associated with each barrel of oil in the formation. Since oil and gas recoveries from the formation are quite different (e.g. 30% of the oil and 60% of the gas) this ratio does not indicate the amount of gas that will be produced per barrel of oil produced. The ratio is used to estimate the gas reserve in the formation and the ratio of oil recovered to gas recovered is used to estimate the average gas production per barrel of oil.

(9) Average oil in place:

There are 43,560 square feet in an acre or 43,560 cubic feet in a volume one acre in area and one foot thick. There are 5.61 cubic feet in a (42-gallon) barrel of oil; therefore, there are 7,758 barrels per acre per foot of formation thickness.

Calculation (a) is the product of the barrels per acre-foot factor times the porosity (0.2) times the pore space not occupied by water (1-0.3) times the reciprocal of the volume factor (1.2). The result is the estimated barrels per net acre foot (B/NAF) of the formation.

Calculation (b) uses the estimated formation thickness (7 ft.) and the expected B/NAF to calculate the estimated barrels per acre (B/Acre) on the prospect. The result of these calculations is the volume of oil potentially recoverable measured at the surface.

(a) 7758 (0.2) (1-0.3) x (1/1.2) = 905 B/NAF

(b) 7 x 905 = 6335 B/Acre

(10) Average well spacing: 40 Acres

This is an engineering calculation based on an assumed spacing for maximum recovery from the field.

(11) Average oil in place per well: 40 x 6335 = 253,400 barrels per well

(12) Estimated recovery factors:

Oil - 30%
Gas - 70%

Recovery will depend on the type of trap and the type of drive pushing the oil. Gravity drainage is most effective but slow, dissolved gas drive is least effective but rapid. The third drive is water, which usually falls in between. A weak water and gas drive results in a range of oil recovery between 18% and 38%. The gas comes out of solution as the oil comes to the surface.

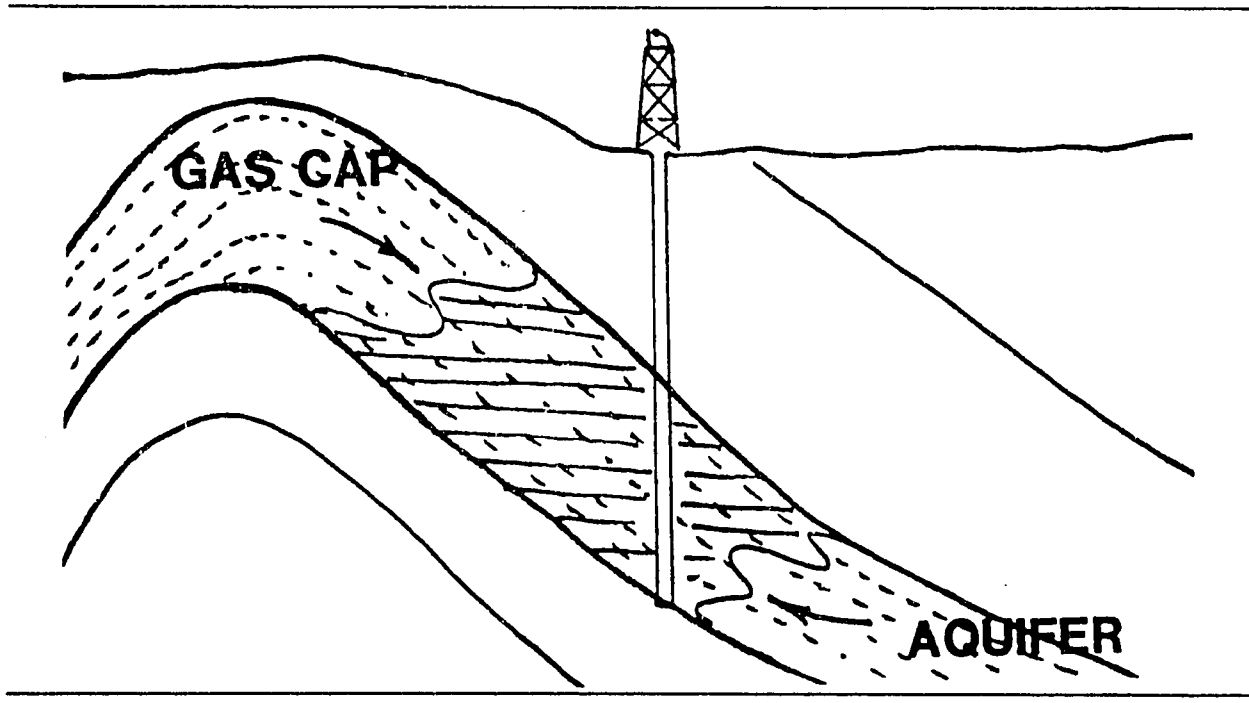



FIGURE 1 OIL/GAS TRAP

(13) Total estimated economically recoverable reserves per well:

Oil recovery is the product of the expected barrels of oil under each 40 acre well multiplied by expected recovery. Gas reserves are the product of the total oil contained in the formation under a 40 acre well times the gas oil ratio (GOR) times the expected gas recovery.

(a) Oil: 253,400 X 0.3 = 76,020 barrels

(b) Gas: 253,400 X 354 X 0.7 = 62,792,520 standard cubic feet (62.8 MMSCF)

(14) Average initial producing rate: 30 barrels per day per well (B/D/W) and 816 standard cubic feet per day per well (816 SCF/D/W).

The initial producing rate is the rate of production assumed during the flat life of the project or as the beginning of declining production. This rate is an assumption based on performance of similar wells.

(15) Minimum life factor:

This factor is the minimum number of years of expected production. It is the total reserve divided by 365 times the daily production. In some cases there will be a flat life where the production rate maintains a constant annual rate. Thereafter production will decline as the drive pressure gets lower and the oil and gas reserves are depleted.

(16) Flat Life = 0 years

For this prospect there is no flat production rate. The annual rate of production declines each year after the first year of production. If this project had a flat life of two years the flat life reserves would be 2 times 365 times 30 equals 21,900 barrels over two years.

(17) Economic limit: 10 Bbls/Day

It is assumed that the well will flow down to a 1 barrel per day ultimate rate of production. There is; however, an economic limit which depends on oil and gas prices and total costs of production. This economic limit will vary with cost and price levels. A 21-year time horizon is assumed in the financial analysis of this project. During the 21st year of production, 8,000 barrels or 22 barrels per day is forecast, well above the economic limit under current cost price levels.

(18) Declining reserves: 76,020 Bbls./Well

Since there is no flat life all reserves are produced at a declining production rate.

(19) AY = 0.1393 (Estimated linear annual decline factor);
DY = 13.9% (Annual exponential decline rate)

The annual decline factor and the percentage annual decline rate are determined by the relationships between head pressure and fluid flow. As head pressure drops, fluid flow drops in proportion following an exponential relationship. In this analysis the annual decline factor is a preliminary linear estimate of the exponential annual decline rate.

The basic formula for an exponential decline in flow is:

$$q_i = q_o e^{-at}$$

where: $q_i$ = the initial production rate in barrels per year
$q_o$ = the final production rate in barrels per year
$e$ = the base of natural logs
$a$ = the decline rate or slope of the decline curve as a decimal fraction
$t$ = the period of time involved in years

The decline factor is estimated assuming a linear decline in flow and that the limits of production are determined by the oil reserve under the well. The formula is:

$$a = \frac{q_i - q_e}{N}$$

where: $q_i$ = initial production rate in barrels per year
$q_e$ = economic cutoff production rate in barrels per year
$a$ = estimate of annual decline factor, decimal fraction
$N$ = recoverable reserve subject to the decline rate. In this case it is the total reserve.

Substituting in the above equation we have:

$$a = \frac{(30 - 1) \times 365}{76000} = 0.1395$$

The head and flow relationship allows calculation of the expected period of production for a given reserve following an exponential decline as follows:

$$\frac{q_e}{q_o} = e^{-at}$$

In solving the preceeding formula for t we use the annual decline factor as the estimate of the annual decline rate by substituting in the exponential formula as follows:

$$\ln \frac{q_e}{q_o} = -at$$

$$\ln \frac{1}{30} = (-0.1395)\,t$$

$$t = 24.4 \text{ years}$$

Thus the expected life of the project is 24.4 years and the annual decline rate is approximately 13%. Production each year is 87% of the prior year production.

(20) Declining life = total life: 24.4 years. Since this field begins to decline in production from the first year the total expected life and the declining life are the same.

(21) Well Costs ($000)

Exploratory drilling usually requires more detailed analysis than development wells. For this reason costs of such wells are likely to be higher. If a hole turns out to be a producer it must be fitted with pumping units and other equipment and this is called "completion" to prepare a well for production.

| | Exploratory | Development |
|---|---|---|
| (a) Dryhole | 80 | 50 |
| (b) Completion flowing | 140 | 110 |
| (c) With artificial lift or special facilities after 5 years | 150 | 115 |

(22) Operating Cost ($1976)

The operating cost used in the analysis that follows is measured at 1976 price levels and includes the following:

| Item | Amount Per Barrel |
|---|---|
| Direct cost ($400 per well per month) | $1.54 |
| Overhead ($50 per well per month) | .15 |
| Production tax (4%) | .49 |
| Total | $2.18 |

## 2.2 Total Project Profitability

The evaluation to this point is in terms of an average development well. It remains to calculate the number of development wells on the productive acreage of the prospect and the investment required to develop the project.

The initial step in developing cost estimates is to develop an engineering concept of how and over what period of time the field would be developed. In this example a land position is secured through leasing and rentals prior to initiating geological and geophysical reconnaisance over a period of two years.

Success in initial reconnaisance narrows down the exploration target for detailed seismic exploration and geologic interpretation. A total of three exploratory test wells determine whether the 40 acre prospect is dry or productive.

If the prospect is dry it is abandoned and the loss is absorbed by the company.

If the prospect is productive, investment continues to complete three additional test wells, sixteen development wells, and two dry development holes. Thus the total investment for a productive field is larger and must be justified by future cash flows.

After two years of production, pressures have declined sufficiently to install pumping equipment for artificial lift of the petroleum. At this point, additional investment is required.

## SUMMARY OF INVESTMENT EXPENDITURES

| Cost Estimates: | Prospect Dry | Prospect Productive |
|---|---|---|
| (23) Leasehold costs | $35,000 | |
| (24) Rentals | $72,000 | |
| (25) Geological and geophysical expense | $16,000 | |
| (26) Cost of 3 exploratory test wells The three exploratory test wells would be expanded to five if gas is to be sold from the property. | $240,000 | |
| (27) Total investment if prospect tests dry | $363,000 | $363,000 |
| (28) Completion cost of 3 test wells | | $ 60,000 |
| (29) 15 subsequent development wells | | $1,650,000 |
| (30) Cost of artificial lift or special facilities (2 yrs. @ $15,000/well) | | $240,000 |
| (31) Cost of 2 development dry holes: | | $100,000 |
| (32) Total investment if prospect is productive | | $2,413,000 |

In the analysis that follows the total investment measured in 1976 dollars is escalated at a rate of 8.6% annually which increases the total dollar cash flow to $2,551,000. It is this escalated investment that is used in the calculations.

Profit:

(33) Estimated probability of success: 20%
Probabilities are subjective estimates based on previous experience. In the United States onshore drilling success averaged one out of fourteen or 7% while offshore exploration success was one in three or 33%.

(34) Potential investment =

$$(\$2,551,000) + \frac{1}{0.2} - 1 \quad (\$363,000) = \$4,003,000$$

This calculation indicates that with a probability of success of 20% the expected investment will include four dry prospect investments plus one productive investment.

(35) Expected value:

The expected value is equal to the probability of success (0.20) times the present value of success ($1,477,000 ) minus the probability of failure (0.80) times the cost of a dry hole ($363,000) thus 0.20 X $1,477,000 - 0.80 X $363,000=
$295,400 - 290,400 = 5000

The appendices to this chapter summarize the investment analysis of this project, calculating the present value and rate of return if successful, the potential investment including investment in unsuccessful prospects and gamblers ruin. Some investors also calculate a minimum allowable probability of success to achieve a minimum acceptable discounted cash flow rate of return on the project.

An analysis of the prospect is only complete when the financial resources of the company involved are considered. If the probability of success is 0.20 the probability of failure is 0.80 and the probability of 10 consecutive failures is 0.11 because $(0.80)^{10} = 0.11$. Thus there is an 11 % chance that the company will have a string of 10 failures . The cost of these 10 failures will be 10 X $363,000 or $3,630,000. It is imperative that the assets of the company be sufficient to avoid "gambler's ruin" by running out of money before the odds of success are realized.

Some analyses are made before taxes. The computer analyses appended to this chapter are after-tax analyses with detailed consideration to the timing of the various expenditures. The criteria for the decision to invest in the project are present value, rate of return and the minimum allowable probability of success to achieve a minimum discounted cash flow rate of return of 25% on the project.

PETROLEUM ANALYSIS REFERENCE NUMBER 100.
FIRST YEAR OF INVESTMENT CASH FLOWS 1976.
LAST YEAR OF INVESTMENT CASH FLOWS 1977.
PRICE INDEX THAT APPLIES TO OPERATING COSTS 183.0
MINIMUM ACCEPTABLE DISCOUNT RATE 20.0
PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (% ) 8.6
SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1977.

| YR. | COST INDEX | CASH FLOW(1968 $) TOTAL | CASH FLOW(1968 $) NET EQUITY | CASH FLOW (ESC. $) TOTAL | CASH FLOW (ESC. $) NET EQUITY | NO. EMPL. |
|---|---|---|---|---|---|---|
| 1976. | 0.0 | 804. | 804. | 804. | 804. | 0. |
| 1977. | 0.0 | 1609. | 1609. | 1747. | 1747. | 0. |
| NET INVESTMENT | | 2413. | 2413. | 2551. | 2551. | |

DEPRECIABLE INVESTMENT ($000) 638.
INTANGIBLE INVESTMENT RECOVERED THROUGH DEPLETION 1913.
AVG. NET PAY (FEET) 7.
AVG. POROSITY (%) 20.
AVG. WATER SATURATION (%) 30.
AVG. FORMATION VOLUME FACTOR 1.20
AVG. INITIAL GAS/OIL RATIO (SCF/BBL) 354.
AVG. OIL IN PLACE (BBL/NET ACRE FT.) 905.
AVG. WELL SPACING (ACRES) 40.
ESTIMATED OIL RECOVERY (%) 30.
ESTIMATED GAS RECOVERY (%) 70.
TOTAL RECOVERABLE OIL RESERVES PER WELL (000 BBL) 76.
TOTAL RECOVERABLE GAS RESERVES PER WELL (000 SCF) 62799.
AVG. INITIAL OIL PRODUCTION RATE (BBL/DAY/WELL) 30.
AVG. INITIAL GAS PRODUCTION RATE (000 SCF/DAY/WELL) 24780.
FLAT LIFE (YEARS) 0.
ECONOMIC PRODUCING LIMIT (BBL/DAY) 1.
DECLINING OIL RESERVES (000 BBL) 76.
ANNUAL DECLINE RATE (%) 13.9
DECLINING LIFE (YEARS) 24.
TOTAL LIFE (YEARS) 24.
PRODUCTIVE ACREAGE EXPECTED (ACRES) 640.
NO. OF DEV. WELLS 15.
TOTAL OIL RESERVES (000 BBL) 1140.
ASSOCIATED GAS RESERVES 941992.
ESTIMATED PROBABILITY OF SUCCESS (%) 20.0
INVESTMENT FOR DRY PROSPECT ($000) 363.
EXPECTED INVESTMENT ($000) 4003.
NUMBER OF PHASES OF PRODUCTION
FOR THE CASH FLOWS IN PHASES
1. 2. 3.

---

FIRST YEAR OF OPERATING NET CASH FLOW
1976. 1977. 1987.
LAST YEAR OF OPERATING NET CASH FLOW
1976. 1986. 1996.
PROJECTED RATE OF OIL AND GAS PRICE ESC.
15.0 15.0 15.0
INITIAL REPLACEMENT INV. ($000)
0. 0. 0.
PROJECTED RATE REPLACEMENT INV. ESCALATION (% AN.)
7.0 7.0 7.0
PROJECTED RATE OF COST ESCALATION (% ANNUALLY)
8.0 8.0 8.0
ANNUAL ROYALTY RATE (% OF GROSS REV.)
25.0 25.0 25.0

```
 PETROLEUM  ANALYSIS REFERENCE NUMBER          100.
            PETROLEUM  CASH FLOW CALCULATION FOR PHASE
YEAR
    1976.
PRICE OF OIL PER BBL ($U.S.)
    11.50
PRICE OF GAS PER THOUSAND STANDARD CUBIC FT. (MSCF) ($U.S.)
     0.80
ANNUAL PRODUCTION RATE OF OIL (000 BBL)
     164.
ANNUAL  PRODUCTION RATE OF GAS (000 SCF)
  135671.
AVERAGE TOTAL COST ($/BBL OIL )
     4..5
AVG. OPERATING COST ($/BBL OIL)
     2.18
REVENUE ($000 U.S.)
    1997.
LESS ANNUAL ROYALTY ($000)
     499.
LESS ANNUAL OPERATING COST ($000)
     358.
EQUALS GROSS INCOME  ($000)
    1140.
LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000)
     116.
LESS DEPLETION ($000)
     276.
TAXABLE INCOME  ($000)
     749.
EFFECTIVE INCOME TAX RATE (%)
      50.
LESS TAX ($000)
     374.
EQUALS NET INCOME AFTER TAX ($000)
     374.
PLUS NON CASH FLOWS ($000)
DEPRECIATION AND AMORTIZATION
     116.
AND DEPLETION  ($000)
     276.
LESS REPLACEMENT INVESTMENT ($000)
      33.
EQUALS NOMINAL DOLLAR CASH FLOW ($000)
     733.
CONSTANT ( 1976.) DOLLAR CASH FLOW ($000)
     733.
```

PETROLEUM ANALYSIS REFERENCE NUMBER 100.
PETROLEUM CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1977. | 1978. | 1979. | 1980. | 1981. | 1982. | 1983. | 1984. | 1985. | 1986. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE OF OIL PER BBL ($U.S.) | 13.23 | 15.21 | 17.49 | 20.11 | 23.13 | 26.60 | 30.59 | 35.18 | 40.46 | 46.52 |
| PRICE OF GAS PER THOUSAND STANDARD CUBIC FT. (MSCF) ($U S.) | 0.92 | 1.06 | 1.22 | 1.40 | 1.61 | 1.85 | 2.13 | 2.45 | 2.81 | 3.24 |
| ANNUAL PRODUCTION RATE OF OIL (000 BBL) | 141. | 122. | 105. | 90. | 78. | 67. | 58. | 50. | 43. | 37. |
| ANNUAL PRODUCTION RATE OF GAS (000 SCF) | 116782. | 100523. | 86528. | 74481. | 64111. | 55186. | 47502. | 40889. | 35196. | 30296. |
| AVERAGE TOTAL COST ($/BBL OIL ) | 4.91 | 5.65 | 6.47 | 7.38 | 8.39 | 9.51 | 10.75 | 12.13 | 13.65 | 15.64 |
| AVG. OPERATING COST ($/BBL OIL) | 2.35 | 2.54 | 2.75 | 2.97 | 3.20 | 3.46 | 3.74 | 4.04 | 4.36 | 4.71 |
| REVENUE ($000 U.S.) | 1977. | 1957. | 1937. | 1918. | 1898. | 1879. | 1860. | 1841. | 1823. | 1804. |
| LESS ANNUAL ROYALTY ($000) | 494. | 489. | 484. | 479. | 475. | 470. | 465. | 460. | 456. | 451. |
| LESS ANNUAL OPERATING COST ($000) | 333. | 309. | 288. | 267. | 249. | 231. | 215. | 200. | 186. | 173. |
| EQUALS GROSS INCOME ($000) | 1150. | 1158. | 1165. | 1171. | 1175. | 1178. | 1180. | 1181. | 1181. | 1181. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 104. | 93. | 81. | 70. | 58. | 46. | 35. | 23. | 12. | 12. |
| LESS DEPLETION ($000) | 237. | 204. | 176. | 151. | 130. | 112. | 96. | 83. | 71. | 62. |
| TAXABLE INCOME ($000) | 809. | 862. | 909. | 950. | 987. | 1020. | 1049. | 1075. | 1098. | 1108. |
| EFFECTIVE INCOME TAX RATE (%) | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. |
| LESS TAX ($000) | 404. | 431. | 454. | 475. | 494. | 510. | 525. | 538. | 549. | 554. |
| EQUALS NET INCOME AFTER TAX ($000) | 404. | 431. | 454. | 475. | 494. | 510. | 525. | 538. | 549. | 554. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 104. | 93. | 81. | 70. | 58. | 46. | 35. | 23. | 12. | 12. |
| AND DEPLETION ($000) | 237. | 204. | 176. | 151. | 130. | 112. | 96. | 83. | 71. | 62. |
| LESS REPLACEMENT INVESTMENT ($000) | 30. | 28. | 26. | 24. | 22. | 20. | 18. | 17. | 16. | 14. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 716. | 700. | 685. | 672. | 660. | 648. | 637. | 627. | 617. | 612. |
| CONSTANT ( 1976.) DOLLAR CASH FLOW ($000) | 669. | 611. | 560. | 513. | 471. | 432. | 397. | 365. | 335. | 311. |

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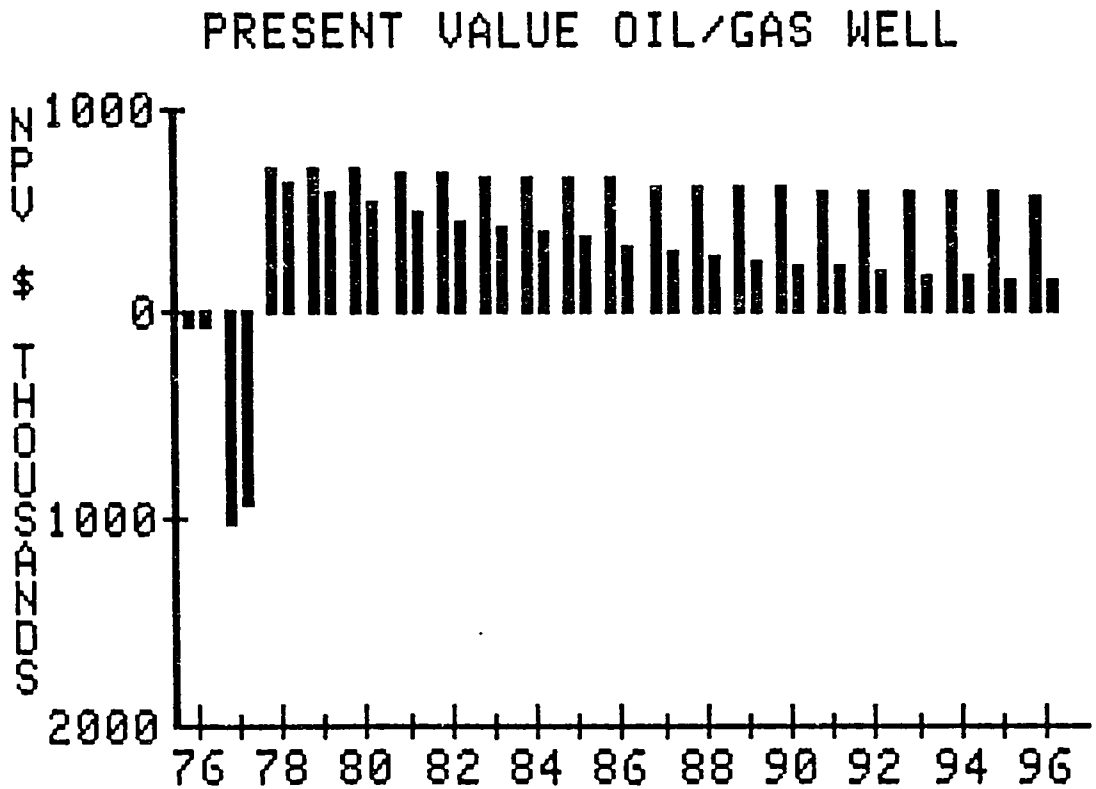
PETROLEUM ANALYSIS REFERENCE NUMBER 100.
PETROLEUM CASH FLOW CALCULATION FOR PHASE 3.

| YEAR | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. | 1994. | 1995. | 1996. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE OF OIL PER BBL ($U.S.) | 53.50 | 61.53 | 70.76 | 81.37 | 93.58 | 107.61 | 123.75 | 142.32 | 163.67 | 188.22 |
| PRICE OF GAS PER THOUSAND STANDARD CUBIC FT. (MSCF) ($U.S.) | 3.72 | 4.28 | 4.92 | 5.66 | 6.51 | 7.49 | 8.61 | 9.90 | 11.39 | 13.09 |
| ANNUAL PRODUCTION RATE OF OIL (000 BBL) | 32. | 27. | 23. | 20. | 17. | 15. | 13. | 11. | 10. | 8. |
| ANNUAL PRODUCTION RATE OF GAS (000 SCF) | 26078. | 22447. | 19322. | 16632. | 14316. | 12323. | 10608. | 9131. | 7860. | 6765. |
| AVERAGE TOTAL COST ($/BBL OIL ) | 17.92 | 20.50 | 23.45 | 26.81 | 30.65 | 35.02 | 40.01 | 45.71 | 52.22 | 59.66 |
| AVG. OPERATING COST ($/BBL OIL) | 5.08 | 5.49 | 5.93 | 6.40 | 6.92 | 7.47 | 8.07 | 8.71 | 9.41 | 10.16 |
| REVENUE ($000 U.S.) | 1786. | 1768. | 1750. | 1733. | 1715. | 1698. | 1681. | 1664. | 1647. | 1630. |
| LESS ANNUAL ROYALTY ($000) | 447. | 442. | 438. | 433. | 429. | 424. | 420. | 416. | 412. | 408. |
| LESS ANNUAL OPERATING COST ($000) | 160. | 149. | 139. | 129. | 120. | 111. | 104. | 96. | 90. | 83. |
| EQUALS GROSS INCOME ($000) | 1179. | 1177. | 1174. | 1171. | 1166. | 1162. | 1157. | 1151. | 1146. | 1139. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. |
| LESS DEPLETION ($000) | 53. | 46. | 39. | 34. | 29. | 25. | 22. | 19. | 16. | 14. |
| TAXABLE INCOME ($000) | 1115. | 1120. | 1123. | 1125. | 1126. | 1125. | 1124. | 1121. | 1118. | 1114. |
| EFFECTIVE INCOME TAX RATE (%) | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. | 50. |
| LESS TAX ($000) | 557. | 560. | 562. | 563. | 563. | 563. | 562. | 561. | 559. | 557. |
| EQUALS NET INCOME AFTER TAX ($000) | 557. | 560. | 562. | 563. | 563. | 563. | 562. | 561. | 559. | 557. |
| PLUS NON CASH FLOWS ($000) DEPRECIATION AND AMORTIZATION | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. | 12. |
| AND DEPLETION ($000) | 53. | 46. | 39. | 34. | 29. | 25. | 22. | 19. | 16. | 14. |
| LESS REPLACEMENT INVESTMENT ($000) | 13. | 12. | 11. | 10. | 10. | 9. | 8. | 7. | 7. | 6. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 609. | 605. | 601. | 598. | 594. | 590. | 587. | 583. | 580. | 576. |
| CONSTANT ( 1976.) DOLLAR CASH FLOW ($000) | 289. | 269. | 249. | 232. | 215. | 200. | 186. | 173. | 160. | 149. |

NOMINAL DOLLAR EVALUATION
THE NET PRESENT VALUE AT 20.0 PERCENT DISCOUNT RATE IS ($000) 1421.
EXPECTED VALUE OF THIS PROJECT ($000) - 6.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 59.3 PERCENT
ASSUMED GENERAL INFLATION RATE IS 7.0PERCENT
CONSTANT DOLLAR EVALUATION
THE NET PRESENT VALUE AT 13.0 PERCENT DISCOUNT RATE IS ($000) 1410.
EXPECTED VALUE OF THIS PROJECT ($000) - 8.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 48.9 PERCENT


PRESENT VALUE OIL/GAS WELL
NPV $ THOUSANDS
1000
0
1000
2000
76 78 80 82 84 86 88 90 92 94 96

```
W 27;GOTO 27.1

27.10 E ;T "WILDCAT PETROLEUM PROSPECT",!
27.12 E ;S M=1976;S N=1977;S NW=15;S WP(O)=183.0;S R(1)=.20;S IN(1)=2413;S EX=1
27.15 S NP=7;S PR=.20;S WS=.30;S VF=1.20;S GO=354;S SS=40;S RO=.30;S RG=.70;S BB(1)=30;S EL=1;S PL=640
27.20 S I%(1976)=.333;S I%(1977)=.667;S D%=0;S LF=0
27.30 S CD=1;S IE=.0856;S X=3;S IN(5)=363;S PS=.20;S NF=.07
27.33 S WI(1976)=127.4;S WI(1977)=138.3
27.35 S K(1)=1976;S N(1)=1976;S K(2)=1977;S N(2)=1986;S K(3)=1987;S N(3)=1996
27.40 S RE=.07;S RB(1976)=.20;F J=1977,1996;S RB(J)=1.07*RB(J-1)
27.42 F J=1976,N(X);S TX(J)=.50
27.45 S PE=.15;S PO(1976)=11.50;F J=1977,N(X);S PO(J)=(1.00+PE)*PO(J-1)
27.47 S PG(1976)=0.80;F J=1977,N(X);S PG(J)=(1.00+PE)*PG(J-1)
27.49 S CE=.08;S CB(1976)=(1.54+.49+.15);F J=1977,N(X);S CB(J)=(1.00+CE)*CB(J-1)
27.50 F W=1,X;S AR(W)=.25;S AM(W)=0;S IT(W)=0;S DP(W)=.0
27.55 S EC=0;S PY=0
27.90 IF (SM) , , 30.1
27.92 T "BASE CASE ANALYSIS #100",!
27.93 A "TYPE 1 FOR SPANISH, 0 FOR ENGLISH ",SP
27.94 IF (SP) ,27.95,27.96
27.95 S Y=100;L O #1=P100;GOTO 1.57
27.96 S Y=100;L O #1=PSP100;GOTO 51.57

WILDCAT PETROLEUM PROSPECT
BASE CASE ANALYSIS #100
TYPE 1 FOR SPANISH, 0 FOR ENGLISH 0
COST DEPLETION

NOMINAL DOLLAR EVALUATION


THE NET PRESENT VALUE AT     20.0    PERCENT DISCOUNT RATE IS  ($000)          1421.

EXPECTED VALUE OF THIS PROJECT ($000) -       6.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS          59.3      PERCENT


CONSTANT DOLLAR EVALUATION


THE NET PRESENT VALUE AT     13.0    PERCENT DISCOUNT RATE IS  ($000)          1410.

EXPECTED VALUE OF THIS PROJECT ($000) -       8.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS          48.9      PERCENT

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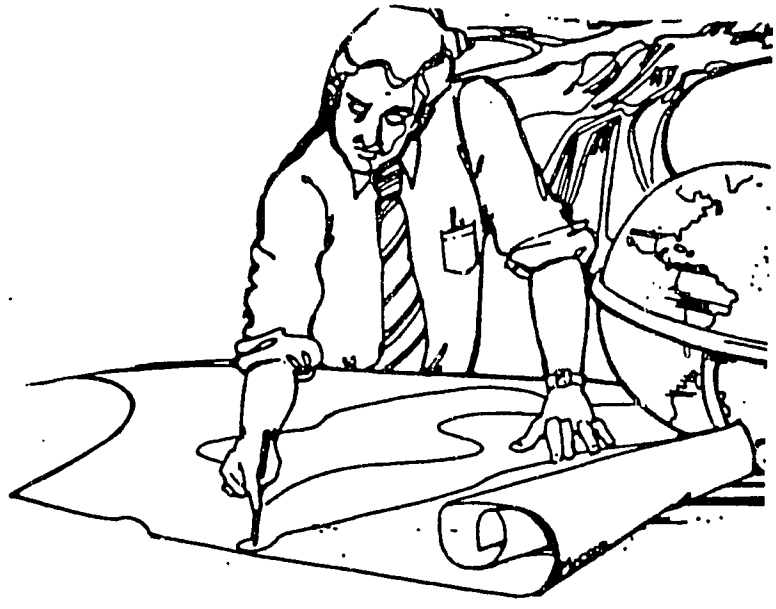
# EXPECTED VALUE AND DECISION TREES



# EXPECTED VALUE AND DECISION TREES

## 1. Expected Monetary Value Concept

The investment in exploration is especially concerned with a combination of risks expressed by probabilities.

Petroleum explorationists, and to a lesser extent, mineral explorationists use Expected Monetary Value (EMV) to rank investment alternatives. The decision rule is to select the alternative with the highest positive EMV.

EMV includes all of the risk and uncertainty of exploration into one estimate of the probability of success for a particular outcome. If all possible outcomes are included in the analysis, the sum of the probabilities must be equal to 1.0. Any number of alternatives or outcomes can be considered and although there are various ways to express the value of success or failure we will use net present value in the analyses to follow.

## 2. Use of EMV in a Drilling Decision

Consider an oil well drilling venture where the net present value of success includes drilling the initial wildcat well plus developing and equipping production wells. The net present value of a successful venture is estimated at ten million dollars. If only the wildcat well is drilled and it is a dry hole the cost is five hundred thousand dollars. Based on geological data and success ratios in the region the probability of success is estimated at 0.3 and the only alternative considered is a failure in the form of a dry hole with a probability of 0.7. In this case the expected monetary value of the venture (EMV) is calculated as follows:

$$\begin{aligned} EMV &= 0.3 \times \$10{,}000{,}000. + 0.7 \times (-\$500{,}000) \\ &= 3{,}000{,}000 - 350{,}000 = \$2{,}650{,}000. \end{aligned}$$

### 3. Exercise-Expected Value

If we toss a well balanced coin, the probability of heads is 0.5 and tails is 0.5. Assume that heads constitutes failure with a cost of -$5.00 and that the value of success represented by tails is +$10.00. What is the expected monetary value? Test the answer by tossing a coin. Assume that your total liquid assets to play the game are $10.00 . How many tosses of the coin are necessary before the expected monetary value is reached? How close did you come to running out of liquid assets before the EMV was realized?

### 4. Expected Value in the Toss of the Coin

The EMV in the example is:

EMV = 0.5 X (-$5.00) + 0.5 X ($10.00) = $2.50.

However the probability of three successive failures is 0.5 X 0.5 X 0.5 = .125 or 12.5%. Therefore there is a 12.5% chance of "gamblers ruin", a string of bad luck consisting of three failures which depletes total monetary reserves before the expected monetary value can be reached. Even if success comes earlier, a string of losses exceeding total cumulative monetary reserves can bankrupt the firm.

Figure 1 shows the cumulative asset position and the average monetary value for ten tosses of the coin as outlined in the preceding exercise. The average monetary value approaches $2.50 but has some wide variations before arriving at this average.We assumed that the player had total assets of $10.00 and that these assets were depleted to 0 on the second toss which would mean that the gambler had experienced "gambler's ruin" and no longer had sufficient assets to continue. He would never reach the expected monetary value unless he could find additional assets to continue playing the game. This result is especially significant if we consider that the odds of success in many exploration ventures is much less than 0.5. U.S. onshore drilling success averages 1 in 14 or 7% while offshore exploration success was 1 in 3 or 33% while mineral exploration managers indicate that for each one thousand prospects perhaps one hundred will warrant detailed investigation and one will be a commercial deposit. It is imperative that the assets of the exploration group are adequate to avoid "gambler's ruin".

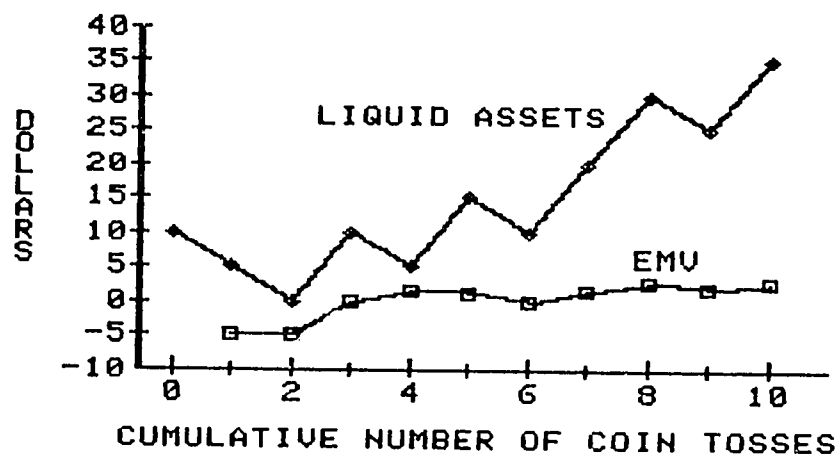



Figure 1 Expected Monetary Value and Gambler's Ruin

Imagine a small exploration group with assets of one million dollars. The group repeatedly invests in exploration ventures with a 10% chance of success and a 90% chance of failure. Cost of each venture is one hundred thousand dollars and the value of success is twenty million dollars. Although the expected monetary value is $1,100,000, the probability of a string of ten failures is 34.9% as follows:

$$EMV = 0.9 \times -\$100{,}000 + 0.1 \times \$20{,}000{,}000 = \$1{,}910{,}000$$

$$P\,(\text{Failure}) = (0.9)^{10} = 0.349$$

At this point the liquid assets of the exploration firm are depleted and they are out of business. Of course, there is an assumption that the sequence of failures are independent which is often not the case; each failure may increase the

probability of success on the next venture. Nevertheless the point is made that the liquid assets of the firm must be sufficient to realize the odds of a gambling game.

### 5. Expected Value of Petroleum Prospect

Refer to the cash flow model Colorado Wildcat oil well prospect. The prospect was located in the state of Colorado where 640 acres were involved in an oil play. The proposal was to run ten miles of seismic line to gain information on a stratigraphic trap, then, given favorable results, to drill three test wells. How can we use EMV to evaluate this opportunity? In this section we follow an approach outlined by Newendorp (Newendorp, 1975). Basic data on the Colorado prospect include the following:

Total Investment if the Prospect is Successful: $2,551,000. (escalated $). Includes leasehold cost, rentals, geological and geophysical expense, exploratory test wells, development wells and special facilities.

Total Investment If the Prospect Tests Dry: $363,000.

Economically Recoverable Reserves:
1.1 million barrels of oil
942 million standard cubic feet of gas

Probability of Success: 20%

Net Present Value (20%) of a Successful Project: $1,477,000.

Expected Value :

EMV = 0.2 X $1,477,000 -0.8 X $363,000
= $295,400 - $290,400 = $5,000

The reason for the small expected value was a combination of low probability of success (20%) and the small size of reserves hence low conditional net present value.

Assume that the Colorado wildcat prospect has a potential for reserves greater than the 1.1 million barrels given in the first example. The probabilities of reserves of 1.1 million, 3 million, 5 million, and 7 million barrels with associated gas are summarized in table 1. These reserve estimates are based on intensive study of the physical characteristics of the formation and the historical record of past discoveries under similar geological conditions.

Table 1 Possible Outcomes for Colorado Wildcat

| Possible Outcomes | Probability Outcome Will Occur |
|---|---|
| Dry Hole | 0.80 |
| 1.1 MM BBL* | 0.08 |
| 3 MM BBL | 0.08 |
| 5 MM BBL | 0.03 |
| 7 MM BBL | 0.02 |

* MM BBL stands for million barrels of oil with associated gas

**6. Effect of Alternative Development Agreements on EMV**

Three possible alternatives are identified for development of the prospect :

1. Drill the well and, if productive, continue to hold a 100% working interest during development and production.

2. Farmout the acreage and retain a 10% overriding royalty on 256 net acres.

3. Participate in a "back-in" agreement. We assume that we do not choose to participate in the risk of drilling the well. Another company will do the drilling and be allowed to recover say 150% of their investment before we "back-in" and share in additional revenues. In this case we share no risk or revenues until the well has recovered the previously determined amount of revenue.

Our engineering appraisal of the venture required estimates of production, costs and investments of the prospect under assumption of different possible outcomes. Each engineering analysis led to an economic evaluation similar to the first which resulted in an expected monetary value. We need to select the agreement which maximizes the expected monetary value given the uncertainties of future outcomes. The results are summarized in table 2.

Table 2 Expected Monetary Value of Alternative Outcomes; Colorado Wildcat Prospect

| | | Drill with 100% Working Interest | | Farm Out with Overriding Royalty | | Penalty with Back-in | |
|---|---|---|---|---|---|---|---|
| Possible Outcomes | Probability Outcomes Will Occur | Conditional NPV ($000) | Expected NPV ($000) | Conditional NPV ($000) | Expected NPV ($000) | Conditional NPV ($000) | Expected NPV ($000) |
| Dry Hole | 0.80 | -363 | -290 | 0 | 0 | 0 | 0 |
| 1.1 MM BBL | 0.08 | 1477 | 118 | 352 | 28 | 352 | 28 |
| 3 MM BBL | 0.08 | 2500 | 200 | 476 | 38 | 1190 | 95 |
| 5 MM BBL | 0.02 | 5000 | 100 | 859 | 17 | 2891 | 58 |
| 7 MM BBL | 0.02 | 7000 | 140 | 1058 | 21 | 4558 | 91 |
| Sum | 1.00 | | 268 | | 105 | | 272 |
| Acres | | | 640 | | 640 | | 640 |
| EMV ($/Acre) | | | 418 | | 163 | | 426 |

The key questions in connection with the leasehold area include:

(1) How much can the purchaser afford to pay for leasehold rights?

(2) Which of the decision alternatives will maximize the expected monetary value?

The answers as indicated by the preceding economic analysis are the following:

(1) The decision alternative which maximizes expected monetary value is the penalty with back-in alternative.

(2) Under the penalty with back-in alternative, we can afford to pay up to $426. per acre for the 640 acre tract.

### 7. Exercise-Bringing Uncertainty of Discovery into the Analysis

The preceding analysis recognizes uncertainty in the size of field but ignores uncertainty in the probability of discovery of hydrocarbons. In the example, the assumption is that the probability of a dry hole is 0.80, therefore the probability of finding hydrocarbons is 0.20. If there is a possibility of higher or lower ratios of success, a different exploration agreement may be the optimum. Modify Table 2 to consider the probability of a dry hole equal to 0.20 rather than the 0.80 in the preceding example. Does the recalculation change the choice of exploration agreement?

## 8. The Effect of a Change in the Probability of Discovery

The recalculation indicated in the preceding exercise is given in Table 3.

Table 3 Expected Monetary Value of Alternative Outcomes; Colorado Wildcat Prospect

| | | Drill with 100% Working Interest | | Farm Out with Overriding Royalty | | Penalty with Back-in | |
|---|---|---|---|---|---|---|---|
| Possible Outcomes | Probability Outcomes Will Occur | Conditional NPV ($000) | Expected NPV ($000) | Conditional NPV ($000) | Expected NPV ($000) | Conditional NPV ($000) | Expected NPV ($000) |
| Dry Hole | 0.20 | -363 | -73 | 0 | 0 | 0 | 0 |
| 1.1 MM BBL | 0.32 | 1477 | 473 | 352 | 113 | 352 | 113 |
| 3 MM BBL | 0.32 | 2500 | 800 | 476 | 152 | 1190 | 381 |
| 5 MM BBL | 0.08 | 5000 | 400 | 859 | 69 | 2891 | 231 |
| 7 MM BBL | 0.08 | 7000 | 560 | 1058 | 85 | 4558 | 365 |
| Sum | 1.00 | | 2160 | | 418 | | 1089 |
| Acres | | | 640 | | 640 | | 640 |
| EMV ($/Acre) | | | 3375 | | 654 | | 1702 |

The change in probability of a dry hole has a drastic effect on the choice of exploration joint venture agreements. In the latter case the drill with 100% working interest becomes the best agreement and it's expected value is $2,160 per acre as compared to $426 per acre under the back-in agreement and the low probability of success.

Figure 2 presents the results of calculation of expected monetary values for a range of probability of a dry hole from 0 to 1. The technique is a powerful tool for the determination of the best decision alternative under conditions of uncertainty and risk.

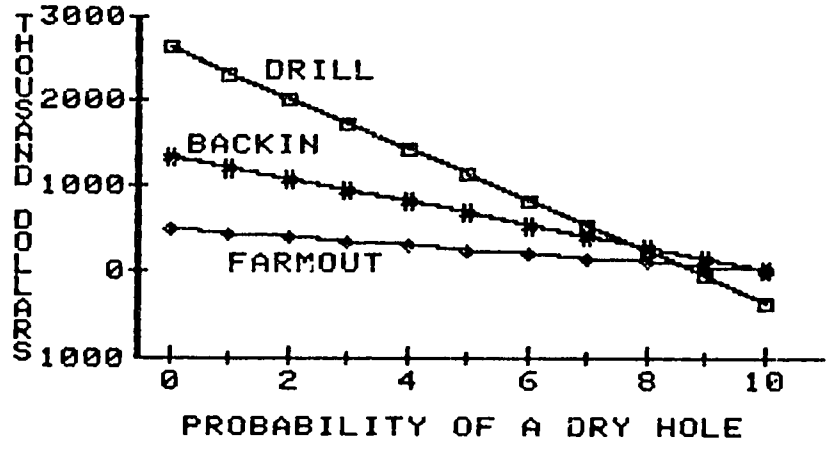



Figure 2 Expected Monetary Value Under Alternative Probabilities of Success

## 9. Decision Trees

Decision trees are an extension of the expected monetary value concept. They are a graphical approach to long range planning wherever there is a chain of decisions to anticipate. The technique is most widely used in the evaluation of oil and gas drilling ventures but it has application in the minerals area as well.

Figure 3 is a partial decision tree for the Colorado wildcat oil/gas prospect The data for the alternative to drill with a 100% working interest is displayed as a decision tree.

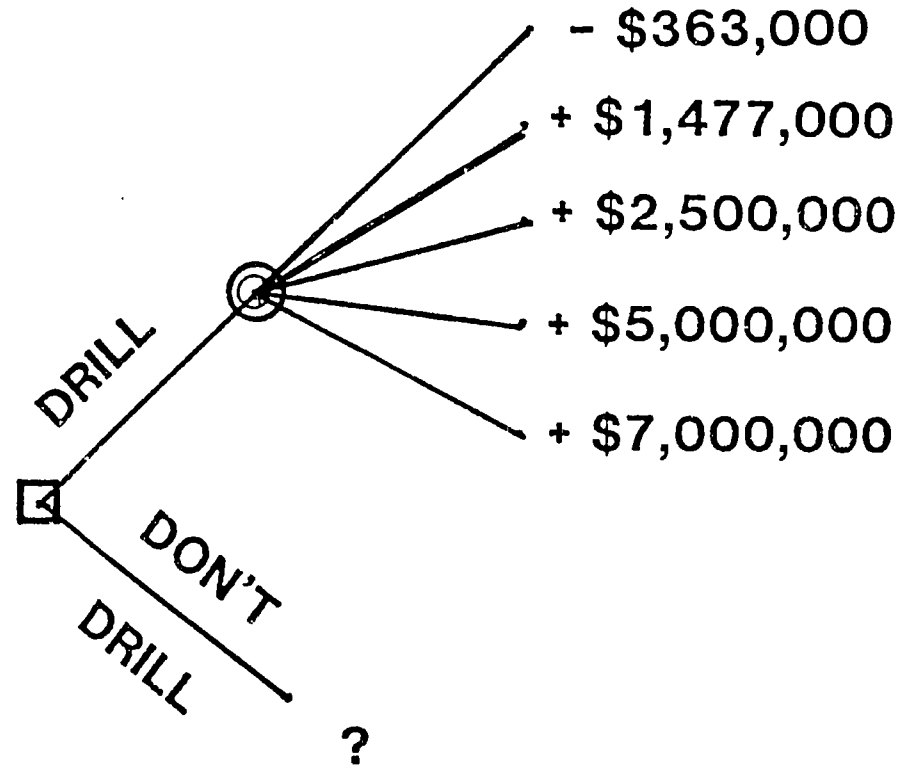



Figure 3 Partial Decision Tree for Colorado Wildcat Prospect

The convention in decision tree analysis is to label decision nodes with a box and chance nodes with a circle. The tree is constructed from left to right showing the alternatives available and labeling the branches of the chance nodes with the expected probabilities. Conditional net present values based on economic analysis of cash flow models are assigned to the possible outcomes.

Decision trees are solved in reverse, from the end point working backwards toward the first decision node. In our example, the alternative to drill leads us to a chance node with several branches each of which leads to an outcome and a value. Multiplying the probabilities and the net present values, the EMV at the chance node is $277,000. Since no other alternatives are considered in this example, the decision is between (1) drill with working interest or (2) don't drill. If our objective is to maximize EMV we will select the drilling alternative.

The following is the step by step sequence for constructing and solving a decision tree.

(1) Construct the tree showing graphically the alternatives for action available to the decision maker.

(2) Identify decision nodes and chance nodes.

(3) Estimate probabilities to all branches from the chance node. The sum of the probabilities must equal 1.0.

(4) Estimate conditional net present values for final outcomes .

(5) Solve the tree. Begin with the net present values, then multiply by probabilities to calculate expected monetary value at the chance node.

(6) Continue until the current decision node is reached.

**10. Exercise-Decision Tree Analysis**

Consider the following problem from Newendorp (Newendorp, 1975 page 115).

Management is considering the purchase of drilling rights on a large block of acreage where there appears to be a potential oil structure. Critical values for analysis follow:

Bonus Required: $3,000,000.

Seismic Survey: $2,000,000.

Levels of Possible Reserves:
Large: NPV=$40,000,000
Small: NPV=$15,000,000

Both of these values are the result of a Net Present Value analysis of future cash flows.

The preliminary analysis of the prospect suggest two possible exploration strategies:

(1) Begin at once with plans to drill an exploratory test on the basis of present geologic intrepretations and extrapolations.

(2) Spend $2,000,000 for seismic and defer decisions on drilling until review of the seismic

results. The staff estimates the odds about 50-50 that the geologic lead is a structure. The staff indicates it may even be feasible to consider drilling a second exploratory test hole if the first one is dry.

Draw the tree for this example.

## 11. Decision Tree for the Drilling Alternative

The decision tree for the problem described in the last section is shown in figure 4 . Quantification of the result now relies on good estimates of the probabilities involved in calculation of the expected monetary values at each chance node.

Decision trees have advantages for analysis of sequential decision making. The problem is broken into parts and the technique helps to develop a rational basis for the first decision. In addition the technique provides a better chance for consistency in decision making. The process is repeated as events are realized and more information becomes available.

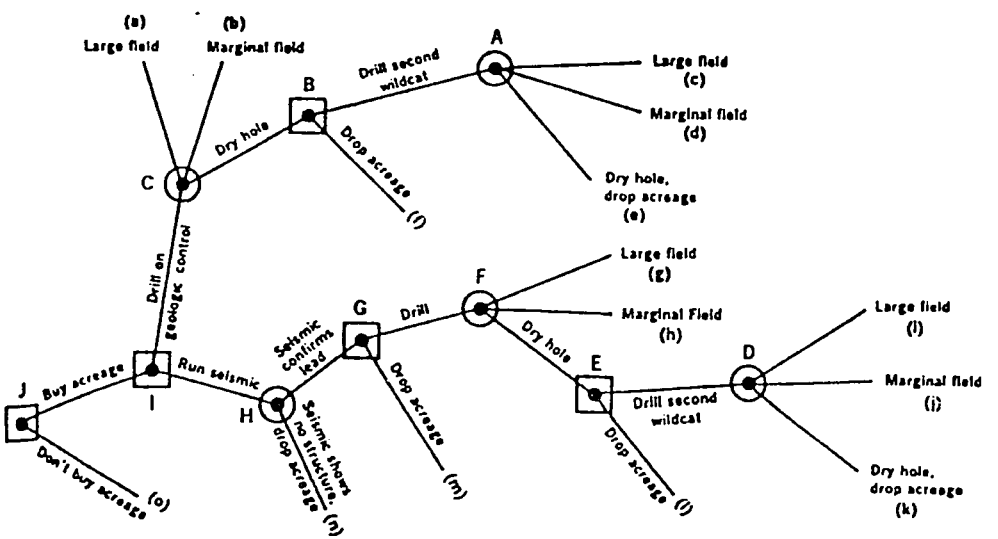
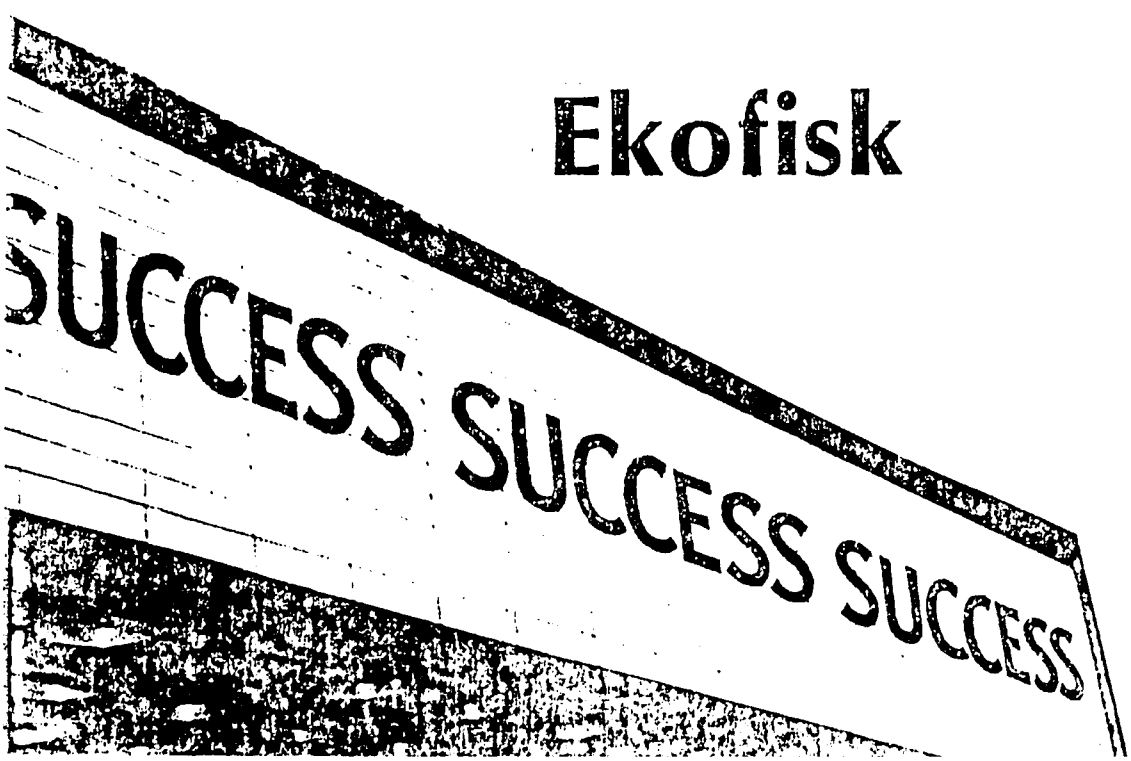



Figure 4 Decision Tree for Drilling Problem

# Ekofisk



# EKOFISK

## 1. INTRODUCTION — "YOU DON'T JUST TURN ON THE VALVES"

"You don"t just turn on the valves. We've been working on a crash basis, seven days a week, 52 weeks a year, dispite some of the worst weather any where in the world. We will continue working this way until the project is completed - and we still have several years of work ahead of us."

The World of Phillips, Phillips Petroleum Co., 1978

Today, Phillips Petroleum greatest effort overseas is in the development of huge oil and gas discoveries in the Norwegian sector of the North Sea. Phillips began exploring the area in 1963, as operator for the Phillips Norway Group, in which they hold a 37% interest. After eight dry holes they found the giant Ekofisk field in 1969.

On September 18, 1969 Phillips spudded-in on Block 2/4-2 with Ocean Viking, having abandoned 2/4-1 three days earlier. When the well was completed on December 23, 97 days later, Phillips had discovered the largest oil field in Western Europe - Ekofisk. They went on to prove it with three more wells, delineating a field 8 miles by 4 and opening up the North Sea which is now an established and mature oil patch.

Ekofisk was the turning point for exploration in the North Sea. The discovery came at the point where Phillips was ready to join the rest of the exploration groups in the region and move elsewhere.

Ekofisk ushered in a new era in the history of the Phillips Petroleum Company. It was by far the biggest discovery in the lifetime of the company But, finding Ekofisk was just the beginning of their job in the North Sea. Producing oil and gas and getting it to market presented a set of problems never before encountered in the history of the oil industry.

Ekofisk is one of the world's largest oil fields but it combined obstacles of deep water, stormy, sometimes violent seas, and a great distance to shore. Much of the technology for developing the field had to be developed step by step as the field was brought into production. Innovative technology included sub-sea completions, a unique, million-barrel, steel reenforced concrete crude oil storage tank, a pioneering system to inject gas at 9,200 PSI to maintain reservoir pressure, and a host of other technologic advances in mooring lines, mid-sea housing, pipelines and terminals.

When the initial discovery was made, few people realized the scope of the Ekofisk project. By the end of 1978 the Phillips group had a total investment in the Greater Ekofisk Development of $5.5 billion. The investment includes development of Ekofisk and six nearby fields, an oil pipeline to Teesside, England, a natural gas pipeline to Emden, Germany, and related processing facilities on shore. The pipelines and onshore facilities account for about one-half the total cost.

One of the biggest problems in the project has been rapidly rising costs. Phillips estimates that to develop Ekofisk today, would involve costs of close to $10 billion.

The rewards of the project are high. They include more secure energy supplies for Western Europe and the United States. The oil pipeline has a capacity of one million barrels of oil per day and the gas pipeline can carry two billion cubic feet of natural gas each day.

Oil Production from the Ekofisk area fields in 1978 averaged 357,000 barrels a day. Phillips' 37% share of this production averaged 116,800 barrels a day. Production began from the Tor field, the fourth of the seven Ekofisk area fields and production increased again in 1979 when the last three fields, Albuskjell, Edda and Eldfisk, were brought into production. At the same time facilities for handling natural gas liquids were finished at the Teesside terminal in England.

Natural gas production from the Ekofisk area began in 1977 and averaged 948 million cubic feet a day in 1978. Phillips' share of the production was 313 million cubic feet a day. The product is sold to a consortium of German, Dutch, Belgium and French transmission and distribution companies.

The Ekofisk discoveries, oil pipeline, gas pipeline and tanker route are shown in figure 1.

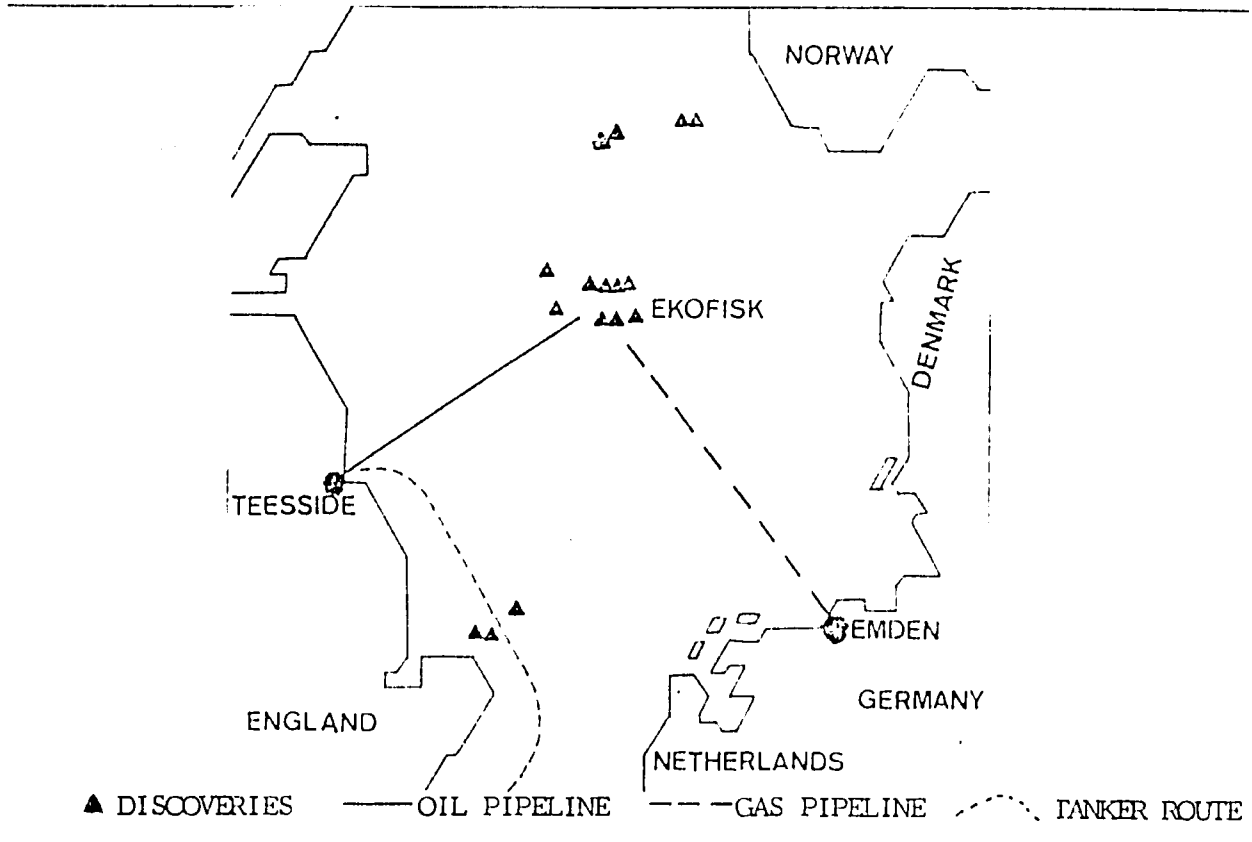



FIGURE 1 THE EKOFISK* COMPLEX

Initial research on this chapter done by Phillip Thayer as part of graduate work at the Colorado School of Mines

Despite the hostile conditions in the North Sea area, and the immense costs associated with exploration and development work in the North Sea, the economics look good for large fields. This may be in part because this area is not in an OPEC country, and is not as severely taxed as in the Middle East.

## 2. 1959-1969 — PRELUDE

In 1959 the discovery of the giant Groningen gas field in the Netherlands led many geologists to believe that the whole North Sea area was probably a good area for exploration. Correlation of stratigraphic sections in this field and fields in England indicated that the North Sea was underlain by vast sedimentary basins. Subsequent seismic work indicated a variety of structures of the type associated with productive petroleum basins.

Actual drilling commenced in the North Sea in 1965, and several gas fields were discovered off the southeastern coast of England. Exploration further north proved to be very difficult. In particular, many areas were in water as deep or deeper than had been drilled in before. In addition, weather conditions were far worse than in the Gulf of Mexico, where much of the recent offshore technology had been developed.

Norway had received requests to explore on the Norwegian continental shelf as early as 1962, but it was not until 1963 that actual licenses were awarded for seismic exploration and 1965 before drilling and production licenses were obtained.

### 2.1 Rights to Explore

The licenses issued gave exclusive rights to explore, drill and exploit petroleum deposits in specified areas. The Norwegian offshore areas were divided into blocks of approximately 500 square kilometers (about 93,000 acres). Under the terms of the licenses, issued for 46 year periods, one quarter of the area must be relinquished to Norway after six years, and another quarter after nine years.

The Norwegian government, in light of the hostile conditions in the North Sea, laid down strict requirements for acquiring licenses. Operators had to have experience in offshore development in deep water, and have substantial financial strength in order to qualify for production licenses. Much to the consternation of the Norwegian government, no Norwegian company could qualify.

### 2.2 Eleven Blocks Awarded to Phillips

Three licenses covering eleven blocks were awarded to the Phillips group, of which Phillips held a 36.96% interest, and was operator. Under the terms of the agreement with the Norwegian government, the Phillips group would have to have written permission from the government for any development work in the area. The government would get a 10% royalty, to be taken partly or wholly in the form of oil and gas, at the Norwegian government's option.

Between 1966 and 1969, the Phillips group and other groups drilled 32 wells in the Norwegian continental shelf without any commercial discoveries. This represented approximately 2,333 drilling days collectively. During this period, semi-submersible drilling rigs were costing in the order of $16,000 per day. This means that about 37 million had been spent by all the operators in the area without a significant find. Phillips alone drilled seven wells at an estimated cost of $18 million before the last drill hole penetrated the Ekofisk field.

### 2.3 Weather — Ridiculous

Weather conditions in the North Sea are severe. It is described as "a nasty, agressive stretch of sea, better crossed by air and left to foolhardy trawlermen." In the winter months, typical conditions included waves of 60 to 70 feet and 100 mph winds. Substantial down time was experienced due to storm damage.

The North Sea is set apart from the rest of the world by the horrible weather. Hurricanes have often hit in the Gulf of Mexico, blowing down production platforms and sinking drilling rigs. Such storms are trackable allowing operators several days to prepare.

In the North Sea, a good lead time for a storm is often a single day, sometimes hours. Personnel on production platforms and drilling rigs must be prepared to ride out the worst of the blows for frequently there is not time to evacuate. In terms of design and expense, this means stable drilling structures that will stay on locations during extreme weather. It means spending millions of dollars on huge steel or concrete production platforms. Construction of such platforms takes time and lots of money.

## 3. 1969 — DISCOVERY

By 1969 many operators were quitting the North Sea. The Phillips group had found gas in what was later to become the Cod Field, but as a single unit, this find was considered non-commercial. In August of 1969, Phillips moved a rig to Block 2/4, and started well 2/4-IX. This well had been authorized partly because of contractual commitments with the drilling rig owners. This particular well was eventually abandoned, but did hit a hydrocarbon bearing zone at about 5,550 feet.

On the basis of this well, a substitute well was authorized about 1,000 meters away from 2/4-IX. This last well, 2/4-AX, found 650 feet of oil pay at 10,000 feet. Subsequent wells drilled found five more fields in the immediate area; Tor, West Ekofisk and Eldfisk in 1970, and Edda and Albuskjell in 1972. These fields are shown in figure 2.

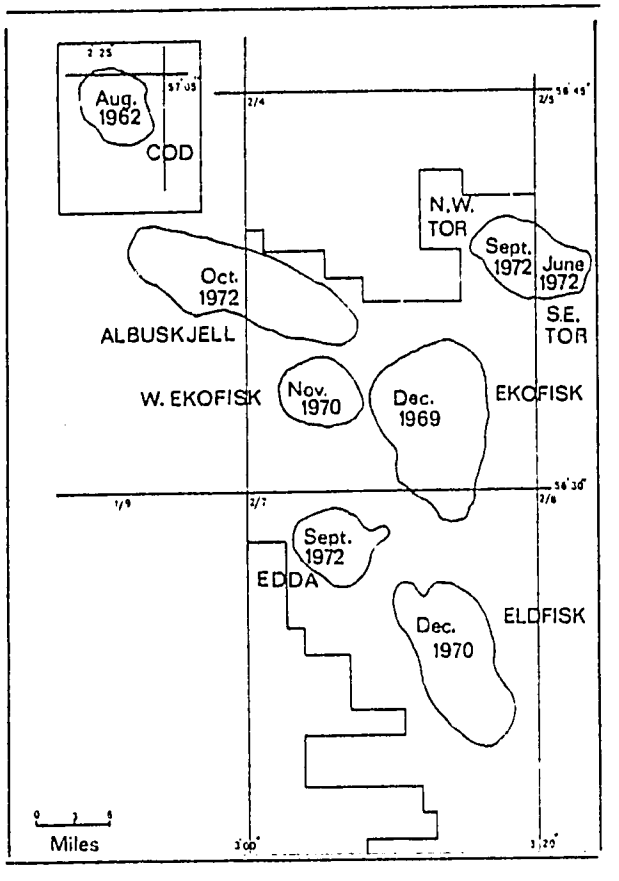



FIGURE 2 FIELDS IN THE EKOFISK AREA

### 3.1 One of the World's Largest

At the time of its discovery, the Ekofisk Field was the largest field in western Europe, with an estimated one billion barrels of recoverable oil. To put the size of this field in perspective, it is one of the top 60 fields in the world ranked by size. It is still one of the largest fields in Europe and is larger than any U.S. field, with the exception of East Texas and Prudhoe Bay in Alaska.

Table 1 The World's Largest Oil Fields (million bbl), 1976.

| Field, country, disc. date | No. wells | 1976 Prod. | Cum. 1-1-77 | Est.rem.* res.77 (million bbl) 1976 | Pay, ft | API,. grav. | Geologic province | Type of trap |
|---|---|---|---|---|---|---|---|---|
| FIELDS WITH MORE THAN 1 BILLION BBL REMAINING RESERVES | | | | | | | | |
| Burgan, Kuwait, 1938 | 342 | 360 | 12,980 | 56,000 | Burgan, 4800 | 31.3 | Arabian platform | Dome |
| Ghawar, Saudi Arabia, 1948 | 372 | 1,894 | 14,757 | 45,521 | Arab, Jubailia, 6,700 | 35.0 | Arabian platform | Anticline |
| Safania, Saudi Arabia, 1951 | 97 | 227 | 3,490 | 14,361 | Cretaceous, 5,100 | 27.0 | Arabian platform | Anticline |
| Samotlorskoye, USSR, 1965 | 1,700 | 810 | 2,510 | 12,090 | L. Cret., 7,316 | 35.0 | West Siberian basin | Anticline |
| Purdhoe Bay, USA, 1968 | 5 | 5 | 14 | 10,000 | Triassic, 8,210 | ... | North Slope | Anticline |
| Salym, USSR, 1963 | 25 | 10 | 11 | 9,989 | Cretaceous, 7,200 | 33.0 | | |
| Kirkuk, Iraq, 1927 | 45 | 350 | 7,665 | 8,655 | Reef, 2,800-4,200 | 36.0 | Zagros fold belt | Anticline |
| Manifa, Saudi Arabia, 1957 | 2 | .02 | 131 | 8,493 | Arab, 7,950 | 28.0 | Arabian platform | Anticline |
| Marum, Iran, 1963 | 44 | 492 | 3,295 | 7,592 | Asmari, 11,000 | 32.9 | Iranian basin | Anticline |
| Sarir, Libya, 1961 | 68 | 99 | 960 | 7,346 | U. Cret., 9,000 | 37.2 | Sirte basin | Faulted anticline |
| Gachsaran, Iran, 1937 | 30 | 226 | 4,149 | 7,286 | Asmari, 9,000 | 31.1 | Iranian basin | Anticline |
| Ahwaz Asmari, Iran, 1958 | 48 | 342 | 2,081 | 7,049 | Asmari, 8,700 | 31.9 | Iranian basin | Anticline |
| Bibi Hakimeh, Iran, 1961 | 21 | 85 | 2,110 | 6,840 | Asmari, 5,400 | 29.7 | Iranian basin | Anticline |
| Berri, Saudi Arabia, 1964 | 45 | 295 | 1,547 | 6,388 | Arab, 7,450 | 33-38 | Arabian platform | Anticline |
| Raudhatain, Kuwait, 1955 | 41 | 73 | 1,658 | 6,042 | Zubair, 8,500 | 34.8 | Arabian platform | Anticline |
| Chiapas, Mexico, 1974 | 270 | 202 | 1,015 | 5,498 | Cretaceous, | ... | Chipas | Anticline |
| Zuluf, Saudi Arabia, 1965 | 12 | 1 | 153 | 5,224 | ..., 5,800 | 32.0 | Arabian platform | Anticline |
| Minas, Indonesia, 1944 | 235 | 130 | 2,075 | 5,140 | Miocene, 2,400 | 35.4 | Central Sumatra basin | Anticline |
| Khafji, Neutral Zone, 1961 | 132 | 73 | 1,385 | 5,087 | "A", 4,300-12,000 | 28.4 | Arabian platform | Anticline |
| Hassi Messaoud, N. Algeria, 1956 | 108 | 82 | 995 | 4,603 | Cambrian, 11,000 | 49,0 | Erg Oriental | Faulted anticline |
| Uzen, USSR, 1961 | 1,350 | 115 | 845 | 4,410 | Jurassic, 2,667 | 33.9 | Mangyshlak basin | Anticline |
| Khurais, Saudi Arabia, 1957 | 13 | 11 | 75 | 4,281 | | | Arabian platform | Anticline |
| Statfjord, Norway, 1974 | | | | 3,900 | Jurassic, | 37.0 | North Sea basin | Anticline |
| Romashkino, USSR, 1948 | 8,000 | 570 | 10,170 | 3,870 | Devonian, 5,791 | 31.7 | Volga-Ural basin | Anticline |
| Abqaiq, Saudi Arabia, 1940 | 64 | 301 | 5,215 | 3,861 | Arab, 6,670 | 38.0 | Arabian platform | Anticline |
| Sabriya, Kuwait, 1956 | 36 | 2 | 210 | 3,790 | ..., 8,000 | 32.9 | Arabian platform | Anticline |
| Abu-Safah, Saudi Arabia, 1963 | 16 | 37 | 302 | 3,737 | Arab, 6,650 | 30.0 | Arabian platform | Anticline |
| Amal, Libya, 1959 | 69 | 24 | 534 | 3,701 | Cambro-Ord, 9,900 | 36.0 | Sirte basin uplift | Intra-Cratonic |
| Agha Jari, Iran, 1936 | 43 | 311 | 6,512 | 3,572 | Asmari, 7,500 | 33.8 | Iranian basin | Anticline |

Table 1 (continued)

| Field, country, disc. date | No. wells | 1976 Prod. | Cum. 1-1-77 | Est.rem.* res.77 (million bbl) 1976 | Pay, ft | API,. grav. | Geologic province | Type of trap |
|---|---|---|---|---|---|---|---|---|
| FIELDS WITH MORE THAN 1 BILLION BBL REMAINING RESERVES | | | | | | | | |
| Zubair, Iraq, 1948 | 33 | 70 | 846 | 3,496 | Zubair, 11,000 | 34.2 | Arabian platform | Anticline |
| Pazanan, Iran, 1961 | 7 | 13 | 164 | 3,354 | Asmari, 7,500 | 33.6 | Iranian basin | Anticline |
| Shaybah, Saudi Arabia, 1968 | | | | 2,855 | | ... | Arabian platform | Anticline |
| Gialo, Libya, 1961 | 155 | 97 | 1,279 | 2,848 | Eocene, 2,200-6,300 | 35.7 | Sirte basin | Anticline |
| Qatif, Saudi Arabia, 1945 | 20 | 30 | 504 | 2,657 | Arab, 7,050 | 31.0 | Arabian platform | Anticline |
| Wafra complex, Neutral Zone, 1953 | 295 | 39 | 943 | 2,657 | Yamama, et al, 4,300-12,000 | 24-34 | Arabian platform | |
| Paris, Iran, 1964 | 20 | 130 | 812 | 2,247 | Asmari, 7,500 | 34.2 | Iranian basin | Anticline |
| Lama, Venezuela, 1957 | 171 | 54 | 1,983 | 2,187 | Tertiary, 8,320 | 32.6 | Maracaibo basin | Faulted anticline |
| Rag-e Safid, Iran, 1964 | 18 | 73 | 405 | 2,114 | Asmari, 7,500 | 28.5 | Iranian basin | Anticline |
| Brent, UK, 1971 | | | | 2,090 | Jurassic, | ... | North Sea basin | Anticline |
| Arlan, USSR, 1955 | 3,000 | 150 | 2,500 | 2,085 | Carb., 4,429 | 27.2 | Volga-Ural basin | Anticline |
| Ust-Balyk, USSR, 1961 | 820 | 110 | 800 | 2,047 | L. Cret., 8,845 | 29.0 | West Siberian basin | Anticline |
| Forties, UK, 1970 | 9 | 40 | 42 | 1,962 | Paleocene, 2,000-8,000 | 36.6 | North Sea basin | Anticline |
| Idd El Shargi, Qatar, 1960 | 4 | 4 | 155 | 1,958 | Arab. Fadhili, 8,250 | 35.0 | Arabian platform | Anticline |
| Lagunillas, Venezuela, 1926 | 2,689 | 196 | 8,975 | 1,807 | Tertiary, 3,000 | 24.4 | Maracaibo basin | Strat trap, faults |
| Minagish, Kuwait, 1959 | 7 | 21 | 224 | 1,776 | Minagish, 10,000 | 33.9 | Arabian platform | Anticline |
| Khursaniyah, Saudi Arabia, 1956 | 16 | 17 | 503 | 1,771 | Arab, 6,750 | 31.0 | Arabian platform | Anticline |
| Duri, Indonesia, 1941 | 426 | 12 | 270 | 1,744 | Miocene, 600 | 21.1 | Central Sumatra basin | Anticline |
| Umm Shaif, Abu Dhabi, 1958 | 26 | 62 | 605 | 1,644 | ..., 9,150 | 37.0 | Arabian platform salt uplift | Deep-seated |
| East Texas, USA, 1930 | 12,709 | 67 | 4,377 | 1,622 | Woodbine, 3,600 | 39.0 | E. Texas embayment | Updip truncation structural nose |
| Bachaquero, Venezuela, 1930 | 8,156 | 135 | 5,100 | 1,549 | Tertiary, 3,444 | 22.6 | Maracaibo basin | Strat trap |
| Masjid-e-Suleiman, Iran, 1908 | 22 | 4 | 1,362 | 1,510 | Asmari, 1,630 | 40.3 | Iranian basin | Anticline |
| Tia Juana, Venezuela, 1928 | 1,732 | 84 | 3,067 | 1,413 | Tertiary, 3,000 | 20.0 | Maracaibo basin | Strat trap |
| Mamontovo, USSR, 1965 | 450 | 70 | 400 | 1,352 | Cretaceous, 6,300 | 27.0 | West Siberian basin | Anticline |
| Ekofisk, Norway, 1970 | 29 | 88 | 196 | 1,328 | Danian, 10,000 | 37.0 | North Sea | Anticline |
| Sovetskoye, USSR, 1962 | 200 | 50 | 370 | 1,300 | Cretaceous, 11,130 | 34.0 | West Siberian basin | Anticline |
| Marjan, Saudi Arabia, 1967 | 11 | 3 | 11 | 1,278 | | ... | Arabian platform | Anticline |

Table 1 (Continued)

| Field, country, disc. date | No. wells | 1976 Prod. | Cum. 1-1-77 | Est. rem.* res. 77 (million bbl) 1976 | Pay, ft | API, grav. | Geologic province | Type of trap |
|---|---|---|---|---|---|---|---|---|
| FIELDS WITH MORE THAN 1 BILLION BBL REMAINING RESERVES | | | | | | | | |
| Zakum, Abu Dhabi, 1964 over | 47 | 88 | 748 | 1,226 | ..., 9,100 | 39.8 | Arabian platform | Anticline deep-seated salt uplift |
| Ninian, UK, 1974 | | | | 1,200 | Jurassic, | ... | North Sea basin | Anticline |
| Dukan, Qatar, 1940 | 60 | 88 | 1,649 | 1,181 | Arab, 6,550 | 41.1 | Arabian platform | Anticline |
| El Morgan, Egypt, 1965 | 43 | 33 | 507 | 1,127 | Paleozoic, 11,300 | ... | Gulf of Suez graben | Faulted anticline |
| Bu Hasa, Abu Dhabi, 1962 | 51 | 183 | 1,410 | 1,106 | ..., 8,500 | | Arabian platform | Reef on anticline |
| Intisar "A", Libya, 1967 | 9 | 22 | 546 | 1,085 | "A", 9,750 | 45.0 | Sirte basin | Reef |
| Sassan, Iran, 1966 | 18 | 56 | 469 | 1,037 | Arab, 8,100 | 34.0 | Arabian platform | Anticline |
| Malongo, N., Cabinda, 1966 | 52 | 12 | 299 | 1,005 | Cretaceous, 8,750 | 25.5-33.8 | | |
| Ramadan, Egypt, 1974 | 3 | 13 | 24 | 1,000 | L. Cret., 11,300 | 31.7 | Gulf of Suez graben | Faulted anticline |
| Elk Hills, USA, 1919 | 344 | 11 | 296 | 1,000 | Stevens, 2,300 | 36.0 | San Joaquin Valley | Faulted anticline |
| Santa Ynez, USA, 1934 | | | | 1,000 | Miocene, 10,000 | | Ventura basin | |

As a result of the discovery of Ekofisk, exploration accelerated with new enthusiasm in the North Sea, where additional discoveries have been made in both Norwegian and English waters. Some estimates put current total North Sea reserves at 25 billion barrels of oil, and this number is expected to increase.

## 4. GEOLOGY AND RESERVES

### 4.1 The North Sea Basin

Figure 3 is a plan of the North Sea Basin and figure 4 is a generalized cross-section through the basin from Norway to England.

Before 1965, central North Sea geology was unknown. Forty-five years of prior exploration in northern Europe had attracted little attention to the area. Small oil fields had been found in the Carboniferous reservoirs in the eastern United Kingdom and gas production had been established in Permian and Lower Triassic reservoirs with oil in Upper Triassic, Jurassic and Lower Cretaceous reservoirs in northwest Germany. Small oil and gas fields had been found in the Mesozoic of Holland and a small n umber of wells had been drilled without success in territorial waters of Holland and Germany.

In 1959, a gas discovery at Slochteren in northern Holland led to estimates in 1963 that recoverable reserves were of the order of 58 trillion cubic feet. By that time, exploration activities were already underway in the North Sea. Offshore areas of the world were being actively explored and geological theories indicated the possible existence of extensive potential oil producing horizons in the North Sea area.

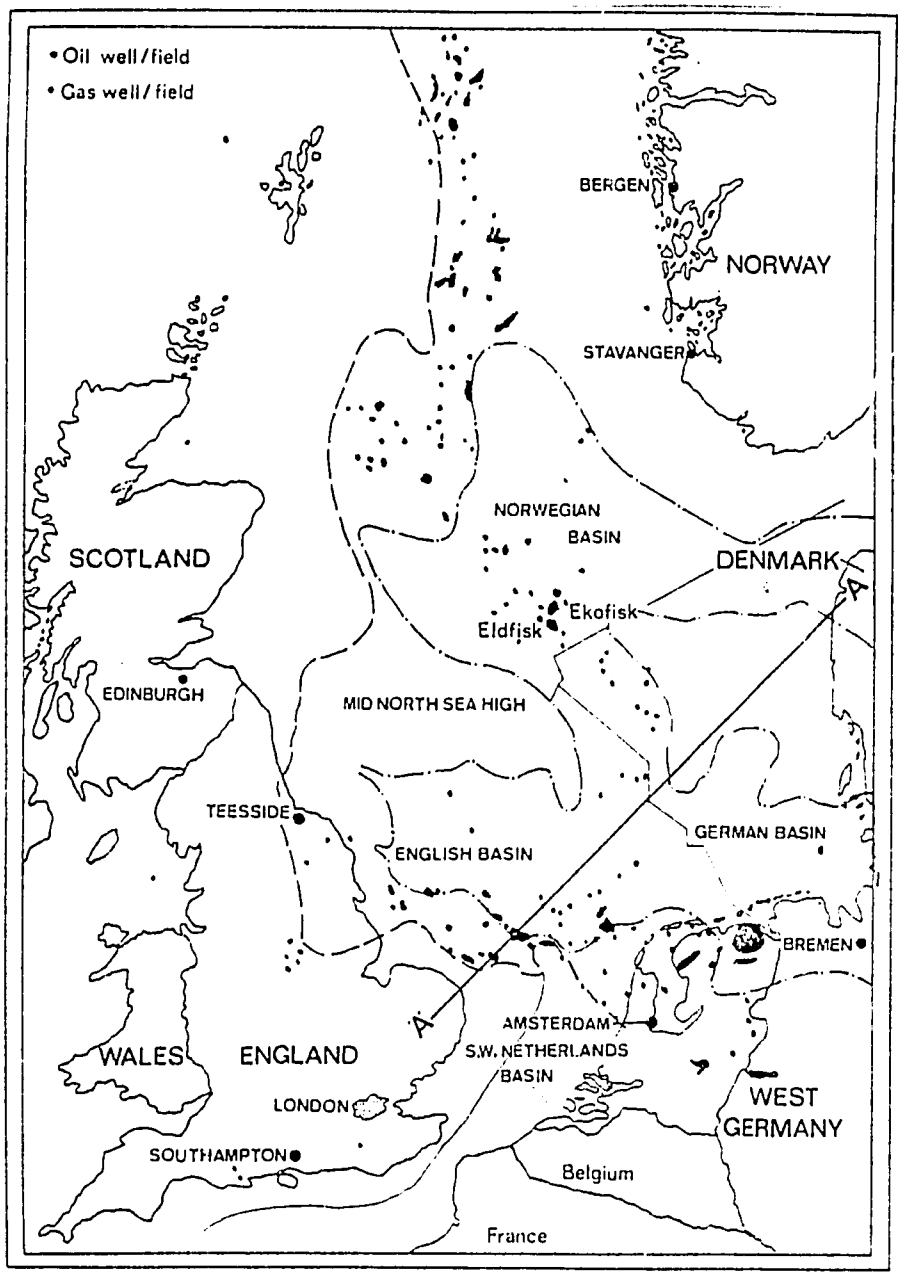



FIGURE 3 NORTH SEA BASIN

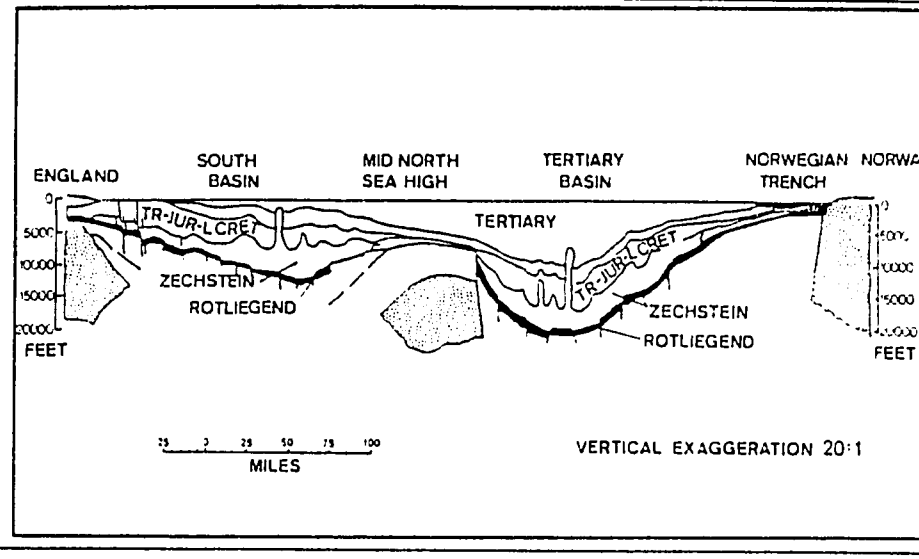



FIGURE 4 NORTH SEA BASIN CROSS-SECTION

## 4.2 Ekofisk Area Reserves

The Ekofisk area consists of seven fields, Ekofisk, West Ekofisk, Cod, Tor, Eldfisk, West Ekofisk, Cod, Tor, Eldfisk, Edda and Albuskjell.

### 4.2.1 Ekofisk

Ekofisk Field produces volatile oil from a Danian/Upper Cretaceous fractured limestone. The field covers an area of about 19 square miles, and has a maximum gross thickness of about 1100 feet. Initial pressure was 7,135 psia at 10,900 feet.

### 4.2.2 West Ekofisk

This field is a gas condensate reservoir producing from a Danian/Upper Cretaceous fractured limestone. This field covers an area of approximately 2.5 miles square and has a maximum gross thickness of 350 feet. Initial pressure was 7,220 psia at 10,700 feet.

### 4.2.3 Cod

This field produces gas from a Palecocene sandstone. The field covers an area of about 4 x 2.5 miles and is about 250 feet thick at its maximum. Initial pressure was 5,565 psia at 9,750 feet.

### 4.2.4 Tor

Tor field produces volatile oil from the Danian/Upper Cretaceous fractured limestone. The field covers an area of around 2.5 x 4.5 miles with a maximum gross thickness of 700 feet. Initial pressure was 7,135 psia at 10,350 feet.

### 4.2.5 Eldfisk

Eldfisk field produces volatile oil from the Danian/Upper Cretaceous fractured limestone. The field covers about 2.5 x 8 miles and has a maximum gross thickness of 600 feet. Initial pressure was 6,815 psia at 9,500 feet.

### 4.2.6 Edda

Edda Field produces volatile oil from the Danian/Upper Cretaceous. It has an area of about 2.5 x 2.5 miles, and a maximum gross thickness of 200 feet. Initial pressure was 7,175 psia at 10,350 feet.

### 4.2.7 Albuskjell

Albuskjell Field produces gas condensate from the Danian/Upper Cretaceous. It has an area of 3 x 12.5 miles and a maximum gross thickness of 400 feet. Initial pressure was 7,266 psia at 10,600 feet.

All of oil reservoirs are primary solution gas drives with initial pressures above the fluid bubble point pressures. The gas reservoirs exhibit retrograde condensate behavior with initial pressures above the fluid dew-point pressures.

### 4.2.8 Published Reserves

Phillips has never officially released reserve information; however, many sources have published estimates. The reserve estimates shown in table 2 were published by the Petroleum Economist , April 1978, and are representative of most estimates presented in oil industry publications.

Table 2 Ekofisk Area Reserves, 1978

| Field | Block | Water Depth Meters | Estimated Recoverable Reserves: Oil million bbls | Oil Recovery % | Gas trillion cu. ft. | Gas Recovery Factor % | Quality ,API | Sulfur Content % | Gas/Oil Ratio (cu.ft/bbl) | Discov. Ratio | Start-up Date | No. of wells per platform: Date |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ekofisk | 2/4 | 72 | 1295 | 25 | 4.13 | 67 | 37 | 0.2 | 4441 | 1969 | 1971 | Oil 11, 15, 4<br>Gas 5<br>NGL 3 |
| West Ekofisk | 2/4 | 67 | 165 | 37 | 0.70 | 55 | 43 | 0.2 | 3570 | 1970 | 1977 | 10 |
| Cod | 7/11 | 79 | 22 | 59 | 0.28 | 57 | 44 | low | 3000 | 1968 | 1977 | 6 |
| Tor | 2/4,2/5 | 69 | 180 | 24 | 0.67 | 66 | 40 | 0.1 | 4389 | 1970 | 1978 | 15 |
| Edda | 2/7 | 72 | 45 | 23 | 0.21 | 75 | 39 | 0.1 | 4167 | 1972 | 1979 | 10 |
| Eldfisk | 2/7 | 73 | 858 | 24 | 1.97 | 36 | 37 | 0.23 | 4827 | 1972 | 1978 | 19, 30 |
| Albuskjell | 2/4,2/6 | 67 | 230 | 60 | 1.8 | 93 | 44 | 0.05 | 13043 | 1972 | 1978 | 12, 11 |
| Total Ekofisk Area: | | | | | | | | | | | | |
| Recoverabale | | | 2795 | | 9.76 | | | | | | | |
| In Place (based on recov.) | | | 10567 | | 16.75 | | | | | | | |
| Average recoveries, % | | | 26.5 | | 58.3 | | | | | | | |

### 4.3 Calculated Reserves

Published geological data on the Ekofisk Field was used to calculate reserves. Results are compared with the published figures. Calculations are as follows:

$$\text{STB in place} = \frac{7{,}758\ APh(1-Sw)}{FVF}$$

where:

STB = Stock tank barrels in place
7,758 = barrels per acre-foot
A = reservoir area in acres
P = porosity = rock void volume/rock bulk volume
H = average net formation thickness, feet
S = initial water saturation as a fraction of pore volume
FVF = formation volume factor = reservoir barrels/stock tank barrels

The only field with sufficient data to calculate reserves is the Ekofisk. The basic assumptions for calculation of Ekofisk reserves are:

A = area = 12,145 acres
H = thickness = 479 feet
P = porosity = .30
S = water saturation = .21
FVF = formation volume factor = 2.1

These geologic assumptions result in a calculated reserve of 5,090 million stock tank barrels in place which is in close agreement with the published figures. A recovery factor of 25% for this type of field is typical, however, this value can vary between 10% and 40%. A 25% factor leads to an estimated recoverable reserve of 1250 million barrels, consistent with the 1295 million barrels shown in table 2.

## 5. DEVELOPMENT AND PRODUCTION PLANNING

### 5.1 Stage I

The development of the Ekofisk Field is be divided into four stages. The first stage involved the testing of the Ekofisk reservoir. A jackup drilling barge was converted to a temporary production platform, and four discovery wells were completed on the ocean floor. Production from these wells was loaded into tankers from single bouy moorings (SMB's). The wells could produce only when a tanker was present to collect the oil produced. On the platform, oil and gas were separated, the oil was pumped to the SBM for loading, while the gas was flared.

Ekofisk Field was produced in this manner from June 1972 to April 1974. During this period, 28 million STB of oil were produced at rates of 20,000 to 40,000 STB/day. The objective of this method was two-fold. It allowed production to commence only 18 months after discovery of the field, and also gave pressure production data necessary for the evaluation of the Ekofisk reservoir.

### 5.2 Stage II

The next phase of development, which actually started in 1971, involved the erection of three drilling platforms over the Ekofisk reservoir. Also erected was a production platform, a platform for crew's quarters and storage, and an emergency gas flare platform. In addition, a one million barrel storage tank was installed. This tank would act as temporary storage for oil during periods when weather conditions prohibited tanker loading. Later, when pipelines were laid to shore, the tank served as additional storage for the on-shore facilities. The tank is also used as a platform for the additional processing equipment necessary for producing the other fields in the Ekofisk area.

An oil pipeline was laid to Teesside, England, 220 miles away, and a gas line was laid to Emden, Germany, 274 miles away. Prior to completion of the gas line, gas was reinjected into the reservoirs. On-shore facilities include oil and NLG processing equipment in Teesside, England, and gas processing equipment in Emden, Germany.

The Ekofisk storage tank was installed in 1973 and was functioning by the end of 1974. Oil production during 1973 to 1975 averaged about 35,000 barrels per day. By the end of 1975, the oil pipeline to Teesside was completed and oil was flowing to England. The gas pipeline was not completed until 1977.

### 5.3 Stage III

The third stage of development involved the drilling of three additional fields, Cod, West Ekofisk and Tor, and connecting them to the Ekofisk center. Platforms were erected over these fields, and pipelines laid to the Ekofisk center. Cod Field is 50 miles from the Ekofisk center, while Tor and West Ekofisk are 7.5 and 5 miles from Ekofisk center respectively. West Ekofisk and Cod came on stream in 1977 and Tor came on stream in 1978. Offshore processing facilities for these fields are located on top of the million barrel storage tank.

### 5.4 Stage IV

The final stage of development involves the connecting of Eldfisk, Edda and Albuskjell fields to the Ekofisk center as shown in figure 4. Edda and Albuskjell fields are 8 miles from Ekofisk center; Eldfisk is 11 miles from the center.

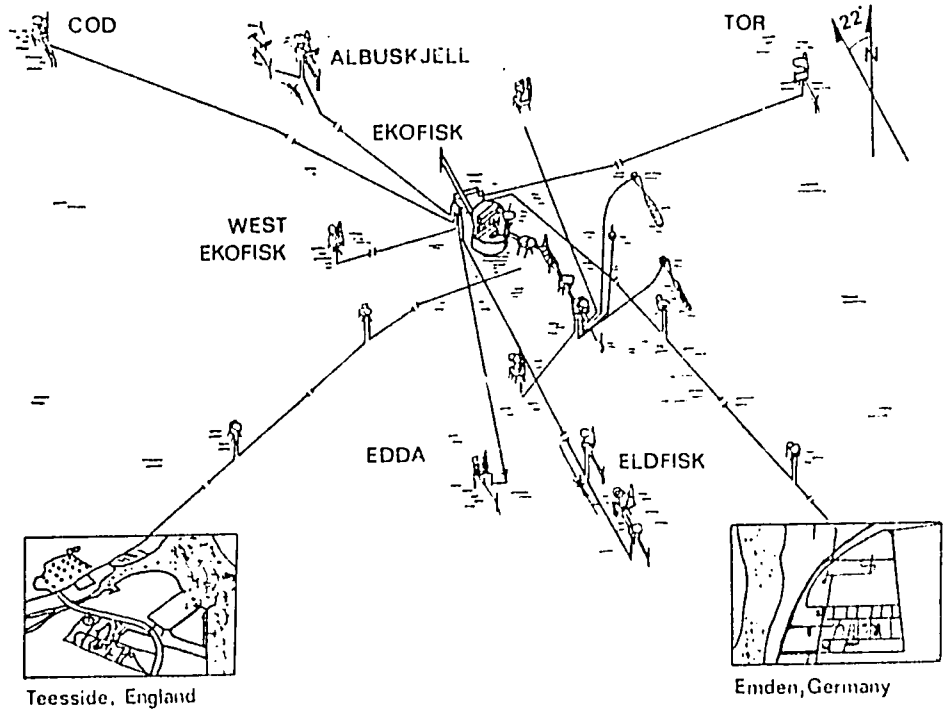



FIGURE 4 EKOFISK PRODUCTION FACILITIES

Peak production from the Ekofisk Field should be about 700,000 barrels per day in 1981 when all fields will be producing at maximum capacity. Gas production, which started in 1977, is expected to reach a peak of 1,900 million cubic feet per day in 1987.

Figure 4 shows a schematic diagram of what the Ekofisk complex will look like when completed. The complex will consist of 11 production platforms, 7 additional platforms, 163 wells, and nearly 600 miles of pipeline. Total costs for the Ekofisk complex, pipelines, Teesside and Emden facilities are expected to exceed 5.2 billion dollars. The total development period will have lasted 13 years, although production started only 18 months after discovery.

The development of the Ekofisk area was burdened with more than the usual risks associated with development of petroleum deposits. Prior to the discovery of Ekofisk, no offshore fields had even been developed under such hostile environmental conditions. Much new technology had to be developed in order to cope with these conditions. Offshore loading of tankers had never been attempted in such deep water or in such rough seas. The million barrel concrete storage tank was also a new idea. The importance of these two innovations is that they allowed for startup of production sooner than would have been possible by pipeline. With capital investment requirements in excess of one billion dollars, production is required as soon as possible for recovery of costs.

An additional factor affecting this project was inflation. Current development cost estimates are now more than four times what they were originally. Numerous delays

have also occurred, particularly in the construction of on-shore facilities. Delays have been caused by labor problems and by shortages in materials, and by the Danish goverment requiring the pipeline to be buried where it passed through Danish water. Because of Norwegian government regulations on flaring gas, oil production had to be limited and gas reinjected until pipelines and offshore facilities could be completed. For a short time, difficulties with compressors limited the rate at which gas could be reinjected. Delays in completing the natural gas liquid (NGL) facilities at Teesside required reinjection of these liquids until facilities were completed.

## 6. MARKETS

A pipeline to move Ekofisk-area North Sea production to shore moved ahead in 1972 when a government appointed committee recommended to the Norwegian government that crude oil and condensate be landed in the United Kingdom at North Tees. It was clear that Norway was not a logical outlet for the expected 510,000 barrels per day of crude and condensate and more than one billion cubic feet per day of gas expected from Ekofisk, West Ekofisk, Tor and Cod. The Norwegian oil market at that time amounted to only about 202,000 barrels per day and the combined capacity of the country's three refineries was less than one-half of the expected output from the Ekofisk complex. Furthermore, Ekofisk, 185 miles offshore, is separated from the Norwegian coast by a deep submarine trench in which divers could not repair possible line breaks. The actions of the Norwegian government set the stage for stage II of Ekofisk development, the oil pipeline to Teesside, England and a gas line to Emden, Germany. Natural gas moves to Emden through a 268-mile pipeline to a buyer, a four-company group of western European gas firms. Phillips has an option to remove all constituents, except methane, from the gas stream. Markets for the crude delivered to Teesside, England were not defined.

In 1975, a second contract for sale of Norwegian North Sea gas was signed with the same consortium that agreed earlier to purchase gas from four Ekofisk area fields. The new agreement provided for the European gas distribution consortium to purchase gas from the three new fields, commencing in early 1978. Gas deliveries under both contracts eventually will total about 1.7 billion cubic feet per day.

In 1977, Phillips announced the beginning of natural gas sales under a twenty-year contract to ther consortium of German, Dutch, Belgium and French transmission and distribution companies.

## 7. FINANCING

### 7.1 Size of Investment and Cost Escalation

Difficult operating conditions in the North Sea mean high capital costs. Initial estimates of $4.5 billion for development of the Ekofisk oil and gas fields, processing facilities and pipelines was revised to $5.2 billion in 1977. Reasons for the higher capital costs were cited as tightening government regulations, labor disputes and higher equipment costs. Specifically increased manpower and transportation costs resulted from a 36-hour offshore work week required by the Norwegian government. Higher drilling costs also resulted from regulations prohibiting simultaneous drilling and

production from the same platform and higher construction costs resulted from labor disputes at Teesside. Governmental requirements on backfilling of the gas pipeline, higher rates for drilling rigs, barge schedule delays caused by bad weather and safety modifications throughout the complex also increased costs.

### 7.2 The Joint Venture Partners

Initial conditions for obtaining production licenses in the Norwegian portion of the North Sea were based on stringent requirements of the Ministry of Industry as to the financial strength and experience of the operating company, particularly experience in the North Sea or equivalent areas.

The composition of the Phillips group is shown in table 4.

Table 4 Joint Venture Partners

| | per cent |
|---|---|
| Phillips Petroleum Co. Norway (USA) | 36.96 |
| Norske Fina A/S (Belgium) | 30.00 |
| Norske Agip A/S (Italy) | 13.04 |
| | 80.00 |
| A/S Petronord | |
| Norsk Hydro A/S (Norway) | 6.70 |
| Elf Norge A/S (France) | 5.396 |
| Aquitaine Norge A/S (France) | 2.698 |
| Total Marine Norsk A/S (France) | 0.47 |
| Eurafrep Norge A/S (France) | 0.456 |
| Coparex Norge A/S (France) | 0.304 |
| | 20.000 |

Phillips has always been the operator for the group which obtained exclusive rights of exploitation and the legal right to use any discovered resources. The State reserved the right to abstract 10% royalties wholly or partly in the form of petroleum. In addition, all installations and facilities offshore would have to be approved by the Ministry before emplacement on the sea bed and special permission would be required for storage tanks and pipelines.

The Norwegian government wanted national control on the transport system so that decisions regarding choice of reserves to be transported, capacities and tariffs to be applied would be theirs. The Ministry decided that the State Oil Company should take as much as 50% participation in the transport system including landing facilities to insure sufficient control. On this basis Norpipe A/S was formed to own and operate oil and gas lines on a 50/50 partnership between the Phillips group and the State Oil Company. Total costs of the project in 1972 was estimated to be about 7 billion Norwegian Krona (Nkr) with equity capital amounting to 10%. Loans were to be procured by the Phillips group

which would also carry risk due for payments of interest and amortization of the loan. Thus, the State acquired a strong controlling interest in the transport system with a financial risk associated with control of only 5% of the equity.

### 7.3 Long-Term Debt

At this writing, we do not have a detailed breakdown of the sources of long-term debt capital on the project. Apparently equity participation by the joint venture partners totalled about 10% of the total capital investment. This would indicate an equity investment of $520 million of which $192.2 million would be supplied by Phillips.

Assuming 90% debt, the Ekofisk project would require $4.68 billion in long-term loan capital. In 1971 a loan from the Export-Import Bank of the United States was announced for $40.5 million matched by Phillips equity of $49.5 million for Ekofisk development. In 1975 a loan from Barclays Bank International Limited for $12 million was announced for pipeline construction. The full accounting for the sources of loan capital is not available at this writing.

## 8. ECONOMICS

### 8.1 The Phillips Group

The Phillips group, discover of Ekofisk is made up of eight companies representing Norway, France, Belgium, Italy and the United States. Phillips is the operator and holds the largest single interest, 36.96%. The group holds total interest in all fields except Albuskjell in which Shell holds a 50% interest, and Tor in which AMOCO holds a 25.5% interest. The outside interest result from the fact that the latter two fields extend outside of the Phillips group license areas. The AMOCO and Shell oil will pass through the Ekofisk centerso that these groups will pay a tariff for use of the pipelines and treating facilities.

The Phillips group also owns and operates the shore facilities in Teesside, England, and Emden, Germany. Both pipelines from Ekofisk to the shore facilities are owned and operated by separate companies in which the Phillips group has a 50% interest. Statoil, the Norwegian State Oil Company, owns the remaining 50% interest in these companies.

### 8.2 Project Cash Flows

The analysis that follows is based on cash flows of the entire project. Actually, the project involves fifteen separate companies operating seven distinct profit centers; including the Phillips group's share, the AMOCO and Shell share, the two pipelines and the two shore facilities.

### 8.3 Production assumptions

Production data is based on the estimated reserves. Estimates of actual production were used through 1978. After 1978, the rates of production are escalated to peaks of 695,000 barrels of oil per day and 1,600 million standard cubic feet of gas per day in

1981, the year development is expected to be completed. Although maximum throughput capacity of surface facilities is expected to be as high as one million barrels per day, a peak of 695,000 barrels per day is assumed in 1981 to account for downtime, maintenance and technical problems.

After 1981, oil production rates are assumed to decline at 15% per year for 19 years. Gas rates are held constant at 1,600 million standard cubic feet per day until 1989 when gas rates begin to decline. Gas in excess of 1,600 million standard cubic feet per day is assumed to be reinjected. The gas rate also reflects a lower yearly average than the 2,000 million cubic foot peak capacity.

Capital cost data were collected from oil industry periodicals and the annual and 10-K reports of Phillips Petroleum. Estimated total project cost is $5.9 billion which includes all offshore and onshore facilities. Of the total costs used in the analysis, 3.7 billion dollars are attributable to field development and 2.2 billion are attributable to pipeline and shore facilities.

A further breakdown of capital costs is shown in tables 6 and 7. Development costs include demobilization costs of 1.5 billion dollars in the last year of the project. This is the projected escalated cost of abandoning the wells and dismantling and removing the offshore structures. The costs shown in 1971 include some costs incurred in 1969 and 1970; such as the jackup rig and loading buoys to produce the first four wells in the Ekofisk Field.

Tables 5, 6 and 7 summarize oil and gas production assumptions and development costs over the life of the project. These are the basis for the financial analyses in the appendix to this chapter.

Table 5 Production Projection

| Year | Oil Production 1,000 STB/D | Gas Production MMSCF/D |
|---|---|---|
| 1971 | 6 | |
| 1972 | 33 | |
| 1973 | 33 | |
| 1974 | 35 | |
| 1975 | 190 | |
| 1976 | 280 | |
| 1977 | 277 | 200 |
| 1978 | 560 | 900 |
| 1979 | 600 | 1,100 |
| 1980 | 640 | 1,550 |
| 1981 | 695 | 1,600 |
| 1982 | 598 | 1,600 |
| 1983 | 515 | 1,600 |
| 1984 | 443 | 1,600 |
| 1985 | 381 | 1,600 |
| 1986 | 328 | 1,600 |
| 1987 | 283 | 1,600 |
| 1988 | 243 | 1,600 |
| 1989 | 209 | 1,540 |
| 1990 | 180 | 1,450 |
| 1991 | 155 | 1,300 |
| 1992 | 133 | 1,200 |
| 1993 | 115 | 1,000 |
| 1994 | 99 | 900 |
| 1995 | 85 | 800 |
| 1996 | 73 | 700 |
| 1997 | 63 | 600 |
| 1998 | 54 | 500 |
| 1999 | 47 | 300 |
| 2000 | 40 | 100 |

Table 6 Field Development Costs
(Million Dollars)

| Year | Platforms | Platform Equipment | Installation Costs | Drilling | Pipelines | Misc. | Total |
|---|---|---|---|---|---|---|---|
| 1971 | 7 | 30 | | | | 2 | 39 |
| 1972 | 8 | 10 | | | | 3 | 21 |
| 1973 | 50 | 20 | | | 5 | 10 | 85 |
| 1974 | 120 | 125 | 60 | 40 | 25 | 30 | 400 |
| 1975 | 190 | 205 | 90 | 60 | 35 | 45 | 625 |
| 1976 | 150 | 260 | 120 | 80 | 35 | 60 | 705 |
| 1977 | 110 | 235 | 140 | 100 | | 60 | 645 |
| 1978 | | 160 | 150 | 120 | | 50 | 480 |
| 1979 | | 120 | 80 | 130 | | 20 | 350 |
| 1980 | | 50 | 40 | 120 | | 15 | 225 |
| 1981 | | 30 | | 100 | | 10 | 140 |
| | 635 | 1,245 | 680 | 750 | 100 | 305 | 3,715 |

Table 7 Transportation Facilities Costs
(Million Dollars)

| Year | Oil Pipeline | Booster Stations | Oil Terminal | Gas Pipeline | Booster Stations | Gas Terminal | Total |
|---|---|---|---|---|---|---|---|
| 1973 | 80 | 20 | 90 | | | | 190 |
| 1974 | 115 | 40 | 240 | 160 | 10 | 20 | 585 |
| 1975 | 115 | 20 | 160 | 240 | 50 | 60 | 645 |
| 1976 | 10 | 35 | 90 | 120 | 35 | 45 | 335 |
| 1977 | | 35 | 70 | 90 | 65 | 20 | 280 |
| 1978 | | 25 | 30 | | 70 | | 125 |
| 1979 | | | | | 40 | | 40 |
| | 320 | 175 | 680 | 610 | 270 | 145 | 2,200 |

## 8.4 Operating Costs

Operating costs for the project tend to be fixed with respect to production rate because most involve operation and maintenance charges for the platforms, pipelines and shore facilities. Costs used in the analysis are based on an estimated cost of $411 million measured in 1979 price levels. In the analysis, annual costs are porportional to production and increase from $6 million in 1971 to $411 million in 1979 to a peak of $729.8 million in 1995, then decline rapidly as the project approaches completion. Past costs are based on the historical record. Future costs are calculated from a 1979 base with escalation at 6% per year.

## 8.5 Prices

Product prices used were $14.84 per barrel and $2.12 per thousand standard cubic feet of gas. These are 1979 price levels and they are escalated at 6% thereafter over the life of the project. Oil prices prior to 1979 are estimated at actual market prices.

## 8.6 Royalties

Royalties paid are based on a sliding scale rate, as a function of producing rate. The royalty varies between 8% and 16%, increasing as yearly production increases. For tax calculations, royalties are based on gross oil value, however, the Norwegian government is currently taking its royalty in the form of oil, which is being marketed by Statoil.

## 8.7 Taxes

Taxes on the project include the Norwegian corporate tax of 50.8% plus the Special Petroleum tax of 25%. Deductions for tax purposes include royalty, interest charges and depreciation. All capital expenditures are depreciated straight line over five years.

In calculating the special tax a 150% investment uplift is permitted. This means that 150% of all capital expenditures may be taken as deductions, limited to 10% in any one year. This is equivalent to taking straight line depreciation over 15 years on 1.5 times total investment. No taxes are paid on the project until 1978.

## 8.8 Present Worth and Rate of Return

The present worth calculated for this project is 1.6 billion dollars, discounting at 15%. The calculated rate of return is 32.3%, which is based on 71% debt financing with a five year loan life. The interest rate on loans was assumed to average 10% per year. Net cash flows become positive in 1978, eight years from the start of the project. Cash flow projections are summarized in the appendix to this chapter.

Despite high development costs, the economics for this field look fairly good. These are several factors which enhance the economics. First, product sales are not delayed until completion of all facilities. In fact, payout occurs before completion of all facilities. It appears that overall project planning and coordination can be the single most important factor in a project of this magnitude. Another factor is that this field is not in an OPEC country. The project is not taxed by the host government to the extent that it would be in many countries.

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## APPENDIX - FINANCIAL ANALYSES

The following cash flow projections were used for evaluation of the Ekofisk discovery. The computer program calculates gross revenue based on production of oil and gas at rates described in the text. Estimated royalties, operating costs, interest and taxes are calculated to determine the net cash flow. Based on the timing of development costs and production the cumulative investment position, cumulative present worth at 15% discount rate are calculated.

The annual rates for production of oil and gas are equal to the daily rate times 365. It is assumed that maximum oil capacity is reached in the eleventh year (1981) when an output of 695,000 stock tank barrels per day or 253.6 stock tank barrels per year are produced. In the same year the production of gas reaches a maximum of 1,600 million standard cubic feet daily or 548 billion standard cubic feet annually. All gas produced above this rate is assumed reinjected.

# Cash Flow Projections

## TABLE IV

## CASH FLOW PROJECTIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17:50CST
PROJECT: 0.
PAGE: 1.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 1. | 2. | 3. | 4. | 5. | 6. | 7. | 8. | 9. | 10. | 10.0 YR S TOT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PROJECT PRODUCTION AND REVENUE | | | | | | | | | | | |
| GROSS OIL, MMB | 2.2 | 12.0 | 12.0 | 12.8 | 69.4 | 102.2 | 101.1 | 204.4 | 219.0 | 233.6 | 968.7 |
| GROSS GAS, BCF | 0. | 0. | 0. | 0. | 0. | 0. | 73.0 | 328.5 | 401.5 | 565.8 | 1368.8 |
| REAL OIL PRICE/BBL | 2.400 | 2.500 | 3.000 | 12.000 | 12.500 | 13.000 | 13.500 | 14.000 | 14.840 | 15.730 | 14.010 |
| GAS PRICE/MCF | 0. | 0. | 0. | 0. | 0. | 0. | 2.000 | 2.000 | 2.120 | 2.250 | 2.139 |
| GROSS REVENUE, MM | 5.3 | 30.0 | 36.0 | 153.6 | 867.5 | 1328.6 | 1510.9 | 3518.6 | 4101.1 | 4947.6 | 16499.1 |
| DEVELOPMENT COSTS(MILLIONS) | | | | | | | | | | | |
| EQUITY CAPITAL | 60.0 | 275.0 | 246.3 | 317.5 | 260.0 | 231.3 | 151.3 | 97.5 | 56.3 | 35.0 | 1730.0 |
| BORROWED CAPITAL | 0. | 0. | 738.8 | 952.5 | 780.0 | 693.8 | 453.8 | 292.5 | 168.8 | 105.0 | 4135.0 |
| TOTAL CAPITAL | 60.0 | 275.0 | 985.0 | 1270.0 | 1040.0 | 925.0 | 605.0 | 390.0 | 225.0 | 140.0 | 5915.0 |
| EQUITY + PRINCIPAL | 60.0 | 275.0 | 246.3 | 465.3 | 598.3 | 725.5 | 784.3 | 821.3 | 690.8 | 512.8 | 5179.3 |
| CAPITALIZED INTEREST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| INTEREST PAYMENT | 0. | 0. | 0. | 73.9 | 154.4 | 198.5 | 218.5 | 200.6 | 157.4 | 110.9 | 1114.1 |
| W.I. SHARE(MILLIONS) | | | | | | | | | | | |
| ACTUAL REVENUE | 5.3 | 30.0 | 36.0 | 153.6 | 867.5 | 1328.6 | 1510.9 | 3518.6 | 4101.1 | 4947.6 | 16499.1 |
| ROYALTY PAYABLE | 0.4 | 2.4 | 2.9 | 12.3 | 104.1 | 186.0 | 220.3 | 589.3 | 690.2 | 842.5 | 2650.4 |
| AREA FEES & BONUSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TRANSPORTATION COSTS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 6.1 | 15.7 | 17.9 | 23.7 | 103.8 | 141.9 | 199.3 | 318.4 | 411.4 | 417.7 | 1656.0 |
| INTEREST PAID | 0. | 0. | 0. | 73.9 | 154.4 | 198.5 | 218.5 | 200.6 | 157.4 | 110.9 | 1114.1 |
| TAXES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 680.0 | 1186.8 | 2066.3 | 3933.3 |
| AFTER TAX NET | -1.3 | 11.9 | 15.3 | 43.8 | 505.2 | 802.2 | 872.8 | 1730.3 | 1655.3 | 1509.9 | 7145.4 |
| CAPITAL OUTLAY | 60.0 | 275.0 | 246.3 | 465.3 | 598.3 | 725.5 | 784.3 | 821.3 | 690.8 | 512.8 | 5179.3 |
| NET CASHFLOW | -61.3 | -263.1 | -231.0 | -421.5 | -93.0 | 76.7 | 88.6 | 909.1 | 964.5 | 997.2 | 1965.1 |
| CUM. POSITION | -61.3 | -324.4 | -555.4 | -976.9 | -1069.9 | -993.2 | -904.6 | 4.4 | 969.0 | 1966.1 | 1966.1 |
| CUM. PRESENT WORTH AT 15.0 % | -57.2 | -270.7 | -433.7 | -692.4 | -742.0 | -706.4 | -670.7 | -351.7 | -57.5 | 207.1 | 207.1 |
| R/R = 32.3 % | | | | | | | | | | | |
| PAID TO GOVERNMENT | 0.4 | 2.4 | 2.9 | 12.3 | 104.1 | 186.0 | 220.3 | 1269.3 | 1877.0 | 2909.0 | 6583.7 |

# TABLE V

## CASH FLOW PROJECTIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17:50CST
PROJECT: 0.
PAGE: 2.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 11. | 12. | 13. | 14. | 15. | 16. | 17. | 18. | 19. | 20. | 20.0 YR & TOT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PROJECT PRODUCTION AND REVENUE | | | | | | | | | | | |
| GROSS OIL, MMB | 253.7 | 218.3 | 188.0 | 161.7 | 139.1 | 119.7 | 103.3 | 88.7 | 76.3 | 65.7 | 2383.2 |
| GROSS GAS, BCF | 548.0 | 548.0 | 548.0 | 548.0 | 548.0 | 548.0 | 548.0 | 540.0 | 562.1 | 539.3 | 6844.2 |
| REAL. OIL PRICE/BBL | 16.670 | 17.670 | 18.740 | 19.860 | 21.050 | 22.310 | 23.650 | 25.070 | 26.580 | 28.170 | 17.849 |
| GAS PRICE/MCF | 2.380 | 2.520 | 2.680 | 2.840 | 3.010 | 3.190 | 3.380 | 3.580 | 3.800 | 4.020 | 2.939 |
| GROSS REVENUE, MM | 5533.4 | 5238.3 | 4991.8 | 4767.7 | 4577.5 | 4418.6 | 4295.3 | 4185.5 | 4164.0 | 3978.6 | 62649.9 |
| DEVELOPMENT COSTS(MILLIONS) | | | | | | | | | | | |
| EQUITY CAPITAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1730.0 |
| BORROWED CAPITAL | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 4185.0 |
| TOTAL CAPITAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5915.0 |
| EQUITY + PRINCIPAL | 342.8 | 204.0 | 113.3 | 54.8 | 21.0 | 0. | 0. | 0. | 0. | 0. | 5915.0 |
| CAPITALIZED INTEREST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| INTEREST PAYMENT | 73.6 | 39.3 | 18.9 | 7.6 | 2.1 | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| W.I. SHARE(MILLIONS) | | | | | | | | | | | |
| ACTUAL REVENUE | 5533.4 | 5238.3 | 4991.8 | 4767.7 | 4577.5 | 4418.6 | 4295.3 | 4185.5 | 4164.0 | 3978.6 | 62649.9 |
| ROYALTY PAYABLE | 937.5 | 893.4 | 857.4 | 825.1 | 798.4 | 723.5 | 712.5 | 703.7 | 670.6 | 647.6 | 10420.0 |
| AREA FEES & BONUSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TRANSPORTATION COSTS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 446.8 | 448.7 | 457.8 | 460.4 | 487.9 | 518.0 | 509.1 | 530.5 | 574.9 | 610.5 | 6708.6 |
| INTEREST PAID | 73.6 | 39.3 | 18.9 | 7.6 | 2.1 | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| TAXES | 2595.0 | 2569.5 | 2510.2 | 2430.5 | 2324.1 | 2260.4 | 2183.5 | 2091.6 | 2097.4 | 1979.0 | 26974.4 |
| AFTER TAX NET | 1480.6 | 1287.4 | 1147.5 | 1044.1 | 965.1 | 916.7 | 890.2 | 851.8 | 821.2 | 741.5 | 17291.4 |
| CAPITAL OUTLAY | 342.8 | 204.0 | 113.3 | 54.8 | 21.0 | 0. | 0. | 0. | 0. | 0. | 5915.0 |
| NET CASHFLOW | 1137.8 | 1083.4 | 1034.2 | 989.3 | 944.1 | 916.7 | 890.2 | 851.8 | 821.2 | 741.5 | 11376.4 |
| CUM. POSITION | 3104.0 | 4187.4 | 5221.6 | 6210.9 | 7155.0 | 8071.7 | 8962.0 | 9813.8 | 10634.9 | 11376.4 | 11376.4 |
| CUM. PRESENT WORTH AT 15.0 % | 469.6 | 686.9 | 867.3 | 1017.4 | 1141.9 | 1247.0 | 1335.8 | 1409.7 | 1471.6 | 1520.2 | 1520.2 |
| R/R = 32.3 % | | | | | | | | | | | |
| PAID TO GOVERNMENT | 3532.5 | 3462.9 | 3367.6 | 3255.6 | 3122.5 | 2983.9 | 2896.0 | 2795.3 | 2767.9 | 2626.6 | 37394.4 |

# TABLE VI

## CASH FLOW PROJECTIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17:50CST
PROJECT: 0.
PAGE: 3.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 21. | 22. | 23. | 24. | 25. | 26. | 27. | 28. | 29. | 30. | 30.0 YR TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **PROJECT PRODUCTION AND REVENUE** | | | | | | | | | | | |
| GROSS OIL, MMB | 56.6 | 48.5 | 42.0 | 36.1 | 31.0 | 26.6 | 23.0 | 19.7 | 17.2 | 14.6 | 2698.5 |
| GROSS GAS, BCF | 474.5 | 438.0 | 365.0 | 328.5 | 292.0 | 255.5 | 219.0 | 182.5 | 109.5 | 36.5 | 9545.2 |
| REAL. OIL PRICE/BBL | 29.860 | 31.6[illegible] | 33.550 | 35.520 | 37.700 | 39.960 | 42.360 | 44.900 | 47.590 | 50.450 | 20.048 |
| GAS PRICE/MCF | 4.270 | 4.520 | 4.790 | 5.080 | 5.390 | 5.710 | 6.050 | 6.410 | 6.800 | 7.210 | 3.569 |
| GROSS REVENUE, MM | 3716.2 | 3514.8 | 3157.5 | 2951.1 | 2742.6 | 2521.8 | 2299.2 | 2054.4 | 1563.1 | 999.7 | 88170.3 |
| **DEVELOPMENT COSTS(MILLIONS)** | | | | | | | | | | | |
| EQUITY CAPITAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1500.0 | 3230.0 |
| BORROWED CAPITAL | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 4185.0 |
| TOTAL CAPITAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1500.0 | 7415.0 |
| EQUITY + PRINCIPAL | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1500.0 | 7415.0 |
| CAPITALIZED INTEREST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| INTEREST PAYMENT | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| **W.I. SHARE(MILLIONS)** | | | | | | | | | | | |
| ACTUAL REVENUE | 3716.2 | 3514.8 | 3157.5 | 2951.1 | 2742.6 | 2521.8 | 2299.2 | 2054.4 | 1563.1 | 999.7 | 88170.3 |
| ROYALTY PAYABLE | 608.0 | 580.2 | 510.8 | 462.0 | 431.6 | 398.1 | 362.4 | 322.4 | 230.8 | 126.3 | 14460.6 |
| AREA FEES & BONUSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TRANSPORTATION COSTS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 645.2 | 649.4 | 633.8 | 706.8 | 729.8 | 677.5 | 666.2 | 483.3 | 325.5 | 224.0 | 12450.1 |
| INTEREST PAID | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| TAXES | 1809.8 | 1698.2 | 1500.8 | 1341.8 | 1195.0 | 1096.3 | 963.1 | 946.5 | 763.2 | 492.3 | 38781.4 |
| AFTER TAX NET | 653.2 | 587.0 | 504.1 | 440.4 | 386.1 | 350.0 | 307.5 | 302.2 | 243.7 | 157.2 | 21222.7 |
| CAPITAL OUTLAY | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1500.0 | 7415.0 |
| NET CASHFLOW | 653.2 | 587.0 | 504.1 | 440.4 | 386.1 | 350.0 | 307.5 | 302.2 | 243.7 | -1342.8 | 13807.7 |
| CUM. POSITION | 12029.6 | 12616.6 | 13120.6 | 13561.1 | 13947.2 | 14297.2 | 14604.7 | 14906.9 | 15150.5 | 13807.7 | 13807.7 |
| CUM. PRESENT WORTH AT 15.0 % | 1557.5 | 1586.6 | 1608.3 | 1624.8 | 1637.4 | 1647.3 | 1654.9 | 1661.4 | 1665.9 | 1644.2 | 1644.2 |
| R/R = 32.3 % | | | | | | | | | | | |
| PAID TO GOVERNMENT | 2417.8 | 2278.4 | 2019.6 | 1803.8 | 1626.6 | 1494.3 | 1325.6 | 1268.9 | 994.0 | 618.6 | 53242.0 |

# TABLE VII

## TAX CALCULATIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17150CST
PROJECT: 0.
PAGE: 1.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 1. | 2. | 3. | 4. | 5. | 6. | 7. | 8. | 9. | 10. | 10.0 YR S TOT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TAX DATA(MILLIONS) | | | | | | | | | | | |
| TAXABLE REVENUE | 5.3 | 30.0 | 36.0 | 153.6 | 867.5 | 1328.6 | 1510.9 | 3518.6 | 4101.1 | 4947.6 | 16499.1 |
| AREA FEES & BONUS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ROYALTY | 0.4 | 2.4 | 2.9 | 12.3 | 104.1 | 186.0 | 220.3 | 589.3 | 690.2 | 842.5 | 2650.4 |
| TRANSPORTATION CST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 6.1 | 15.7 | 17.9 | 23.7 | 103.8 | 141.9 | 199.3 | 318.4 | 411.4 | 417.7 | 1656.0 |
| INTEREST | 0. | 0. | 0. | 73.9 | 154.4 | 198.5 | 218.5 | 200.6 | 157.4 | 110.9 | 1114.1 |
| DEPRECIATION | 7.8 | 12.0 | 67.0 | 264.0 | 518.0 | 718.2 | 899.0 | 965.0 | 846.0 | 637.0 | 4934.0 |
| NET TAXABLE | -9.1 | -0.1 | -51.7 | -220.2 | -12.8 | 84.0 | -26.2 | 1445.3 | 1996.1 | 2939.5 | 6144.7 |
| LOSS CARRYFORWARD | 9.1 | 0.1 | 51.7 | 220.2 | 12.8 | -84.0 | 26.2 | -106.7 | -106.7 | -22.7 | -0.0 |
| TAXABLE INCOME | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| TAXABLE INCOME | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| 1/2 OUTSIDE LOSSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| MUNICIPAL TAX BASIS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| MUNICIPAL TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 307.8 | 434.5 | 670.8 | 1413.1 |
| MUNICIPAL TAX BASIS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| ESTIMATED DIVIDENDS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| STATE TAX BASIS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| STATE TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 372.2 | 525.3 | 810.9 | 1708.4 |
| 10% WITHHOLDING TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TAXABLE INCOME | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 1889.4 | 2916.7 | 6144.7 |
| UPLIFTED INVESTMENTS | 90.0 | 412.5 | 1477.5 | 1905.0 | 1560.0 | 1387.5 | 907.5 | 585.0 | 337.5 | 210.0 | 6 72.5 |
| TAX FREE ALLOWANCE | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1338.6 | 981.4 | 577.5 | 2897.5 |
| SPECIAL TAX BASIS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 908.0 | 2339.2 | 3247.2 |
| SPECIAL TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 227.0 | 584.8 | 811.8 |
| PROPERTY TAX BASIS | 0. | 60.0 | 335.0 | 581.3 | 1046.5 | 1644.8 | 2370.3 | 3154.5 | 3975.8 | 4666.5 | 4666.5 |
| PROPERTY TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ALL TAXES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 680.0 | 1186.8 | 2066.5 | 3933.3 |

# TABLE VIII

## TAX CALCULATIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17150CST
PROJECT: 0.
PAGE: 2.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 11. | 12. | 13. | 14. | 15. | 16. | 17. | 18. | 19. | 20. | 20.0 YR S TOT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TAX DATA(MILLIONS) | | | | | | | | | | | |
| TAXABLE REVENUE | 5533.4 | 5238.3 | 4991.8 | 4767.7 | 4577.5 | 4418.7 | 4295.3 | 4185.5 | 4164.0 | 3978.6 | 62649.9 |
| AREA FEES & BONUS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ROYALTY | 937.5 | 893.4 | 857.4 | 825.1 | 798.4 | 723.5 | 712.5 | 703.7 | 670.6 | 647.6 | 10420.0 |
| TRANSPORTATION CST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 446.8 | 448.7 | 457.8 | 460.4 | 487.9 | 518.0 | 509.1 | 538.5 | 574.9 | 610.5 | 6708.6 |
| INTEREST | 73.6 | 39.3 | 18.9 | 7.6 | 2.1 | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| DEPRECIATION | 457.0 | 272.0 | 151.0 | 73.0 | 28.0 | 0. | 0. | 0. | 0. | 0. | 5915.0 |
| NET TAXABLE | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| LOSS CARRYFORWARD | -0.0 | -0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.0 | -0.0 | 0. | 0.0 | 0.0 |
| TAXABLE INCOME | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| TAXABLE INCOME | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| 1/2 OUTSIDE LOSSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| MUNICIPAL TAX BASIS | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| MUNICIPAL TAX | 832.2 | 824.4 | 806.4 | 782.3 | 750.0 | 730.6 | 706.9 | 676.9 | 671.2 | 625.6 | 8819.6 |
| MUNICIPAL TAX BASIS | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| ESTIMATED DIVIDENDS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| STATE TAX BASIS | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| STATE TAX | 1006.1 | 996.7 | 974.9 | 945.7 | 906.7 | 883.3 | 854.6 | 818.4 | 811.4 | 756.4 | 10662.6 |
| 10% WITHHOLDING TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TAXABLE INCOME | 3618.5 | 3584.9 | 3506.6 | 3401.6 | 3261.2 | 3177.1 | 3073.7 | 2943.4 | 2918.5 | 2720.4 | 38350.8 |
| UPLIFTED INVESTMENTS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 8872.5 |
| TAX FREE ALLOWANCE | 591.5 | 591.5 | 591.5 | 591.5 | 591.5 | 591.5 | 585.5 | 558.0 | 459.5 | 332.5 | 8382.0 |
| SPECIAL TAX BASIS | 3027.0 | 2993.4 | 2915.1 | 2810.1 | 2669.7 | 2585.6 | 2488.2 | 2385.4 | 2459.0 | 2387.9 | 29968.8 |
| SPECIAL TAX | 756.8 | 748.4 | 728.8 | 702.5 | 667.4 | 646.4 | 622.1 | 596.4 | 614.8 | 597.0 | 7492.2 |
| PROPERTY TAX BASIS | 5179.3 | 5522.0 | 5726.0 | 5839.3 | 5894.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 |
| PROPERTY TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ALL TAXES | 2595.0 | 2569.5 | 2510.2 | 2430.5 | 2324.1 | 2260.4 | 2183.5 | 2091.6 | 2097.4 | 1979.0 | 26974.4 |

# TABLE IX

## TAX CALCULATIONS

EKOFISK AREA
NORWEGIAN NORTH SEA
TOTAL PROJECT ECONOMICS

FILE: EKOFISK
DATE: 04/21/79
TIME: 17:50CST
PROJECT: 0.
PAGE: . 3.

N O R W A Y  R E S E R V E S  A N D  E C O N O M I C S

AS OF DATE: 1/ 1/1971

| PROJECT YEAR | 21. | 22. | 23. | 24. | 25. | 26. | 27. | 28. | 29. | 30. | 30.0 YR TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TAX DATA(MILLIONS) | | | | | | | | | | | |
| TAXABLE REVENUE | 3716.2 | 3514.8 | 3157.5 | 2951.1 | 2742.6 | 2521.8 | 2299.2 | 2054.4 | 1563.1 | 999.7 | 88170.3 |
| AREA FEES & BONUS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ROYALTY | 608.0 | 580.2 | 518.8 | 462.0 | 431.6 | 398.1 | 362.4 | 322.4 | 230.8 | 126.3 | 14460.6 |
| TRANSPORTATION CST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| OPERATING COSTS | 645.2 | 649.4 | 633.8 | 706.8 | 729.8 | 677.5 | 666.2 | 483.3 | 325.5 | 224.0 | 12450.1 |
| INTEREST | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 1255.5 |
| DEPRECIATION | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 5915.0 |
| NET TAXABLE | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| LOSS CARRYFORWARD | -0.0 | 0.0 | 0. | -0.0 | -0.0 | -0.0 | 0. | 0.0 | 0. | -0.0 | 0.0 |
| TAXABLE INCOME | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| TAXABLE INCOME | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| 1/2 OUTSIDE LOSSES | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| MUNICIPAL TAX BASIS | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| MUNICIPAL TAX | 566.4 | 525.5 | 461.1 | 409.9 | 363.6 | 332.6 | 292.2 | 287.2 | 231.5 | 149.4 | 12439.0 |
| MUNICIPAL TAX BASIS | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| ESTIMATED DIVIDENDS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| STATE TAX BASIS | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| STATE TAX | 684.8 | 635.4 | 557.4 | 495.5 | 439.6 | 402.1 | 353.3 | 347.2 | 279.9 | 180.6 | 15038.3 |
| 10% WITHHOLDING TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| TAXABLE INCOME | 2463.0 | 2285.3 | 2004.9 | 1782.2 | 1581.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 54089.1 |
| UPLIFTED INVESTMENTS | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 8872.5 |
| TAX FREE ALLOWANCE | 228.5 | 136.0 | 75.5 | 36.5 | 14.0 | 0. | 0. | 0. | 0. | 0. | 8872.5 |
| SPECIAL TAX BASIS | 2234.5 | 2149.3 | 1929.4 | 1745.7 | 1567.1 | 1446.2 | 1270.6 | 1248.6 | 1006.9 | 649.5 | 45216.6 |
| SPECIAL TAX | 558.6 | 537.3 | 482.4 | 436.4 | 391.8 | 361.6 | 317.7 | 312.2 | 251.7 | 162.4 | 11304.1 |
| PROPERTY TAX BASIS | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 5915.0 | 0. |
| PROPERTY TAX | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| ALL TAXES | 1809.8 | 1698.2 | 1500.8 | 1341.8 | 1195.0 | 1096.3 | 963.1 | 946.5 | 763.2 | 492.3 | 38781.4 |

# Uranium Economics: USA

# URANIUM ECONOMICS - USA

## 1. INTRODUCTION

The recognition of an "energy crunch" and more specifically the spectacular increases in the price of $U_3O_8$ after 1973 has stimulated a worldwide interest in developing new uranium mines.

This chapter focuses on the economics of U.S. uranium deposits -- in particular, the economics of lower grade open pit mines in Wyoming that make possible exploitation of thin pod-like deposits that require extraordinary ore grade control and extremely selective mining. Their exploitation is possible because of low unit costs for stripping the thick overburden and the ability to selectively mine the underlying uranium bearing formations.

Improvements in processing technology are also a source of increased uranium supplies. In February of 1978, Department of Energy officials indicated that "laser stripping" of U.S. enrichment plant tails held in inventory could add almost 12% current world estimates of yellow-cake reserves. A new laser isotope-separation technique was estimated capable of economically reducing tails to an assay of 0.1% from the present level of 0.25%. This would mean that laser stripping could recover the equivalent of 191,000 metric tons of $U_3O_8$ by the early 1990's. This estimate was 11.5% of the latest estimate of known uranium reserves and illustrates the tremendous impact of technological advance on potential uranium supplies. The process was described as "making good progress and offers tremendous promise of meeting future energy needs." (Nucleonics Week Special Report, Uranium Supply and Prices, 1978).

Improvements in mining technology are also a source of increasing uranium reserves. A uranium mining method was announced in February of 1979 which recovers ore from deposits too small to mine conventionally. The process avoids sending miners underground and will be used commercially in 1979. The process was developed by the U.S. Bureau of Mines and consists of fragmenting uranium-bearing sandstones with a water-jet device lowered through a bore hole, then pumping the water-sand mixture to the surface. The Rocky Mountain Energy Company will use the new method at it's Bear Creek, Wyoming, uranium operation later this year, (Mining Activity Digest, February 9, 1979).

### 1.1 Growth of Inventories

The looming "shortage" of uranium remains uncertain because of a lack of a national policy toward the development of nuclear power and the desire of the utilities for assurance of long-term uranium supplies for new power plants. Inventories of $U_3O_8$ have increased steadily as prices have increased. Stocks of natural uranium held by producers and consumers increased from 25,579 short tons in 1973 to 35,000 short tons at year end 1977. This large and increasing inventory is an indication that the price increases reflect projected shortages rather than current shortages.

### 1.2 Unexpected inflation

The break in the rate of cost inflation after 1973 has increased the cost of producing uranium as it has increased the cost of most mineral production. A portion of cost increases are the result of mining industry response to higher prices. Producers make changes in their operations in response to a higher price level. For example, if a mining company is exploiting uranium ore containing 4 pounds of $U_3O_8$ per ton at a total cost of $20.00 per ton mined and processed, it will report a cost per pound of $5.00. At the $5.00 price level it will just break even on ore containing 4 pounds of $U_3O_8$. If the price rises to $40.00 per pound for any reason, the miner can now exploit any ore from which he can recover one or more pounds of $U_3O_8$ per ton. His breakeven cost is now $40.00 per pound rather than $5.00 per pound. This response to a higher price will in itself, lower the average grade of material mined and will increase the cost per pound proportionately.

In addition to the effects of exploiting lower grades, a sharp increase in market price will tend to increase the costs of acquiring land and paying royalties. The profitability of the industry increases demand for capital equipment and labor, thus forcing up their prices as well. These higher costs result directly in a higher cost per ton and a higher cost per pound. In some cases the response to a higher price will be to increase the rate of production from an orebody with consequent declines in efficiency and productivity. These effects also will tend to increase the total cost per ton and the total cost per pound.

### 1.3 Cost Derived Prices

If the investment and operating expenditures for a specific uranium mine are known, it is possible to calculate a price that will pay the cash costs of operation, amortize the investment, and pay a 12% return on the capital invested. If all expenditures beginning with exploration are included, the price is one that provides incentive for exploration and development. First, producers look for profitability on existing facilities where the investment is a "sunk cost", hence not necessarily covered by the sales price. If supply expansion is required, producers will demand full coverage of all investment and operating expenditures as well as an adequate return on investment. This section develops the economic model used by producers in this type of analysis.

## 2. CASH FLOW RELATIONSHIPS

Expected revenues, royalties, capital and operating costs, and taxes of a mining project occur over time for a given uranium project. Such a pattern of cash flows is depicted in figure 1, Pattern of Cash Flows for a Uranium Project.

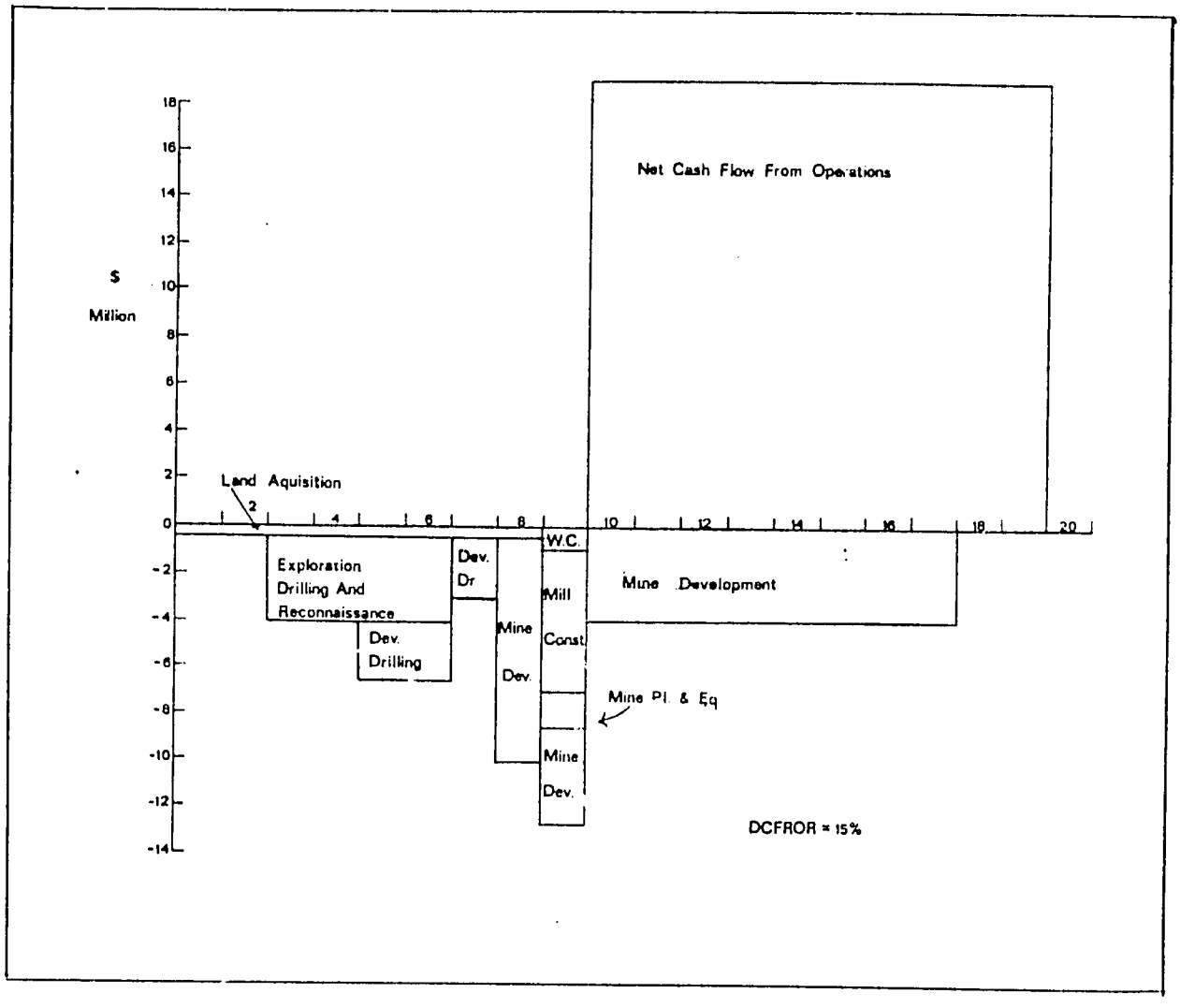



FIGURE 1 PATTERN OF CASH FLOWS FOR A URANIUM PROJECT

This pattern of cash flows is based on Department of Energy information and analyses by John Klemenic (Klemenic, 1974). The negative cash flows shown in the diagram are investments. They are based on estimated costs beginning with the initial land acquisition and including exploration drilling and reconnaissance, development drilling, mine development, mill construction and working capital. Figure 1 illustrates that on the average, a period of nine years elapses between initial land acquisition and the beginning of production. After production begins, work continues on mine development throughout most of the life of the mine until the end of the seventeenth year.

At the beginning of the tenth through the nineteenth year there is production, hence revenues derived from the sale of uranium oxide. After revenues are determined, royalties and all costs, including taxes are deducted. The result is the net cash flow from operations. The net cash flow from operations and the investment cash flows are discounted at a rate approximating the company's marginal cost of capital. The result places a value on the property and leads to a decision by the company to develop the property or to seek other investment opportunities.

## 2.1 Components of Investment

The negative cash flows of figure 1 account for all components of investment from the earliest expenditures to acquire land and do exploration drilling and reconnaissance to the investment in mine development and mill construction necessary to bring the mine into production. These components of investment have the following characteristics:

(1) Land acquisition includes expenditures to acquire property having geologic characteristics favorable to discovery. These expenditures include staking of claims, trading parcels of land, field work, filing claims, legal expenses and land purchase arrangements with private owners.

(2) Exploration drilling and reconnaissance are defined as the drilling and geologic exploration work that takes place prior to defining a "commercial ore deposit". The time that tonnages and grades are sufficient to define a commercial ore body is not precisely defined, but it is when exploration ends and development begins. If the company involved has production, revenues and profits from other mines, exploration expenditures are expensed against current income for tax purposes. Thus, the definition is important when calculating taxes.

If the effective federal, state, and local tax rate is 50%, a $2.00 expenditure for exploration or reconnaissance results in a $1.00 tax reduction, thus reducing current cash costs. This situation is common and is an incentive for exploration because it's financing is partially through a tax reduction.

If the company does not have producing income, there will be no offsetting tax benefits. The exploration expenditures are recovered only if they are successful in generating revenues from a profitable mining operation.

The investments for exploration and reconnaissance shown in figure 1 are assumed recovered through the depletion allowance which reduces taxes and increases the net cash flow from operations. In some cases it is more realistic to include a continuing exploration expenditure as part of the costs of the operating mine. This is consistent with the situation where current exploration costs are expensed against current income for tax purposes. Such expenditures would <u>not</u> be part of a feasibility analysis of a mining project because exploration is not part of the cash operating cost of the mine. However these costs are included in the analyses if the question is "whether to get involved in the uranium business" beginning with the exploration phase. At this point the investment in exploration is necessary and it must be profitable if the industry is to expand by the discovery and development of new sources of uranium.

(3) The development drilling investment takes place after a commercial ore body is defined in order to define the size, shape, depth and grade of the ore body. Additional ore reserves are often defined during the development period, and the scope and capacity of the project are changed to take advantage of larger reserves. As additional ore reserves are defined, a larger scale, lower cost operation may appear feasible. At some point during development the ore body is defined sufficiently for a detailed feasibility study including engineering of the mine and mill.

(4) When detailed engineering designs and cost estimates are prepared, construction of the mine and mill can begin. This is shown beginning in year 8 of figure 1. The cash flow pattern shows preproduction mine development as well as mill

construction expenditures and an investment in working capital (WC). Mine development continues throughout most of the productive life of the mine in order to prepare new areas for production in advance of mining operations.

## 2.2 Components of Operating Net Cash Flow

Operating net cash flow is calculated by subtracting all cash costs from sales revenue. A simple example of the calculation follows.

(1) Annual revenue is the product of the annual production of ore (tons annually), the ore grade (pounds of $U_3O_8$ per ton), the metallurgical recovery of contained $U_3O_8$ (percent), and the $U_3O_8$ price (dollars per pound). The ore grade is often expressed as a percent, for example 0.1% $U_3O_8$ contained in a 2,000 pound (short) ton is 0.001 x 2,000 or 2 pounds of $U_3O_8$ per ton. Assuming ore production of 650,000 short tons annually, ore grade of 2 pounds per ton, metallurgical recovery of 95% and a price of $10 per pound, the annual revenue is 650,000 x 2 x .95 x 10 = $12,350,000.

Revenue must be sufficient to pay cash operating costs, royalties, and taxes. It must also generate a sufficient return on the investment to interest the investor in the project. In our analysis the required price to generate such a revenue is determined.

(2) Royalties are usually deducted from sales revenue prior to the deduction of operating costs or taxes. Then cash operating costs and taxes are deducted to determine the net operating cash flow. To determine taxes, deduction of non-cash costs of depreciation and depletion are required. In the example that follows, cash operating costs of $5 million per year, depreciation of $4 million per year and percentage depletion equal to 22% of the gross income but limited to 50% of the net income after depreciation is assumed. Royalties are assumed at 4% and the company tax rate at 50%.

**Net Cash Flow Calculation**

| | |
|---|---|
| Annual Revenue | $12,350,000 |
| Less Royalty (4%) | 494,000 |
| Equals Gross Income | 11,856,000 |
| Less cash operating cost | 5,000,000 |
| Equals net income before depreciation and depletion | 6,856,000 |
| Less taxes | 714,000 |
| Equals net cash flow from Operations | 6,142,000 |

**Tax Calculations**

| | |
|---|---|
| Net income before depreciation or depletion | 6,856,000 |
| Less depreciation | 4,000,000 |
| Net income before depletion | 2,856,000 |
| Less depletion | |
| Lessor of .22 x 11,856,000 | |
| or .50 x 2,856,000 | 1,428,000 |
| Taxable income | 1,428,000 |
| Taxes (50%) | 714,000 |

In this simplified example, we assume that the operating net cash flow occurs over the life of the mine. It will be affected by any changes that affect rate of operation, metallurgical recovery, mining or milling costs, or market price. If prices are high enough and costs are low enough, this net cash flow will be sufficient to amortize an investment and pay sufficient return to provide incentive for exploration and development of new properties.

## 2.3 Acceptable Rate of Return

An acceptable rate of return for a specific mineral project is the rate of interest that could be realized in competitive investment opportunities. This acceptable return is usually described in terms of two components, a "risk free" return such as that received on government bonds, plus an adjustment for risk of the investment in a specific project, firm and industry. This risk is often defined as the expected variability in the return on investment. Risk of an individual project is lower when the company has sufficient resources to undertake a large number of projects and to finance these projects, some of which may be extremely profitable and others extremely unprofitable.

A "risk free" rate of the "pre-energy crisis era" of the 1971-75 period was 4 to 6%. In January of 1980, because of increasing inflation, the rate on government bonds is in the range of 10 to 13% One must keep in mind that the interest on a government bonds is before taxes, thus at a 50% tax rate, the interest is cut in half. In contrast the interest (rate of return) on a uranium project investment is calculated on an after tax basis. Therefore, for someone in a 50% tax bracket, the after-tax yield on government bonds is closer to 5 to 7%.

The preceding analysis is consistent with known discount rates used by exploration and mining companies in the 12 to 15% range in the United States. These after tax returns include a premium for risk of 8 to 11% on top of an after tax risk free return. The "acceptable rate" is also a function of the method of analysis. If the financial evaluation is very conservative, lower rates of return are likely to be acceptable.

A factor that increases return to stockholders from uranium projects is the use of loan capital. In the analyses that follow, no loans are assumed. Actually, the mining firm will probably leverage the return to equity on the project by the use of loans up to 80% of the total required capital. The ability to acquire such loans increases as the market for the product improves. This can increase the return on equity capital by a factor of 3 or 4; however, the higher return is accompanied by higher risks associated with the commitment to pay annual interest and loan amortization charges whether operations are profitable or not. Bankers do not participate in profits when economic conditions are improving, therefore they seek to avoid those risks that might prevent scheduled repayment of loans.

## 2.4 Cost Updating

Any analysis of cost or price must be referred to a specific point in time to be meaningful. Costs and prices are continuously changing, thus they must be time dated. For example, capital or operating cost estimates taken from the literature or from company reports dated 1975 must be corrected using cost indexes if they are to be compared with costs in 1980. In the analyses which follow, such corrections are made using standard cost engineering techniques and indexes.

One of the characteristics of operating costs during the 1970-80 decade is the sharp break in cost trends after 1972. This break was worldwide and shows in the cost indexes of the United States, Canada, Australia, and worldwide.

## 2.5 Derivation of Required Price

A computer program, "UMET FCL", was developed to make corrections for cost changes and to calculate the required $U_3O_8$ price for a large number of uranium operations around the world.

Given the amount and timing of investment and production cost data, the derivation of required $U_3O_8$ price is a four step process.

(1) Estimation and updating of capital and operating costs based on the available information.
(2) Calculation of the required net operating cash flow necessary to amortize and pay a 12% return on the capital investment.
(3) Determination of the required revenue necessary to meet the cash flow requirements calculated in step 2. This requires knowledge of production costs and the depreciation, depletion, tax, and royalty rates.
(4) Division of the total revenue requirement determined in step 3 by the expected annual production of $U_3O_8$. This requires knowledge of the tonnage operating rate, metallurgical recovery, and ore grade of the deposit. The result of the calculation is the required $U_3O_8$ price.

## 2.6 Input and Output of Computer Price Analysis

Table 1 summarizes the input data and the output calculations for a specific uranium project. It is illustrative of the numerous analyses made of uranium deposits situated throughout the world.

Table 1 Uranium Price Analysis

| | | |
|---|---|---|
| 1. | Number of Investment Cash Flows | 8. |
| 2. | Acceptable Discount Rate,% | 12. |
| 3. | First Year of Operating Net Cash Flows | 11. |
| 4. | Last Year of Operating Net Cash Flows | 20. |
| 5. | Summary of Investment Cash Flows ($000) Through Year 16. | |

| Year | Cashflow ($000) | Year | Cashflow ($000) |
|---|---|---|---|
| 1. | 628 | 9. | 13580 |
| 2. | 628. | 10. | 12951. |
| 3. | 5344. | 11. | 2075. |
| 4. | 5344. | 12. | 0. |
| 5. | 8488. | 13. | 0. |
| 6. | 8488. | 14. | 0. |
| 7. | 3772 | 15. | 0. |
| 8. | 7544. | 16. | 2075. |

| | | |
|---|---|---|
| 6. | Total Capital Investment is ($000) | 70918. |
| 7. | Cumulative Net Present Value of Investment cash flows ($000) | 32133. |
| 8. | Required Average Annual Cash Flow ($000) | 17663. |
| 9. | Depreciable Investment ($000) | 46397. |
| 10. | Depreciable Life, Years | 10. |
| 11. | Combined Effective Tax Rate,% | 50.0 |
| 12. | Production Rate (000) Tons of Ore Annually | 680. |
| 13. | Production Rate (000) Pounds of $U_3O_8$ Annually | 3230. |
| 14. | Overall Metallurgical Recovery,% | 95.0 |
| 15. | Average Ore Grade,% | 0.250 |
| 16. | Annual Royalty Payment, ($000) | 1702. |
| 17. | Annual Operating Costs, ($000) | 13497. |
| 18. | Royalty Per Pound Recovered Is | $ 0.53 |
| 19. | Operating Cost Per Pound Recovered Is | $ 4.18 |
| 20. | Amortization of Capital Investment Per Pound Is | $ 2.20 |
| 21. | Income Taxes Per Pound Recovered Are | $ 1.47 |
| 22. | Margin Left For Return On Inv. Is | $ 3.27 |
| 23. | Required Price Per Pound, Dollars | $11.65 |
| 24. | Cash Cost Per Ton Is | $29.34 |
| 25. | Indicated Cash Cost Cutoff Ore Grade,% | 0.13 |
| 26. | Marshall and Swift Index For These Costs | 343. |
| 27. | Wholesale Price Index For These Costs | 135. |

This analysis is based on data developed by John Klemenic of the Department of Energy in 1972. The project analyzed is a 2,000 ton per day underground uranium mine in a typical western sandstone geological situation. In order to update prior-year cost information it is necessary to label the data with standard capital and operating cost indexes. This labeling is indicated on the computer output by use of 1973 cost index numbers given in items 26 and 27.

Item 23 indicates the required price per pound of uranium oxide is $11.65. This means that $11.65 per pound of uranium oxide was necessary to pay all costs, taxes, royalties, and generate sufficient additional profit to give a 12% return on investment in terms of 1973 cost levels.

Items 18 through 22 of table 1 distribute the components of uranium price. These components of price are shown in figure 2.

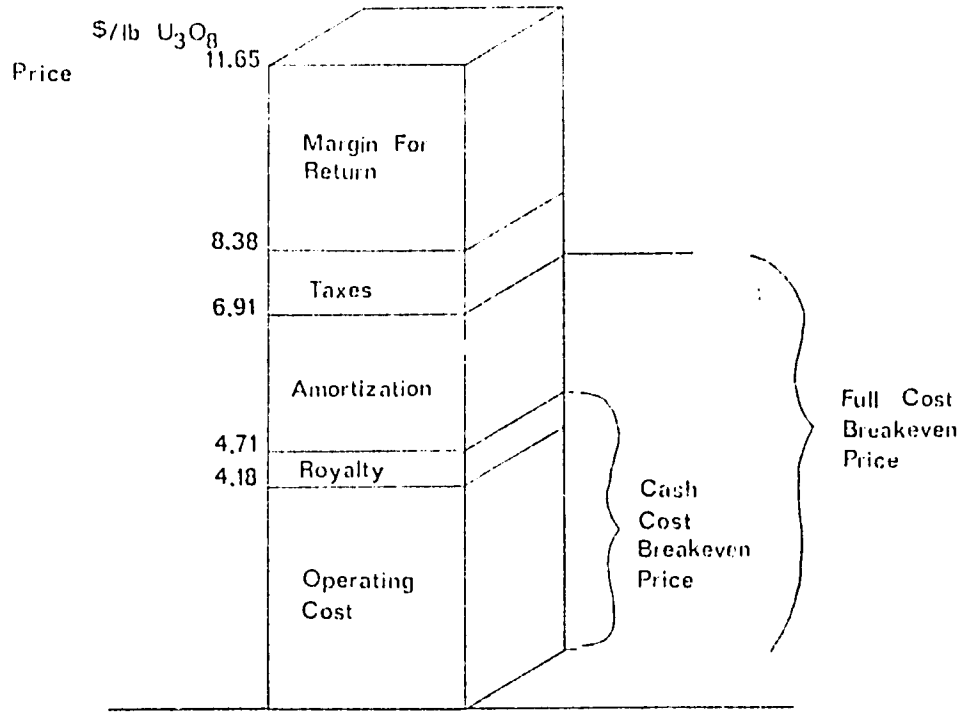



FIGURE 2 COMPONENTS OF $U_3O_8$ PRICE

The components of price include the cash operating costs and royalties which must be paid even at a zero profit breakeven price. In this case these costs add up to $4.71 per pound $U_3O_8$. A breakeven price of $6.91 per pound covers full costs including the amortization of the capital investment.

After coverage of full costs the addition of taxes and a margin for return on the capital investment leads to the total required price of $11.65 per pound $U_3O_8$. If all investment costs including exploration are included, then the price is one that will amortize all capital investments and pay 12% each year on the unamortized portion of the investment.

### 2.7 The Meaning of the Price Analyses

When the discounted cash flow method of analysis is used on an individual project it indicates the price required to make that project look attractive. When a large number of current and future projects with different physical conditions are considered, it provides an indication of the level of price that would generate required investment in exploration and development. As indicated, all components of price are reflected in the

analysis. The price calculated includes recovery of all investment, payment of all cash costs and sufficient margin to generate a reasonable rate of return on the invested capital.

### 2.8 Sunk Costs

Usually in a feasibility study of a specific uranium project, the capital expenditures for exploration are not included in the analysis. At the point of determining economic feasibility, exploration is a sunk cost and therefore does enter into the investment decision. In the case of an operating mine, the investment in mine development and in the plant and equipment is also a sunk cost. The objective of this analysis is a price designed to cover full costs including exploration, development, and construction of the mine and mill - one that provides incentive prior to any expenditures.

### 2.9 Financial Leverage

Many producers are able to increase the rate of return on their investment by the use of loan capital. Such action increases the return on equity and thus allows an acceptable return on equity at a lower price than indicated by our analyses. In the analyses that follow no financial leverage is assumed. Therefore prices calculated are higher than those required to generate a 12% return on equity when loan capital is involved in the project.

## 3. ANALYSIS OF DEPARTMENT OF ENERGY DATA

John Klemenic, Director of the Supply Analysis Division of the Grand Junction, Colorado Office of the Department of Energy presented a series of papers dealing with uranium costs, prices and economics between 1966 and 1974. These summaries were accepted by industry as the best publicly available information on U.S. uranium costs because of the Department of Energy access to individual company data. Because most of the producing properties were in western sandstone geological environments, they represent models of underground and open pit mines of varying size, grade, and depth in that type of environment.

Klemenic's 1972 paper is the one that is most relevant because it embodied the current cost data as of 1972. Klemenic first provided two "base case" analyses, one for an underground mining situation and another for an open pit mining situation. The base case open pit mine assumed a rate of operation of 2000 tons per calendar day, an ore grade of 0.20% $U_3O_8$, a depth to thickness ratio of 24 to 1, a production life of 10 years and exploration costs of $0.90 per pound of $U_3O_8$ in ore. The underground base case assumed a 1000 ton per day rate of operation, 0.25% ore grade, and a 76 to 1 depth to thickness ratio. Assumptions with regard to production life and exploration costs were the same as the open pit mine.

In order to bracket the range of expected industry conditions and operations, Klemenic did "sensitivity analyses" on the base cases by assuming different rates of operations, ore grades, depth/thickness ratios and exploration costs.

### 3.1 Summary of Department of Energy (DOE) Analyses

The Klemenic analyses simulate a wide range of operating conditions. These operating conditions include a range of operating rate from 500 to 5,000 tons per day, ore grades from 0.15% $U_3O_8$ to 0.25% $U_3O_8$, depth/thickness ratios from 10 to 1 to 300 to 1, and exploration expenditures from $.50 per pound to $1.30 per pound $U_3O_8$. The result is a price range from $6.58 per pound $U_3O_8$ to $13.20 per pound $U_3O_8$. The "base case" analyses result in a price range of $7.67 per pound $U_3O_8$ for the open pit mine and $9.80 per pound $U_3O_8$ for the underground mine. At 1972 cost levels, these prices would pay operating costs, amortize the investment and pay a 12% rate of return on a full investment in exploration, development, and construction of the mine and mill plants.

### 3.2 Extension of the DOE Analyses to include current U.S. and World Producers

The Department of Energy models provide a general view of uranium economics in the United States looking forward from the year 1973. Because these models are constructed with information from the extensive data bank of the Department of Energy in Grand Junction, Colorado, they have enjoyed credibility within the uranium industry.

The major changes in the uranium market and the break in cost inflation since 1973 make it necessary to reevaluate the economics of uranium production. Order of magnitude estimates of costs can be made using cost curves such as though given in the STRAAM Handbook or by using standard factoring techniques. The balance of this chapter applies such methods to current operations in the United States and abroad.

Table 2 summarizes production, reserves, and estimated additional resources from the major uranium producing countries of the western world as of the end of 1973. These figures were cited by R.D. Nininger at a nuclear industry seminar in September of 1973, (Nininger, 1973) and in a more detailed article by H.H. Adler at the uranium seminar in Grand Junction in November of 1974, (Adler, 1974).

Table 2 World Production, Reserves and Resources of Uranium, 1974
At $10/LB. $U_3O_8$ (Tons $U_3O_8$)

| | Actual Production 1973 | Resources Reasonably Assured | Resources Estimated Additional | Total |
|---|---|---|---|---|
| Australia | - | 210,000 | 48,000 | 258,000 |
| Canada | 4,800 | 241,000 | 247,000 | 488,000 |
| France | 2,000 | 47,000 | 31,000 | 78,000 |
| Niger | 1,300 | 52,000 | 26,000 | 78,000 |
| Gabon | 500 | 26,000 | 6,000 | 32,000 |
| S and SW Africa | 3,500 | 263,000 | 10,000 | 273,000 |
| Others, Non-Communist | 300 | 68,000 | 69,000 | 137,000 |
| Total Foreign | 12,400 | 907,000 | 437,000 | 1,340,000 |
| United States | 13,200 | 340,000 | 700,000 | 1,040,000 |
| Total (rounded) | 25,600 | 1,250,000 | 1,140,000 | 2,400,000 |

Source: Adler H.H. Uranium Seminar 11-74

Table 2 provides a check list of possible uranium supply sources. Because of major changes in uranium economics the reserve and resource pattern to be exploited in the 1980's is changing rapidly.

## 4. CURRENT AND POTENTIAL URANIUM PROPERTIES IN THE UNITED STATES

U.S. domestic uranium production capability and potential capability is identified by the U.S. Department of Energy (DOE) utilizing the concept of "production center". A production center is a uranium processing mill together with associated resources and mining facilities. Four classes of production centers are considered:

1. **Existing Production Centers**

   This category includes existing uranium mills, supporting mines and other resources.

2. **Committed Production Centers**

   This category includes uranium mills and supporting resources, for which construction commitments are evident and mine development has been announced or is underway. The lead time to production ranges from one to three years.

3. **Justified Production Centers**

   Uranium mills and tributary resources are postulated in areas where the amount and grade of reserves justify a production center, but where commitments for mill construction are not yet evident. Three to five years lead time is estimated for mine and mill installation.

4. **Potential Production Centers**

   Areas in which known reserves are not sufficient to support production facilities, but where exploration has indicated potential of sufficient magnitude to warrant the assumption of future production. Estimated total lead time for higher grade reserve development and mine and mill construction ranges from four to ten years.

As indicated in figure 3 the U.S. current and future potential is concentrated in Wyoming, Colorado, Utah, New Mexico and the Texas coast (Klemenic, 1975).

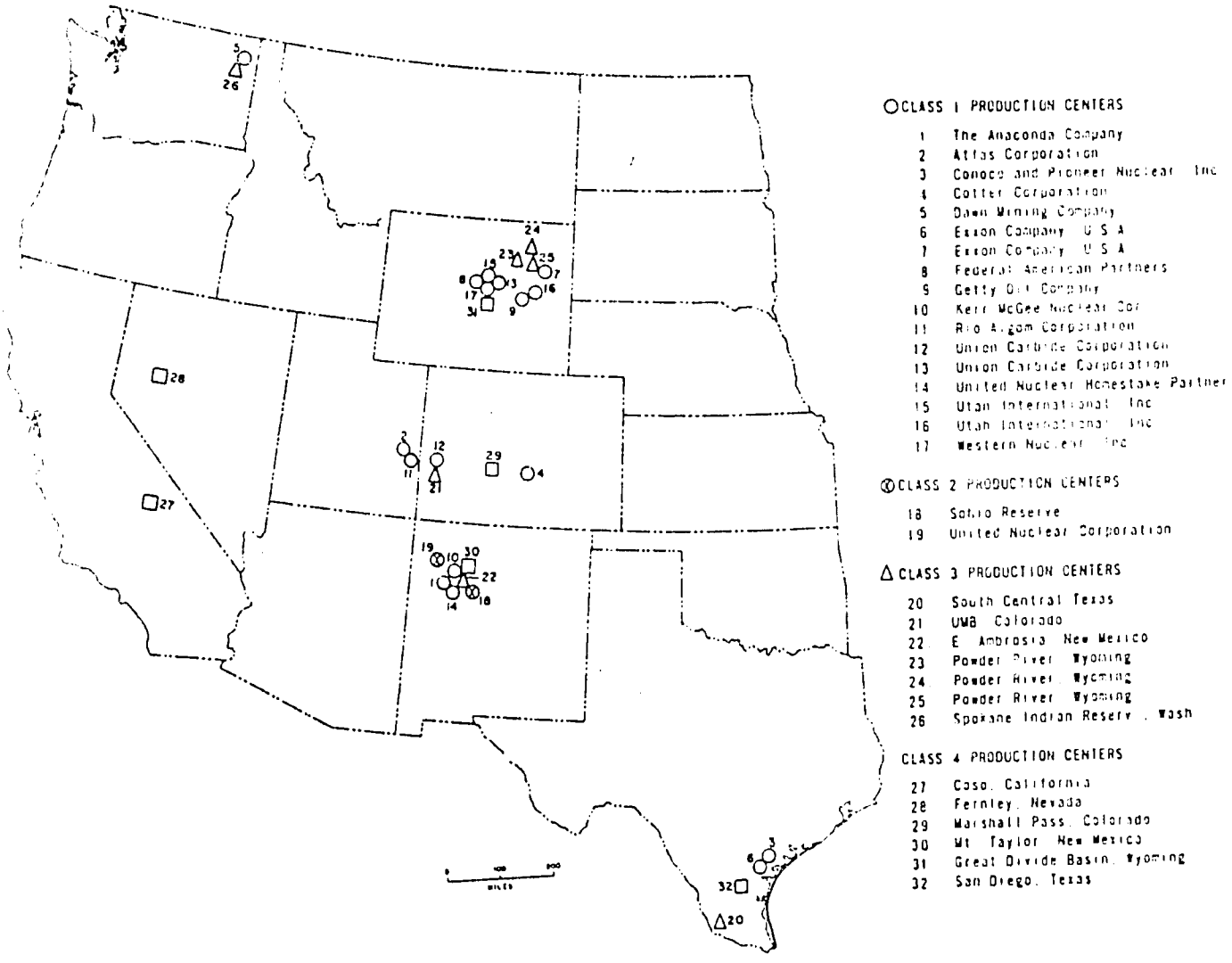



FIGURE 3 PRODUCTION CENTERS IN THE UNITED STATES

Table 3 is a list of U.S. existing and potential future uranium mills with associated $U_3O_8$ reserves. The economics of holders of major portions of the U.S. reserve are indicated by an asterisk and discussed in the text that follows.

Table 3 Major Uranium Deposits of the United States

| Company | Nominal Mill Capacity tons ore per day (1973-8) |
|---|---|
| Existing Mills | |
| Anaconda | 2500 (expansion 1975-6) |
| Atlas | 1500 |
| Conoco and Pioneer | 1750 |
| Cotter | 450 |
| Dawn Mining | 400 |
| Exxon (Highland,Wyo) | 2000-3000 |
| Federal American Ptnrs. | 950 |
| Kerr McGee (New Mex) | 7000 |
| Petrotomics | 1500 |
| Rio Algom | 500 |
| Union Carbide (Wyo) | 1000 |
| Union Carbide (Colo) | 1300 |
| United Nuclear Homestake | 3500 |
| Utah Int'l (Gas Hills) | 1200 |
| Utah Int'l (Shirley Basin) | 1200 |
| Western Nuclear (Crooks Gap) | 1200 |
| Subtotal | 28,450 |
| Committed Mills | 750 |
| Potential Future Mills (additional capacity) | |
| Kerr McGee (Powder River) | 1000 |
| United Nuclear (Churchrock) | 1000 |
| Western Nuclear (Spokane) | 750 |
| Gulf (Ambrosia) | 1500 |
| Kerdamex-Gulf (Ambrosia) | 1500 |
| Exxon (Expansion) | 3000 |
| Federal American (expansion) | 2050 |

The total estimated reserves of the properties shown in table 3 were estimated at 340,000 tons of $U_3O_8$ by the DOE based on a $10/lb forward cost. The AEC estimate for these properties at $8/lb forward cost was 276,700 tons $U_3O_8$ (Barnes, CH, USAEC, October 22, 1974).

## 5. U.S. URANIUM ECONOMICS

Table 3 and figure 3 indicated the concentration of U.S. uranium operations in Wyoming, Colorado, New Mexico and Texas. We now focus analysis on uranium operations exploiting low-grade uranium by open pit methods in Wyoming. After review of several existing operations an analysis is made of a representative situation.

### 5.1 Exxon Corporation, Highland Deposit, Wyoming

The Highland deposit is a "typical" western sandstone uranium rollfront deposit. Exxon began mining operations at the Highland Mine in 1972 with a design milling capacity of 2,000 tons per day. The mill has been operated as high as 3,000 to 3,500 tons per day but in 1979 they were running the plant at 2,000 tons per day. In the future, capacity might reach 6,500 to 7,000 tons per day on a one-shift five-day week for production of ore and three-shift, seven-day operation for the mill. The original Highland mine and mill investment was approximately $70 million 1972 dollars spread over the 1971-72 period.

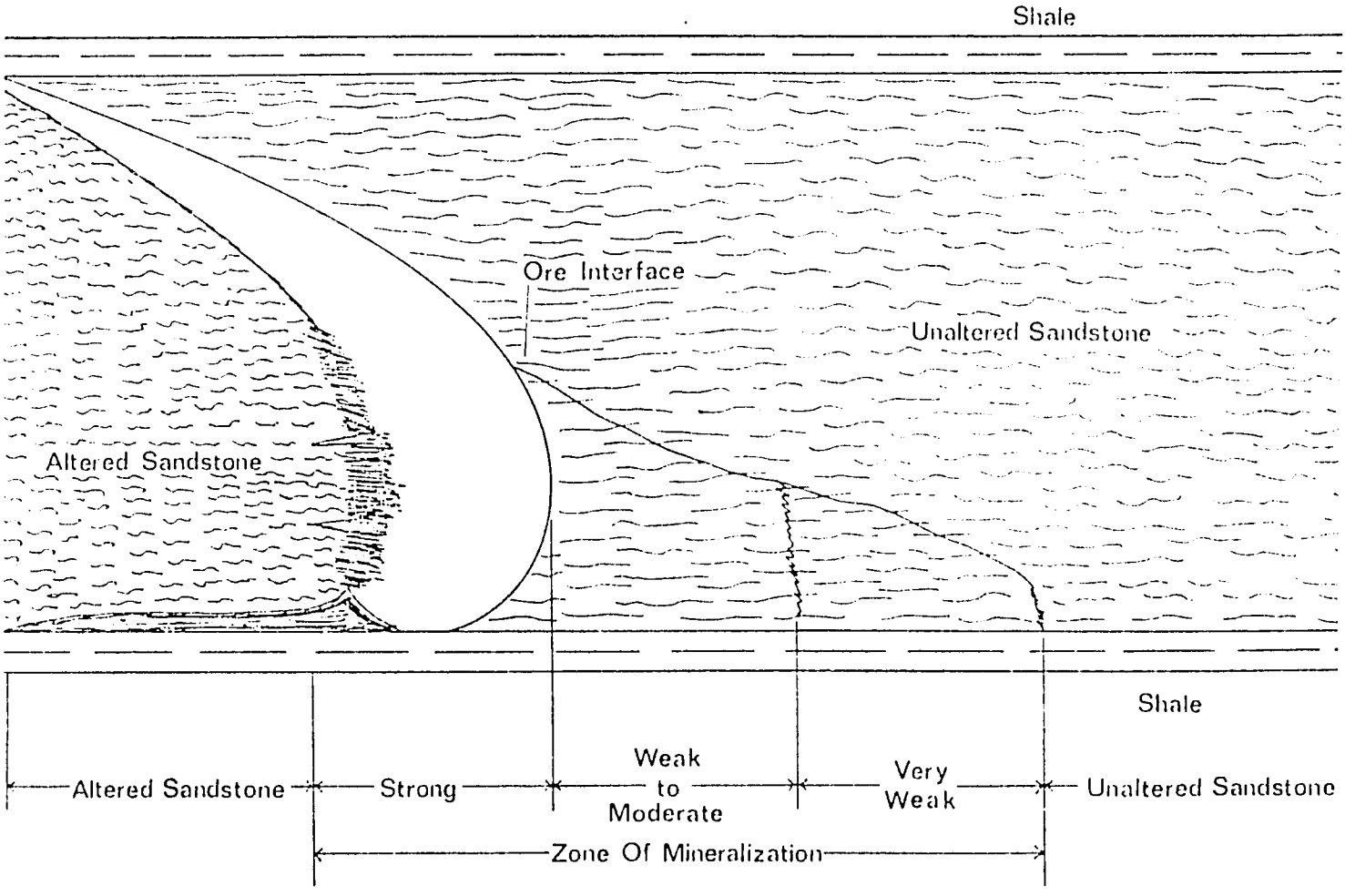



FIGURE 4 CROSS-SECTION OF A ROLLFRONT DEPOSIT

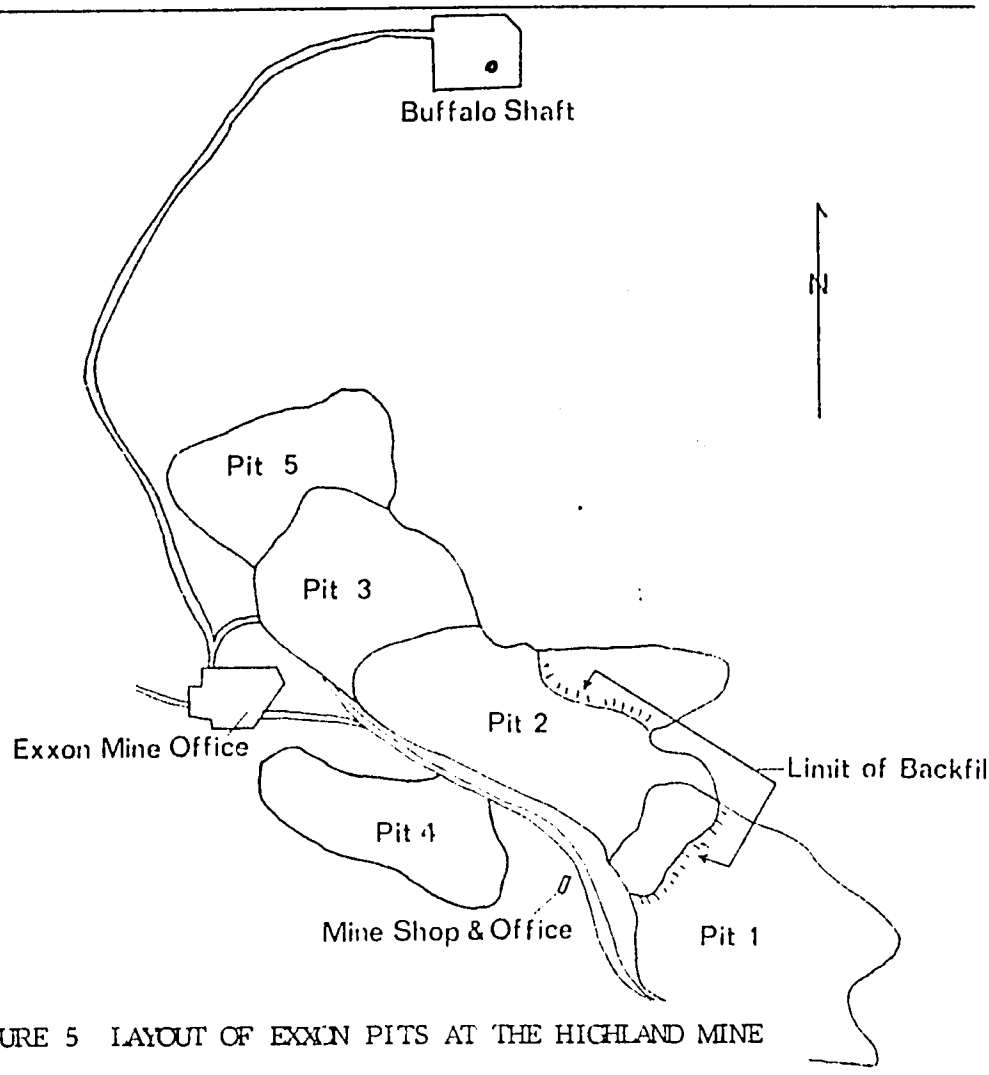



FIGURE 5 LAYOUT OF EXXON PITS AT THE HIGHLAND MINE

In 1979, Exxon classified material as follows:

Waste: less than 0.02% $U_3O_8$

Resource: 0.02% to 0.035% $U_3O_8$

Protore: 0.035% to 0.45% $U_3O_8$

Ore classification 1: 0.045% to 0.07% $U_3O_8$

Ore classification 2: 0.07% to 0.30% $U_3O_8$

Ore classification 3: Ore above 0.30% $U_3O_8$

With prices above $43 per pound $U_3O_8$, all material detected as radioactive with gieger counters in the pit is sent to the mill or to a stockpile. This material is of the order of 0.01% $U_3O_8$ or 0.2 pounds $U_3O_8$ per ton, indicating the economic cutoff is between $8 and $16 per ton considering incremental costs only.

The stripping in this pit is done with three 15-cubic yard shovels loading in to 100-ton trucks. By mid-1979 they had removed 100 million cubic yards of primary waste and 33 cubic yards of secondary waste to recover 9 million tons of ore indicating an overall waste/ore ratio of almost 15:1.

As indicated in figure 5 the mining occurs in a sequence of pits following the orebody to the northwest. Ore occurs in a red sandstone underlying grayish-green shale material which is the primary waste. When pits are completed they are drilled to assure that there is no ore below the final mining zone. Then, it is possible to backfill the pits without danger of covering a future economic reserve. Reclamation costs average $1000 per acre for moving and replacing top soil while the backfilling of the pits is included in stripping costs. The pits begin at a surface level of 5300 feet and in 1979 went to a depth of 350 feet to the 4950-foot level. The deepest the surface mining is expected to go is 500 feet. Below that level, underground mining operations are more economic.

The Buffalo shaft to the north is access to the underground mine where the cutoff grade is 0.08% $U_3O_8$. Methods are expensive using room and pillar and square set techniques. In 1979 underground costs for a mine operating at 650 tons per day are above market price. The cutoff grade of 1.6 pounds of $U_3O_8$ at the current market price of $40 implies incremental costs of $50 to $60 per ton. If capacity is increased to 1500 to 2000 tons per day it might be an economic operation.

Underground mining problems include large amounts of water in soft rock requiring pumping in order to dry out the sandstones before production begins. The underground mine was pumped for 1.5 years using four holes to dry out out the central mine area.

Exxon also has a solution mining experiment which is complete and will be checked out by open pit mining to check uranium recoveries. The solution mining requires 4 to 5 wells in a circle around the center well on a 100-foot diameter circle.

Secondary stripping in the pit is done on a contract basis because economics do not dictate equipment purchase. Inflation has increased stripping costs from $0.65 per cubic yard to $0.85 per cubic yard or 14.4% annually over the last two years.

Total employment at this operation in the underground and the open pit mine, mill and administration is 600. Approximately 200 work in the open pit mine and on surface, 200 work in the underground mine, 100 in the mill with 100 administrative employees. The orebody will be depleted by 1986.

### 5.2 Federal-American Partners

Federal Resources Corporation is a Nevada corporation with interest in exploration, development and exploitation of mining properties containing uranium, coal, and base and precious metals. The corporation is the managing partner and 60% owner of a Wyoming partnership known as Federal-American Partners. They operate under a long-term uranium lease and supply contract with the Tennessee Valley Authority.

The operation includes a large number of properties, some held by the Federal-American Partnership and others by Federal or American Nuclear. TVA is the supplier of capital and the guaranteed market for the product. The area involves over 1700 claim owners with consequent problems of control.

There are problems in controlling ore grade here because of disequilibrium in the ore which causes a difference between the estimated ore grade using the gieger counter or beta readings and the actual content of uranium. The only way to overcome the problem is to perform wet assays or x-ray assays and compare these with the gamma readings. For field work a map indicates the ratio between gamma readings and the actual $U_3O_8$ content of the ore.

The ore occurs in pods and ranges in grade as follows:

To stockpile for possible future heap leaching

Pod ore C 0.010% $U_3O_8$ to 0.015 $U_3O_8$

Pod ore B 0.015% $U_3O_8$ to 0.029% $U_3O_8$

Ore grades

Pod Ore A 0.03% $U_3O_8$ to 0.04% $U_3O_8$

Low grade ore...0.04% $U_3O_8$ to 0.095% $U_3O_8$

Number 1 grade ore...0.095% $U_3O_8$ to 0.175% $U_3O_8$

High grade ore...anything over 0.175% $U_3O_8$

Classification of ore grade indicates a cut-off of 0.03% $U_3O_8$. This amounts to 0.6 pounds of uranium oxide per ton and at $43.00 per pound indicates a breakeven incremental cost of $25.80 per ton.

Stripping is done with 15 cubic-yard shovels and in 1979 they were assembling a 25 cubic-yard shovel to be used in future stripping operations.

In the Sagebrush pit they produce 1000 tons of ore plus 500 tons of low grade ore for stockpiles plus 10,000 to 20,000 cubic yards of waste daily. At full capacity the pit would utilize the following equipment:

1 backhoe
4 35-ton trucks
2 dozers
1 water truck
1 roadgrader
4 to 5 number 633 scrapers
1 lubrication truck
1 field maintenance truck

The work crew includes a pit foreman, 2 or 3 ore control people and a survey crew plus the equipment operators. A contractor does the pre-mine stripping while the number 633 scrapers are used to remove top soil and number 657 scrapers remove waste in the pit. All of the ore is handled by the backhoes because of their ability for selective mining of the rollfront. The pits are backfilled in a manner similar to that at Exxon. Eventually they will open 4 pits and the last one will be filled with tailings to completely restore the surface of the mining area.

Cut-off grade at the Sagebrush pit is 0.035% $U_3O_8$ and they send 0.08 to 0.11% $U_3O_8$ average grade to the mill. The cut-off of 0.035% $U_3O_8$ indicates .7 pounds of uranium per ton or equal to $28 breakeven cost not including any stripping. When the uranium content is approximately one pound per ton or $43.00 worth of final product, total costs are covered.

The ore in the Sagebrush pit is from 1 to 20 feet in thickness with an average of approximately 10 feet. The controls on ore deposition are the rollfront faults and shale beds. A fault may bring solutions up against impervious material and cause it to concentrate at a specific location.

Dilution in the pit is figured as one foot above and one foot below the ore pods and is therefore difficult to average because of the wide range of thickness.

Time losses in the pit are due to rain and mud in the summer and snow and cold during the winter. In the winter of 1978 frost got ahead of the mining operations and caused considerable trouble in handling frozen materials.

At the Cap pit, stripping is done with 120-ton trucks (unit rig using diesel electric engines). Shovels are 15 cubic-yard Marion's. Estimated costs for stripping are $0.60 per cubic yard working two shifts over five days at nine hours per shift. They average 425,000 cubic yards per month over 21.5 days. A new P & H shovel with a 24 cubic-yard bucket costing $2.4 million will be used for stripping in conjunction with 120-ton trucks which cost about $220,000 each.

### 5.2.1 Federal Resources Mill

The Federal-American Partners mill began operating in October, 1959 with an initial rated capacity of 520 tons per day. Subsequent expansions and process modifications through 1979 resulted in an operating rate of 1000 tons per day of ore per day producing 1600 pounds of $U_3O_8$ from a feed averaging 0.09% $U_3O_8$. Mill feed in 1971 averaged 0.15% $U_3O_8$. This had been revised to 0.09% $U_3O_8$ at mid-1979. Reported uranium recovery was 94.5% in 1971 declining to 90% in 1979 (Merritt, 1971).

There is a relationship between ore grade and metallurgical recovery which is controlled by the fact that it takes a finite period of time of retention in the reactors in order to recover the uranium. They are unable to hold low-grade ore in the reactors for a long enough time to maintain production and at the same time hold up metallurgical recoveries. The ore is held for 12 hours and the reactors at the operating rate of 1000 tons per day.

The ore is crushed, sampled and fed to ball mills for grinding in closed circuit with classifiers. Sulfuric acid is used to leach the uranium from the ore and then transferred to a resin in a countercurrent process. Sulfuric acid moves in one direction and the resin in the other direction. Uranium ions are collected on the resin.

Loaded resin containing 2 to 3 pounds of $U_3O_8$ per cubic foot is washed and transferred to the elution circuit where more concentrated sulfuric acid extracts the uranium from the resin. Periodically it is necessary to use a caustic wash to clean molybdenum from the resin. The molybdenum takes up active location and excludes collection of uranium.

### 5.2.2 Environmental Problems

There are a number of environmental problems in this and other uranium operations which are often misunderstood by the general public. One of the problems is the radionuclide concentrations in the operation. Polonium-210 can concentrate in the lungs but it has been found that it concentrates on particulates of cigarette smoke when employees smoke in the presence of the nuclide. There is, therefore, a correlation between miners or mill operators who smoke and cancer. Other problems relate to the necessity of clean up by men who load druns with $U_3O_8$. The $U_3O_8$ is not a danger because of its radioactivity but it has a very long life and concentrates in the liver if ingested due to improper clean up by men loading the drums with the final product. Regulation gets into problems of regulating personal habits of men and forcing them to clean up to some standard after finishing work. It is, therefore, a most difficult set of problems to solve.

There are environmental problems in dealing with the tailings to meet objectives for no liquid in the tailings to seep underground into water supply. One new plan is to seal tailings in the old pits with a system that does not permit seepage but keeps tailings moist and restricts radon escape. If tailings are allowed to dry there are large emissions of radon gas. The new proposal would load tailings into the old pit after lining the pit and finally covering it with 10 feet of overburden to seal in all emissions. Dewatering of tailings can be extremely expensive, especially if the tailings contain a lot of slimes. In addition to design of special tailings ponds environmental requirements involve monitoring of wells and continuous sampling and drilling over a 100-year period to make sure there is no pollution as a result of the tailings disposal.

The development of at least one property has been postponed because of environmental costs. An estimated $61 million was added to development costs due to environmental regulations, mainly due to the rehandling of materials. The Pach property was expected to supply 1500 tons of ore per day in connection with a mill expansion by Federal-American. The postponment of the development of the property cut expected ore supply by 50% for the new 3000-ton per day operation.

Reclamation of drill holes in the area requires sealing of aquifers, putting cement plugs in the hole, replacing top soil, and restoring land to original contour and reseeding. Most of the regulations are a result of the Environmental Quality Act of 1973 and regulations from the Department of Environmental Quality.

Some areas are not explored at all because the disturbance would create environmental problems. For example, areas designated as eligible for registry as archeological sites are generally avoided.

Another problem involves the permitting process. It is very often better to modify an existing installation than to try to go through the permitting process for a new one. The company is also required to make socio-economic surveys over an 80-kilometer radius within the region of the mine. This includes monitoring of animals, vegetation, water supplies, rainfall, food production and the development of new population centers.

There are additional problems due to the Mine Safety (MSHA) program which requires safety training of 20 hours before a miner can start work. If a miner quits and a new replacement is not found after the current weekly training program is underway, it is possible to lose two weeks instead of two days in replacing the man. The ratio is replacement in about $2^1/_2$ days to replacement in about 11 days.

### 5.2.3 Employment

The mine employs about 400 people and the mill about 55 people, including analysis, and maintenance. The balance of 45 people is support and administrative activities for a total of 500 people. Turnover at the operation is rated high, perhaps 60%.

### 5.2.4 The Future and Expansion

Looking to the future, Federal-American will develop some 11 pits in the area in the future, requiring moving 10 million cubic yards of overburden from each pit. They estimate stripping in terms of bank yards per contained pound. This ratio is from 17 to 20 bank yards per contained pound of $U_3O_8$.

The mill expansion will be from 950 tons per day to 3000 tons per day while holding labor relatively constant. The main changes will be to semi-autogenous grinding but with the same hydrometallurgy as before. The expansion cost is estimated at $35 million which includes escalation through the planned December, 1981 start-up. It is likely that start-up will be moved to May, 1981 as a result of delays.

## 5.3 Utah International

Utah International Inc. (Utah) is principally engaged in mining and ocean shipping. In 1972, 93% of Utah's gross profit came from mining operations and 7% from oil and gas. The largest mining revenues are derived from investments in coking and steam coal with smaller amounts from iron ore and uranium. Prior to 1971 the company was known as the Utah Construction and Mining Company and in 1976 the corporation merged with General Electric. At that time the uranium assets held by Utah International were transferred to the Lucky Mc Uranium Corporation, a wholly owned uranium subsidiary of Utah. Utah and General Electric retained beneficial ownership of Lucky Mc Uranium Corporation which changed its name to Pathfinder Mines Corporation effective 1978.

The original discovery of the Lucky Mc is attributable to a weekend prospector working with partners. The prospectors formed a small mining corporation called Lucky Mc which produced and sold ore to the Atomic Energy Commission Buying Station in Riverton, Wyoming.

In 1955, negotiations led to an option agreement whereby Utah agreed to conduct a long-range exploration and geological program in return for a 60% interest in the Lucky Mc Uranium Corporation. Before the end of 1955 it became apparent that the extent of mineralization on the Lucky Mc claims exceeded original expectation and Utah negotiated for a long-term sales contract with the Atomic Energy Commission. This was secured and assured development of the mine and facilities.

Production began from the Lucky Mc mill in 1958. Two years later, Utah acquired the remaining 40% of Lucky Mc Uranium Corporation. During 1960 Utah extended its uranium mining operations to the Shirley Basin Mine, a deposit originally worked by underground methods but today operated as an open pit mine. Utah constructed a modern uranium mill and facilities adjacent to the Shirley Basin Mine.

In 1977 Pathfinder Mines Corporation began development on a third mine, the "Big Eagle" open pit mine near Jeffrey City, Wyoming. Current production capacity at the

two mills is approximately 4.2 million pounds of uranium oxide in concentrate per year. This makes Pathfinder Mines Corporation the largest producer in Wyoming. The company has committed significant amounts of future production on long-term sales agreement and some product is available for "spot" sales.

Plans of the Shirley Basin and Lucky Mc mining operations are shown in figure 6.

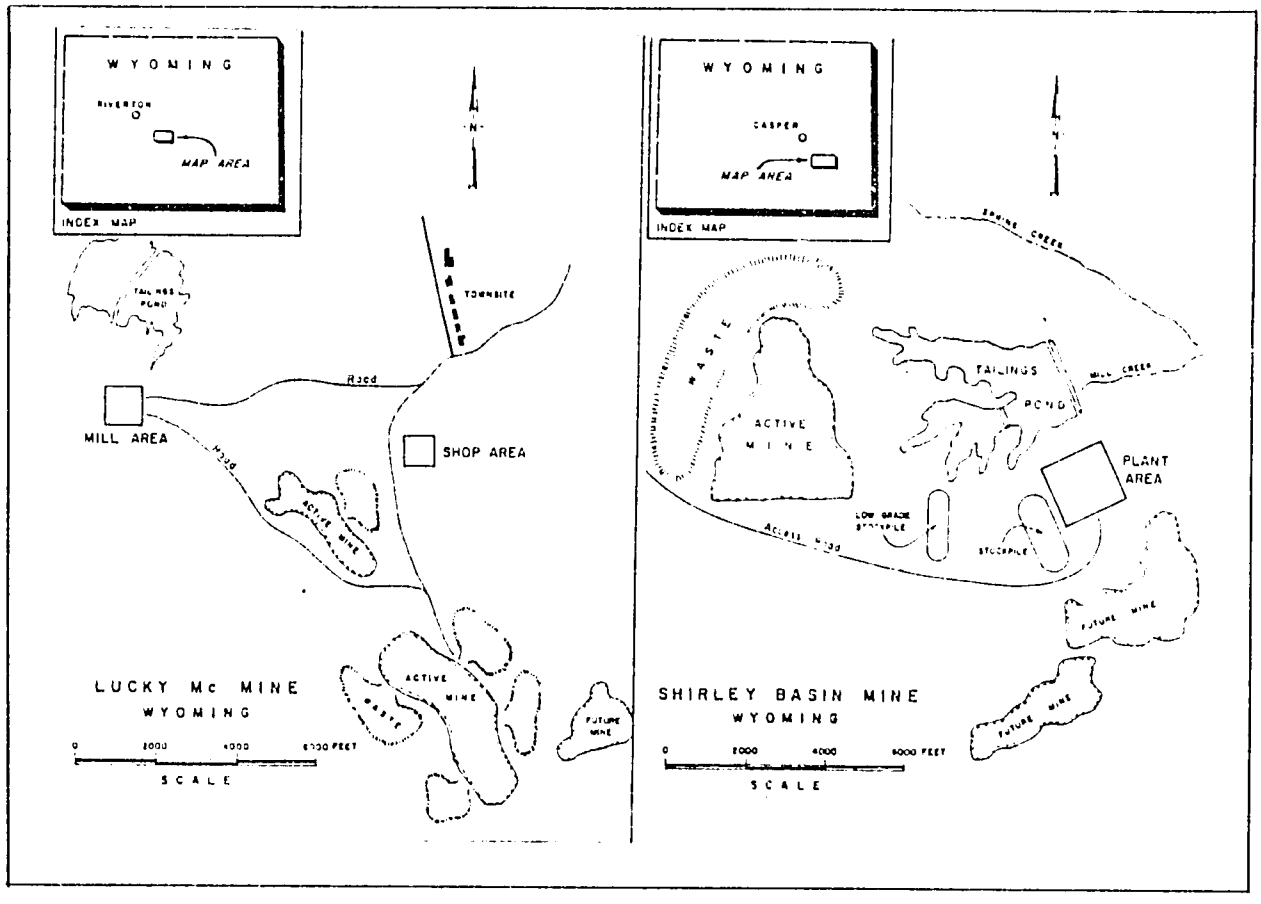



FIGURE 6 LOCATION AND MINE PLANS OF UTAH INTERNATIONAL PROPERTIES IN WYOMING

The Utah International 10-K report to the Securities and Exchange Commission generally gives detailed information on production, ore grade and operating costs.

Between 1970 and 1974 the average ore grade at the Gas Hills properties was 0.26% $U_3O_8$ and the average ore grade at the Shirley Basin properties was 0.156% $U_3O_8$. The Gas Hills mill recovered an average of 2.2 million pounds annually from these ores and the Shirley Basin mill recovered an average of 3.3 million pounds of $U_3O_8$ annually. The average operating cost for both operations over the 1970-74 period rose from $3.07 per pound in 1970 to $5.36 per pound $U_3O_8$ in 1974. Average production costs rose from $3.35 per pound in 1970 to $6.84 per pound in 1974. The average price received for the combined production rose from $5.72 in 1972 to $7.62 in 1974. Operating costs include on-site mine and mill costs only, not depreciation, depletion or amortization of mine and facilities. Average production cost includes on-site mine and mill costs, including depreciation, depletion and amortization of mine and facilities. Depreciation, depletion and amortization rose from $0.28 in 1970 to $1.48 per pound $U_3O_8$ in 1974.

In mid-1979, the Lucky Mc Mine was operating at 1500-tons per day and was expanding to 3000-tons per day. The average mill grade was 0.12% $U_3O_8$ from 7 pits. Material above 0.06% $U_3O_8$ is called ore and material between 0.03 and 0.06% $U_3O_8$ is stockpiled and called sub-grade. The cut-off grade for ore of 0.06% implies 1.2 pounds of contained $U_3O_8$ per ton. This is a decision based on a price of $25.00 per pound rather than the spot price for uranium because spot prices are not realized on the ore because of previous long term contracts. Indicated breakeven cost is of the order of $25.00 per ton of ore, presumably excluding some sunk costs such as stripping.

Stripping is done in these pits with scrapers, front-end loaders, power shovels and 100 and 120-ton trucks. In some areas it is necessary to blast overburden and it is in these areas that front-end loaders, shovels and trucks are used for stripping. It is necessary to move 60,000 to 80,000 cubic yards of waste material per day to expose the surface of ore at the current mining rate. In 1978 they moved 21 million cubic yards of material in order to maintain production.

Sequencing of stripping and mining is very important in order to have the correct mix of pits and pods available to maintain a uniform mill grade. Pit slopes are maintained at 1.5 to 1 leaving 20-foot benches periodically. Waste immediately adjacent to the ore is removed with small scrapers and the ore itself is usually mined with backhoes with 2.5 cubic yard buckets in order to maintain very precise control at this stage of operations. In some cases a bucket load of material is checker with the gieger counter to determine whether it goes to a stockpile or to the mill. Ore zones are continuously flagged using the gieger counter.

The maximum depth for open pit mining under today's economics is 500 feet. In one area an underground tunnel goes from the pit wall into the ore a total of 3000 feet. The grade in the underground operation is similar to the open pit but the ore zone was too narrow and would not have been able to support a stripping ratio of approximately 40:1. It takes 7 to 8 months to strip a pit of 100 to 300 feet of overburden.

Employment at this operation is 470 to 490 hourly at the mine, mill and maintenance plus 50 to 60 on salary. This crew could produce about 2500 tons of ore per day indicating a rather low productivity of about 5.2 tons per man shift. This is obviously a function of the very high stripping ratios and the very selective mining of the ore itself. When the mill is expanded using autogenous grinding, the expansion will require very few additional personnel.

Prior to mining in each pit at least two core holes are drilled prior to development in an attempt to detect areas of disequilibrium in the ore. Ore comes from the mine to a probe tower for checking and is then deposited in high, low and sub-grade stockpiles at the mining area. This ore is then reloaded and used to blend 6 piles at the mill pad. At that point the metallurgists take over and run assays on the mill pad stockpiles.

The x-ray probe house takes assays and radios the assay information to the stockpile area so that the material will be properly classified. There is some disequilibrium and therefore problems of gamma and beta analyses. An example is a sample x-ray giving a grade of 0.02% whereas a gamma grade of 0.12% $U_3O_8$ had been indicated by radiometric assays. This disequilibrium is particularly severe in the brown oxidized ore. It is reasonable to think in terms of the density of ore pods within the formation as a measure of value of the material being mined. The best ore in terms of high grade is on the rollfront but the limbs of the rollfront are where most of the pounds of uranium (ore reserves) are located.

## 5.4 Bear Creek Uranium Company

On September 22, 1977, Bear Creek Uranium Company formally started operations in Converse County, Wyoming. Bear Creek Uranium is jointly owned by Rocky Mountain Energy Company (Union Pacific Railroad) and Mono Power Company (Southern California Edison Company).

Mono Power Company is a subsidiary of Southern California Edison. They combined with Rocky Mountain Energy in this joint venture which was put together prior to the energy crisis about 1970. Mono splits costs 50/50 with Rocky Mountain Energy and Rocky Mountain Energy also collects a management fee. Mono gets one-half of the product from production and Rocky Mountain Energy sells the balance on contract.

The original rate of operation was 1000 tons per day through the mill but the operation has since been expanded to 2000 tons per day. The investment in this project is approximately $40 million made over the 1975-1977 period. Southern California Edison floated a bond issue in 1977 to finance the project.

This is another open pit mine with pits typically involving 140 feet of stripping down to the top of the ore zone, then another 60 feet in the ore zone to a total depth of 200 feet. The stripping ratio is 24 bank cubic yards per ton of ore or 16 cubic yards per pound of contained uranium at the current average grade of 0.08% $U_3O_8$. Pre-mine stripping is measured in bank cubic yards and in addition, there is removal of "internal waste" of 5 tons of waste per ton of ore removed. This brings the total stripping to 45 tons of waste removed for every ton of ore. The classification of "internal waste" is at a contact between the pre-mine stripping and the material called ore which usually begins 2 to 5 feet above the ore zone. This varies with the pit and is determined within the pit by gamma probes following the stripping.

The average grade over the 1978-79 period was 0.08% $U_3O_8$ with a range from 0.06% to 0.09% $U_3O_8$. Present cutoff grade is 0.02% $U_3O_8$. A grade of 0.02% is 0.4 pounds of $U_3O_8$ per ton indicating a breakeven cost of $16.00 per ton at a $40.00 per pound price. This would not include sunk cost in pre-mine stripping. Assuming 40 bank yards per ton of ore at $0.60 per bank yard would add $24.00 to this estimate bringing it to a total cost of $40.00. This would be a breakeven cost including pre-mine stripping. Stripping in the pits is done with large power shovels using 17 cubic yard buckets and 120-ton trucks. This equipment works 35-foot benches where light blasting is done because it was found to increase shovel production by 30%.

Exploration drilling in these areas is done on 50 x 100 foot grids. Drill holes are concentrated at the perimeter of the ore body, sometimes as close as 25 foot spacing. After the mining is complete, several condemnation holes are drilled in the bottom to assure that there is no ore below the pit before it is backfilled.

The mill flow sheet indicates semi-autogenous grinding to 20-mesh, then leaching in 6 tanks with agitation for 8 hours. The solutions go to countercurrent decantation. At this step, the tailings solids are separated from the solutions and washed. The pregnant solution goes to clarification, filtration and then to solvent extraction.

In solvent extraction, the solution is mixed with kerosene, then the kerosene rises to the top and is taken off and mixed with another batch of the acid leach solution. The solution coming from the acid leach contains one-half gram per liter uranium oxide. In

solvent extraction the uranium oxide ions are transferred from the sulfate complex to the kerosene.

In the stripping phase, the kerosene is mixed with ammonium sulphate solution and the uranium is transferred to the ammonium sulphate. The concentration of uranium at this point is 25 grams per liter of ammonium sulphate. Ammonia gas is added to the ammonium sulphate to bring the pH to 7.4 causing the uranium to precipitate as ammonium diuranate which is yellowcake. In the drying phase the ammonia is driven off leaving the yellowcake.

They backfill the open pits but will end up with three lakes in the portions of pits which are not backfilled. There is a high probability that they will have to dispose of tailings in one of the old pits which could add $4.00 to $20.00 per ton of ore; a good guess might be $15.00 per ton. Presently estimated reclamation costs are $4000 per acre which does not include backfilling the pits which is included in the regular operating costs.

In addition to the land reclamation, these miners have to worry about radium in the mine water that could end up back in local streams. The limit is 3 picocuries per liter of water and in order to meet this environmental standard they have to hold the water in ponds and introduce barium chloride which combines and captures the radium. There is no problem with mill water because it is 100% recycled but they must monitor all water disposal to make sure it is below standards.

They have had some problems with local water wells. A well close to the pit lost its flow and it was determined that it might have been done to the open pit. The company redrilled the well at a cost of $8000 to a new aquifer and purchased a new pumping windmill. All drill holes that pass through aquifers are cemented to prevent criticism by local ranchers who might claim that water supplies were lost.

Spoil piles are graded to a 3 to 1 slope and the newest ones to a 5 to 1 slope recommended by the Wyoming office of the Department of Environmental Quality. All future spoil piles will be on the 5 to 1 slope which makes it possible to grow grass without outside watering or signs of erosion.

The employment on this project is 290 including 187 in the mine, 64 in the mill and 33 in administrative and other activities. This indicates 6.9 tons per man shift overall, a low figure reflecting the very high stripping ratios involved. Turnover is about 40% and sometimes goes as high as 120%. Turnover is lower in some areas such as the Gas Hills because people are established in the area, live in Riverton and like it. The mill is highly automated and could run for short periods of times with as few as three people present.

## 6. WYOMING OPEN PIT ECONOMICS

Utilizing existing technical and economic data on Wyoming mines, two groups of CSM mineral economists estimated capital and operating costs of a project similar to those described in the preceding sections.*

*Mining Group: Mir Heydari, Carl McSpadden, Roger Ballen, Don Ratcliff

Metallurgical Group: Al Kuestermeyer, Victor Virreira

## 6.1 Mining

### 6.1.1 General Description

The proposed Surface Uranium Mine is located approximately 60 miles west of Casper, Wyoming along the road going to Riverton. Mine site accounts for a total area of 4 square miles where about 150 million cubic yards of overburden material (primary and secondary) are underlaid by approximately 10 million tons of ore containing an average of 0.08% $U_3O_8$ or 1.6 lbs of $U_3O_8$ per ton. The overburden ranges from 200 to 300 feet in thickness.

### 6.1.2 Production Schedule

The production of ore tonnage is based on the requirement of 3000 tons per day of mill feed. To meet the above requirement, considering 90% mine recovery and 300 actual working days per year, an average annual ore production of 1 million tons is considered. The overall stripping ratio being 15 (cu. yd.) to 1 (ton), an average of 15 million cubic yards of overburden material has to be removed annually.

The shovels used for overburden removal produce an average of 50,000 cubic yards of overburden per day and the ore production backhoes produce 3300 tons of ore per day. It is considered that about 10% of ore does not met the requirements of cut-off grade and has to be sent to waste dump. Therefore, 3000 tons of material is sent daily to the mill.

With an annual ore production of 1 million tons, the life of the discussed mine site is considered to be 10 years.

Although the initial overburden removal is done by contractor, for the purpose of this study, it is assumed that overburden removal is achieved continuously at a rate of 50,000 cubic yards per year. At the beginning the stripping ratio is much higher than the 15:1 overall stripping ratio.

### 6.1.3 Description of Mining Plan - General

Uranium ore will be produced by a surface mining method with overburden material loaded by Bucyrus-Erie. BE-290B, 20 cubic-yard shovel into 120-ton Rimpull trucks for removal and disposal into previously mined area. This is a haul-back method of strip mining. It eliminates the need for large waste dump areas and speeds the mining operations. The exposed uranium ore will then be loaded by $3\frac{1}{2}$cubic yard backhoes into 36- ton trucks and hauled to coarse ore storage bins at the milling site.

The mine consists of 1000 feet long pits in which mining occurs on one side while backfilling occurs on the other side. Working benches are 30 feet high and 100 feet wide. The $3\frac{1}{2}$cubic-yard backhoes are constantly working in uranium ore while the 20 cubic-yard shovels are handling the overburden removal. Loaded trucks pass through the upper benches to reach the surface and the waste disposal area. Grade of the ramps connecting successive benches is limited to a maximum of 8%.

Depending upon the equipment availability, rock hardness and the mine

superintendent's decision, other mining methods are used simultaneously for the overburden and ore removal. For example, one alternative mining method consists of removing materials with rippers and scrapers.

It is assumed that drilling and blasting will be limited by the softness of the rock and the need for selective mining. Therefore, it is assumed that only one-fifth of the overburden, or 10,000 cubic yards per day, is drilled and blasted.

### 6.1.4 Overburden

After the top soil has been removed, all remaining unconsolidated material is loaded by 20 cubic-yard B.E. shovels into 120-ton trucks to be removed from the pit. For the secondary consolidated materials (about 10,000 cubic yards per day), blast holes are drilled by an Ingersoll-Rand T-4 Drillmaster, 6 inches in diameter on a 16 x 32 foot pattern.

The holes are then charged with an ammonium nitrate-fuel oil mixture. The amount of explosives used is calculated to be 280 lb/hole based on a powder factor of 0.28 lb/ton which is generally used for the type of material in the area.

Initially, a primer is placed at the bottom of the hole and suspended on a single line of reinforced 50 grain primacord. The connection between the holes is provided by 25 grain primacord. The ammonium nitrate and fuel oil mixture is then poured into the hole to a column height of 23 feet by a mix-and-load tank truck.

### 6.1.5 Uranium Ore Removal

When the ore has been uncovered and cleared, CAT backhoes excavate selectively the ore and load it into 36 ton International Trucks for haulage to the crusher facilities. Ore is checked prior to loading with the Geiger counter.

### 6.1.6 Uranium Ore Storage

The ore storage area has a capacity of ten days mine production and is located away from the ultimate limit of the pit.

### 6.1.7 Surface Water Drainage

To assure the quality of natural surface water drainage, water control facilities are constructed at specified areas to intercept all run off water originating within area affected by mining operations. The control facility is designed in such a way to retain water for a period of time to achieve outlet quality standard. Any pit water accumulated is pumped into drainage ditches.

### 6.1.8 Support and Storage Facilities

The support facilities to maintain a safe and efficient mining operation include: stockpile area, space for administration, laboratories, equipment maintenance, general shop, fire installation, charge room and warehousing.

### 6.1.9 Haul Roads

Haul roads are constructed and extended as mining progresses. The width is 65 feet with a usable surface of 50 feet. Construction consists of 12 to 15 in. of rock base topped by 4 to 6 in. of gravel cover. The haul roads are watered to prevent excessive dust for personnel comfort, operational efficiency and maintain air quality standards.

### 6.1.10 Fuel Storage

Diesel oil for fueling mobile equipment and for mixing with dry ammonium nitrate prills is delivered by tank trucks and unloaded into one 50,000 gallon above-the-ground storage tank at the mine facilities.

### 6.1.11 Explosive Storage

Ammonium nitrate prills are stored in a 75-ton, drive-under silo adjacent to the shop warehouse. A magazine at the same location is used for class A explosives. Blasting caps are stored separately.

### 6.1.12 Mining Equipment Ownership and Operating Costs

Following is a list of required mining equipment for the operation.

Table 4 Ownership and Operating Costs for Mining Equipment

Production Data
Overburden/yr: 15,000,000 cu.yd./yr. including 3,000,000 which is drilled and blasted
Ore/yr.: 1,000,000 Tons

Shovel for Overburden
A 20-cu.yd. shovel is handling roughly 6,000,000 cu.yds. of material per year (in the current case assumption therefore 3 shovels (BE 290B, 20 cu.yd. including the spare) are needed. $350,000/yr/unit

Drilling
2 T-4 Ingersoll-Rand Drillmasters
Total Operating Cost per Unit: $130,000/yr.
Total Ownership Cost per Unit: $ 40,000/yr.

Total Blasting Cost/yr.
(AN/FO, primer, etc.) $570,000/yr.

Trucks for Overburden (120T)
12 + 3 spares = 15 trucks (120T) are needed
$320,000/yr/unit

Backhoe for Ore Removal (3 1/2 Cu.Yd.)
3 backhoes: $130,000/yr/unit

Mining Facilities

| | |
|---|---|
| Mine Office | $300,000 |
| Truck/Mobile Equipment Shop | 300,000 |
| Shop Equipment | 100,000 |
| Welding & Shovel Bucket Shop | 100,000 |
| Lube-Wash Building Equipment | 100,000 |
| Mine Warehouse | 100,000 |
| Utilities, Surfacing, Parking, etc. | 50,000 |
| Fuel & Explosive Storage | 50,000 |
| | $1,100,000 |

Water Truck
2 necessary: $150,000/yr/unit

Scraper
5 units: $250,000/yr/unit

Dozer-Ripper D-9
4 units: $180,000/yr/unit

CAT No. 16 Grader
2 units: $120,000/yr/unit

Bulk Explosive Truck
2 units: $30,000/yr/unit

Fuel and Lube Truck
$35,000/yr/unit

Tire Service Truck
$30,000/yr

Miscellaneous Service Vehicle
$25,000/yr

Trucks for Ore Removal )36T)
4 Trucks + 2 extras = 6 Trucks
$125,000/yr/unit

The preceding estimate covers the entire ten year period of the project and includes both operating and ownership costs. On an annual basis the estimate is $110,000 with an equal amount allocated for maintenance and supplies. The total is $220,000 per year.

Equipment Shop Operations
Includes maintenance supervision, shop maintenance and overhead, warehousing costs, etc.
Estimated $500,000/yr.

Mine Services and Facilities

Includes supervision, engineering and geology, development drilling, dewatering and drainage, auxiliary vehicle operation, etc.

Estimated $350,000/yr

Mine General and Administrative Costs

Include project management, accounting and clerical, office overhead, travel expenses and other administrative costs.

Estimated $250,000/yr

Environmental Costs

Estiamted: $200,000/yr

Continuous Reclamation

Estimated: $70,000/yr

Personnel (total) from Manning Table

Estimated: $1,300,00/yr

Equipment Operator's salaries are considered into operating costs of each equipment.

Support People: Total 25

Estimated: $500,000/yr

Miscellaneous: $300,000/yr

### 6.1.13 Manpower Requirements

The following Manning table includes all labor other than that required for operation of the mining equipment listed in the preceding section.

Table 5 Manning Table

| Supervision | No. Employees 4 shifts | Annual Cost per employee | Total Annual Cost |
|---|---|---|---|
| Superintendent | 1 | $36,000 | $ 36,000 |
| Asst. Superintendent | 1 | 33,000 | 33,000 |
| General Mine Foreman | 1 | 30,000 | 30,000 |
| Mine Forman | 1 | 29 000 | 29,000 |
| Shift Foreman | 4 | 22,000 | 88,000 |
| Asst. Shift Foreman | 4 | 21,000 | 84,000 |
| Excavation Foreman | 16 | 20,000 | 320,000 |
| Maintenance Supervisor | 1 | 20,000 | 20,000 |
| Chief Mechanic Foreman | 1 | 22,000 | 22,000 |
| Shift Mechanic Foreman | 4 | 21,000 | 84,000 |
| Mechanic Foreman | 8 | 20,000 | 160,000 |
| Chief Electrical Foreman | 1 | 22,000 | 22,000 |
| Electrical Foreman | 4 | 20,000 | 80,000 |
| Chief Engineer (Excavation) | 1 | 26,000 | 26,000 |
| Mining Engineer (Excavation) | 4 | 19,000 | 76,000 |
| Mine Geologist | 1 | 18,000 | 18,000 |
| Surveyor | 3 | 12,000 | 36,000 |
| Surveyor Helper | 3 | 10,000 | 30,000 |
| Draftsman | 2 | 11,000 | 22,000 |
| Safety Director | 1 | 25,000 | 25,000 |
| Safety Foreman | 4 | 17,000 | 68,000 |
| TOTAL | | | $1,309,000 |

### 6.1.14 Summary of Mining Costs

Table 6 summarizes annual operating and ownership costs for the mine.

Table 6 Total Annual Mining Cost
(including operating and ownership costs)

| Units | Mining Equipment | Cost/Year |
|---|---|---|
| 3 | 20 Cu.Yd. BE 290B Shovel | $ 1,050,000 |
| 2 | T-4 Ingersoll Rand Drillmaster | 340,000 |
| 15 | 120T Trucks for Overburden | 4,800,000 |
| 6 | 35T Trucks for Ore | 750,000 |
| 3 | 3½ Cu.Yd. Backhoes for Ore Removal | 390,000 |
| 2 | Water Truck | 300,000 |
| 5 | Scrapers | 1,250,000 |
| 4 | Dozer - Ripper (D-9) | 720,000 |
| 2 | CAT No. 16 Grader | 240,000 |
| 2 | Bulk Explosive Truck | 60,000 |
| 1 | Fuel and Lube Truck | 35,000 |
| 1 | Tire Service Truck | 30,000 |
| 1 | Miscellaneous Service Truck | 25,000 |
| | Explosive Supplies and Blasting Costs (AN/FO, Primer, etc.) | 570,000 |
| | Mine Facilities (Buildings, etc.) | 220,000 |
| | Equipment Shop Operations | 500,000 |
| | Mine Services and Facilities | 350,000 |
| | Mine General and Administrative Costs | 250,000 |
| | Environmental Costs | 200,000 |
| | Continuous Reclamations | 70,000 |
| 70 | Key Personnel (excluding Equipment Operators | 1,300,000 |
| 25 | Support People | 500,000 |
| | Miscellaneous | 300,000 |
| | TOTAL MINING AND RELATED COSTS | $14,250,000 |

The estimated annual production is 1,000,000 tons of ore per year. Therefore, the unit cost is $14.25 per ton of ore mined or on the assumption of 90% mill recovery and an average grade of 1.6 pounds of $U_3O_8$ per ton the cost is $11.40 per pound $U_3O_8$.

## 6.2 Cost Breakdown

The preceding costs were estimated including both operating and capital costs in a single estimate. A reasonable assumption is that about 20% of these costs or $2.81 per ton is the ownership cost and the balance of $11.44 per ton is operating cost. The ownership costs would correspond to a capital investment in mining equipment of $28.1 million.

# 7. MILLING

## 7.1 General Description

The proposed uranium milling site is located adjacent to the surface mine to minimize haulage costs. The milling site encompasses approximately 500 acres of land which includes the tailings empoundment area. The milled ore will consist of a typical Wyoming sandstone composed primarily of unoxidized uranium minerals. No by-products such as molybdenum and vanadium were considered in this study. The ore does not contain any contaminants such as organic clays, sulfides, or phosphates that require special milling considerations. The ore is amenable to acid leaching, counter-current decantation solid/liquid separation, and solvent extraction.

An average uranium grade of 0.08% uranium is received at the mill site as previously described in the mining section. A mill recovery of 90% is projected to produce a "yellowcake" grade of 90%.

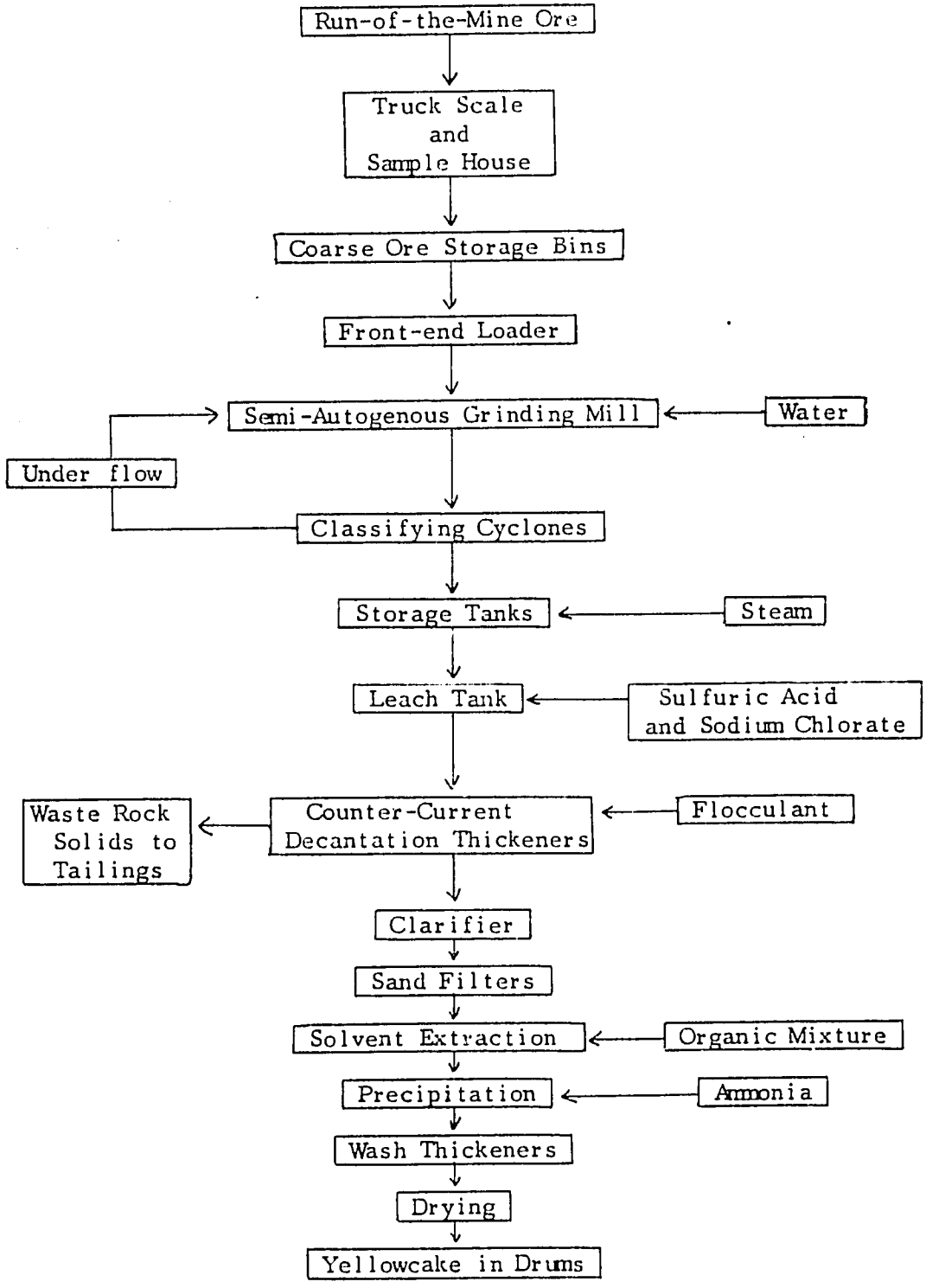
## 7.2 Processing Circuits

The mill consists of the following processing circuits which are briefly discussed separately below:

Ore Preparation and Grinding Circuit
Leach Circuit
Counter-Current Decantation and Clarification Circuit
Solvent Extraction Circuit
Precipitation Circuit
Product Handling and Drying

Figure 7 is a flowsheet of the milling processes.

FIGURE 7 FLOWSHEET OF A URANIUM MILLING CIRCUIT



The run-of-the-mine ore is weighed and sampled prior to being dumped into coarse ore storage bins. The ore is segregated by grade to provide the mill with a uniform feed. A front-end loader transports the ore to the grinding circuit. The grinding circuit reduces the ore to a nominal minus 28 mexh product. A grinding charge of 6% 3-inch forged steel balls will be used for grinding. The ball mill discharge is classified in a hydrocyclone with the coarse sand underflow returned to the grinding mill. The ground ore is stored in tanks prior to leaching. Steam is added to the storage tanks to raise the pulp tempature to 40–45 degrees centrigrade for leaching.

The ground pulp is leached for eight to ten hours in eight agitated leach tanks where sulfuric acid and sodium chlorate are added. The pulp is maintained at a 40–45 degree leach temperature and 55-60% solids.

The uranium-bearing solution is separated from the waste rock solids in a six thickener counter-current decantation circuit. Fast-settling thickeners were chosen to reduce thickener area so that the circuit could be totally enclosed and minimize heat loss. The clarifier and sand filters reduce the solids in the aqueous pregnant solution to les than five parts per million.

The solvent extraction circuit recovers the uranium by transfering the uranium from the aqueous phase to an organic phase. The organic phase consists of 96% isodecanol. The uranium is stripped from the pregnant organic phase and precipitated using ammonia as ammonia sulphate. Mixer/settler units are used to ensure maximum aqueous/organic contact and phase separation.

The pregnant strip solution is pumped to precipitation tanks where the pH is raised to precipitate the uranium as a yellowcake pulp. The pulp is washed in thickeners in series to reduce contaminants in the final yellowcake product. The thickener underflow is centrifuged and the yellowcake fed to a 5-ft diameter, 6-hearth natural gas roaster. The yellowcake is dried at 600 degrees Fahrenheit and packaged in 55-gallon drums for shipment.

### 7.3 Capital and Operating Cost Estimation Procedures

A factored capital cost estimate was used to determine initial capital expenditure for a 3,000 ton per day uranium mill. Table 8 summarizes the major equipment components with costs obtained from informal manufacture price quotes. The same table shows results for a factored capital cost estimate of the total plant. Operating costs were determined from uranium industry data and are summarized in tables 9 through 16. Table 17 is a total cost summary including both mine and mill components.

Table 8 Capital Costs for Purchased Equipment

| Item | Cost |
|---|---|
| Ore Preparation and Grinding Circuit | $1,095,450. |
| Leaching Circuit | 825,050. |
| Counter-Current Decantation and Clarification | 1,910,850. |
| Solvent Extraction and Strip Circuit | 603,200. |
| Precipitation Circuit | 185,400. |
| Product Drying and Handling | 256,400. |
| Reagent Storage | 110,200. |
| Auxiliary Equipment and Yard Facilities | 394,050. |
| Total Cost for a 3,000 TPD Uranium Leach Plant | $5,380,600. |
| **Factoring of Total Plant Cost** | |
| 1. Purchased Equipment Cost | $5,380,600. |
| 2. Installed Equipment Costs: 1.43 times Item 1 | 7,694,000. |
| 3. Process Piping: 25% of Item 2 | 1,923,500. |
| 4. Instrumentation: 15% of Item 2 | 1,154,100. |
| 5. Buildings and Site Development: 80% of Item 2 | 6,155,200. |
| 6. Auxiliaries: 75% of Item 2 | 5,770,500. |
| 7. Outside Lines: 10% of Item 2 | 769,400. |
| 8. Total Physical Plant Costs (2+3+4+5+6+7) | 23,466,700. |
| 9. Engineering and Construction: 20% of Item 8 | 5,900,000. |
| 10. Contingencies: 10% of Item 8 | 2,346,700. |
| 11. Size Factor: 2% of Item 8 | 470,000. |
| 12. Total Plant or Fixed Capital Costs (8+9+10+11) | $32,183,400. |
| 13. Tailings Dam and Environmental Permitting | 1,900,000. |
| 14. Total Plant Costs | $34,083,400. |

## 7.4 Operating Costs

Table 9 Reagent Consumption and Costs

| Reagent | Consumption/Ton of Ore | Cost/Unit | Cost/Ton of Ore |
|---|---|---|---|
| Sulfuric Acid | 60.0 pounds | $50./ton | $1.50 |
| Sodium Chlorate | 2.0 pounds | 0.22/lb | 0.44 |
| Flocculant (Percol 351) | 0.2 pounds | 1.42/lb | 0.28 |
| Kerosene | 0.15 gallons | 0.70/gal | 0.11 |
| Isodecanol | 0.03 pounds | 1.15/lb | 0.03 |
| Tertiary Amine(Alamine 336) | 0.03 pounds | 1.15/lb | 0.03 |
| Ammonia | 2.0 pounds | 0.10/lb | 0.20 |
| Total Cost of Reagents per Ton of Ore | | | $2.57 |

Table 10 Operating and Maintenance Supplies

| Item | Consumption/Ton of Ore | Cost/Unit | Cost/Ton of Ore |
|---|---|---|---|
| Grinding Media | 0.25 | 0.23/lb | $0.06 |
| Mill Liners | 0.176 | 0.47/lb | 0.08 |
| Lubricants & Fuels | - | - | 0.13 |
| Maintenance Supplies | - | - | 0.75 |
| Operating Supplies | - | - | 0.19 |
| Total Cost for Operating and Maintenace Supplies | | | $1.21 |

Table 11 Sundry Costs

| Item | Annual Cost | Cost/Ton of Ore |
|---|---|---|
| Insurance (2% of Fixed Capital Cost) | $470,000. | $0.45 |
| Equipment Leasing | 63,000. | 0.06 |
| Contract Services | 52,500. | 0.05 |
| Total Cost for Sundries | $585,500. | $0.56 |

Table 12 Energy Costs

| Item | Consumption | Cost/Ton of Ore |
|---|---|---|
| Electrical | 30.0 KWH/Ton of Ore | $1.13[2] |
| Fuels[1] | 280,000 BTU's/Ton of Ore | 0.33[3] |
| Total Cost per Ton of Ore | | $1.46 |

[1]Estimated to use a 75/25 mixture of diesel fuel and propane, respectively.

[2]Cost based on:
1. $2.70 per kilowatt of peak usage at 2500 kilowatts per month, and
2. $0.01164 per kilowatt-hour of electrical usage

[3]Cost calculation based on:
1. 140,000 BTU's per gallon of diesel fuel at $0.75 per gallon, and
2. 92,000 BTU's per gallon of propane at $0.43 per gallon.

## 7.5 Labor Costs

Table 13 Manning Table

| Job | Number of Employees | Class | Hours Turns | Adjusted Per Year | Annual Hourly Wage | Cost |
|---|---|---|---|---|---|---|
| Operators: | | | | | | |
| Chief Operator | 4 | 15 | 21 | 8736 | $12.686 | $110,825. |
| Loader Op. | 2 | 9 | 10 | 4160 | 11.572 | 48,739. |
| Crusher Op. | 2 | 11 | 10 | 4160 | 12.097 | 50,323. |
| Solution Op. | 4 | 11 | 21 | 8736 | 12.097 | 105,679. |
| CCD Operator | 4 | 11 | 21 | 8736 | 12.097 | 105,679. |
| SX Operator | 4 | 11 | 21 | 8736 | 12.097 | 105,679. |
| Dryer Operator | 4 | 11 | 21 | 8736 | 12.097 | 105,679. |
| Barrell Op. | 4 | 8 | 21 | 8736 | 11.406 | 99,643. |
| Op. Helpers | 16 | 7 | 15 | 32512 | 11.239 | 365,402. |
| Day Laborers | 18 | 5 | 21 | 36576 | 10.908 | 398,971. |
| Technicians | 4 | 12 | 21 | 8736 | 12.233 | 106,867. |
| Tailings Op. | 2 | 7 | 10 | 4062 | 11.239 | 45,653. |
| Utilities: | | | | | | |
| Op. Engineers | 4 | 13 | 21 | 8736 | 12.358 | 107,959. |
| Helpers 1 | 5 | 5 | 2032 | 10.908 | 22,765. | |
| Maintenance: | | | | | | |
| Electrician | 3 | 14 | 15 | 6096 | 12.462 | 75,968. |
| Mechanics | 3 | 14 | 15 | 6096 | 12.462 | 75,968. |
| Welders 2 | 14 | 10 | 4160 | 12.462 | 51,842. | |
| Helpers 3 | 8 | 15 | 6096 | 11.406 | 69,531. | |
| Machinist | 2 | 14 | 10 | 4160 | 12.462 | 51,842. |
| Iron Worker | 2 | 14 | 10 | 4160 | 12.462 | 51,842. |
| Instrument | 2 | 13 | 10 | 4160 | 12.358 | 51,409. |
| Apprentices | 4 | 7 | 10 | 8320 | 11.239 | 93,508. |
| Administrative: | | | | | | |
| Security Guard | 3 | 5 | 15 | 6096 | 10.908 | 66,495. |
| Ambulance Dr. | 1 | 9 | 5 | 2032 | 11.572 | 23,514. |
| Warehouseman | 2 | 8 | 10 | 4064 | 11.406 | 46,354. |
| Janitor 1 | 4 | 5 | 2032 | 10.758 | 21,860. | |
| Laboratory: | | | | | | |
| Assayer 3 | 9 | 15 | 6096 | 11.572 | 70.543. | |
| Sampler 2 | 4 | 10 | 4160 | 10.758 | 44,753. | |
| Total Hour Labor Cost for 106 Employees | | | | | | $2,573,383. |
| Unscheduled Overtime at 5% | | | | | | 128,669. |
| Total Hourly Labor Cost | | | | | | $2,702.052. |
| Total Hourly Labor Cost per Ton of Ore | | | | | | $2.57 |

Table 14 Salaried Labor Costs

| Job | Number of Employees | Base Salary per Year | Annual Cost |
|---|---|---|---|
| Processing: | | | |
| Milling Superintendent | 1 | $30,000 | $30,000. |
| Maintenenace Superintendent | 1 | 26,000 | 26,000. |
| Metallurgist/General Foreman | 3 | 24,000 | 72,000. |
| Shift Foreman | 4 | 19,000 | 76,000. |
| Utility Foreman | 2 | 20,000 | 40,000. |
| Maintenance Foreman | 2 | 22,000 | 44,000. |
| Total Salaried Labor Costs for 13 Employees | | | $288,000. |
| Fringe Benefits at 25% | | | 72,000. |
| Total Salaried Labor Costs | | | $360,000. |
| Total Salaried Labor Cost per Ton of Ore | | | $0.34 |

Table 15 Total Operating Cost per Ton of Ore

| Item | Cost Per Ton of Ore |
|---|---|
| Reagents | $2.57 |
| Operating and Maintenance Supplies | 1.21 |
| Sundry 0.56 | |
| Energy 1.46 | |
| Labor (Hourly and Salaried) | 2.91 |
| Total Operating Cost per Ton of Ore | $8.71 |

Table 16 General and Administrative Costs

| | Mill | Mine |
|---|---|---|
| | cost per short ton | |
| 1. Administrative Salaries and Wages | 30¢ | 19¢ |
| 2. Administrative Purchases | .04¢ | .02¢ |
| 3. Administrative Equipment Operation | | |
| Tires | .0002¢ | .0002¢ |
| Repair Parts | .005¢ | .005¢ |
| Fuel and Lub | .006¢ | .006¢ |
| Repair and Labor | .003¢ | .003¢ |
| Total Cost per Ton | 30.05¢ | 19.03¢ |

## 7.6 Total Cost Summary

Table 17 Total Cost Summary

| | |
|---|---|
| Mine Capital Cost per Ton, 28,100,000/10,000,000 | $ 2.81/Ton |
| Mining Operating Cost per Ton | $11.44/Ton |
| Milling Operating Cost per Ton | $ 8.71/Ton |
| Milling Capital Cost per Ton $34,083,400= / 10,000,000 Ton Reserve = | $ 3.40/Ton |
| Mill General and Administration Cost | $ 0.30/Ton |
| Total Operating & Capital Cost per Ton of Mining and Milling Uranium in Wyoming | $26.66/Ton |

Note: This cost is the sum of capital & operating cost. A life of 10 years for mine and mill has been assumed with a reserve of 10,000,000 tons of Uranium Ore (production 3,000 tons per day).

This figure, $26.66 per ton, is used in our evaluation of the economics of mining and milling uranium in Wyoming open pits.

## 7.7 Some Comparative Cost Data

It is useful to compare earlier estimates of uranium mining costs by Klemenic and Lootens with the preceding estimate of uranium mining costs in Wyoming. Changes in costs between 1974 and 1979 reflect both the effects of general inflation as well as the impact of changing technology and economics on cost.

The two tables that follow are from John Klemenic's work in 1974 on low-grade uranium economics (Klemenic, 1974).

Table 18 Typical Overall Economics for a Future Cycle of Uranium Concentrate Production Based on Open Pit Mining[1] Operations at 0.10% $U_3O_8$ in Ore

| Costs | 500 T/D | | 1,000 T/D | | 2,000 T/D | | 3,000 T/D | | 5,000 T/D | | Years |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/T | $/#Rec. | $/T | $/#Rec. | $/T | $/#Rec. | $/T | $/# Rec. | $/T | $/#Rec. | Incurred |
| Capital: | | | | | | | | | | | |
| Field Expense | 0.30 | 0.162 | 0.30 | 0.162 | 0.30 | 0.162 | 0.30 | 0.162 | 0.30 | 0.162 | 1-5 |
| Property Acquisition | 0.24 | 0.130 | 0.24 | 0.130 | 0.24 | 0.130 | 0.24 | 0.130 | 0.24 | 0.130 | 1-5 |
| Exploration Drilling | 0.40 | 0.216 | 0.40 | 0.216 | 0.40 | 0.216 | 0.40 | 0.216 | 0.40 | 0.216 | 3-6 |
| Development Drilling | 0.12 | 0.065 | 0.12 | 0.065 | 0.12 | 0.065 | 0.12 | 0.065 | 0.12 | 0.065 | 5-7 |
| Mine Primary Development | 5.98 | 3.232 | 5.98 | 3.232 | 5.64 | 3.049 | 5.52 | 2.984 | 5.30 | 2.865 | 8-17 |
| Mine Plant & Equipment[2] | 0.20 | 0.108 | 0.20 | 0.108 | 0.19 | 0.103 | 0.19 | 0.103 | 0.19 | 0.103 | 8,14 |
| Mill Construction | 2.36 | 1.276 | 1.92 | 1.033 | 1.56 | 0.843 | 1.38 | 0.746 | 1.18 | 0.638 | 8,9 |
| Total Capital | 9.60 | 5.189 | 9.16 | 4.946 | 8.45 | 4.568 | 8.15 | 4.406 | 7.73 | 4.179 | |
| Operating: | | | | | | | | | | | |
| Mining | 1.80 | 0.973 | 1.55 | 0.838 | 1.40 | 0.757 | 1.30 | 0.703 | 1.15 | 0.622 | 9-19 |
| Hauling | 0.75 | 0.405 | 0.75 | 0.405 | 0.75 | 0.405 | 0.75 | 0.405 | 0.75 | 0.405 | 9-19 |
| Milling | 6.59 | 3.562 | 5.28 | 2.854 | 4.22 | 2.281 | 3.70 | 2.000 | 3.13 | 1.692 | 9-19 |
| Royalty[3] | 0.525 | 0.284 | 0.475 | 0.257 | 0.416 | 0.225 | 0.394 | 0.213 | 0.370 | 0.200 | 9-19 |
| Total Operating | 9.66 | 5.224 | 8.05 | 4.354 | 6.79 | 3.668 | 6.14 | 3.321 | 5.40 | 2.919 | |
| Total Costs | 19.26 | 10.413 | 17.21 | 9.300 | 15.24 | 8.236 | 14.29 | 7.727 | 13.13 | 7.098 | |

[1]At 24 ore depth to ore thickness ratio.

[2]Some of the mining equipment is included under "Primary Development".

[3]At prices required to generate 15% cash flow rate of return.

Table 19 Typical Overall Economics for a Future Cycle of Uranium Concentrate Production Based on Open Pit Mining[1] Operations at 0.03% $U_3O_8$ in Ore

| Costs | 1,000 T/D | | 2,000 T/D | | 3,000 T/D | | 5,000 T/D | | 10,000 T/D | | Years' |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/T | $/#Rec. | $/T | $/#Rec. | $/T | $/#Rec. | $/T | $/# Rec. | $/T | $/#Rec. | Incurred |
| Capital: | | | | | | | | | | | |
| Field Expense | 0.09 | 0.103 | 0.09 | 0.103 | 0.09 | 0.103 | 0.09 | 0.103 | 0.09 | 0.103 | 1-5 |
| Property Acquisition | 0.07 | 0.080 | 0.07 | 0.080 | 0.07 | 0.080 | 0.07 | 0.080 | 0.07 | 0.080 | 1-5 |
| Exploration Drilling | 0.12 | 0.137 | 0.12 | 0.137 | 0.12 | 0.137 | 0.12 | 0.137 | 0.12 | 0.137 | 3-6 |
| Development Drilling | 0.04 | 0.046 | 0.04 | 0.046 | 0.04 | 0.046 | 0.04 | 0.046 | 0.04 | 0.048 | 5-7 |
| Mine Primary Development | 5.28 | 6.034 | 4.80 | 5.486 | 4.58 | 5.234 | 4.58 | 5.234 | 4.44 | 5.074 | 8-17 |
| Mine Plant and Equipment[2] | 0.18 | 0.206 | 0.17 | 0.194 | 0.16 | 0.183 | 0.16 | 0.183 | 0.16 | 0.183 | 8,14 |
| Mill Construction | 1.81 | 2.069 | 1.47 | 1.680 | 1.30 | 1.486 | 1.12 | 1.280 | 0.91 | 1.040 | 8,9 |
| Total Capital | 7.59 | 8.675 | 6.76 | 7.726 | 6.36 | 7.269 | 6.18 | 7.063 | 5.83 | 6.663 | |
| Operating: | | | | | | | | | | | |
| Mining | 0.80 | 0.914 | 0.70 | 0.800 | 0.65 | 0.743 | 0.60 | 0.686 | 0.55 | 0.629 | 9-19 |
| Hauling | 0.75 | 0.857 | 0.75 | 0.857 | 0.75 | 0.857 | 0.75 | 0.857 | 0.75 | 0.857 | 9-19 |
| Milling | 5.10 | 5.829 | 4.04 | 4.617 | 3.52 | 4.023 | 2.95 | 3.371 | 2.29 | 2.617 | 9-19 |
| Royalty[3] | 0.163 | 0.186 | 0.140 | 0.160 | 0.133 | 0.152 | 0.121 | 0.138 | 0.109 | 0.124 | 9-19 |
| Total Operating | 6.81 | 7.786 | 5.63 | 6.434 | 5.05 | 5.775 | 4.42 | 5.052 | 3.70 | 4.227 | |
| Total Costs | 14.40 | 15.461 | 17.39 | 14.160 | 11.41 | 13.044 | 10.60 | 12.115 | 9.53 | 10.890 | |

[1]At 24 ore depth to ore thickness ratio.

[2]Some of the mining equipment is included under "Primary Development".

[3]At prices required to generate 15% cash flow rate of return.

Another source of comparative data on New Mexico and Wyoming mines is Lootens' work in 1976 (Lootens, 1976).

Table 20 Operating Cost Estimate Summary
Hypothetical Uranium Processing Operations
New Mexico and Wyoming

| | | Operating Cost Estimates 1975 Dollars | | |
|---|---|---|---|---|
| | | Mine | Mill | Total |
| Underground Mining | | | | |
| New Mexico | | | | |
| 2000 feet deep | 500 tpd | $18.27 | $12.98 | $31.25 |
| tons milled, | 1000 tpd | 15.78 | 11.18 | 26.96 |
| | 2000 tpd | 13.76 | 9.59 | 23.35 |
| 4000 feet deep | 500 tpd | 23.68 | 12.98 | 36.66 |
| tons milled, | 1000 tpd | 20.43 | 11.18 | 31.61 |
| 2000 tpd | 18.19 | 9.59 | 27.78 | |
| Wyoming | | | | |
| 500 feet deep | 500 tpd | 18.55 | 12.98 | 31.53 |
| tons milled, | 1000 tpd | 16.13 | 11.18 | 27.32 |
| 2000 tpd | 13.84 | 9.59 | 23.43 | |
| Surface Mining | | | | |
| New Mexico* | | | | |
| tons milled, | 500 tpd | 16.43 | 12.98 | 29.41 |
| 1000 tpd | 14.29 | 11.18 | 25.47 | |
| 2000 tpd | 13.74 | 9.59 | 23.33 | |
| Wyoming* | | | | |
| tons milled, | 500 tpd | 22.12 | 12.98 | 35.10 |
| 1000 tpd | 19.43 | 11.18 | 30.61 | |
| 2000 tpd | 19.72 | 9.59 | 29.31 | |

* Provision for surface land reclamation is included.

Our estimate of the Wyoming operations might be compared with Klemenic's 3,000 ton-per-day operation and 0.10% $U_3O_8$ ore. Klemenic's total capital and operating costs per ton of $14.29 would be compared with our total estimate of $26.66 per ton. Such a difference would represent a cost escalation of 17% per year between 1975 and 1979. While this is not unreasonable given recent inflation rates, probably some of the difference is also due to different assumptions with regard to physical characteristics of the mine. For the analyses that follow at the end of this chapter we use a capital cost of $62.2 million and an operating cost of $20.15 per ton as the base case.

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APPENDIX A

URANIUM ANALYSIS REFERENCE NUMBER 100.

FIRST YEAR OF INVESTMENT CASH FLOWS 1979.
LAST YEAR OF INVESTMENT CASH FLOWS 1985.
PRICE INDEX THAT APPLIES TO OPERATING COSTS 222.3
MINIMUM ACCEPTABLE DISCOUNT RATE 10.0
TOTAL ESTIMATED INVESTMENT (1979) ($000) IS 76769.
LESS LOANS ($000) (29% DEBT) AT 0.0% INTEREST 0.
LESS TAX DEDUCTIONS:
FROM INVESTMENT TAX CREDIT ($000) 3367.
FROM EXPENSING OF DEV. COSTS ($000) 8232.
EQUALS NET EQUITY INVESTMENT ($000) 62183.
PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (%) 0.0
SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1985.

| YR. | COST INDEX | CASH FLOW(BASE YR. $) | CASH FLOW (ESC. $) | NO. OF EMPLOYEES |
|---|---|---|---|---|
| 1979. | 613.4 | 6405. | 6405. | 684. |
| 1980. | 613.4 | 6405. | 6405. | 684. |
| 1981. | 613.4 | 9141. | 9141. | 976. |
| 1982. | 613.4 | 9141. | 9141. | 976. |
| 1983. | 613.4 | 4042. | 4042. | 431. |
| 1984. | 613.4 | 12996. | 12996. | 1387. |
| 1985. | 613.4 | 14053. | 14053. | 1500. |
| NET INVESTMENT | | 62183. | 62183. | |

DEPRECIABLE INVESTMENT ($000) 44150.
MINEABLE ORE RESERVE (000 S.T.) AT 0.000 MOS2 CUTOFF GRADE 10000.
MINE LIFE (YEARS) ORE RESERVES/AN. PROD. RATE 10.
NUMBER OF PHASES OF PRODUCTION 1.
FOR THE CASH FLOWS IN PHASES 1.

---

FIRST YEAR OF OPERATING NET CASH FLOW 1986.
LAST YEAR OF OPERATING NET CASH FLOW 1995.
PROJECTED RATE OF PRICE ESCALATION (% ANNUALLY) 0.0
PRICE AT BEGINNING OF EACH PHASE ($/LB. U3O8) 40.00
ANNUAL PRODUCTION (000) (SHORT TONS, OF ORE) 1050.
TOTAL PRODUCTION EMPLOYMENT 750.
AVERAGE DILUTED ORE GRADE,PERCENT U3O8 (ASSUMES 0.% DIL.) 0.080
METALLURGICAL RECOVERY,PERCENT 90.0
ANNUAL PRODUCTION (000) POUNDS U3O8 1512.
REPLACEMENT INV. BEGINNING OF EACH PHASE ($000) 871.
PROJECTED RATE REPLACEMENT INV. ESCALATION (% ANNUALLY) 0.0
PROJECTED RATE OF COST ESCALATION (% ANNUALLY) 0.0
ANNUAL OPERATING COSTS BEGINNING OF EACH PHASE ($000) 26250.
ANNUAL ROYALTY RATE (% OF GROSS REV.) 4.0
DEPLETION RATE (PERCENT,LIMITED TO 50% OF NET) 22.
COMBINED EFFECTIVE TAX RATE 51.0

URANIUM ANALYSIS REFERENCE NUMBER 100.

U.S. CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. | 1994. | 1995. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,PER POUND OF U3O8 EQUIVALENT ($U.S.) | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 | 40.00 |
| ANNUAL PRODUCTION RATE (000) POUNDS OF U3O8 EQUIVALENT ($U.S.) | 1512. | 1512. | 1512. | 1512. | 1512. | 1512. | 1512. | 1512. | 1512. | 1512. |
| AVERAGE TOTAL COST ($/POUND U3O8 EQUIVALENT ) | 20.42 | 19.76 | 19.09 | 18.76 | 18.50 | 18.24 | 17.98 | 17.71 | 17.45 | 17.19 |
| REVENUE ($000 U.S.) | 60480. | 60480. | 60480. | 60480. | 60480. | 60480. | 60480. | 60480. | 60480. | 60480. |
| LESS ANNUAL ROYALTY ($000) | 2419. | 2419. | 2419. | 2419. | 2419. | 2419. | 2419. | 2419. | 2419. | 2419. |
| LESS ANNUAL OPERATING COST ($000) | 26250. | 26250. | 26250. | 26250. | 26250. | 26250. | 26250. | 26250. | 26250. | 26250. |
| EQUALS GROSS INCOME ($000) | 31811. | 31811. | 31811. | 31811. | 31811. | 31811. | 31811. | 31811. | 31811. | 31811. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 8027. | 7225. | 6422. | 5619. | 4816. | 4014. | 3211. | 2408. | 1605. | 803. |
| LESS DEPLETION ($000) | 11892. | 12293. | 12694. | 12773. | 12773. | 12773. | 12773. | 12773. | 12773. | 12773. |
| LESS TAX ($000) | 6065. | 6269. | 6474. | 6843. | 7253. | 7662. | 8072. | 8481. | 8890. | 9300. |
| EQUALS NET INCOME AFTER TAX ($000) | 5827. | 6024. | 6220. | 6575. | 6968. | 7362. | 7755. | 8148. | 8542. | 8935. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 8027. | 7225. | 6422. | 5619. | 4816. | 4014. | 3211. | 2408. | 1605. | 803. |
| AND DEPLETION ($000) | 11892. | 12293. | 12694. | 12773. | 12773. | 12773. | 12773. | 12773. | 12773. | 12773. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 871. | 871. | 871. | 871. | 871. | 871. | 0. |
| EQUALS OPERATING CASH FLOW ($000) | 25746. | 25541. | 25337. | 24097. | 23687. | 23278. | 22869. | 22459. | 22050. | 22511. |

THE NET PRESENT VALUE AT 10.0 PERCENT DISCOUNT RATE IS ($000) 34714.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 19.6 PERCENT

# CERREJON

## 1. INTRODUCTION

Of Latin America's approximately 20 billion metric tons of coal of all ranks, an estimated 10 billion metric tons are Colombian. Large reserves of high-volatile bituminous and subbituminous coal with low sulfur and ash content are found in the numerous basins and intermountane valleys of central Colombia. These are the largest commercial coal deposits in all of Latin America. Some of this bituminous coal produces a dense, high ash, high-volatile coke used in blast furnaces and for domestic and commercial space heating. Other deposits are an important source of fuel for steam power plants — an alternative to petroleum as a source of electric power for Colombian industry, commerce and domestic use.

Of all of the Colombian coal deposits, "El Cerrejon" is the most studied of all the sub-basins because of its amenability to low cost open pit mining methods and its access to a deep-water port. The deposit is a prime candidate for exploitation and development in the near future.

El Cerrejon has been under consideration in Colombia since 1972, first by the Peabody Coal Company, a subsidiary of Kennecott Copper Corporation, and later by the National Colombian Coal Company, Carbones Colombianos (CARBOCOL). This chapter is an account of the exploration, discovery and feasibility analysis of this large Colombian coal deposit. It is also a story of a state-owned mining corporation and its successes and failures in meeting national objectives.

### 1.1 Location of Latin American and Colombian Coal Deposits

Figure 1 locates the Latin American coal deposits and figure 2 locates the El Cerrejon coal deposits only 74 miles from the Caribbean coast. The coal is low in sulfur and ash content while recoverable reserves of the field are estimated at 350 million metric tons.

FIGURE 1 PRINCIPAL COAL DEPOSITS OF LATIN AMERICA

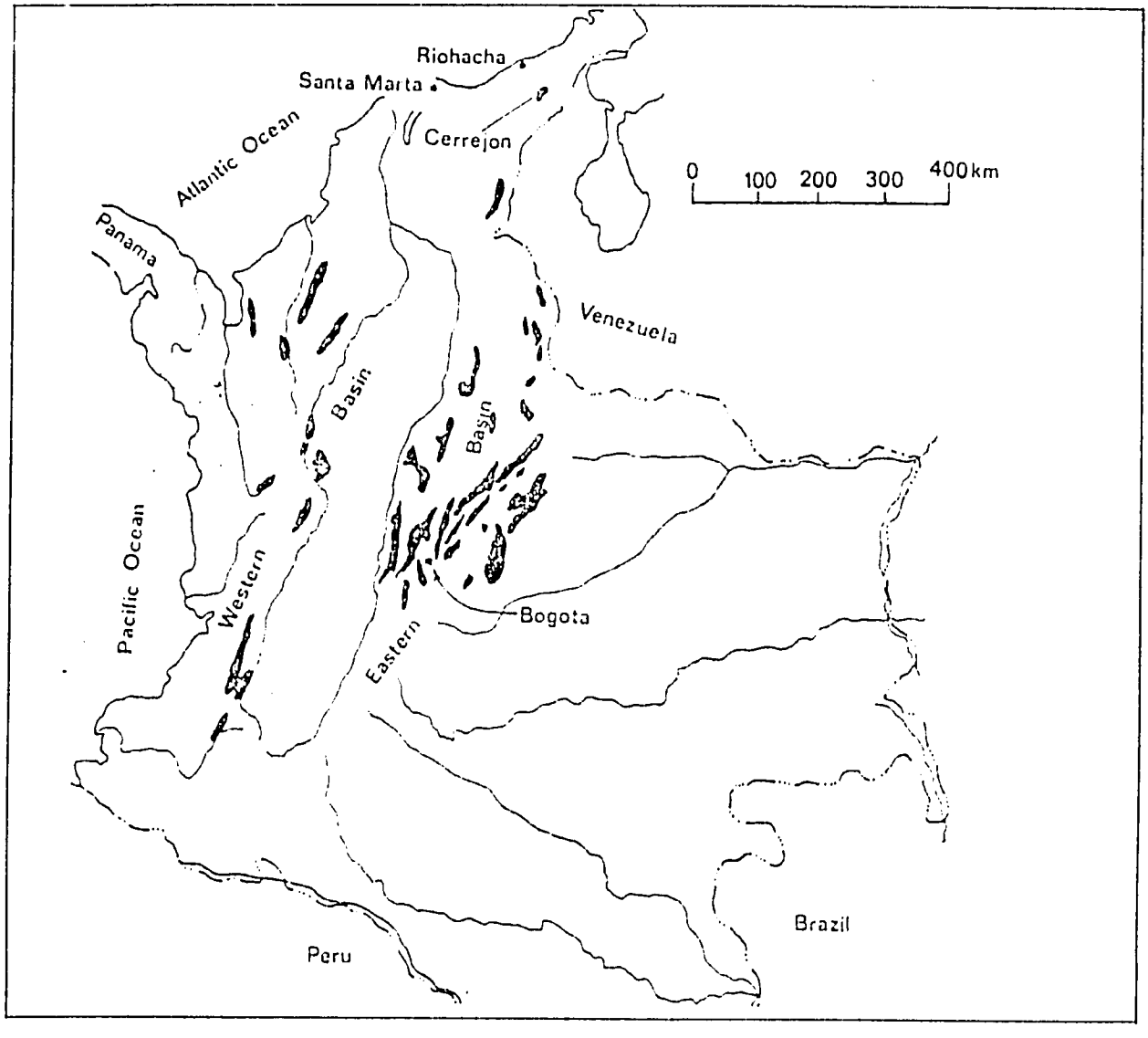



FIGURE 2 COLOMBIAN COAL DEPOSITS

## 2. COLOMBIA, COLOMBIANS AND COLOMBIAN COAL

### 2.1 The Country..."where the condor makes its nest"

Colombia -- 440,000 square miles of land extending one thousand miles from north to south and 800 miles from east to west -- is comparable in size to the combined areas of Texas and California. As indicated in figure 3, three ranges of mountains or "cordilleras" divide the country from south to north and cause extreme geographical and climatic contrasts. The western two-fifths of Colombia is mountains divided by intermontane lowlands while the eastern three-fifths is flat savannahs and rain forests.

Altitude plays an important role in the nation's industry, economics, and agriculture. Bogota, the economic, political and cultural center of the country, is

located at an elevation of 8600 feet above sea level in the state of Cuindamarca, translated, "the height where the condor makes its nest".

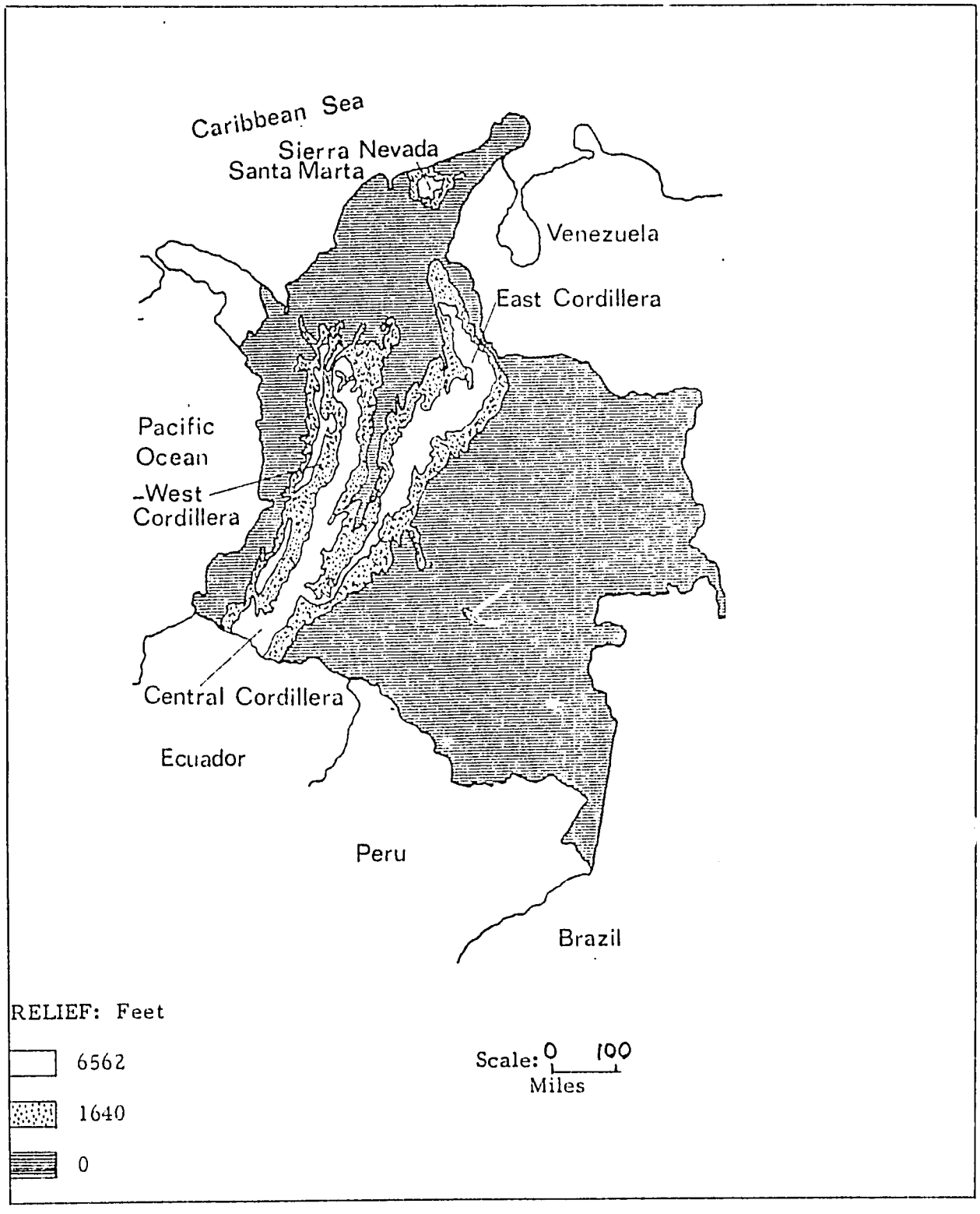



FIGURE 3 GEOGRAPHICAL DIVISIONS OF COLOMBIA

In 1979, Ninety-eight percent of an almost thirty million Colombian population is concentrated in the western region. The principal language is Spanish reflecting rule by Spain from the sixteenth through the nineteenth century and the development of the Hispanic culture. Colombia's independence was won early in the nineteenth century in a war of liberation led by Simon Bolivar — a common struggle that led to independence for Venezuela, Colombia, and Ecuador.

## 2.2 Government and Politics

During the 168 years of Colombian independence there have been short periods of dictatorial rule but the present government is democratic under a constitution in force since 1886. Executive power is centralized in the president, the most powerful political figure in a politically minded society, who is elected by popular vote to a four year term. All classes and levels are split by party allegiance. The thirteen cabinet members and the twenty-three departmental (state) governors are appointed by the president.

The Colombian Congress has a structure similar to that of the United States in that there are two houses, a Senate and a House of Representatives. Members are elected by popular vote. Since the adoption of the 1886 constitution, Colombia's political life has been traditionally centered on a two-party - conservative and liberal - system. Both parties favor social and economic reform programs. Even though the country has 168 years of democratic institutions, its history includes periods of violent political conflicts between the traditional parties.

In 1953, political disturbances led to two military regimes, the last of which was overthrown in 1957. During that year the political parties proposed a coalition called The National Front to promote political stability. The constitution was amended to provide for an alternation of the Presidency between liberals and conservatives. The National Front dissolved in 1974 and Colombia returned to Presidential elections by a two-party system.

The current President, Julio Cesar Turbay, took office on August 7, 1978. So far there have been no dramatic changes from policies established from his predecessor, Alfonso Lopez Michelsen. The major problem facing the Turbay Administration during its first months in office was inflation. During 1978 the inflation rate was kept below 20 percent for the first time in several years. The 1979 program now aims at increasing government spending on major infrastructure projects, such as power generation, highways, and airports. President Turbay sent the Congress a draft tax reform bill which he hopes will solve problems emanating from President Lopez's tax reform legislation. Turbay's Administration hopes to increase incentive for investment and industrial development.

Historically Colombia's involvement in world affairs has been minor. They have been detached from global conflicts, maintaining neutrality during World War I, and belligerence but non-involvement in World War II. Colombian soldiers were involved in the Korean conflict.

## 2.3 Economics

### 2.3.1 Agriculture and Industry

Colombia's economy is varied and productive as a result of its diverse geographic conditions and abundant natural resources. For 400 years the economy of Colombia was based on agriculture and small scale mining. In the 1920's an industrial sector began to develop and by 1940 textile and agricultural processing industries were well established.

The economy has long been extensively dependent on coffee but there has been a growing industrialization, especially since World War II. Unemployment levels continue at ten to fourteen percent while rising per capita incomes, about $800 per capita in 1979, reflect a slowly improving standard of living.

As the world's second largest exporter of coffee, Colombia derives about 60 percent of its total foreign exchange from sales of this commodity. Diversification of exports has taken place in agriculture and extended to exports of chemicals, textiles, pharmaceuticals and wood products. The United States continues as the major consumer of Colombian products although less important in recent years because of the development of markets in western Europe and Japan.

### 2.3.2 LAFTA and the Andean Pact

Colombia has expanded its trade within the Latin American Free Trade Association (LAFTA) countries, including Mexico and all of South America except Guyana, Surinam, and French Guiana. Small national markets led to a movement in Latin America for the establishment of a free trade area.

The slow progress achieved by LAFTA in achieving the goals of a common market lead to a sub-regional Andean integration agreement known as the "Andean Pact". The original agreement signed in May of 1969 included Bolivia, Chile, Colombia, Ecuador and Peru with Venezuela joining in February of 1973. The Andean Pact was organized under LAFTA rules and approved by the full LAFTA membership. The main achievements of the group include the following:

1. Establishment of the Andean Development Corporation with an authorized capital stock of 100 million U.S. dollars to promote regional development.
2. A common policy toward foreign investment.
3. Reduction of tariffs between Andean Pact countries.

### 2.3.3 Inflation

During the 1970's the Colombian economy grew at healthy rates of approximately 7 percent per year. However this was offset by an accelerating rate of inflation that rose above 20 percent per year after 1970 as indicated by the Colombian wholesale price index shown in Figure 4.

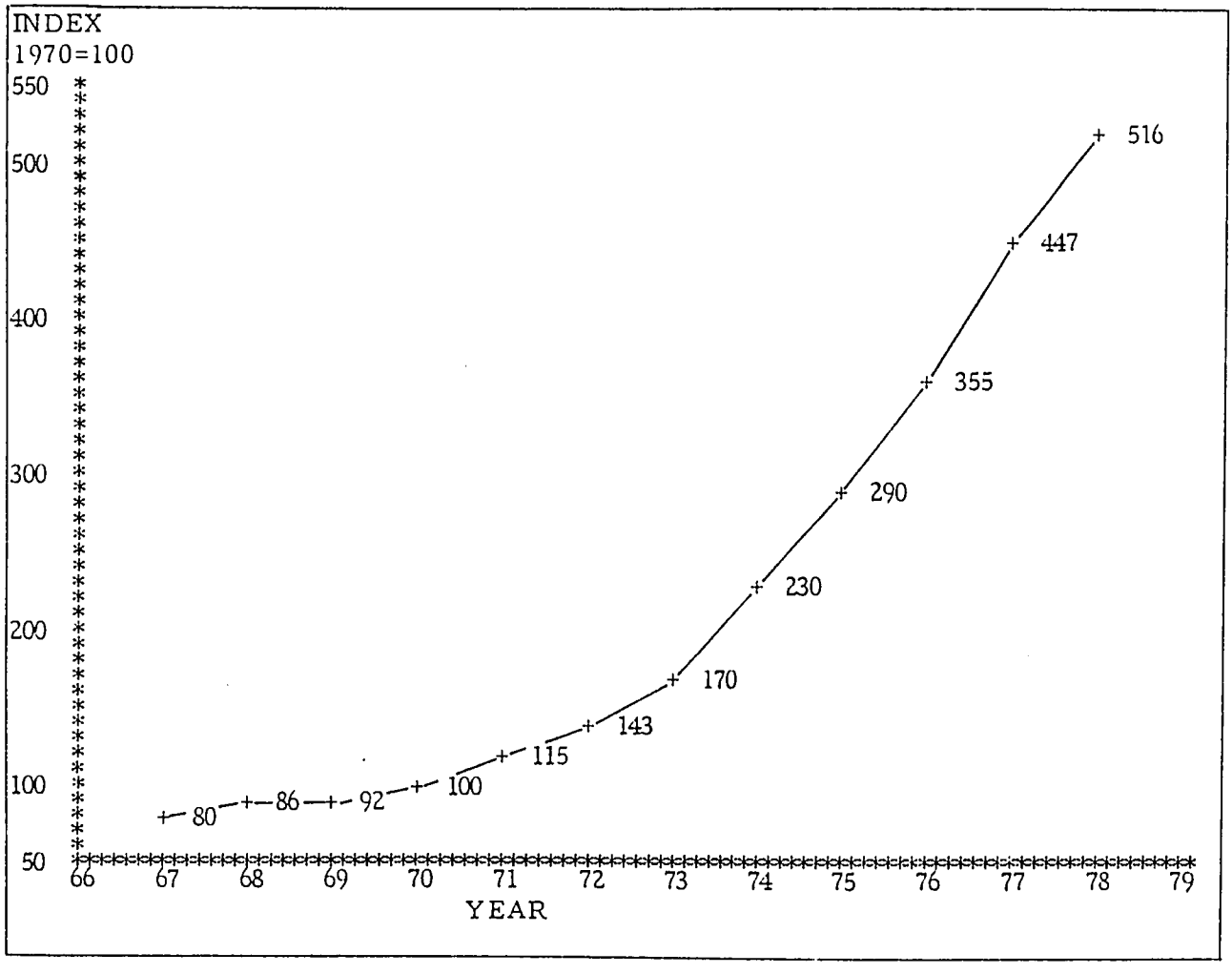



FIGURE 4 COLOMBIAN WHOLESALE PRICE INDEX, 1966-79

Colombia's inflation can be traced to rapid expansion in the money supply. In addition to coffee export earnings, narcotics and coffee smuggled out of the country to avoid taxes raised the money supply 850 million dollars in 1977. Foreign exchange reserves increased from 500 million dollars in 1975 to 2.3 billion dollars in 1978.

Another factor in Colombia's inflation is the fiscal deficit of the government. Government expenditures have been much higher than tax collections and this accompanied by growth in the money supply added to inflationary momentum after 1971. President Alfonso Lopez Michelsen, Liberal Party candidate elected in 1974, campaigned principally on a platform of combating inflation and improving income distribution. After Michelsen's election a three year development plan was aimed at financial and monetary policies designed to reduce the cost of living. The main goal of fiscal policy was to redistribute the tax burden so that higher taxes would fall on the wealthiest people, while foreign trade policy was aimed at opening new markets abroad to stimulate exports. Agrarian policy was aimed at expansion of existing enterprises and creation of new ones to satisfy basic needs of the population.

### 2.3.4 Devaluation of the Colombian Peso

The high rate of inflation in Colombia has led to the devaluation of the Colombian peso in an attempt to maintain competitiveness of non-coffee exports.

Another major problem in Colombia has been the sale of gasoline at subsidy prices. The Lopez Administration increased gasoline prices and the cost of public transportation by 30 percent in an attempt to eliminate the transport subsidy and to provide incentive to save energy. The not surprising result was riots in the streets as consumers found the cost of getting to work much more expensive. In the past Colombia was a net exporter of oil but by 1975 the country had to import large amounts of oil at very high prices.

## 2.4 Minerals Development

The Spaniards came to Colombia in search of gold that led to placer development in the western highlands along the major rivers. The country has also been a significant producer of platinum and silver and is the world's largest producer of emeralds - believed to be the world's finest quality. Today several large projects are underway for development of major deposits of coal, uranium, nickel, copper, phosphate rock and asbestos. The government desires to offset the country's petroleum deficit through a diversification of exports through new mining projects — yet resource development is constrained because much of the country remains unsurveyed and the full extent of the mineral resource potential is unknown.

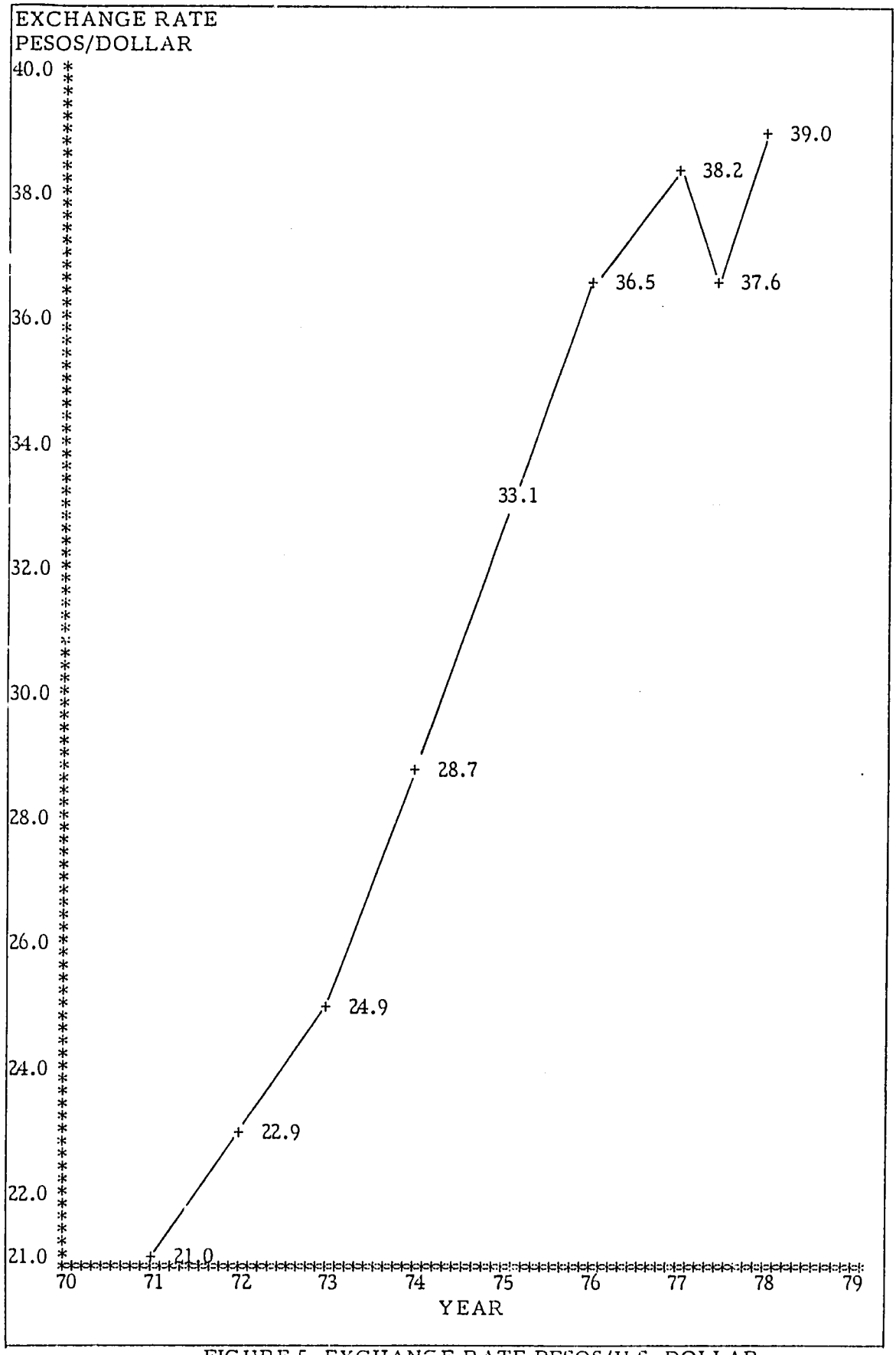



FIGURE 5 EXCHANGE RATE PESOS/U.S. DOLLAR

### 2.4.1 The Colombian Coal Industry

Coal producing countries of the LAFTA area are Mexico, Colombia, Brazil, Chile, Peru, and Venezuela, but only Colombia and Mexico mine coking coals and all of the countries with the exception of Colombia import coal and coke to meet domestic consumption needs.

Extensive deposits of coal now are more important to an industrialized Colombia than precious metals or emeralds. The potential market for Colombian coal has been expanded because of the regional trade efforts in the Andean Pact countries which have created potential markets for Colombian coal in Venezuela, Brazil, Mexico, Argentina, and Chile.

The most important Colombian deposits in terms of estimated reserves and coal rank are those along the eastern cordillera from the south of Bogota, thence north to Venezuela. Some of these deposits contain good metallurgical coking coals.

## 2.5 Domestic and Export Markets

Colombian coal production reached 3.6 million short tons in 1978 but for the last 15 years there has been little growth in output because of competition from petroleum and natural gas. About 35 percent of the present coal output is coking coal but a third of this production is being used as steam coal for manufacturing and electric utilities. Colombia has exported small amounts of coal and coke to Venezuela and Ecuador and smaller amounts to France, Belgium and Spain in recent years.

Colombian coal production and exports could grow substantially between 1978 and 1985 if the Cerrejon and Carare coal fields are developed. CARBOCOL estimates that total coal production would likely reach 4 million metric tons in 1978 and rise to 6 million metric tons by 1980-81. Exports are expected to increase from 200,000 metric tons in 1978 to 500,000 metric tons in 1980 and perhaps to 700,000 to 1 million metric tons by 1985 Carare is developed. Without Carare exports in 1985 would stay at 500,000 metric tons annually.

Colombian exports from Cerrejon and Carare are tied to marketing agreements with Somisa, the state steel works in Argentina, and the Brazilian steel concern Siderbras. The Brazilian firm of Siderugica Paulista (CCSIPA) has been an importer of Colombian coal.

Lack of infrastructure is a problem in developing Colombian coal exports. Coal output cannot increase without adequate rail and port facilities. The lack of such facilities has hampered negotiations between Colombia and Brazil, Romania and Spain on joint coal mine exploitation projects. In 1978 INTERCOR and CARBOCOL were both working on a feasibility study for a coal port but construction was not expected prior to 1981.

Domestic consumers of coal are the steel mills, cement plants and electric utilities. The cement plants are on the Caribbean coast and will need 500 metric tons daily by 1980-81. It is expected that coal will account for 24 percent of the fuel burned by electric generating plants in 1985 and today, Corelca, a utility on the Caribbean coast requires 2000 metric tons daily of Cerrejon coal to fuel its plants. It was estimated that Colombia's current half-million metric tons annual steel output will rise to 1.25 million

metric tons by 1981 thus increasing demand for coking coals, a market of particular interest because coking coals command a premium price. The initial price for coking coal in an agreement between Colombia and Spain calls for production to begin in 1979-1980 with an initial price for coal estimated at $50.00 per metric ton f.o.b. Colombian ports.

### 2.6 Problems Facing Coal Development

The nature of Colombian coal deposits dictates that most output comes from underground mines. Five big companies produce 60% of the total output with varying degrees of mechanization but in many mines mechanization is almost nonexistent and the coal is mined with hand picks, wheel barrows and candles. Fifty percent of the mining laborers are illiterate so that when a new mine starts production, farmers and shepards are converted to miners without training. The result is a low level of skill in both labor and supervision.

Until recently, government policy has been against investment in mining projects because of the capital intensive nature of the industry and the lack of foreign exchange for such type of development. Activities in manufacturing, commerce or real estate can be undertaken with lower risk and faster profits. It appears that the private sector will play a very small role in coal development. Aside from foreign investment, the development of coal in Colombia will rely on government.

## 3. DESCRIPTION OF THE PROJECT

### 3.1 Cerrejon Development Areas

As indicated in figures 6 and 7, two areas are involved in Cerrejon development north of Barroncas, Colombia. Area A includes 25,000 acres, explored by Peabody Coal between 1972 and 1976 and area B to the north and south includes 95,000 acres opened to bids during 1976. This chapter focuses on area A, the central portion of the Cerrejon coal field under development by CARBOCOL.

INTERCOR, a subsidiary of EXXON Corporation, won the bid for exploration and development of area B and in 1979 EXXON planned start-up of a mine in 1985. Output is projected rising from 2 million metric tons in 1985 to 15 million metric tons in 1989. Reportedly development could be accelerated for production in 1983-84 if port studies prove favorable.

INTERCOR's success has been followed by increased interest by other foreign investors including ARCO, Island Creek De Colombia, the coal subsidiary of Occidental, Pan Ocean, a subsidiary of Marathon Oil, Shell, Siberbras of Brazil, and Minera Utah, a subsidiary of Utah International. In addition, Venezuelan and Japanese companies have shown interest in Colombian coal but no agreements have been signed.

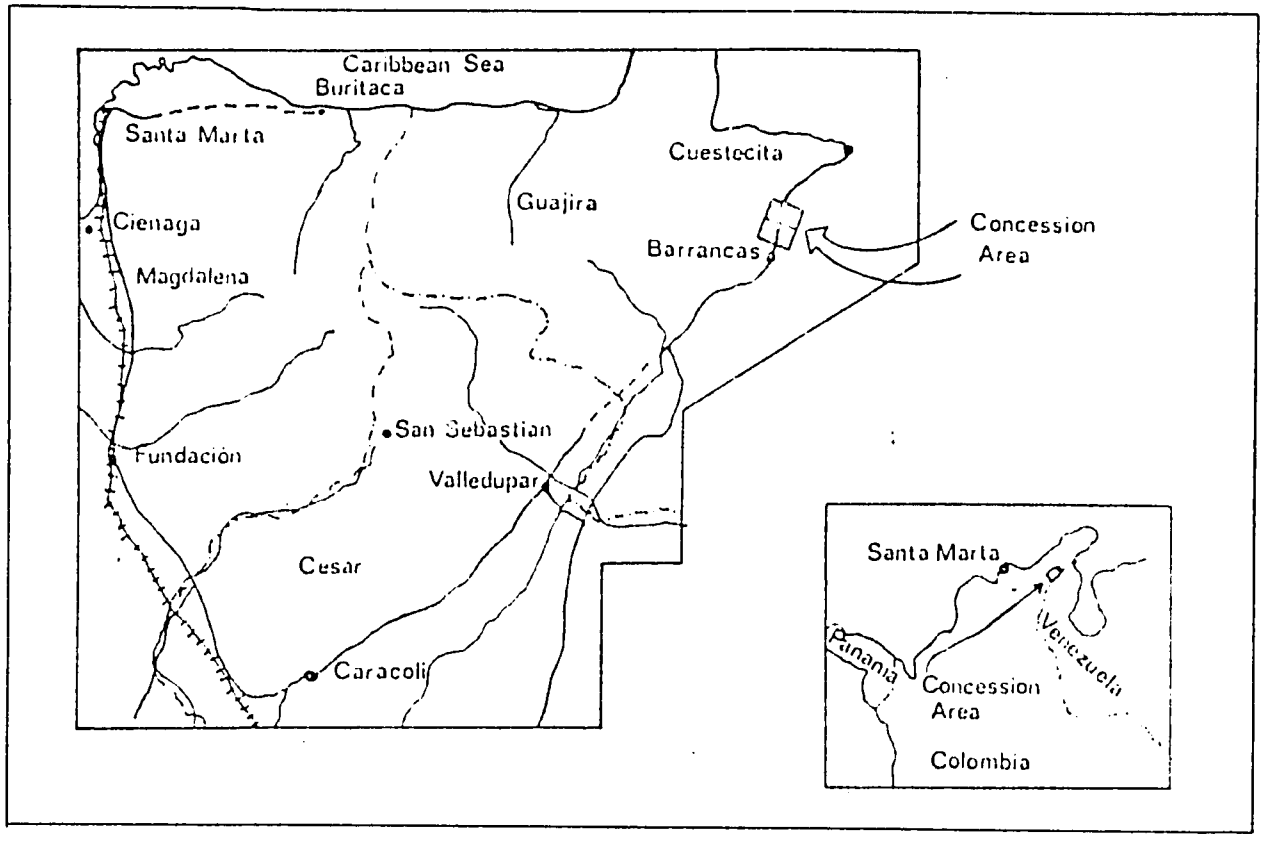



FIGURE 6 LOCATION OF THE CERREJON PROJECT

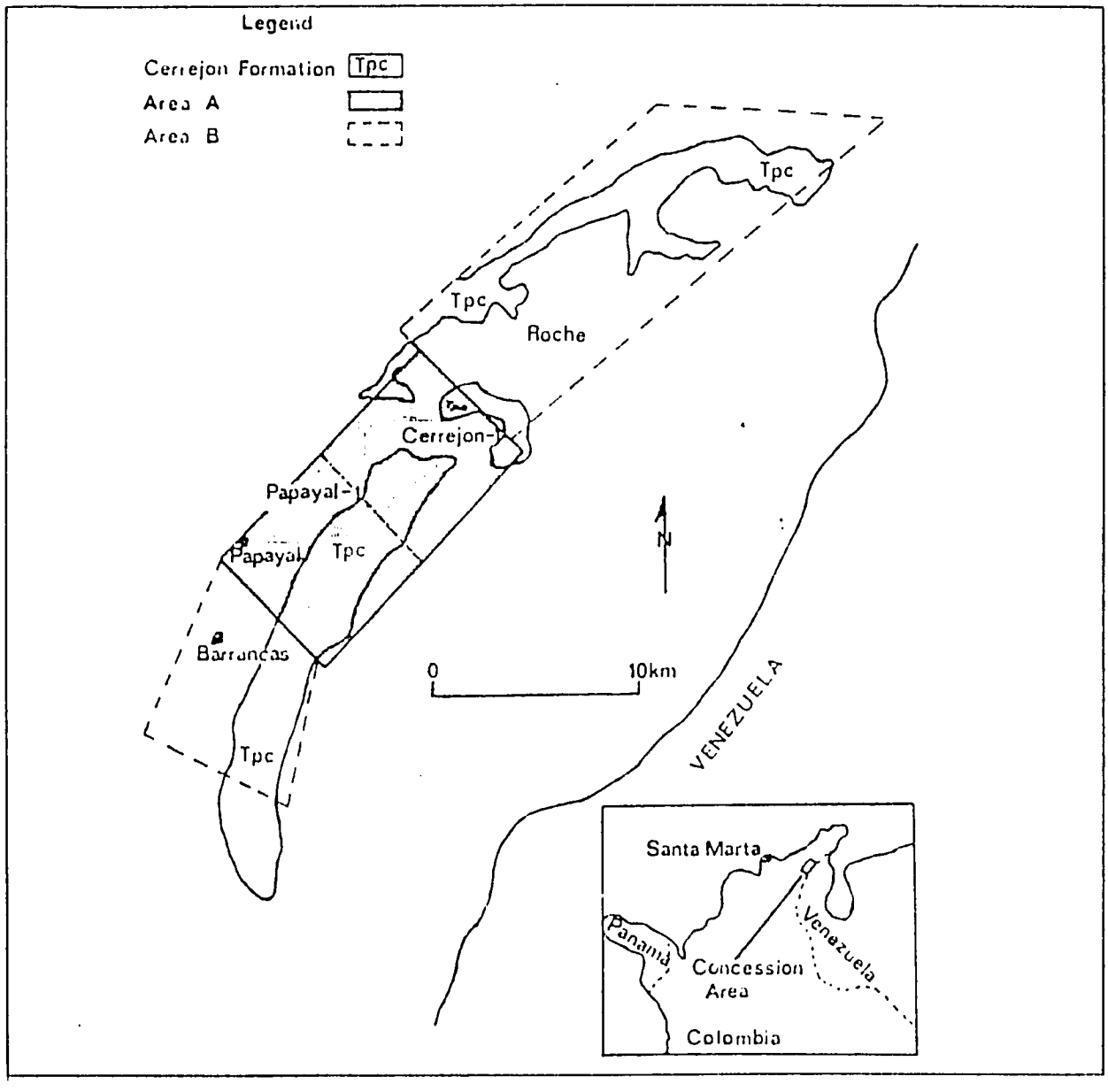



FIGURE 7 LAND STATUS AND LIMITS OF THE CERREJON COAL FIELD

### 3.2 The Pilot Mine Plan

In the early 1970's, Peabody considered beginning Cerrejon development with a pilot mine designed to produce 750,000 tons per year to test the feasibility of production from the field. Estimates were made for a $12.2 million pilot mine with coal truck haulage to a simple ship loading arrangement at Rio Hacha. Full scale production was envisioned as a mine with production between 2.5 and 7.5 million metric tons per year.

Peabody withdrew from Cerrejon development in 1976 but in July of 1978 Coal Week announced that a pilot mine developed by CARBOCOL was at last a reality. Production was scheduled to be underway by mid-July, 1978 at a rate of 500 to 1,000 metric tons per day for delivery to Atlantic coast cement and electric generating stations.

### 3.3 Geology and Exploration

The Tertiary coals of Cerrejon are overlain by Quaternary alluvium and talus and underlain by Cretaceous and Tertiary marine sediments, characterisically limestones. The coal zone consists of coal, shales and sandstones occurring between the lower fossiliferous calcareous sandstone marker and the uppermost coal beds. Above this seam there are further coal ccurrences but no detailed drilling has been done.

Even after 48,000 feet of drilling at the end of 1975, the knowledge of the geology of Cerrejon was far from precise. The coal beds strike north 40 degrees east and, as indicated in figure 8, dip southeasterly at 15 to 20 degrees in the west and 35 to 40 degrees in the east. Structures flatten out updip and may be near horizontal near Rio Rancheria. Roof and floor strata are usually 13 foot thick mudstones with fine sandstones in the northeast.

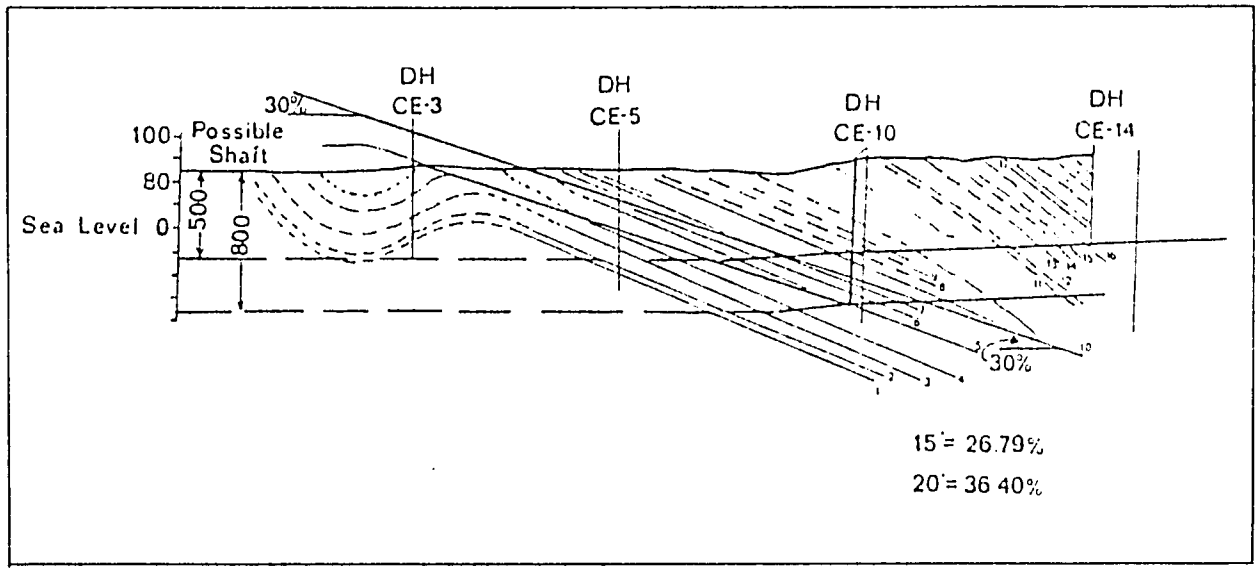



FIGURE 8 CROSS SECTION OF EL CERREJON COAL FORMATIONS

Correlation of the 20 workable coal seams in the area is complicated by the occurrence of many minor coal seams and due to the splitting of the coal into two or more beds. Exploration is made difficult by densely vegetated hardwood trees and cactus. Seams, 2 to 40 feet thick, are extensively faulted causing difficulty in correlation of beds. Environmental problems are created by the fact that the best aquifers in the region are often sheared coal seams. Boreholes indicate that some of the seams are gassy.

### 3.4 Reserves

Coal reserves in the entire, 80 square kilometer, sub-basin are estimated to be 330 to 350 million metric tons. The sub-basin is divided into 4 areas, Palmarito, Sarahita, Corazonal, and Rosillas. Of these 4 areas, Sarahita combines the most favorable mining access conditions. Total reserves in the Sarahita area are summarized in Table 1. These figures do not assume a specific mining procedure.

Table 1 Sarahita Coal Reserves and Grades

| Mining Methods | Reserves (million s.t.) | Stripping Ratios (cu.yd. of overburden) Average | Range |
|---|---|---|---|
| Opencast mining to 500 ft. below surface | 30.9 | 12.7/1.0 | 4.3/1.0 TO 30.3/1 |
| Opencast mining to 500 ft. below the surface | 51.2 | 8.1/1.0 | 4.3/1.0 to 13.9/1 |
| Opencast mining to 800 ft. below surface | 121.6 | 13.05/1.0 | |

In 1975, Peabody estimated recoverable coal reserves in the Sarahita block. Reserves of coal in seams pitching more than 30 degrees or greater than 50 meters (164 feet) below the surface were not included in the estimate because of difficulties in mining by open pit methods. The estimates were divided into coal occurring in seams with a pitch of less than 15 degrees and seams with a pitch greater than 15 degrees and less than 30 degrees. The reason for this last classification is the serious mining problems associated with coal removal from pits dipping more than 15 degrees. In such situations coal haulage by truck is difficult and loading methods differ from pits with more gentle slopes; terracing is required.

In the Sarahita block, 47.3 million metric tons of recoverable coal occur in seams with a dip of less than 15 degrees. Another 31.7 million metric tons of recoverable coal occurs in seams with a pitch of more than 15 degrees but less than 30 degrees, thus using basic parameters of a 50 meter (164 foot) cover limit and a minimum acceptable seam thickness of 2 meters, reserves within the concessions were estimated as 79 million metric tons of recoverable coal with an average virgin strip ratio of 6.3 cubic meters to one metric ton of coal. Allowing for a rehandle of a portion of the overburden the effective operating ratio is 8.8 cubic meters of overburden to one metric ton of coal. At a 5 million metric ton operating rate this reserve would last 16 years.

The reserves estimates were calculated with the formula (mean seam thickness) times planimetered area) times 1.3. The tonnage assumes a 1.3 specific gravity for the coal that leads to an estimate of 13,000 metric tons of coal per hectare for each meter of coal thickness. Mining losses in coals dipping 15 degrees were assumed at 10 percent and this was raised to 20 percent for coals dipping 15 to 30 degrees. A similar approach was used to calculate overburden.

### 3.5 Coal Quality

The quality of this coal is measured as an average grade of 15.5 percent moisture, 3.7 percent ash, 32.8 percent volatiles, 56.1 percent fixed carbon, and 0.52 percent sulphur. The coal has a swelling index of 1 1/2 to 1, an ash fusion temperature of 1100 to 1300 degrees centigrade, and a corrected calorific value of 11,264 BTU per pound.

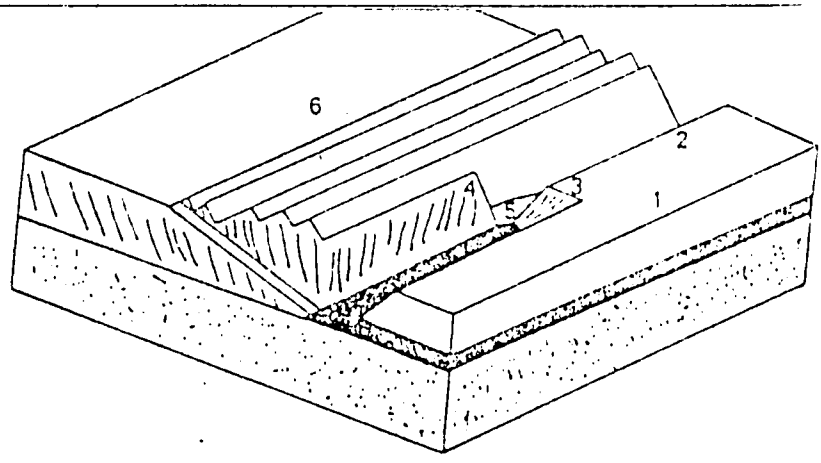
The analysis shows that the coal is bituminous with high volatile and moisture content and low ash and sulphur content. It is not a coking coal but is a good steam coal for use in spreader fired boilers, chain grate or underfeed fuel beds and pulvurized coal fired power plants.

### 3.6 Mining

Peabody's 1975 study considered alternate methods of mining, transport and handling of the coal for production rates of 2.5, 5.0 and 7.5 million metric tons annually. The initial cost estimate assumes the 5 million metric ton annual production rate in terms of 1979 cost levels. The annual production rate implies 15,000 tons per day over 330 days per year.

For analysis purposes, a mine life of 20 years is assumed, implying a coal reserve of 100 million tons at the 5 million metric ton per year operating rate. With the 5 million metric ton project as a basis for analysis, corrections are made for the larger and smaller mines estimated by Peabody in order to discuss the economies of scale for a range of mines between 2.5 and 7.5 million metric tons annually. Obviously the proved coal reserve estimate by Peabody of 79 million metric tons would have to be increased by CARBOCOL in order to justify the higher rates of production at this mine life.

The planned sequence for stripping and mining at Cerrejon is illustrated in Figures 9 and 10.




1. Topsoil
2. Overburden drilling and blasting
3. Overburden removal
4. Coal drilling and blasting
5. Coal loading and hauling
6. Reclamation

FIGURE 9 SEQUENCE OF COAL MINING OPERATIONS

The conventional method of coal surface mining is the procedure of excavating a sequence of parallel pits, placing the overburden from the pit being dug into the adjoining open pit previously excavated.

Area 1 is the location of vegetation and top soil removal. Scrapers move from Area 1 to Area 6 once the full cycle has been established replacing top soil on reclaimed spoil piles at location 6. In Area 2 the crawler drills are used for overburden drilling and blasting followed by the dragline at location 3 which removes overburden from the coal. Overburden from location 3 is cast by the dragline in to the spoil piles at location 4. Coal drilling, blasting, loading and hauling take place in the open panel at location 5

connected to the haulage roads and the rail loading facilities. Reclamation takes place in area 6 in several stages. The spoil piles are graded to an acceptable contour, top soil is replaced, and the area is replanted with vegetation.

Where overburden is thick the scrapers may be used in conjunction with the dragline to simplify scheduling and rehandle of overburden material. The scrapers are also useful in smoothing topography ahead of the dragline when it is knobby. Any low grade material on the surface of the coal seams is removed by a front-end loader.

One important consideration is the type of machine to be used for overburden removal. The types of machines widely used for this purpose include (1) shovel, (2) wheel excavator and (3) the dragline. The shovel and the pit operate from the pit floor and would not be suitable to the El Cerrejon application because of the steep pitch of the coal seams. The final alternative is the dragline which operates as indicated in Figure 10 from a bench of the overburden overlying the coal. The dragline has an advantage of excavating a deeper initial cut as any required in this coal field and is therefore the logical selection for the operation. Two crawler drills are used for drilling and blasting of overburden. Scrapers supplement the dragline operation to satisfy reclamation requirements that require handling of top soil.

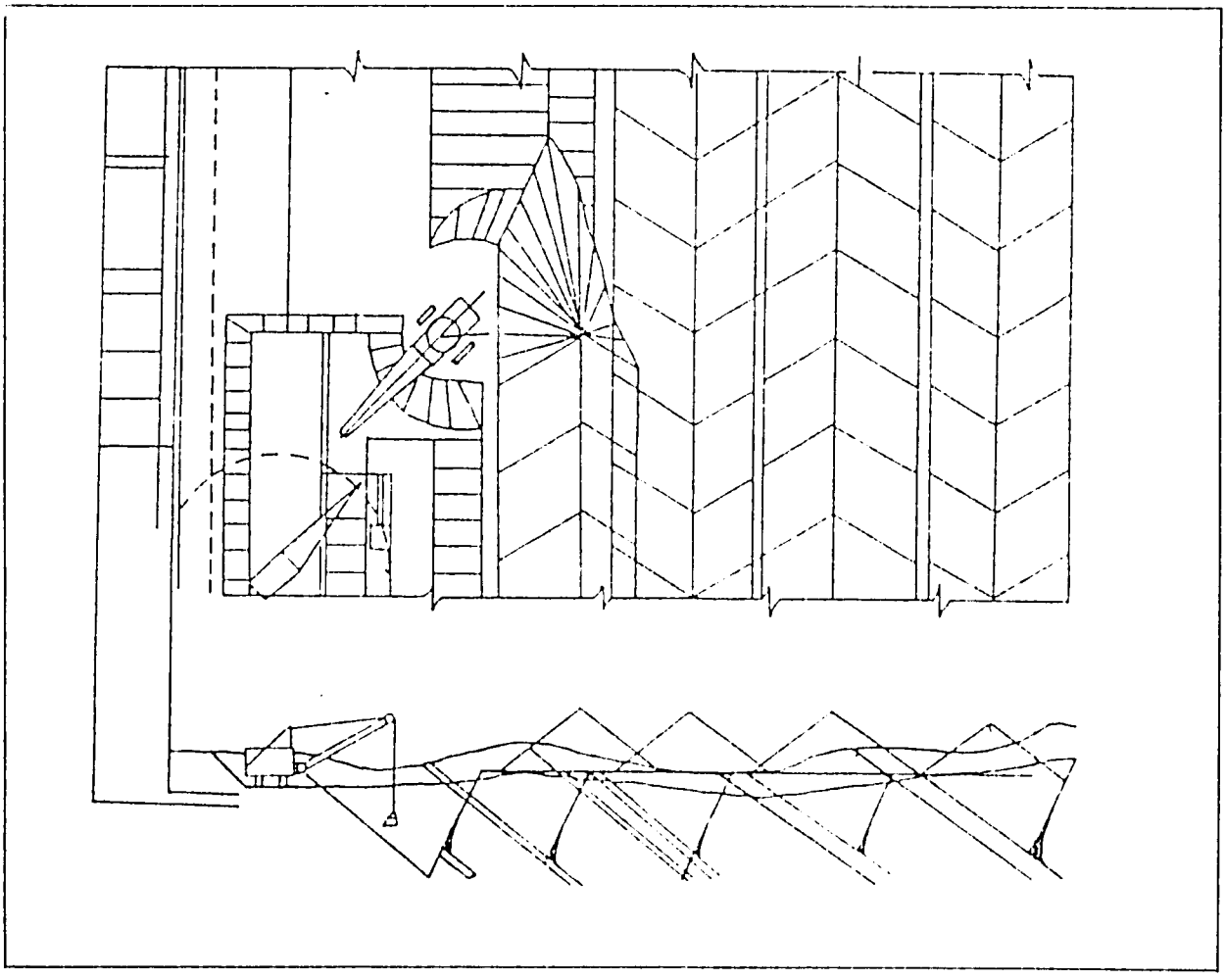


FIGURE 10 PLAN AND CROSS-SECTION OF COAL MINING OPERATION

The coal at El Cerrejon also requires drilling and blasting prior to loading. Four crawler-mounted diesel-powered rotary drills are used for this purpose. Plans for coal loading include a coal shovel with a 24 cubic yard bucket expected to load at a rate of 1300 tons per hour. Two front-end loaders assist the shovel with clean-up.

In areas with coal dipping 15 degrees or less a coal shovel will load coal directly in to haulage trucks. Haulage trucks traverse the open pit delivering the coal to a hopper at the plant loading site or to a belt conveyor designed to transport the coal to the plant loading site. Where coal dips greater than 15 degrees there are serious problems. Coal haulage by truck is difficult and alternative methods must be employed. Various alternatives include using terraces to provide a level road bed in combination with coal loading procedures that use dozers, shovels, high lifts, and front-end loaders. Procedures are determined by pit conditions.

### 3.7 Coal Transport at the Mine

It is assumed that coal hauling will be done using 120 ton bottom dump tractor-trailer units. Costs are based on estimation of hourly operating and ownership costs which include fuel consumption, tire life, speed, haul distance, road grade, and load and position time assumptions. Based on a simulated load haul cycle it was estimated that 22 trucks would be required to meet El Cerrejon production objectives. Because the road grade in the pit is over 15 percent, profile studies indicated that the large coal hauling units would have trouble getting out. Wheel dozers were added to help push the trucks up the adverse ramps. These units are also available for general cleanup in the pit.

Initially, the coal haulage trucks deliver the coal directly to a receiving hopper at the plant loading site. Later, as the working face becomes more distant from the plant, trucks deliver to a receiving hopper for belt conveyor transport to the plant loading site. Access to the pit is gained through a road system entering from the northeast. Haul road ramps are extended cut by cut utilizing the drag line, dozers and motor-graders. The main roads are located at a convenient distance from the bottom of the coal seam with a 15 percent ramp connecting the operational areas to these main haulage ways. All haul roads are surfaced with clinker material and are maintained with motor graders and water trucks. Scrapers are used for major damage.

The coal handling facilities will be major consumers of electric power. Electric power will be made available from the power generation plant consuming coal from the field.

### 3.8 Reclamation

Reclamation regulations require salvage of top soil from all areas. Stockpiling is necessary during the early phases of production in order to have top soil on hand when reclamation of the spoil piles begins. Once the cycle is established two scraper units can haul directly from prestripping areas to dump points where reclamation is under way.

### 3.9 Transport Alternatives to the Coast

The mountains to the west of the Cerrejon field block direct access to a suitable deep water port on the north coast. The possible alternatives include truck, rail, conveyor belt and pipeline. These alternatives are summarized in Figure 11.

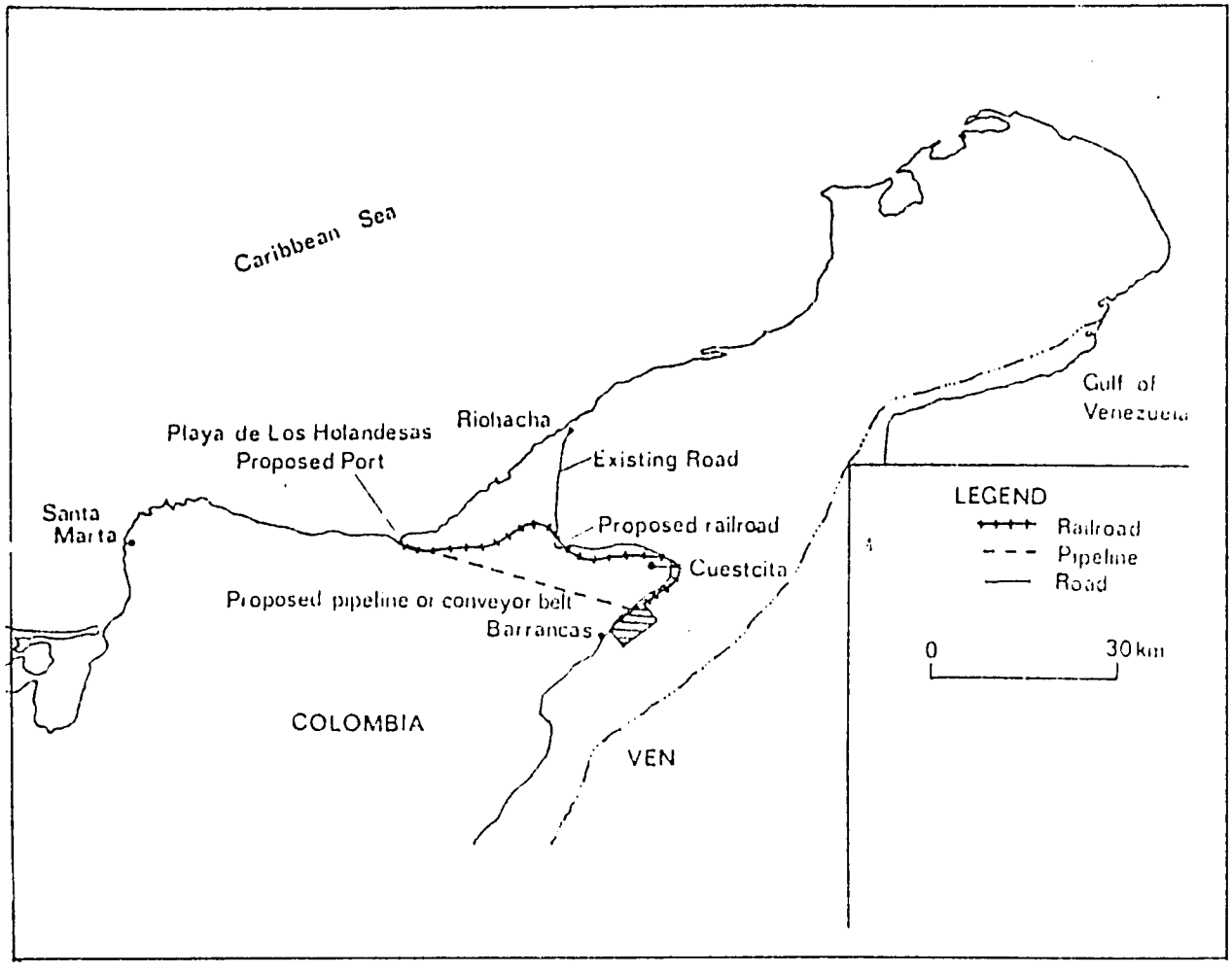



FIGURE 11 TRANSPORT ALTERNATIVES TO THE NORTH COAST

### 3.9.1 The Truck Alternative

In development of the pilot mine consideration was given to truck haulage as far as Rio Hacha, a distance of 80 kilometers (50 miles) from the project. However, the full scale mining operation would ship to a more distant deep water port at Playa de Los Holandesas, a distance of 120 kilometers (75 miles). Estimated truck haulage costs over this distance in 1979 dollars would be $0.15 per ton-mile or $11.25 per ton plus $0.15 for road maintenance — an expensive alternative.

### 3.9.2 The Conveyor Alternative

Long distance belt conveyors have proven themselves for coal transport. For this reason, an 80 kilometer (50 mile) conveyor belt in a straight line from the project to Playa de Los Holandasas was considered by Peabody. The estimated cost in 1975 was $80 million for the conveyor and preparation of the right-of-way and road over the rugged terrain. The conveyor would have to rise 1600 feet in the first 25 miles, then decline 2000 feet to the sea in the second 25 miles.

Capital costs would be higher in 1979, perhaps as much as $2.2 million per mile compared to $1.6 million per mile in 1971. The investment in 1979 then would be $110 million which, if amortized over 10 years, would move 24 million tons of coal a year for $4.58 per ton exclusive of operating costs or return on investment. Thus the conveyor alternative indicates a cost of $6.00 to $7.00 per ton.

### 3.9.3 The Pipeline Alternative

Pipelining of coal is also a possibility. The Cadiz Ohio 10-inch diameter, 108 mile long coal pipeline and the Black Mesa 273 mile coal pumping system have been successful. However, the key to success of these installations was a one mine-one destination arrangement with sufficient water for one-way flow. Conditions at Cerrejon are more difficult. Topography is rough causing high construction costs and the water system would have to be closed because of an inadequate supply at the plant. In addition, the system would require a customer that would find it profitable to install a slurry recovery and drying system to receive a high tonnage. Cost estimates on the assumption of 8000 tons per day or 2.2 million tons per year. This amounts to $2.50 per ton in 1975 dollars which would update to approximately $3.40 per ton in 1979. The alternative is attractive.

### 3.9.4 The Rail Alternative

The fourth alternative for transport from mine to port is a railroad. The route must be chosen to meet limitations on road grade (maximum 0.5 percent) and curvature (maximum 6 degrees). The proposed system assumes direct loading of coal into railroad cars without stockpiles. Extra railroad cars provide coal loading while locomotives are moving between mine and port. The 1975 estimate for the railroad to transport 2.4 million tons annually was $31 million. Total costs were $5.9 million annually including depreciation, interest, and insurance. The estimated cost of $2.36 per ton of coal would be corrected to about $2.90 per ton in 1979. This is the lowest cost of the alternatives and has additional advantages in that it provides rail transportation for the region between Cerrejon and the coast.

## 3.10 Coal Preparation

Coal preparation is assumed limited to a breaker to reduce size of the coal and eliminate waste. It is unlikely that washing of the coal will be required.

## 3.11 Power

Coal from the Cerrejon field will be a source of fuel for a steam power plant which will produce power required at the mine. Principal consumer of electric power at the mine will be the 18 cubic yard dragline used for stripping the coal.

## 3.12 Port Site Handling

A port site storage and handling facility for Playa de Los Holandasas is shown in Figure 12. Order of magnitude estimates of the cost of the facility are based on Peabody experience.

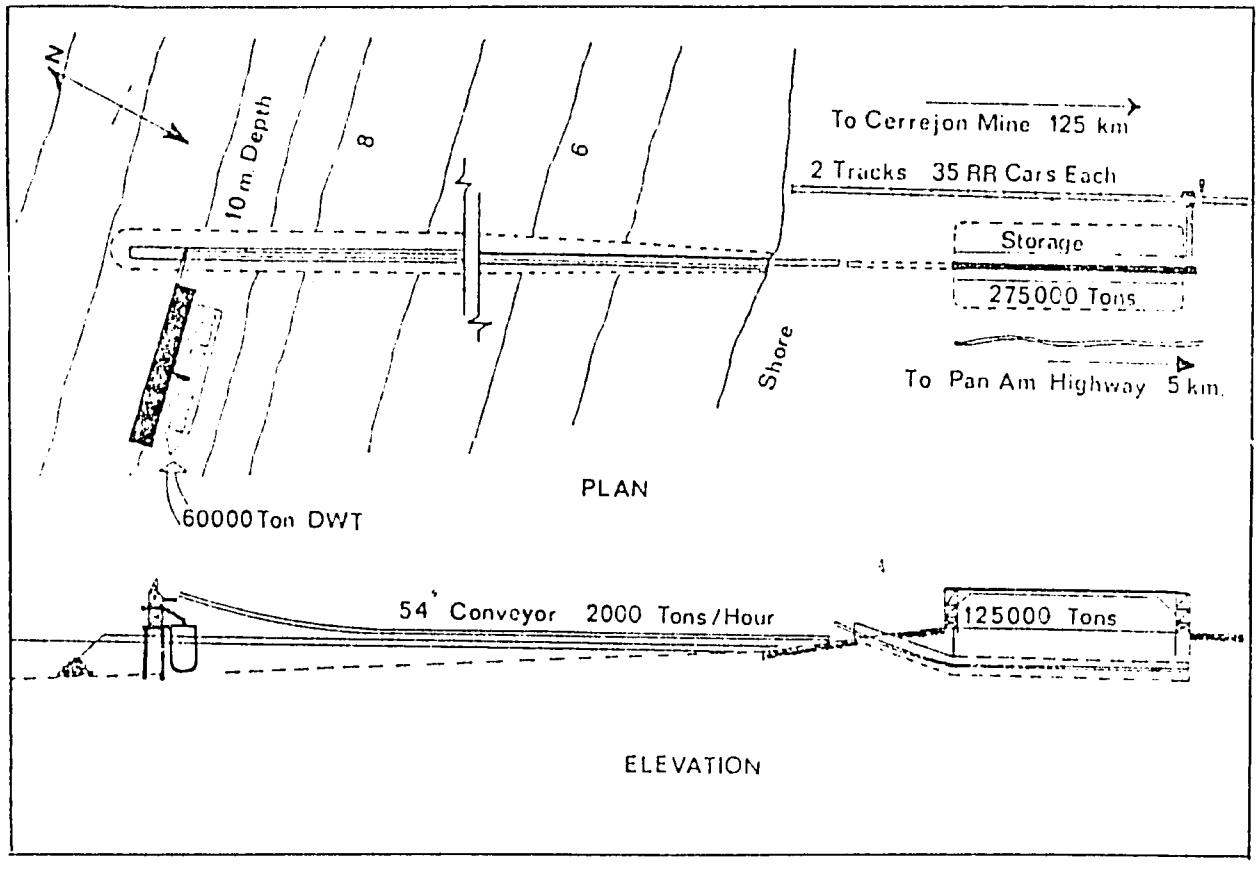



FIGURE 12 PROPOSED SHIPLOADING FACILITY AT PLAYA DE LOS HOLANDASAS

## 4. ESTIMATED COSTS

### 4.1 Capital Costs

The preceding physical description of the Cerrejon project leads to estimates of capital and operating costs. In 1975, Peabody considered three project sizes; 2.5 million, 5.0 million and 7.5 million metric tons annually. The 5 million ton project was re-estimated in 1979 dollars in more detail than the original estimates. Costs were estimated using the Stramm Handbook (Stramm, 1979), supplier quotes, and the Canadian Handbook of Mineral Processing Equipment Costs (Mular, 1978).

Table 2 summarizes the 1979 estimate.

Table 2 Cerrejon Capital Costs, 1979

| | $ Millions |
|---|---|
| Mining Equipment | |
| 2 draglines plus erection: $61.9 million | |
| 22 haulage trucks: $7.9 million | |
| Balance: drills, dozers, loader, crane, coal breaker and loadout facility | 91.1 |
| Operations and Maintenance Support | |
| trucks: explosives, welding, water, mechanics, lubrication, etc. | 1.7 |
| Total, Mine | 92.8 |
| Repair Shops and Warehouses | 4.8 |
| Townsite | 8.6 |
| Railroad | 42.2 |
| Port and Loading Facilities | 18.9 |
| Other Ancillary Facilities | |
| water systems, communications, offices, laboratories, surface buildings | 0.9 |
| Total, Ancillary | 75.4 |
| Total Mine Equipment and Ancillary | 168.2 |
| Location Correction (US, Canada to Colombia) (30%) | 50.5 |
| Contingency (30%) | 65.6 |
| Working Capital (6 mo. operating costs) | 13.0 |
| Total Required Capital | 297.3 |

Only one detailed update of the Peabody estima was prepared. Table 3 is a summary of estimated capital costs for other mine siz based on the assumption that changes in 1979 are porportional to the changes due to size estimated by Peabody in 1975. The current estimate includes correction for location as well a a contingency factor and working capital which were not included in the Peabody estimates. The right hand column includes all of these corrections. The contingency factor covers unforeseen but expected cost increases. It is not a substitute for an inadequate estimate.

Table 3 Summary of Estimated Capital Costs

| Size million metric tons annually | 1975 mine equipt + ancillary | 1979 mine equipt +ancillary | 1979 including location correction contingency and working capital |
|---|---|---|---|
| | $ million | $million | $ million |
| 2.5 | 103.0 | 120.8 | 204.2 |
| 5.0 | 143.5 | 168.2 | 297.3 |
| 7.5 | 179.0 | 209.8 | 354.6 |

## 4.2 Operating Costs

The annual operating costs for the Cerrejon project require an estimate of manpower, equipment, supplies and fuels which is then translated into the estimate of annual operating costs summarized in Table 4.

Table 4 Summary of Annual Operation Costs for 5 Million Metric Ton Annual Production, 1979

| | Annual Cost $(000) | Cost per Metric Ton, $US |
|---|---|---|
| Mining | | |
| Overburden blasting | 3006 | 0.60 |
| Stripping | 7193 | 1.44 |
| Coal blasting | 442 | 0.09 |
| Coal loading | 3401 | 0.68 |
| Coal haulage | 3323 | 0.66 |
| Road maintenance | 1080 | 0.20 |
| Reclamation | 556 | 0.11 |
| Management and Supervision | 1964 | 0.39 |
| General operations | 1408 | 0.28 |
| Railroad | 2112 | 0.42 |
| Port and loading facilities | 1647 | 0.33 |
| Total | 26,132 | 5.23 |

These operating cost estimates do not include a "contingency" factor similar to the one applied to the capital cost estimates. However, there is an implicit contingency factor built into the estimate through assumptions of a 50 minute hour, ample cycle times to complete work in less than 100 percent availability.

The figures in Table 4 assume 1979 wage rates, 70 percent fringe benefits and 1979 equipment operation costs. Employment for the 5 million metric ton mine totals 576 men of which 210 are operating labor, 248 are maintenance and supply labor, and 109 are management and supervision. On the basis of 240 man days per year the productivity is 99 tons per man shift in the mine and 36 tons per man shift overall. The Peabody estimates assumed 427 men in the 5 million metric ton per year mine, an average productivity of 49 tons per man shift overall.

### 4.3 Corrections for Alternative Mine Sizes

The 1975 Peabody estimates were calculated for 3 different mine sizes and the relationship between operating costs for these 3 mines was used to extend the 1979 estimate to all 3 projects. These relationships are summarized in Table 5.

Table 5 Annual Operating Costs
2.5, 5.0 and 7.5 Million Metric Ton Mines

| Size million metric tons | 1975 $ (000) | 1979 $ (000) |
|---|---|---|
| 2.5 | 10,548 | 14,641 |
| 5.0 | 18,826 | 26,132 |
| 7.5 | 27,117 | 37,641 |

The preceding annual cost estimates provide a basis for financial analysis of three alternative size mines for the Cerrejon project.

## 5. HISTORICAL DEVELOPMENT OF THE PROJECT

The files of Instituto de Fomento Industrial de Bogota (IFI) document the extensive studies of the Cerrejon coal basin. These studies date back to a first report in 1882 when Jose Carlos Mano reported the occurrence of coals in the Cerrejon sub-basin, 100 kilometers inland from Colombia's northern coast. Development work on these deposits is summarized in chronological sequence as follows:

### 1882-1970

A series of technical reports over many years culminated in an extensive report by Engineering and Woomer Associates, Vetter, Mutis and finally an extensive report by Engineering Technical Services Pty Ltd of South Africa in accordance with an agreement with IFI. The report was based on 24 cored boreholes, field work and reserve calculations in the Sarahita block. This report was submitted to IFI in September of 1970.

## 1971

Preliminary investigations by Peabody Coal led to a pilot mine proposal in the Sarahita block. The pilot mine would involve production of 750,000 tons per year, shipment by truck to a simple shiploading facility at Riohacha. The investment projected was 12.2 million U.S. dollars.

## 1972

A memorandum of agreement was drawn up between IFI, the Colombian Development Organization holding exploration rights, and Peabody with exploration confined to 10,000 hectares (24,700 acres).

## 1973

Phase 1 of the Peabody work began with the Cerrejon exploration camp located at Maguey midway between the two IFI concession areas. An old camp was rehabilitated sufficient for the needs of a field staff of 30. Survey lines established lines and tied them to national geodetic stations. Surveyors ran traverses to define the Sarahita block and extended the block to the west bank of Rio Rancheria on the basis of favorable drilling results.

Conventional rotary geophysical shothole drill rigs were determined an effective drilling system for reconnaisance with a geologist kept on hand to keep a log of cuttings. A drilling contract provided for using Mayhew No. 1000 rigs on holes drilled to 160 meters (525 feet). Progressive interpretation of reserves were made from boreholes plotted on a 1 to 2000. Volumes and tonnages were calculated based on a specific gravity of pure bitiminous coal (1.32).

The result indicated coal reserves in the field of 347 million metric tons of high volatile bitiminous coal. A total of 193 million metric tons are determined within the IFI concessions and it remains to prove recoverable coal. A report was submitted in August of 73.

## 1974

Phase two of Peabody work began with exploration extended to define the full extent of the field and delineate seams and structures to determine recoverable reserves and define coal quality. In late 1974 the Colombian government decided to restrict work to the IFI concessions.

## 1975

Phase Two of Peabody work was terminated in September of 1975 because of a governmental decision to restrict exploration and because sufficient data was available for further negotiations. A preliminary technical and economic analysis report was prepared dated November, 1975.

## 1976

Peabody decided to abandon development of the Cerrejon project. Since 1976 CARBOCOL has undertaken a pilot mining project which is expected to produce 1000 tons per day by 1980. This pilot development of the coal deposits is expected to lead to full scale production at a rate of 13,000 tons per day.

During 1978, CARBOCOL announced production at the Cerrejon field will begin in mid-July. Initial production will be 500 to 1,000 metric tons per day for delivery to cement and electric generating stations on the Atlantic coast.

## 6. MARKETING

Production at CARBOCOL's Cerrejon coal field began in July of 1978. The plan is to produce 500 to 1000 metric tons a day of steam coal to be sold to Colombian cement plants and electric generating stations on the northern coast of the Caribbean.

The Colombian Department of Planning estimates that domestic coalfired power plant demand will rise by a factor of 2.3 between 1981 and 1985, from 997,000 metric tons to 2.3 million metric tons per year. Specific markets for Cerrejon coal include the Corelca Utility Plant on the Caribbean which is bargaining for 2000 metric tons daily of Cerrejon coal. The cement plant market is expected to be 500 metric tons per day by 1980-81.

Development of the full production capacity of Cerrejon in the near future will depend on export markets in the United States, South America, Europe and Asia as indicated in Figure 13.

FIGURE 13 EXPORT MARKETS FOR CERREJON COAL

### 6.1 Freight Rates

Freight rates for coal between the east coast of the United States and Brazil was $9.50 to $10.00 per ton in June of 1979. For this analysis, estimated ocean freight costs for Cerrejon coal are assumed $10.00 per metric ton to New Orleans and $32.00 per metric ton to Tokyo.

## 6.2 Prices

Prices of fuel for steam power electric generation have soared since 1972-73 as a result of the oil embargo and OPEC price increases. The disproportionate increase in oil costs shown in Figure 14 have accelerated a shift toward coal as a power source. A 1978 report by the U.S. Department of Energy indicates that in 1974 57 percent of fossil fuel electric generating was due to coal while in 1976 this proportion had increased to 61 percent.

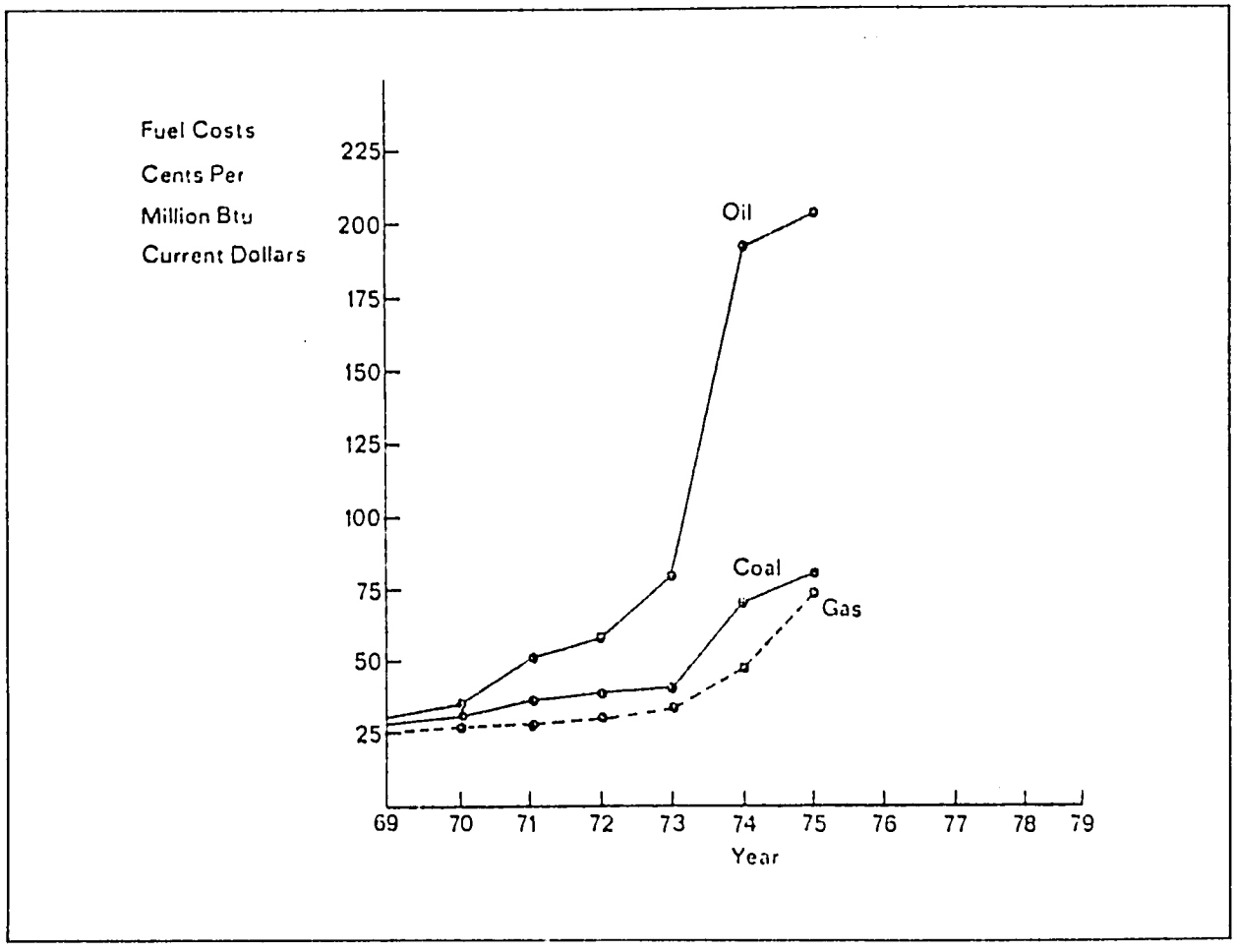



FIGURE 14 FOSSIL FUEL COSTS FOR UTILITY STEAM-ELECTRIC GENERATION PLANTS, 1969-75

In June of 1979, Coal Week reported "Spot and term marker prices" for steam coal. "Marker" prices are derived from confidential discussions with buyers, sellers, traders and brokers. Prices do not represent actual transactions but rather a "state of the market". Quality specifications are held constant in the quotes and represent coals of current interest. "Spot" prices in contrast to term prices relate to theoretical deliveries that span one year or less.

Coal prices vary with quality differences; thus corrections are necessary for deviation from marker coal specifications for heat value, sulfur, and ash content. Some examples of term marker prices in June of 1979 are summarized in Table 6.

Table 6 Selected Contract and Spot Marker Steam Coal Prices in the U.S. (Coal Week, 6-4-79)

| Producing Districts | Specifications | | | FOB Mines $/t | |
|---|---|---|---|---|---|
| | BTU/lb | Sulfur% | Ash% | Term | Spot |
| Central Pennsylvania | 12,300 | 2.0 | 13.0 | $23.50 | $22.25 |
| Northern West Va. | 12,300 | 3.0 | 13.0 | 23.00 | 21.50 |
| Illinois | 10,500 | 3.5 | 13.0 | 21.00 | 18.50 |
| Alabama and southern Tenn. | 12,500 | 0.75 | 10.0 | 31.00 | 28.00 |
| New Mexico and Arizona | 10,000 | 0.5 | 10.5 | 16.00 | 15.00 |
| Utah | 11,500 | 0.6 | 9.0 | 19.75 | 19.00 |
| Northern Colorado | 10,700 | 0.5 | 9.1 | 17.50 | 16.75 |
| Southern West Va., eastern Kentucky, northern Tenn., parts of West Va. | 13,000 | 0.7 | 9.0 | 32.25 | 31.00 |

The international spot steam coal price at Mobile, Alabama was $38.50 per long ton FOB Piers in June, 1978 for coal with specifications of 12,200 BTU per pound, 1.25 percent sulfur and 14 percent ash.

### 6.3 Coal Characteristics and a Price for Cerrejon Coal

Coal quality at Cerrejon was determined by Peabody Coal drilling at 67 locations with a minimum acceptable core recovery of 70 percent. The weighted average in-place coal seam assay based on 85 seam analyses was 8.28 percent moisture, 4.32 percent ash, 38.83 percent volatile matter, 0.62 percent sulfur, and a calorific value of 13,325 BTU per long ton. Difficult mining conditions indicated a mining dilution factor should be relatively high.

Eight analyses were carried out by Peabody's central laboratory and corrections made in the average equilibrium moisture in the samples. On the basis of this result a corrected assay is summarized in Table 7.

Table 7 Coal Characteristics

AREA A

| | |
|---|---|
| Area (Hectares)* | 10,000 |
| Seams Encountered | 20 |
| Seam Thickness (range, ft) | 2 to 40 |
| Dip (Degrees) | 15 to the East<br>Up to 40 |
| Density (lb./cu ft) | 80 |
| Reserves (Short Tons) | 120,000,000 |
| Stripping Ratio | 10.4/1.0 |

*2.47 acres= 1 hectare

CORE ANALYSIS

| | |
|---|---|
| Moisture Content % | 15.54 |
| Ash (%) | 3.65 |
| Volatile Matter (%) | 32.80 |
| Fixed Carbon (%) | 47.79 |
| Sulfur (%) | 0.52 |
| Caloriforic Content (BTU/lb) | 11,254 |
| Coal Rank | High volatile B Bituminous |

More detailed studies of the market obviously are required before a final decision is made on a range of price for feasibility analysis purposes. For purposes of this analysis we use the Mobile, Alabama market as a basis and make corrections for Cerrejon heat content, sulfur content, and ocean freight.

| | | |
|---|---|---|
| Correction for calorific value | (11254/12200) x $38.50 = | $35.51 |
| Plus Premium for low sulfur<br>($0.40 for each, 0.1% difference) | (12.5 - 5.0) x $0.40 = | 3.00 |
| Total | $38.51 | |
| Less ocean freight | | 10.00 |
| Net value fob<br>Playa de Los Holandesas | | $28.51 |

Given the continuing and accelerating energy problems of the U.S. and a probable shift in the direction of coal, a long term price for feasibility analysis of Cerrejon would seem to be in the range of $25.00 to $35.00 per metric ton. It is worth noting that the coal of the Cerrejon area has been quoted elsewhere in the range of 13,500 to 13,890 BTU's per pound. Apparently this does not take in to account the moisture correction made in the Peabody analysis.

## 7. FINANCING

In 1976, the state-owned corporation Carbones Colombianos "CARBOCOL" was formed to further exploration and development of coal on a joint venture basis. The initial capital of 367.3 million Colombian Pesos ( 10.1 million U.S. dollars) came from government enterprises as indicated in table 8.

Table 8 Financing of Carbones Colombianos, CARBOCOL, 1976

| | PESOS |
|---|---|
| Empresa Colombiana de Petroleos (ECOPETROL) | 180,000,000 |
| Instituto de Fomento Industrial (IFI) | 142,517,000 |
| Cerrejon Carboneras | 4,830,000 |
| Ingeominas | 40,000,000 |
| Colminas | 1,000 |
| Ecominas | 1,000 |

The financial capability of CARBOCOL is limited so that its functions are oriented to promote development of Colombian coal resources with a combination of foreign and national participation. With few exceptions, CARBOCOL will participate directly in such projects as they do in the Cerrejon project.

### 7.1 A Joint Venture Agreement with EXXON

A joint venture contract has been signed by CARBOCOL and INTERCOR, a subsidiary of EXXON to develop a portion of the Cerrejon reserves. The contract was signed in December of 1976 and is a model for future coal development contracts in which foreign capital is involved. CARBOCOL and the foreign investor work on a 50/50 joint account basis. The total investment in the project is 500 million U.S. dollars of which the CARBOCOL portion is 250 million U.S. dollars, the EXXON portion is 175 million U.S. dollars and 75 million dollars will be financed externally during the 1978-1980 period. It is expected that most of the coal production will be exported. EXXON has agreed to expend $20 million in petroleum or gas exploration over the 4 years following the signing of the coal contract. They also agree to expend $5 million over 5 years to help Colombia evaluate its coal reserves beginning with the first export from Cerrejon.

Under the agreement, exploration costs are paid by the foreign investor, INTERCOR, and INTERCOR becomes the operator if economic reserves are discovered. In the event of discovery coal production revenues are split 50/50 between the operator and CARBOCOL. The maximum term of a contract is 30 years broken down in to 3 years for exploration, 4 years for development and 23 years for production. The operator pays a 15 percent royalty to CARBOCOL in cash or in coal. The contract fixes a ceiling on overall government participation.

In addition to profits and remittance taxes, INTERCOR will pay an increasing share of any profits over 35 percent of the indexed investment. The scale ranges from 2 percent on amounts up to $25 million over the basic 35 percent profit and reaches 90 percent on profits of $250 million or more. CARBOCOL's earnings are based on an income tax rate of 52 percent. The foreign investor may remit profits up to a 20 percent ceiling on registered foreign capital. In the case of Cerrejon this remittance restraint

has been raised.

### 7.2 Other Potential Joint Ventures

Contracts similar to the EXXON-CARBOCOL contract are expected to be negotiated with other foreign investors. The Royal Dutch Company and Shell have entered into talks on a joint venture with CARBOCOL under the same agreements concluded with EXXON. ARCO Colombian Oil Corporation has proposed another joint venture with CARBOCOL and the Colombian government has indicated that the area must be divided into two parts for the purpose of negotiating separate agreements between the interested companies.

Another potential coal area known as San Vicente de Chucuri is also a subject of possible joint ventures. Utah International Inc. has proposed an option to begin geological work in the area. In addition contracts were recently signed with Romania, Spain and Brazil to prove reserves in the Cundimarca and Boyaca coal areas. In the future CARBOCOL will negotiate for financial and technical assistance to small mining companies which have been using primitive methods for exploitation of coal deposits.

## 8. FINANCIAL EVALUATION

The appendix to this chapter summarizes a series of financial analyses based on Cerrejon data. These evaluations are an illustrative rather than an exhaustive evaluation of possible future cash flows of the project.

The analyses investigate the sensitivity of project economics to different prices, different rates of cost and price escalation, the effect of three different production rates, sensitivity to tax rate changes and royalty rate changes. They are included in the appendix as a basis for discussion of the economics of the Cerrejon coal field development.

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CERREJON ANALYSIS REFERENCE NUMBER 100.

FIRST YEAR OF INVESTMENT CASH FLOWS 1979.
LAST YEAR OF INVESTMENT CASH FLOWS 1983.
PRICE INDEX THAT APPLIES TO OPERATING COSTS 222.3
MINIMUM ACCEPTABLE DISCOUNT RATE 10.0
PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (% ) 10.0

SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1983.

| YR. | COST INDEX | CASH FLOW(1968 $) TOTAL | CASH FLOW(1968 $) NET EQUITY | CASH FLOW (ESC. $) TOTAL | CASH FLOW (ESC. $) NET EQUITY | NO. EMPL. |
|---|---|---|---|---|---|---|
| 1979. | 600.0 | 29730. | 29730. | 29730. | 29730. | 0. |
| 1980. | 660.0 | 44595. | 44595. | 49054. | 49054. | 0. |
| 1981. | 726.0 | 89190. | 89190. | 107920. | 107920. | 0. |
| 1982. | 798.6 | 89190. | 89190. | 118712. | 118712. | 0. |
| 1983. | 878.5 | 44595. | 44595. | 65292. | 65292. | 0. |
| NET INVESTMENT | | 297300. | 297300. | 370708. | 370708. | |

DEPRECIABLE INVESTMENT ($000) 263203.
MINEABLE ORE RESERVE (000 M.T.) 120000.
MINE LIFE (YEARS) ORE RESERVES/AN. PROD. RATE 0.
ANNUAL ROYALTY RATE (% OF GROSS REV.) 0.0 0.0
COMBINED EFFECTIVE TAX RATE 40.0 40.0

CERREJON ANALYSIS REFERENCE NUMBER 100.
CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1984. | 1985. | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 31.80 | 33.71 | 35.73 | 37.87 | 40.15 | 42.56 | 45.11 | 47.82 | 50.68 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. |
| AVERAGE TOTAL COST ($/METRIC TON) | 20.21 | 21.24 | 22.32 | 23.47 | 24.69 | 25.98 | 27.35 | 28.80 | 30.34 | 31.97 |
| REVENUE ($000 U.S.) | 150000. | 159000. | 168540. | 178652. | 189372. | 200734. | 212778. | 225545. | 239077. | 253422. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 42115. | 44642. | 47320. | 50159. | 53169. | 56359. | 59741. | 63325. | 67125. | 71152. |
| EQUALS GROSS INCOME ($000) | 107885. | 114358. | 121220. | 128493. | 136203. | 144375. | 153037. | 162219. | 171953. | 182270. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. |
| LESS TAX ($000) | 32626. | 35215. | 37960. | 40869. | 43953. | 47222. | 50687. | 54360. | 58253. | 62380. |
| EQUALS NET INCOME AFTER TAX ($000) | 48939. | 52823. | 56940. | 61304. | 65929. | 70833. | 76030. | 81539. | 87379. | 93570. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. | 26320. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 0. | 0. | 5561. | 5894. | 6248. | 6623. | 7020. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 75259. | 79143. | 83260. | 87624. | 92250. | 91592. | 96456. | 101612. | 107077. | 112870. |
| CONSTANT (1969) DOLLAR CASH FLOW ($000) | 56238. | 55793. | 55373. | 54976. | 54602. | 51145. | 50812. | 50498. | 50202. | 49922. |

CERREJON ANALYSIS REFERENCE NUMBER 200.
CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1994. | 1995. | 1996. | 1997. | 1998. | 1999. | 2000. | 2001. | 2002. | 2003. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE, COAL ($/MT) | 53.73 | 56.95 | 60.37 | 63.99 | 67.83 | 71.90 | 76.21 | 80.78 | 85.63 | 90.77 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 32.13 | 34.04 | 36.05 | 38.19 | 40.45 | 42.86 | 45.40 | 47.67 | 50.53 | 53.56 |
| REVENUE ($000 U.S.) | 134314. | 142372. | 150915. | 159970. | 169568. | 179742. | 190526. | 201958. | 214075. | 226920. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 42542. | 45094. | 47800. | 50668. | 53708. | 56930. | 60346. | 63967. | 67805. | 71873. |
| EQUALS GROSS INCOME ($000) | 91772. | 97278. | 103115. | 109302. | 115860. | 122812. | 130180. | 137991. | 146271. | 155047. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 1808. | 1808. | 1808. | 1808. | 1808. | 1808. | 1808. | 0. | 0. | 0. |
| LESS TAX ($000) | 35986. | 38188. | 40523. | 42998. | 45621. | 48402. | 51349. | 55196. | 58508. | 62019. |
| EQUALS NET INCOME AFTER TAX ($000) | 53978. | 57282. | 60784. | 64496. | 68431. | 72602. | 77023. | 82795. | 87762. | 93028. |
| PLUS NON CASH FLOWS ($000) DEPRECIATION AND AMORTIZATION | 1808. | 1808. | 1808. | 1808. | 1808. | 1808. | 1808. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 5111. | 5418. | 5743. | 6087. | 6453. | 6840. | 7250. | 7685. | 8146. | 8635. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 50675. | 53672. | 56849. | 60217. | 63786. | 67570. | 71581. | 75109. | 79616. | 84393. |
| CONSTANT (1969) DOLLAR CASH FLOW ($000) NOMINAL DOLLAR EVALUATION | 21145. | 21128. | 21112. | 21097. | 21082. | 21069. | 21056. | 20843. | 20843. | 20843. |

THE NET PRESENT VALUE AT 10.0 PERCENT DISCOUNT RATE IS ($000) 76857.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 14.0 PERCENT

ASSUMED GENERAL INFLATION RATE IS 6.0PERCENT
CONSTANT DOLLAR EVALUATION

THE NET PRESENT VALUE AT 4.0 PERCENT DISCOUNT RATE IS ($000) 74731.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 7.5 PERCENT

CERREJON ANALYSIS REFERENCE NUMBER 300.

| | | |
|---|---|---|
| FIRST YEAR OF INVESTMENT CASH FLOWS | 1979. | |
| LAST YEAR OF INVESTMENT CASH FLOWS | 1983. | |
| PRICE INDEX THAT APPLIES TO OPERATING COSTS | 222.3 | |
| MINIMUM ACCEPTABLE DISCOUNT RATE | | 10.0 |
| PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (% ) | 10.0 | |

SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1983.

| YR. | COST INDEX | CASH FLOW(1968 $) TOTAL | CASH FLOW(1968 $) NET EQUITY | CASH FLOW (ESC. $) TOTAL | CASH FLOW (ESC. $) NET EQUITY | NO. EMPL. |
|---|---|---|---|---|---|---|
| 1979. | 600.0 | 35460. | 35460. | 35460. | 35460. | 0. |
| 1980. | 660.0 | 53190. | 53190. | 58509. | 58509. | 0. |
| 1981. | 726.0 | 106380. | 106380. | 128720. | 128720. | 0. |
| 1982. | 798.6 | 106380. | 106380. | 141592. | 141592. | 0. |
| 1983. | 878.5 | 53190. | 53190. | 77875. | 77875. | 0. |
| NET INVESTMENT | | 354600. | 354600. | 442156. | 442156. | |

| | | |
|---|---|---|
| DEPRECIABLE INVESTMENT ($000) | 313931. | |
| MINEABLE ORE RESERVE (000 M.T.) | 120000. | |
| MINE LIFE (YEARS) ORE RESERVES/AN. PROD. RATE | | 0. |
| ANNUAL ROYALTY RATE (% OF GROSS REV.) | 0.0 | 0.0 |
| COMBINED EFFECTIVE TAX RATE | 40.0 | 40.0 |

CERREJON ANALYSIS REFERENCE NUMBER 300.

CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1984. | 1985. | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 31.80 | 33.71 | 35.73 | 37.87 | 40.15 | 42.56 | 45.11 | 47.82 | 50.68 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 19.36 | 20.37 | 21.45 | 22.58 | 23.79 | 25.06 | 26.41 | 27.85 | 29.37 | 30.98 |
| REVENUE ($000 U.S.) | 225000. | 238500. | 252810. | 267979. | 284057. | 301101. | 319167. | 338317. | 358616. | 380135. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 60636. | 64274. | 68130. | 72218. | 76551. | 81144. | 86013. | 91174. | 96644. | 102443. |
| EQUALS GROSS INCOME ($000) | 164364. | 174226. | 184680. | 195761. | 207506. | 219957. | 233154. | 247143. | 261972. | 277690. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. |
| LESS TAX ($000) | 53188. | 57133. | 61315. | 65747. | 70445. | 75425. | 80704. | 86300. | 92231. | 98519. |
| EQUALS NET INCOME AFTER TAX ($000) | 79783. | 85700. | 91972. | 98620. | 105668. | 113138. | 121056. | 129450. | 138347. | 147778. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. | 31393. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 0. | 0. | 6632. | 7030. | 7452. | 7899. | 8373. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 111176. | 117093. | 123365. | 130014. | 137061. | 137899. | 145419. | 153391. | 161841. | 170798. |
| CONSTANT (1969) DOLLAR CASH FLOW ($000) | 83077. | 82546. | 82045. | 81572. | 81126. | 77002. | 76605. | 76231. | 75877. | 75544. |

CERREJON ANALYSIS REFERENCE NUMBER 300.
CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1994. | 1995. | 1996. | 1997. | 1998. | 1999. | 2000. | 2001. | 2002. | 2003. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 53.73 | 56.95 | 60.37 | 63.99 | 67.83 | 71.90 | 76.21 | 80.78 | 85.63 | 90.77 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 30.43 | 32.24 | 34.16 | 36.19 | 38.35 | 40.64 | 43.06 | 45.38 | 48.10 | 50.98 |
| REVENUE ($000 U.S.) | 402941. | 427117. | 452744. | 479909. | 508703. | 539226. | 571579. | 605874. | 642226. | 680760. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 108589. | 115105. | 122011. | 129332. | 137091. | 145317. | 154036. | 163278. | 173075. | 183459. |
| EQUALS GROSS INCOME ($000) | 294351. | 312013. | 330733. | 350577. | 371612. | 393909. | 417543. | 442596. | 469151. | 497301. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 3139. | 3139. | 3139. | 3139. | 3139. | 3139. | 3139. | 0. | 0. | 0. |
| LESS TAX ($000) | 116485. | 123549. | 131038. | 138975. | 147389. | 156308. | 165762. | 177038. | 187661. | 198920. |
| EQUALS NET INCOME AFTER TAX ($000) | 174727. | 185324. | 196556. | 208463. | 221084. | 234462. | 248642. | 265557. | 281491. | 298380. |
| PLUS NON CASH FLOWS ($000) DEPRECIATION AND AMORTIZATION | 3139. | 3139. | 3139. | 3139. | 3139. | 3139. | 3139. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 8876. | 9408. | 9973. | 10571. | 11205. | 11878. | 12590. | 13346. | 14146. | 14995. |
| EQUALS NOMINAL DOLLAR CASH FLOW ($000) | 168991. | 179055. | 189723. | 201031. | 213018. | 225723. | 239191. | 252212. | 267345. | 283385. |
| CONSTANT (1969) DOLLAR CASH FLOW ($000) NOMINAL DOLLAR EVALUATION | 70514. | 70484. | 70456. | 70430. | 70405. | 70382. | 70359. | 69990. | 69990. | 69990. |

THE NET PRESENT VALUE AT 10.0 PERCENT DISCOUNT RATE IS ($000) 500826.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 21.8 PERCENT

ASSUMED GENERAL INFLATION RATE IS 6.0PERCENT
CONSTANT DOLLAR EVALUATION

THE NET PRESENT VALUE AT 4.0 PERCENT DISCOUNT RATE IS ($000) 507273.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS 14.9 PERCENT

```
W 27;GOTO 27.1

27.10 T "CERREJON",! ;E ;S Y=100;S M=1979;S N=1983;S WP(O)=222.3;S R(1)=.10;S IN(1)=297300
27.20 S I%(1979)=.10;S I%(1980)=.15;S I%(1981)=.30;S I%(1982)=.30;S I%(1983)=.15
27.30 S MS(1979)=600;S NF=.06;S OR=120000;S X=2;S IE=.10
27.35 F J=1984,2003;S PO(J)=5000
27.40 S DT(1)=0;S S=0
27.50 S K(1)=1984;S K(2)=1994;S N(1)=1993;S N(2)=2003
27.55 S PA(1984)=30;F J=1985,2003;S PA(J)=1.06*PA(J-1)
27.65 S CT(1984)=5.23*(1.10 5);F J=1985,2003;S CT(J)=1.06*CT(J-1)
27.67 F J=1984,2003;S OP(J)=CT(J)*PO(J)
27.70 F W=1,X;S AR(W)=0;S TX(W)=.40
27.90 T "THE BASE CASE VARIABLES (1979-2003)  ARE ENTERED   ",!
27.92 T "5.0 MILLION TON PER YEAR OUTPUT ",!
27.93 A "TYPE 1 FOR SPANISH, 0 FOR ENGLISH ",SP
27.94 IF (SP) ,27.98,27.99
27.98 S Y=100;T "AN. #100",! ;L O #1=CR100;GOTO 1.57
27.99 S Y=100;T "AN. #100", ! ;L O #1=CRSP10;GOTO 51.57

CERREJON
THE BASE CASE VARIABLES (1979-2003)  ARE ENTERED
5.0 MILLION TON PER YEAR OUTPUT
TYPE 1 FOR SPANISH, 0 FOR ENGLISH 0
AN. #100

NOMINAL DOLLAR EVALUATION


THE NET PRESENT VALUE AT     10.0   PERCENT DISCOUNT RATE IS  ($000)        274078.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS            18.4     PERCENT


CONSTANT DOLLAR EVALUATION


THE NET PRESENT VALUE AT      4.0   PERCENT DISCOUNT RATE IS  ($000)        275459.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS            11.7     PERCENT

OUTPUT TO FILE IS COMPLETE.



W 28;GOTO 28.1

28.10 E ;D 27.1,27.2,27.3,27.35,27.5,27.55,27.65,27.67,27.7,27.9,27.92
28.15 S IN(1)=204200;D 27.2
28.20 F J=1984,2003;S PO(J)=2500
28.25 S CT(1984)=5.90*(1.10 5);F J=1985,2003;S CT(J)=1.06*CT(J-1)
28.30 F J=1984,2003;S OP(J)=CT(J)*PO(J)
28.90 T "MODIFICATION TO 2.5 MILLION TON PER YEAR OUTPUT",!
28.92 D 27.93
28.93 IF (SP) ,28.95,28.96
28.95 S Y=200;L O #1=CR200;GOTO 1.57
28.96 S Y=200;L O #1=CRSP20;GOTO 51.57

CERREJON
THE BASE CASE VARIABLES (1979-2003)  ARE ENTERED
5.0 MILLION TON PER YEAR OUTPUT
MODIFICATION TO 2.5 MILLION TON PER YEAR OUTPUT
TYPE 1 FOR SPANISH, 0 FOR ENGLISH 0

NOMINAL DOLLAR EVALUATION

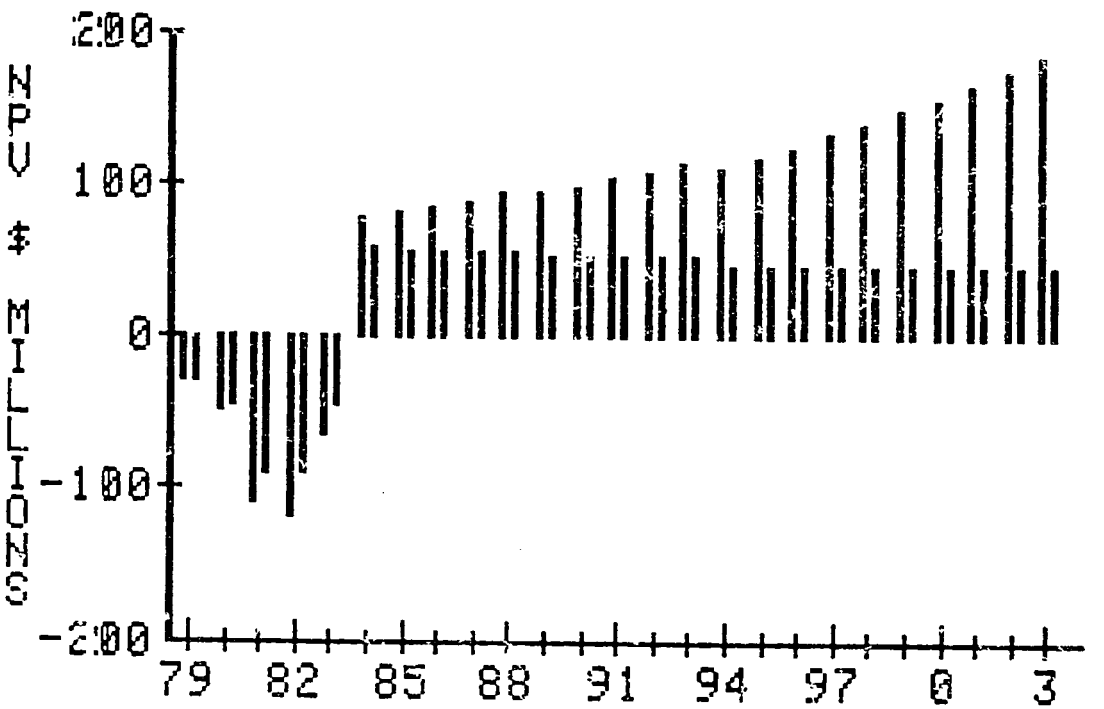

THE NET PRESENT VALUE AT     10.0   PERCENT DISCOUNT RATE IS  ($000)         76857.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS            14.0     PERCENT


CONSTANT DOLLAR EVALUATION


THE NET PRESENT VALUE AT      4.0   PERCENT DISCOUNT RATE IS  ($000)         74731.
THE DISCOUNTED CASH FLOW RATE OF RETURN IS             7.5     PERCENT

OUTPUT TO FILE IS COMPLETE.
```

CERREJON #100 NOMINAL VS CONSTANT $



APPENDIX B

CERREJON ANALYSIS REFERENCE NUMBER 200.

| | |
|---|---|
| FIRST YEAR OF INVESTMENT CASH FLOWS | 1979. |
| LAST YEAR OF INVESTMENT CASH FLOWS | 1983. |
| PRICE INDEX THAT APPLIES TO OPERATING COSTS | 222.3 |
| MINIMUM ACCEPTABLE DISCOUNT RATE | 10.0 |
| PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (%) | 0.0 |

SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1983.

| YR. | COST INDEX | CASH FLOW(BASE YEAR $) | CASH FLOW (ESCALATED $) |
|---|---|---|---|
| 1979. | 600.0 | 20420. | 20420. |
| 1980. | 600.0 | 30630. | 30630. |
| 1981. | 600.0 | 61260. | 61260. |
| 1982. | 600.0 | 61260. | 61260. |
| 1983. | 600.0 | 30630. | 30630. |

| | | |
|---|---|---|
| NUMBER OF PHASES OF PRODUCTION | 2. | |
| FOR THE CASH FLOWS IN PHASES | 1. | 2. |
| FIRST YEAR OF OPERATING NET CASH FLOW | 1984. | 1994. |
| LAST YEAR OF OPERATING NET CASH FLOW | 1993. | 2003. |
| PROJECTED RATE OF PRICE ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| PRICE AT BEGINNING OF EACH PHASE ($/MT.) | 30.00 | 30.00 |
| ANNUAL PRODUCTION (METRIC TONS,M.T.) | 2500. | 2500. |
| REPLACEMENT INV. BEGINNING OF EACH PHASE ($000) | 3500. | 3500. |
| PROJECTED RATE REPLACEMENT INV. ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| PROJECTED RATE OF COST ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| ANNUAL OPERATING COSTS BEGINNING OF EACH PHASE ($000) | 14741. | 14741. |
| AVERAGE ANNUAL DEPRECIATION ($000) | 11500. | 11500. |
| ANNUAL ROYALTY RATE (% OF GROSS REV.) | 0.0 | 0.0 |
| DEPLETION RATE (PERCENT,LIMITED TO 50% OF NET) | 0. | 0. |
| COMBINED EFFECTIVE TAX RATE | 40.0 | 40.0 |

CERREJON ANALYSIS REFERENCE NUMBER 200.
U.S. CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1984. | 1985. | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 |
| REVENUE ($000 U.S.) | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. |
| EQUALS GROSS INCOME ($000) | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. |
| EQUALS NET INCOME AFTER TAX ($000) | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. |
| PLUS NON CASH FLOWS ($000) DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 0. | 0. | 3500. | 3500. | 3500. | 3500. | 3500. |
| EQUALS OPERATING CASH FLOW ($000) | 40755. | 40755. | 40755. | 40755. | 40755. | 37255. | 37255. | 37255. | 37255. | 37255. |

U.S. CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1994. | 1995. | 1996. | 1997. | 1998. | 1999. | 2000. | 2001. | 2002. | 2003. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. | 2500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 | 18.30 |
| REVENUE ($000 U.S.) | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. | 75000. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. | 14741. |
| EQUALS GROSS INCOME ($000) | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. | 60259. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. | 19504. |
| EQUALS NET INCOME AFTER TAX ($000) | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. | 29255. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. |
| EQUALS OPERATING CASH FLOW ($000) | 37255. | 37255. | 37255. | 37255. | 37255. | 37255. | 37255. | 37255. | 37255. | 37255. |

THE NET PRESENT VALUE AT 10.0 PERCENT DISCOUNT RATE IS ($000) 54416.

THE DISCOUNTED CASH FLOW RATE OF RETURN IS 14.0 PERCENT

APPENDIX C

CERREJON ANALYSIS REFERENCE NUMBER 300.

| | |
|---|---|
| FIRST YEAR OF INVESTMENT CASH FLOWS | 1979. |
| LAST YEAR OF INVESTMENT CASH FLOWS | 1983. |
| PRICE INDEX THAT APPLIES TO OPERATING COSTS | 222.3 |
| MINIMUM ACCEPTABLE DISCOUNT RATE | 10.0 |
| PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (%) | 0.0 |

SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1983.

| YR. | COST INDEX | CASH FLOW(BASE YEAR $) | CASH FLOW (ESCALATED $) |
|---|---|---|---|
| 1979. | 600.0 | 35460. | 35460. |
| 1980. | 600.0 | 53190. | 53190. |
| 1981. | 600.0 | 106380. | 106380. |
| 1982. | 600.0 | 106380. | 106380. |
| 1983. | 600.0 | 53190. | 53190. |

NUMBER OF PHASES OF PRODUCTION 2.

| FOR THE CASH FLOWS IN PHASES | 1. | 2. |
|---|---|---|
| FIRST YEAR OF OPERATING NET CASH FLOW | 1984. | 1994. |
| LAST YEAR OF OPERATING NET CASH FLOW | 1993. | 2003. |
| PROJECTED RATE OF PRICE ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| PRICE AT BEGINNING OF EACH PHASE ($/MT.) | 30.00 | 30.00 |
| ANNUAL PRODUCTION (METRIC TONS,M.T.) | 7500. | 7500. |
| REPLACEMENT INV. BEGINNING OF EACH PHASE ($000) | 3500. | 3500. |
| PROJECTED RATE REPLACEMENT INV. ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| PROJECTED RATE OF COST ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| ANNUAL OPERATING COSTS BEGINNING OF EACH PHASE ($000) | 37641. | 37641. |
| AVERAGE ANNUAL DEPRECIATION ($000) | 11500. | 11500. |
| ANNUAL ROYALTY RATE (% OF GROSS REV.) | 0.0 | 0.0 |
| DEPLETION RATE (PERCENT,LIMITED TO 50% OF NET) | 0. | 0. |
| COMBINED EFFECTIVE TAX RATE | 40.0 | 40.0 |

CERREJON ANALYSIS REFERENCE NUMBER 300.

U.S. CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1984. | 1985. | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 |
| REVENUE ($000 U.S.) | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. |
| EQUALS GROSS INCOME ($000) | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. |
| EQUALS NET INCOME AFTER TAX ($000) | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 0. | 0. | 3500. | 3500. | 3500. | 3500. | 3500. |
| EQUALS OPERATING CASH FLOW ($000) | 117015. | 117015. | 117015. | 117015. | 117015. | 113515. | 113515. | 113515. | 113515. | 113515. |

U.S. CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1994. | 1995. | 1996. | 1997. | 1998. | 1999. | 2000. | 2001. | 2002. | 2003. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 | 30.00 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. | 7500. |
| AVERAGE TOTAL COST ($/METRIC TON) | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 | 15.93 |
| REVENUE ($000 U.S.) | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. | 225000. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. | 37641. |
| EQUALS GROSS INCOME ($000) | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. | 187359. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. | 70344. |
| EQUALS NET INCOME AFTER TAX ($000) | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. | 105515. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. | 3500. |
| EQUALS OPERATING CASH FLOW ($000) | 113515. | 113515. | 113515. | 113515. | 113515. | 113515. | 113515. | 113515. | 113515. | 113515. |

THE NET PRESENT VALUE AT 10.0 PERCENT DISCOUNT RATE IS ($000) 346504.

THE DISCOUNTED CASH FLOW RATE OF RETURN IS 22.0 PERCENT

APPENDIX D

CERREJON ANALYSIS REFERENCE NUMBER 400.

| | |
|---|---|
| FIRST YEAR OF INVESTMENT CASH FLOWS | 1979. |
| LAST YEAR OF INVESTMENT CASH FLOWS | 1983. |
| PRICE INDEX THAT APPLIES TO OPERATING COSTS | 307.5 |
| MINIMUM ACCEPTABLE DISCOUNT RATE | 18.0 |
| PROJECTED RATE OF ESCALATION FOR INVESTMENT EXPENDITURES (%) | 8.3 |

SUMMARY OF CAPITAL COST INDEXES AND INVESTMENT CASH FLOWS ($000) THROUGH YEAR 1983.

| YR. | COST INDEX | CASH FLOW(BASE YEAR $) | CASH FLOW (ESCALATED $) |
|---|---|---|---|
| 1979. | 600.0 | 29730. | 29730. |
| 1980. | 649.8 | 44595. | 48296. |
| 1981. | 703.7 | 89190. | 104610. |
| 1982. | 762.1 | 89190. | 113293. |
| 1983. | 825.4 | 44595. | 61348. |

NUMBER OF PHASES OF PRODUCTION 2.

| FOR THE CASH FLOWS IN PHASES | 1. | 2. |
|---|---|---|
| FIRST YEAR OF OPERATING NET CASH FLOW | 1984. | 1994. |
| LAST YEAR OF OPERATING NET CASH FLOW | 1993. | 2003. |
| PROJECTED RATE OF PRICE ESCALATION (% ANNUALLY) | 1.5 | 1.5 |
| PRICE AT BEGINNING OF EACH PHASE ($/MT.) | 30.00 | 34.82 |
| ANNUAL PRODUCTION (METRIC TONS,M.T.) | 5000. | 5000. |
| REPLACEMENT INV. BEGINNING OF EACH PHASE ($000) | 3500. | 5214. |
| PROJECTED RATE REPLACEMENT INV. ESCALATION (% ANNUALLY) | 8.3 | 8.3 |
| PROJECTED RATE OF COST ESCALATION (% ANNUALLY) | 0.0 | 0.0 |
| ANNUAL OPERATING COSTS BEGINNING OF EACH PHASE ($000) | 36148. | 36148. |
| AVERAGE ANNUAL DEPRECIATION ($000) | 11500. | 11500. |
| ANNUAL ROYALTY RATE (% OF GROSS REV.) | 0.0 | 0.0 |
| DEPLETION RATE (PERCENT,LIMITED TO 50% OF NET) | 0. | 0. |
| COMBINED EFFECTIVE TAX RATE | 40.0 | 40.0 |

CERREJON ANALYSIS REFERENCE NUMBER 400.
U.S. CASH FLOW CALCULATION FOR PHASE 1.

| YEAR | 1984. | 1985. | 1986. | 1987. | 1988. | 1989. | 1990. | 1991. | 1992. | 1993. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 30.00 | 30.45 | 30.91 | 31.37 | 31.84 | 32.32 | 32.80 | 33.30 | 33.79 | 34.30 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. |
| AVERAGE TOTAL COST ($/METRIC TON) | 17.72 | 17.90 | 18.08 | 18.27 | 18.45 | 18.65 | 18.84 | 19.04 | 19.24 | 19.44 |
| REVENUE ($000 U.S.) | 150000. | 152250. | 154534. | 156852. | 159205. | 161593. | 164016. | 166477. | 168974. | 171508. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. |
| EQUALS GROSS INCOME ($000) | 113852. | 116102. | 118386. | 120704. | 123057. | 125445. | 127869. | 130329. | 132826. | 135361. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 40941. | 41841. | 42754. | 43682. | 44623. | 45578. | 46548. | 47532. | 48531. | 49544. |
| EQUALS NET INCOME AFTER TAX ($000) | 61411. | 62761. | 64132. | 65523. | 66934. | 68367. | 69821. | 71298. | 72796. | 74317. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 0. | 0. | 0. | 0. | 0. | 3500. | 3791. | 4105. | 4446. | 4815. |
| EQUALS OPERATING CASH FLOW ($000) | 72911. | 74261. | 75632. | 77023. | 78434. | 76367. | 77531. | 78692. | 79850. | 81002. |

U.S. CASH FLOW CALCULATION FOR PHASE 2.

| YEAR | 1994. | 1995. | 1996. | 1997. | 1998. | 1999. | 2000. | 2001. | 2002. | 2003. |
|---|---|---|---|---|---|---|---|---|---|---|
| PRICE,COAL ($/MT) | 34.82 | 35.34 | 35.87 | 36.41 | 36.95 | 37.51 | 38.07 | 38.64 | 39.22 | 39.81 |
| ANNUAL COAL PRODUCTION PROD. (000 METRIC TONS .) | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. | 5000. |
| AVERAGE TOTAL COST ($/METRIC TON) | 19.64 | 19.85 | 20.07 | 20.28 | 20.50 | 20.72 | 20.95 | 21.17 | 21.41 | 21.64 |
| REVENUE ($000 U.S.) | 174081. | 176692. | 179343. | 182033. | 184763. | 187535. | 190348. | 193203. | 196101. | 199043. |
| LESS ANNUAL ROYALTY ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS ANNUAL OPERATING COST ($000) | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. | 36148. |
| EQUALS GROSS INCOME ($000) | 137934. | 140545. | 143195. | 145885. | 148616. | 151387. | 154200. | 157056. | 159954. | 162895. |
| LESS ANNUAL DEPRECIATION AND AMORTIZATION ($000) | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| LESS DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS TAX ($000) | 50573. | 51618. | 52678. | 53754. | 54846. | 55955. | 57080. | 58222. | 59381. | 60558. |
| EQUALS NET INCOME AFTER TAX ($000) | 75860. | 77427. | 79017. | 80631. | 82270. | 83932. | 85620. | 87333. | 89072. | 90837. |
| PLUS NON CASH FLOWS ($000) | | | | | | | | | | |
| DEPRECIATION AND AMORTIZATION | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. | 11500. |
| AND DEPLETION ($000) | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. | 0. |
| LESS REPLACEMENT INVESTMENT ($000) | 5214. | 5647. | 6116. | 6624. | 7173. | 7769. | 8414. | 9112. | 9868. | 10687. |
| EQUALS OPERATING CASH FLOW ($000) | 82146. | 83280. | 84401. | 85508. | 86596. | 87664. | 88707. | 89721. | 90704. | 91650. |

THE NET PRESENT VALUE AT 18.0 PERCENT DISCOUNT RATE IS ($000) - 27072.

THE DISCOUNTED CASH FLOW RATE OF RETURN IS 16.0 PERCENT

*

# Costs

# COST ESTIMATION

## 1. INTRODUCTION

The case studies described in both volumes of this book involve cost and price forecasting. This chapter summarizes the basic concepts of cost forecasting and the methods used in the case studies.

## 2. COST AND PRICE FORECASTS

The accepted method of valuation of mineral projects requires us to forecast and capitalize future net cash flows. Net cash flow is the difference between cash inflows, usually consisting of net sales revenues, and cash outflows, usually consisting of operating and administrative costs and taxes. The objective in the financial evaluation is a set of conceivable values for each. Since the revenue and cost forecasts depend entirely upon assumptions about the future, making "reasonable" or "conservative" assumptions is the most important part of the evaluation procedure.

Cost estimation involves forecasting the current level of capital and operating costs for the project. The accuracy of a "best" estimate, varies with the information and time available for the estimating process. The cost of making a cost estimate can vary from a few hundred dollars for an order of magnitude estimate to 2 or 3 million dollars in the case of detailed estimates. This cost is balanced against the need for accuracy which in turn depends on the proposed use of the estimate. If it is to be used to justify some additional drilling an order of magnitude estimate may be sufficient. If it is to be used as a basis for financing or marketing agreements, accuracy must be much higher and the higher cost is justified. The error of cost estimates may range from as high as plus or minus forty percent in order of magnitude estimates to as low as plus or minus three percent on detailed cost estimates.

The uncertainty in cost estimates varies widely. For an operating property we have some past data and by looking at known changes in cost components such as labor, supplies, power or administration it is possible to make a fairly accurate prediction of costs expected in the current year. The uncertainty of expected future costs increases with the length of the forecast.

A cost forecast is a forecast of physical conditions including all geologic, mining, mineralogic, and metallurgical variables that are unknown or uncertain in the venture. A good cost estimate starts with a careful analysis of the existing physical data, then develops a concept of how the orebody could be explored, mined, and processed, and proceeds to estimate costs for the conceptual physical system. It is the essence of creative engineering.

## 3. COST CONCEPTS

### 3.1 Begin with a Design

Cost studies evaluate exploration or development programs or engineering designs in economic terms. Each design is a new combination of pre-existing knowledge while the cost estimate itself is the numerical forecasting of conceivable economic results. Because of its multi-disciplinary nature, cost estimation requires a grasp of the technical aspects of geology, geophysics, mining, and metallurgy as well as a knowledge of economics, and mathematical techniques. It is not surprising that many organizations involved in cost estimation rely on a team of experts rather than a single individual. The leader of the team is likely to be an experienced engineer able to integrate the views of the individual specialists into a consistent and accurate forecast of costs.

### 3.2 Deviation of Actual Cost from Estimated Cost

Actual costs deviate from estimates because no individual or technique can foresee the future. There are always limitations in time, money, and staff available to develop the estimate. The deviation of the actual cost from the estimate will be a function of five major factors:

(1) Risk. Risk may be subjectively or objectively estimated. When the variable involves known probabilities it can take on several possible values according to the known probability distribution. An example might be the climatic conditions expected during the life of the project. Other risk variables are more difficult to estimate, for example, the risk that charges in the political system or mining code will make it uneconomic to continue operations, the risk of accident or injury in operations, and the risk of delays affecting the transportation system.

(2) Uncertainty. Uncertainty applies to the risk probabilities because we simply do not know what they are. Precise estimates of inflation are not predictable; costs will vary with unpredictable changes in operating conditions. Therefore, cost estimates involve a range of uncertainty which increases with the length of the forecast.

The accuracy of the estimate will be directly proportional to the amount and quality of the physical data available on the mineral deposit thus it will change continuously drillhole by drillhole and with results of new testing and research.

(3) Certainty. Certainty, or near certainty, may apply to some costs, for example, when predicting labor costs, given an existing labor contract, when predicting near-term power and materials costs when new quotations or contracts are available, or when equipment costs are based on firm quotations from a manufacturer.

(4) Mistakes. Mistakes may be errors in calculation or errors in technique, for example, the cost of a screening plant is estimated to be $100,000, using U.S.-Canadian data sources. But the cost of this plant must be corrected for location for installation in Peru. A factor of 1.6 may be necessary to account for transportation costs, import licenses, and tariffs. This means the plant corrected cost would be 1.6 times $100,000 or $160,000 in Peru.

(5) Errors in Concept. Every cost estimate must begin with a plan or a design concept. If this concept is in error, the cost will be in error, for example, failure to recognize that "heavy ground" will require additional support, that metallurgical

recoveries will be low due to the chemical composition of the ore, or that a secondary crusher will be required in the mill.

## 4. TYPES OF COST STUDIES

Four fundamental types of cost estimates can be defined. The type used and the accuracy of the result depend on the amount of data available and the time allotted for preparation of the study. The types include (1) order of magnitude studies, (2) factored estimates, (3) definitive estimates, and (4) detailed estimates. The use of this terminology varies from on organization to another, for example, an exploration company may use "order of magnitude estimate" to describe an estimate of the potential of an ore deposit defined by a very few exploratory drill holes. Another major contractor for mining projects uses the term for an estimate based on relatively detailed drilling and pilot planned investigations.

### 4.1 Order of Magnitude Estimates

A. Purpose: This type of estimate may be for an exploration target model or for management decisions on feasibility before approval of funds for further exploration or development.

B. Accuracy: Highly variable. In the case of the exploration model, it represents characterization of a possible discovery and accuracy has no meaning. In the case of an order of magnitude feasibility study, accuracy might be of the order of plus or minus twenty percent to plus or minus forty percent.

C. Cost: One half to five percent of the cost of a detailed estimate.

D. Time Required: Hours to one week.

E. Required Information:

1. Mine plan and process flow sheets - block diagram or rough sketch.
2. Heat and materials balance - feed, effluents, products, recoveries, capacity, conversion requirements.
3. Equipment list - plant unit operations or process facility only.
4. Utility balance - ratio from process requirements.
5. Plot plan - location, and special site requirement.
6. Engineering - ratio manpower requirements from similar jobs.

F. Methods:

1. Cost-capacity investment curves.

Unit Process Cost = Capital Investment in Dollars/Plant Capacity in Tons per Year

Example: A similar plant required an investment of $900 per annual ton of capacity in this year. Estimate the investment for a plant of 200 tons per day capacity operating 350 days per year.

Investment = 900 x 200 x 350 = $63.000,000

involves the use of cost-capacity investment curves such as the curves shown in Figure 1 taken from the STRAMM "Capital and Operating Cost Handbook" prepared for the U.S. Bureau of Mines minerals availability program. The curve shown is used to estimate capital costs of crushing and grinding equipment including acquisition and installation of equipment to crush mine-run ore and to grind to size for beneficiation.

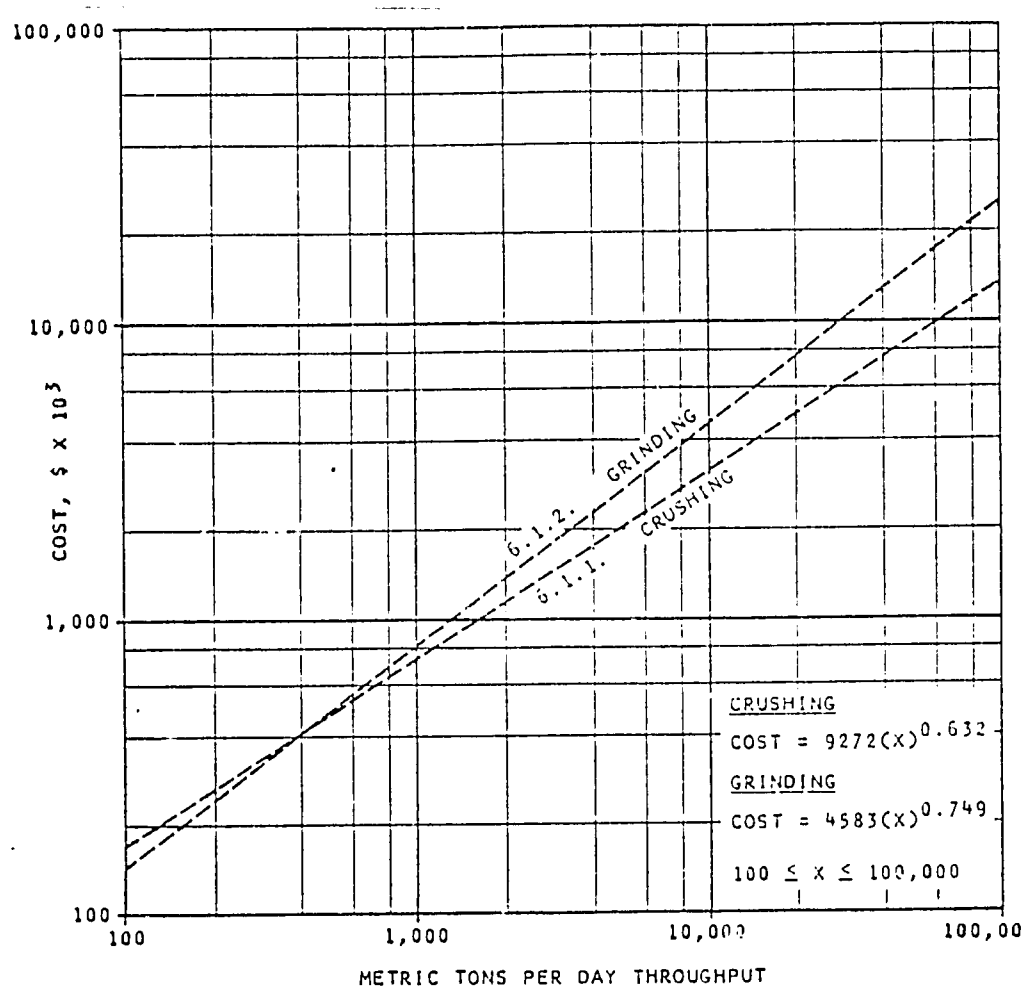



FIGURE 1 CRUSHING AND GRINDING CAPITAL COST CURVES

The curves shown in Figure 1 are based on some important assumptions:

(1)Crusher cost is distributed to purchased equipment 62%, Construction labor 21%, and construction materials 17%.

(2)Crusher curves are based on two-shift operation and on the reduction of a medium ore(work index=12.0) from a mine run size to 0.95 centimeters (3/8 inches).

(3)Grinding cost is distributed to purchased equipment 66%, construction labor 20%, and construction materials 14%.

(4)Grinding cost is based on a three shift operation and on the reduction of a medium ore (work index=12.0) from 0.95 centimeters (3/8 inches) to 100 mesh.

The curves are corrected to the specific cost estimate by using a factor to correct for hardness and product size. The factor is determined by an equation relating product size in centimeters and the work index of the material to the correcting factor. Barite is considered soft and has a work index of 6; lead-zinc ore and manganese ore are considered medium hardness and have work indexes of 12. Taconite and gold ores are considered of medium hardness and have work indexes of 15. Andesite and trap rock are considered very hard and have work indexes of 22. The work indexes are based on an assumption that 80% of the product will pass a certain size. If the users requirements are such that some other percentage passing a product size is desired, it is necessary to obtain or estimate a grain size distribution curve.

The numerous technical factors and implicit assumptions behind the capital cost curve make it imperative that the user have a knowledge of the technology involved. Further, the curves are not to be used to estimate the cost of a single component of a production system. They are to be used to estimate total plant costs.

Data used in the preparation of curves, tables or factors deal in averages. The user must be able to discern any differences between the method or process under consideration and that presented by the curve. In addition the curves and equations are only applicable within limits. The user should not extrapolate outside of these limits because the results will probably be unreliable.

2. Ratio extrapolation. If a defined equipment list or one from a similar plant is available, the "Lang Factor" scales up an equipment list cost to a total installed cost.

Capital Cost = Lang Factor x Equipment Costs

Example: Lang Factors = 3.10 (solids)
3.63 (solid-fluids)
4.74 (fluids).

Estimate the cost of a plant to crush and screen 67,000 tons per stream day of limestone. The delivered equipment cost is $2,900,000, taken from flow sheets and equipment specifications list.

Plant Cost = 3.10 x 2,900,000 = $8,990,000.

The Lang factor involves gross assumptions about all of the additions to equipment that lead to a total plant cost. A more detailed breakdown of the Lang factor is always desirable, but often not possible at the order of magnitude stage of estimation.

3. Turnover ratio also utilizes historical data from similar plants to calculate the capital investment.

Turnover Ratio = Product Value per Ton/Investment, Dollars per Ton of Capacity.

Example: The turnover ratio for a known plant is 0.35. and

the product sells for $75 per ton. Estimate the required investment in a plant to process 70,000 tons per year.

Investment per ton = $75/$0.35 = $214
Investment = $214 x 70,000 = $15,000,000.

In times of rapid inflation of both costs and prices the inadequacy of the turnover ratio as an estimating tool is very evident. The approach may have some validity for process plants during periods of stable price and cost trends, but it is of little use for mineral investments during periods of rapid and erratic price and cost change.

4. Buildings are estimated on a rough dollars per square foot basis.

5. If the investment is an expansion, dollars per unit of capacity ratios must be adjusted for existing facilities.

6. Conversion factors for location, time, and size are necessary.

Historical cost data applies to existing plants at locations other than that of the new project. The new project will have different transportation costs, labor rates, or import duties. Furthermore; historical cost data are obsolete in time and must be corrected for changes in prices and productivity of the system. Finally, historical cost data probably relates to a plant of different size than the new project, curve such as the one shown in figure one use fixed and variable cost relationships to correct for size.

### 4.2. Preliminary or "Factored" Estimate

A. Purpose: This is the first estimate of a project or as a followup on an order of magnitude estimate.

B. Accuracy: Variable, about plus or minus ten percent to plus or minus forty percent depending on the scope of the estimate and the reliability of the data.

C. Cost: Twenty to thirty percent of a detailed estimate.

D. Time Requirements: Two to three weeks to three to four months.

E. Required Information:

1. Process flow sheets-rough but more detailed than order of magnitude estimates.
2. Heat and material balance-preliminary
3. Equipment list-preliminary
4. Process mechanics flow sheet-rough
5. Equipment quotations-prior experience or vendor check
6. Equipment estimate sheets-equipment list with size, capacity, and prices.
7. Utility balance-preliminary estimate
8. Plot plan-preliminary
9. Engineering data sheets-building and general housing requirements
10 Engineering estimate-compare engineering costs to prior experience.

10 Engineering estimate-compare engineering costs to prior experience.

F. Methods:

1. Plant limits (battery limits) estimate. Estimate the individual equipment costs from curves based on equipment variables, for example, trucks on a capacity-horsepower basis, pumps on a capacity-head basis. Alternatively use unit costs, for example, tanks on a cost-per-pound of tank.

The "exponential factor" is often used to size equipment. One of these exponents is 0.6 and is called the "six-tenths factor." While it might possibly be applied to an entire plant, great care must be used because of varying conditions from one plant to another. For example, one plant might involve much more infrastructure and therefore after the correction for capacity a separate correction must be made for infrastructure or for complexity of the larger plant.

Economies of scale are the basis for the exponential sizing model. If we let m=1, we have a linear relationship which denies the law of economies of scale. Ordinarily we expect a larger plant to cost more but not in direct linear proportion to the larger size. The "six-tenths" law was developed for chemical processing equipment. Often the exponent is not 0.6 but some other number between zero and one.

$$C = C_r \left(\frac{Q_c}{Q_r}\right)^m$$

Where $C$ = total value sought for design size
$C_r$ = known cost for a reference size $Q_r$
$Q_c$ = design size
$Q_r$ = reference design size
$m$ = correlating exponent between zero and one.

Example: A 10,000 pound per day plant costs $3,000,000. What would a 20,000 pound per day plant cost?

$$\text{Cost} = \$3{,}000{,}000\left(\frac{20000}{10000}\right)^{0.6} = \$4{,}547{,}150$$

After the cost of equipment is estimated, total plant costs can be forecast using the Lang Factor. Building costs are estimated on a dollar per square foot basis, with adjustment for special requirements, such as special lighting or air conditioning. There are conversion factors for location and time.

Where information is available, use the percent of equipment cost approach.

$$\text{Installed Capital Cost} = (E\,f_1 + E\,f_2 + \ldots + E\,f_n)\,f_I$$

where E = delivered equipment cost
$f_1 \ldots f_n$ = factors for installation, foundations, painting, utilities, piping, etc.
$f_I$ = a factor to account for installation costs not traceable to specific equipment such as engineering

This method breaks down the Lang Factor into individual factors for each component of cost.

2. Overall project estimate.

Use a ratio to account for utilities, services, storage and handling facilities. When adequate information is available, adopt the techniques of a definitive estimate.

### 4.3. Computer Assisted Project Estimating System (CAPES)

A. Purpose: The CAPES method replaces the preliminary or factored estimate in that it is the first estimate of a project or a follow-up on the order of magnitude estimate. The advantage of the CAPES system is a much more detailed breakdown of factors.

B. Accuracy: Plus or minus 10% to plus or minus 20%, depending on available information.

C. Cost: Five to 15% of the cost of a detailed estimate.

D. Time Requirements: Hours to three or four months.

E. Required Information:

CAPES estimates may be preliminary, normal or detailed. Table 1 that follows provides information on three different types of CAPES estimates used by Stearns-Roger, Inc.

TABLE 1 CAPES ESTIMATES - INFORMATION REQUIRED FOR 3 DIFFERENT TYPES

X = Not required D = Desirable R = Required

| | Information | Prel. CAPES +15 to 25% | Normal CAPES +10 to 20% | Detailed CAPES +8 to 15% |
|---|---|---|---|---|
| I. | General Plant Information: | | | |
| | Type Plant & Process | R | R | R |
| | Plant Location | D | R | R |
| | Time Frame for Cost Escalation | R | R | R |
| | Milepost Schedule | D | R | R |
| | Plot Plan | D | D | R |
| | Equipment Layouts & Elevations | X | D | R |
| | Piperack Sizes & Number of Levels | X | D | R |
| | Building Sizes & Usage | D | R | R |
| | Building Details | X | D | R |
| | Structure Sizes & Floor Landings | D | R | R |
| | Craft Wage Rates & Benefits | X | R | R |
| | Engineering Mark-up | X | D | R |
| | Engineering Preliminary Def. Est. | X | D | R |
| | Shipping Restrictions | X | D | R |
| | Freight Costs | X | X | D |
| | Wind Loading (MPH) | X | D | R |
| | Major Sub-Contracts | X | D | R |
| | Sales Taxes | D | R | R |
| | Royalty or Licensing Fees | D | R | R |
| | Contractors' Fee | X | D | R |
| | Mechanical Flow Diagrams | X | D | R |
| II. | Civil Information: | | | |
| | Soil Type, Density & Loading | X | D | R |
| | Special Soil Conditions | X | D | R |
| | Ground Water or Drainage Problems | X | D | R |
| | Depth of Footing | D | R | R |
| | Site Topography | D | R | R |
| | Type Fdn. (Piling, Pad, Spr'd., etc.) | X | R | R |
| | Ready-Mix Concrete Cost | X | D | R |
| | Fire Resistance Rating | X | D | R |
| III. | Process Equipment Information: | | | |
| | Major Parameters | R | R | R |
| | Materials of Construction | R | R | R |
| | Data Sheets | X | D | R |
| | Vendor Prel. Quotes for Costly Items | X | D | R |
| | Spare Parts List | X | D | R |
| IV. | Piping Information: | | | |
| | Type Utility Headers | X | D | R |
| | Offsite & Inter-Area Piping | D | R | R |
| | Process Pipe in Piperacks | X | D | R |
| | All Piping in Main Piperacks | X | D | R |

TABLE 1 CAPES ESTIMATES (CONTINUED)

| | Information | Prel. CAPES +15 to 25% | Normal CAPES +10 to 20% | Detailed CAPES +8 to 15% |
|---|---|---|---|---|
| V. | Electrical Information: | | | |
| | Main Feeder Voltage | D | R | R |
| | Main Feeder Tie-In Point | X | R | R |
| | Class & Division Classification | X | R | R |
| | Buried or AG Cable | X | D | R |
| | Conduit or Armored Cable | X | D | R |
| | MCC Location | X | R | R |
| | Substation Type | X | D | R |
| | Radial or Spot Distribution System | X | D | R |
| | Demand Diversity Factor | X | D | R |
| | Power Factor | X | D | R |
| | Percent Excess Transformer Capacity | X | D | R |
| | Transformer Capacity (KVA) | X | R | R |
| VI. | Instrumentation Information: | | | |
| | Density - Standard or Complex | X | R | R |
| | Pneumatic or Electrical | X | D | R |
| | Control Room Location | X | R | R |
| | Instrument Panel Display Type | X | D | R |
| | Type Signal Wire | X | D | R |
| | Type Thermocouple | X | D | R |
| | Type Thermocouple Wire | X | D | R |

F. Methods:

Cost curves in the STRAMM handbook have been programmed for use on the computer. They provide an example of computerized cost estimating utilizing the rough rough "average" curves in the STRAMM handbook with corrections to adapt those curves for specific physical characteristics, location and time. Other construction contractors such as Stearns-Roger, Inc. have developed their own computer systems in order to use information in their own data banks.

Some contractors also subscribe to the service of the ICARUS Corporation, 11300 Rockville Pike, Rockville, Maryland 20852. ICARUS furnishes the services of several computer models designed to provide a detailed breakdown of cost estimates for all phases from the initial order of magnitude estimate to the detailed estimate. Training is mandatory prior to usage of the computer system. It includes reading of the users' manual and working on sample problems, annual refresher training and telephone assistance to trainees using the system.

Once operators are trained, the procedure for using the system includes preparation of coding forms providing descriptive plant data.

The output of the system is a series of computer printouts including a master summary of labor dollars, material dollars and a total project cost. Typical breakdowns for building construction projects include a site development cost report, a building summary report, a code of accounts, a field labor summary, a manpower and construction

schedule, a cash flow summary, an estimate of prime contractors' indirect cost, an equipment rental summary, a detailed material and labor listing and a bulk material and field labor summary. Where the user of the system is unable to provide detail the system substitutes averages based on past experience. The product therefore indicates all details of the factors that convert from available physical information to an estimate of the project. Where particular items are critical the user of the system obtains additional physical data on the project and substitutes his own details for those assumed by the system.

The cost of the system includes training which may run from $500 to $5,000 per individual, depending on the numbers of people trained. After training, use of the system is by telephone and the charges are approximately $20 per item (1980 price levels). The cost of pricing a medium sized plant may be of the order of $2,000 to $3,000, which can be considerably less than a factored estimate with the additional advantages of knowledge of the details of the factors involved.

### 4.4. Definitive Estimates

A. Purpose: For appropriation of funds or to establish a contract price. Necessary to establish a budget and a basis for project cost status reports, and to establish a format for final cost reports.

B. Accuracy: Plus or minus seven percent to plus or minus fifteen percent.

C. Cost: Ninety percent of a detailed estimate.

D. Time Required: Three to four months for a project of less than $20 million.

E. Required Information:

1. Process flow sheets—detailed
2. Heat and material balance—complete
3. Equipment list—process equipment complete, utility equipment preliminary.
4. Process mechanics flow sheet—detailed.
5. Utility mechanics flow sheet—detailed
6. Equipment data sheet—based on available information
7. Equipment quotes—at least one firm quote from a supplier on all items.
8. Equipment estimate sheets—as complete as possible.
9. Utility balance—based on available vendor information.
10. Instrument data sheets—instrument list only
11. Instrument quotations—major items, one quote.
12. Instrument estimate sheets—complete.
13. Electric motor list—based on available information.
14. Plot plan—complete.
15. Equipment arrangement—preliminary.
16. Engineering item data sheet—major items.
17. Electrical diagrams—preliminary.
18. Structure and foundation specifications—preliminary.
19. Piping specifications—preliminary.
20. Electric specifications—preliminary.
21. Insulation specifications—preliminary
22. Engineering estimate—preliminary.

F. Methods

1. Equipment items require firm or preliminary quotes, labor based on man-hours or historical data.

2. Non-equipment items take quantity approximately from equipment items with labor based on man-hours or historical data.

3. Buildings. Rough structural and finishing estimates on a unit cost basis. Accessories detailed.

4. Conversion factors for location and time if necessary.

### 4.5. Detailed Estimates

A. Purpose: To establish contractor price.

B. Accuracy: Plus or minus three percent to plus or minus five percent.

C. Cost: 100%

D. Time requirements: Six months to eighteen months.

E. Required Information: Same as the detailed estimate for all items are complete and detailed.

F. Methods: Firm quotations and contractor bids. Conversion factors for location and time applied where necessary.

### 4.6. A Summary of Cost Estimating Procedures

Table 2 that follows lists key aspects of four types of cost estimates according to a system developed by a major coal producer in the United States. Category 4 corresponds to the "order of magnitude" estimate while Category 1 corresponds to the "detailed" estimate described.

TABLE 2 KEY ASPECTS OF COST ESTIMATES FOR COAL DEVELOPMENT

| | Order Ranking of Cost Study | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| Reason for Study | Funding | Near Future Plans | Reserve Ranking | Basic Information |
| Time Required | Years | Months | Weeks | Days |
| Information Required | Total | | | Sketch-- |
| Study Group Size | Many | Several | Few | One |
| Contingency | 5-10% | 15% | 20% | 25% ? |
| Maps | 1"-100' | 1"-400' | USGS | Road Maps |
| Transportation | 1"-100' | | | Road Maps |
| Power | | 1"-100' | | Road Maps |
| Surface Ownership | 1"-400' | USGS | Control on | |
| Mineral Ownership | 1"-400' | USGS | Lump Sum | |
| Reserve Quantity | Measured | Indicated | Inferred | Hypothetical |
| Quality | Ultimate Trace and Ash | Short Prox. | Inferred | Hypothetical |
| Overburden | Analyzed | Blasting Slope Stability | Area Figures | Good General Figures |
| Isopachs | All | Ratio | Limited | None |
| Permits | Most Applied For | Many Applied for | Requirements Known | |
| Restrictions | Known | | | Limited Knowledge |
| Environmental Studies | Status Clear | In Progress | Cost Estimated | Requirements Known |
| People | Independent Study | In house with recon | In house no recon | |
| Major Mining Equipt. | Optioned | Sized and Quoted | Verbal Quote | Known Alternate |
| Mine Plan | By Cut | By areas | By Ratio | Very General |
| Production Forecast | Shift | Month | Quarter | Annual |
| Timing and Schedule | Charter by Week | By Quarter | Year | Verbal |
| Location | Plot Plan on 1"-100' | 1"-400' | USGS | Road Maps |
| Capital Equipment | Quotes with Options | Verbal and Written Quotes | Based on Recent Information | Rule of Thumb |
| Labor | By Classification and Shift | Mancount and Average Wage | Based on Recent Information | Rule of Thumb |
| Supervisor | Organization Charts with Names | Organization Charts | Based on Recent Information | Rule of Thumb |
| Supplies | Based on hrs. of Operation | Monthly by Equipment | Yearly | $/Ton from Similar Mine |
| Power | From Rate Sch. | | | - ditto - |
| Other Cash Costs | Calc. by Category | Percentages etc. | Yearly | - ditto - |

TABLE 2 KEY ASPECTS OF COST ESTIMATES (CONTINUED)

| | Order Ranking of Cost Study | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| Non Cash Charges | Calc. by Category | Percentages etc. | Yearly | Rule of Thumb |
| Development Costs | Const. Organization and Costs Detailed | Quantity | Lump Sum | Rule of Thumb |
| Box Cut | Ready for Survey | Good Location | General Area | Unknown |
| Haul Roads and Drainage | Ready for Survey | Good Location | General Area | Unknown |
| Engineer Schedule | By month w/people | Lump Sum | General | None |
| Construction | Detail by Month and Contract | Major Jobs | Time | None |
| Alternatives | Optimum can Selected and Justification Shown | Base Case Well Defined | Started | None |
| Contracts | Most in Progress | Marketing and Governments | Exploration | None |
| Review Time | Days at Many Crucial Points | Days | Hours | Minutes |
| Approvals | Region V. Pres | All Division Function | Chief Engineer | |
| Economic Accuracy | Better than 10% | 15% | 25% | ? |

## 5. SOURCES OF COST INFORMATION

Once the plan or the design is specified, the problem is finding a source of cost data. The estimator seeks prices of equipment, material inputs, power, and labor so that these components can be updated, corrected for size and quantity, corrected for location, then reassembled in proportions representing expenditures of a new project.

### 5.1. Company Sources

The accounting, personnel, operating, purchasing, and marketing departments of the firm can usually supply some of the documents needed by the estimator. This will include copies of the labor contract, recent quotations on materials and power, and recent operating cost data. Usually the new project will have some components in common with existing operations. If the physical model of the mine and mill has been developed, similarities can be identified and the cost estimated.

## 5.2. Government Sources

Government sources often produce information useful to the cost estimator. In the United States, there are a number of government agencies that produce cost or cost-related data. A few of these are listed in Table 3.

TABLE 3 - U.S. Government Sources of Data

| Agency | Type of Data | Reference |
|---|---|---|
| Bureau of Labor Statistics | Wage data, price indexes | Statistical abstract of the U.S. |
| U.S. Department of Commerce Domestic and International | Foreign economic trends and overseas business reports | Foreign economic trends (periodical) |
| Department of Commerce Office of Business Economics | Gross national product and components data | Statistical abstract of the U.S Survey of current business |
| U.S. Bureau of Mines | Cost and availability studies for metals, non-metals and fuels | U.S. Bureau of Mines publications National Technical Information Svc. |
| Energy Research and Development Administration | Cost studies, particularly relating to fuels | National Technical Information Svc. |
| Environmental Protection Agency | Cost studies related to environmental costs | National Technical Information Svc. |

### 5.2.1. STRAMM Handbook

A major study made by STRAMM Engineering (formerly A. A. Mathews, Inc.) for the United States Department of the Interior, Bureau of Mines was completed in December of 1977. The product of the study is "Capital and Operating Cost Estimating System Handbook, Mining and Beneficiation of Metallic and Nonmetallic Minerals Except Fossil Fuels in the United States and Canada".

The STRAMM handbook was prepared for use in the Minerals Availability System (MAS) program of the U. S. Bureau of Mines. The MAS is concerned with costing mineral occurrences where it is unknown if they can be mined and beneficiated at a profit. It is an order of magnitude estimating system using a functional method of costing both mining and beneficiating capital and operating costs. The objective is a preliminary financial analysis to evaluate the economics of mineral resources.

The U.S.B.M. handbook was developed for a user with knowledge and experience in mining and estimating procedures. It is to be used for rough estimates of capital and operating cost of entire mining and beneficiation systems, not for use to determine the cost of a particular component of the system because of its reliance on averages and approximation. Resulting estimates are expected to be within 25% of expected actual cost.

### 5.2.2. National Technical Information Service

To monitor the large volume of technical and economic information coming from U.S. Government agencies subscribe to the weekly government abstract on natural resources published by the National Technical Information Service. This publication provides technical report summaries of government publications. After review of the abstracts, one can obtain the reports themselves in paper copy, microforms, on magnetic tape or punched cards by setting up an account with NTIS. The weekly abstract on natural resources can be purchased from NTIS, 5285 Port Royal Road, Springfield, Virginia 22161. The final issue of each year is a subject index.

## 5.3. Foreign Governmental Agencies

Similar government agencies in other countries assemble cost information: for example, in Venezuela, the Ministero de Minas e Hidrocarburos; in Peru, the Corporacion Financiera de Desarrollo (COFIDE); in Colombia, the Departamento Administracion Nacional de Estadistica (DANE); in Brazil, Departamento Nacional de Produccion Mineral (DNPM). The cost engineer must seek out local sources of information where they are available.

## 5.4. International Agencies

International agencies such as the United Nations and the Organization for Economic Cooperation and Development (OECD) publish reports which sometimes include cost data.

## 5.5. Feasibility Studies

Feasibility studies are valuable sources of cost data. Internal and cost studies made by others are a major source of cost date. They are especially useful when the new project is similar and when the old project has been brought into production.

## 5.6. Professional Associations

In the United States, the American Association of Cost Engineers (AACE) publishes annually a transactions volume from their annual meeting, a cost engineers' notebook, and a bi-monthly magazine. All three of these publications are valuable sources of cost information. The bi-monthly magazine can be obtained by writing to the AACE, 308 Monogahela Building, Morgantown, West Virginia, 26505, U.S.A.

The American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME), 345 East 47th Street, New York, New York 10017, publishes several professional publications including "Mining Engineering" which often includes cost data.

The Canadian Institute of Mining and Metallurgy (CIMM) published in 1972 a useful volume called Mineral Processing Equipment Costs and Preliminary Capital Cost Estimations. The data in this publication is excellent but is getting out of date.

## 5.7. The ICARUS System

The ICARUS Corporation, 11300 Rockville Pike, Rockville, Maryland 20852, (301)881-9350, has developed a computerized timesharing or batch costing system which includes process plant equipment cost estimation on a line item basis. A number of firms involved in detailed cost estimation use the system and thus provide data to update and correct the system. The advantage of ICARUS is a detailed printout of components of a

cost estimate that under other estimating techniques would be lumped into a "factor".

### 5.8. Engineering Periodicals

Various cost indexes are published in U.S. engineering periodicals, for example the Marshall and Swift Equipment Cost Index and the Chemical Engineering Plant Construction Index published in Chemical Engineering, the Nelson Refinery Index published in the Oil and Gas Journal, the Engineering News Record Construction Index published in the Engineering News Record, and the Dodge Building Cost Series published by McGraw Hill.

More information on data sources can be obtained by consulting the bibliography.

## 6. THE STRUCTURE OF COST DATA

Some knowledge of the accounting cycle and methods of costing is essential to properly interpret data provided by accountants. Relationships between accounting costs and price are illustrated in Figure 2.

| | |
|---|---|
| | PRICE |
| PROFIT | COST OF GOODS SOLD |
| SELLING COST | |
| DISTRIBUTION AND ADMINISTRATIVE COSTS | CONVERSION COSTS |
| FIXED AND MISC. COSTS | PRIME COST + OVERHEAD |
| INDIRECT LABOR | |
| INDIRECT MATERIALS | PRIME COST |
| DIRECT LABOR | |
| DIRECT MATERIALS | |

FIGURE 2 COST, PRICE STRUCTURE

Cost data may also be grouped on the basis of similarities or relationships other than accounting classifications. Cost components can be classified according to whether they vary with level of production output (variable costs) or whether they are essentially unchanged by short-term changes in output (fixed costs). Sometimes a third category called semi-variable costs is added to account for those costs that are fixed over a small change in output but vary when greater changes are considered. The three cost categories are shown graphically in Figure 3.

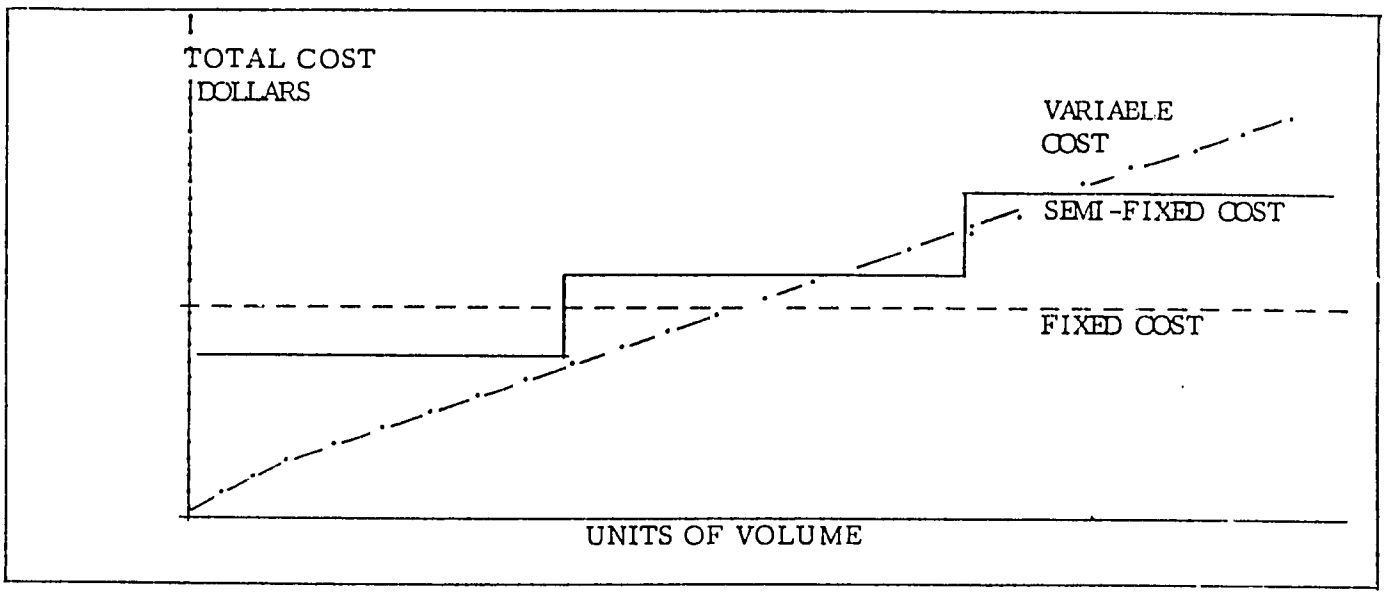



FIGURE 3 RELATIONSHIP OF FIXED AND VARIABLE COSTS

Usually, production cost calculations are based on operation at full capacity. To evaluate the effects of operating at other than full capacity, an estimate of fixed and variable components is required. This problem is extremely common during the start up phases of a project. An approximate breakdown of the fixed, variable, and semi-variable categories is as follows:

A. Fixed Costs - constant at all production levels
1. Depreciation (a book cost which represents the "using up" of prior investment). Depreciation may be a fixed cost where it depends on a uniform obsolescence or other time dependent depreciation; it may also be a variable cost when measured strictly in terms of use of equipment.
2. Taxes (some correlate strongly with output)
3. Insurance

B. Variable Costs—directly proportional to production level
1. Raw materials
2. Utilities
3. Royalties
4. Marketing (transportation, sales costs, packaging, handling)
5. Reagents, chemicals, catalysts

C. Semi-variable Costs—partially proportional to production levels
1. Direct labor
2. Supervision
3. Maintenance
4. General expenses
5. Plant overhead

### 6.1 Fringe Benefit Estimates

Fringe benefit estimates are factored from labor costs. In the United States they include payroll taxes, workman's compensation, group insurance, pensions, wash-up time, paid rest, travel, vacation, sick pay, profit-sharing, employee services, and union steward work.

work.

During 1976, in the United States, thirty percent was added to the base wage rate in the Arizona copper mines to account for fringe benefits. The base wage rate of a truck driver in an open-pit copper mine in 1976 is $6.39 per hour. To this base hourly rate, 33 cents per hour cost-of-living adjustment is added. This cost-of-living adjustment is changed quarterly one cent per hour for each one-third point increase in the Consumer Price Index published by the Bureau of Labor Statistics. The cost-of-living adjustment covers approximately 85% of price increases indicated by the Consumer Price Index and the rest are covered by contract renegotiation.

An estimate of fringe benefits in United States mines is shown in Table 4.

Table 4 Fringe Benefits in U.S. Mines

| Benefit | Percent of a 260-day working year |
|---|---|
| 1. Vacation, 15 days per year | 5.8% |
| 2. Military leave, sick leave, jury duty leave, maternity leave, funeral leave, physical examinations, on-the-job training, clean-up, coffee breaks, grievance time | |
| Assume: 15 days per year | 5.8 |
| 3. Social Security Insurance | 5.8 |
| 4. Unemployment Compensation | 1.5 |
| 5. Workman's Compensation | 1.0 |
| 6. Holidays--9 days per year | 3.5 |
| Total | 23.4% |
| | |
| Sample Wage Calculation: | |
| Base wage rate | $6.39 per hour |
| Cost of living adjustment | .33 |
| Shift premium | .10* |
| Total | $6.82 per hour |
| Fringe benefits @ 30% | 2.05 |
| Total | $8.87 per hour |

The fringe benefit calculation of course will vary according to company policy and country. In Peru, a recent evaluation indicates the fringe benefit factor is 1.69. This would not include massive infrastructure costs of a remote project.

### 6.2. Operating Materials

Another variable cost is operating materials. These costs are calculated from company records of other detailed feasibility studies. In order of magnitude and factored estimates, it is important to identify major inputs as a proportion of the total direct materials cost. At one U.S. open pit mining operation, the distribution of the cost of producing a pound of refined copper is shown in Table 5.

Table 5 Distribution of Refined Copper Cost, 1975

| Item | % of Total Production Cost, Electrolytic Refined Copper 1975 |
|---|---|
| Diesel fuel, explosives, scrap iron, and chemicals | 28% |
| Tires | 2% |
| Steel | 8% |
| Electric power | 6% |
| Total power and materials | 44% |
| Labor | 20% |
| Overhead | 6% |
| Total | 70% |

A cost estimator working on a preliminary estimate of a similar copper system must carefully calculate the consumption of these key inputs. When the estimator has determined these direct material and labor inputs of the mine and mill, he has accounted for 64% of the final cost of the refined copper product.

### 6.3. Depreciation

Depreciation is an important component of fixed cost. For preliminary evaluations, it is common to use "straight-line" depreciation, calculated by dividing the depreciable investment by the economic life of the project. For example, a ten-year mining project will estimate depreciation at 10% of the depreciable investment each year. Depreciation affects mining cash flows only through taxes. It represents the using up of a past expenditure expensed today because today there is production and profit, hence taxes. The U.S. tax laws allow depreciation as an expense to avoid taxation of that portion of cash flow that represents using up of the past capital investment.

There are three other depreciation methods that can be used under U.S. tax laws. Their effect is to accelerate depreciation, hence, lower taxes during the early years of the project. The total amount depreciated under all depreciation methods is the same.

In the declining balance method of depreciation, the percentage rate per year is double that of straight-line depreciation; hence, for a ten-year project, the rate is twenty percent of the book value of the asset per year.

The sum of the year's digits method allows depreciation as a fraction of the remaining years of economic life of the project divided by 55. For example, in the ten year project mentioned, the first year depreciation is 10/55 times the book value the second year is 9/55 times the book value.

The units of production depreciation method allows depreciation in proportion to use of the depreciable equipment. For example, if we estimate the number of hours of useful life of a piece of equipment, and we use 15% of those hours during the year, 15% of the cost of the equipment is the depreciation for that year.

### 6.4. Overhead

Overhead costs may include fixed and variable components. They are not clearly associated with a specific category of production; therefore, they are prorated by accountants using differing methods. For preliminary estimation, overhead cost is usually factored as a lump sum and there is no proration problem. Historical cost data must be used with care because plant overhead may be prorated to activities on an arbitrary basis. The basis of allocation varies, for example, on the basis of labor hour, machine hour, rate of production, or value of output.

### 6.5. Absorptive vs. Direct Costing

Very often cost data for public disclosure are absorptive costing, that is, all fixed and variable costs are assigned to the goods produced. The alternative to absorptive costing is direct costing where the fixed, variable, and semi-variable components of cost are separated. The method is far more useful in cost and profit calculations and imperative if the economics of alternative rates of production are to be considered.

Table 6 provides historical and forecast cost data for a copper mine and mill producing and treating 20 million tons of copper per year in 1976. Column 2 shows that the cost per ton in 1976 was $3.71.

Each variable component of cost can be corrected for changes in level of activity and for expected inflation. Assume a 15% increase due to inflation between 1976 and 1977. Furthermore development activity is expected to be 10% higher in 1977, both factors can be taken into account and a new development cost estimated as indicated in Table 3. Other costs may be estimated with overhead remaining unchanged.

Table 6 Correction for Inflation and Rate of Operation

| Item | $ per ton 1976 | Correction for Inflation 1976-1977 | $ per ton 1977 | Correction for level of Activity | Annual 1977 Cost at Production Rate 18 million tons per year |
|---|---|---|---|---|---|
| Development | 1.11 | 1.15 | 1.28 | 1.10 | 28,085,000 |
| Mining | 0.50 | 1.15 | 0.58 | 0.90 | 10,350,000 |
| Concentrating | 1.74 | 1.15 | 2.00 | 0.90 | 36,018,000 |
| Freight | 0.08 | 1.15 | 0.09 | 0.90 | 16,560,000 |
| Overhead | 0.28 | 1.15 | 0.32 | 1.00 | 6,440,000 |
| Total Cost | | | | | 97,451,000 |
| Per Ton | 3.71 | | 4.27 | 4.87 | |

In the direct costing case, the breakdown of individual categories allows a correction for higher development and lower mining rates as well as a correction for fixed overhead. The result yields a significantly different result for 1977 ($4.87 per ton) compared to a simple updating of the historical cost per ton ($4.27 per ton).

## 7. MEASURED COST TECHNIQUES

Measured cost techniques are useful when cost estimates involve existing operations or when it is possible to perform the proposed operation within the existing system, pilot plant or research facility. Measured cost techniques include:

(1) time studies
(2) work sampling
(3) review of man hour reports
(4) predetermined motion-time data.

### 7.1. Time Studies

Time study techniques break each operation down into components to determine time-labor requirements. Power and material inputs are also estimated and a cost is estimated.

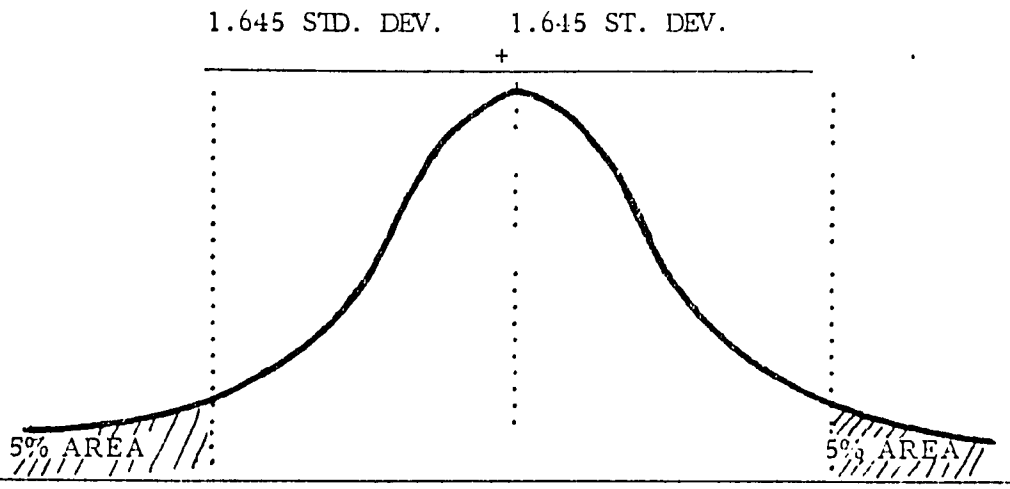
Example: Open pit haulage cost estimate based on time study information.

Basis: 90 ton trucks
Work schedule: 1700 eight hour shifts per month
Estimated tons per truck shift: 1310
Tire cost: $200,000 per month, 90% for ore haulage
Tire cost per shift: .9 x 200,000 divided by 1700 = $106 per shift
Operating labor: $80 per shift
Fuel and oil consumption: $120 per shift
Repairs: $80 per shift
Estimated total cost per shift: $386
Cost per ton of ore: $386 divided by 1310 = $0.29 per ton

### 7.2 Work Sampling

Work sampling is done without the stop watch. A number of observations are made at random intervals, for example, working, idle, waiting, absent; then, statistical techniques are used to quantify results.

A work sampling study consists of a number of observations of men or machines taken at random intervals. Observations are classified in groups. The number of observations will depend upon the consistency of results and the need for accuracy in the estimate. One approach is to record an "event" such as working or idle and tally the result. For this type of choice the "binomial" distribution applies and when the number of observations becomes large the binomial approaches the normal distribution of Figure 4.




SAMPLING. INTERVAL

90% OF AREA UNDER CURVE

FIGURE 4 NORMAL DISTRIBUTION

With this distribution, a tolerable maximum sampling error can be established according to a formula. A normal distribution with a confidence interval of 90% is often used for work sampling studies. To indicate a confidence interval of 90% is the same as

stating that the true value of the mean of our observations falls within a range of two standard deviations on each side of the mean, 90% of the time. Therefore, the sampling interval is given by:

$$I = 2a \left(\frac{P(1-P)}{n}\right)^{1/2}$$

where I = confidence interval obtained from the study expressed as a decimal
a = factor chosen from tables of the normal distribution for a given confidence interval.
For 90% the confidence interval a= 1.645.
P = the observed occurrence of the event expressed as a decimal percent.
n = the total number of random observations taken

Solving the equation for n gives:

$$n = \frac{4a^2P(1-P)}{I^2}$$

Example: A work sampling study of an open-pit haulage unit is made. The question is, what percent of the time does the haulage unit wait on the loading shovel? Assume we have made 250-300 observation cases and have some preliminary results. The results indicate that during 25-38 observation cases or 15% of the time, the truck was waiting on the shovel. We can now calculate the confidence interval for 90% confidence.

$$I = 2(1.645)\left(\frac{(.15)(.85)}{250}\right)^{1/2} = .0743$$

Thus, our best estimate at the moment is that the haulage unit is waiting 15% of the time plus or minus 7.43%/2 or a range of 11.3% to 18.7% of the time. If this result is close enough for our estimating purposes, the study is complete. If we wish to reduce the interval "I" to 5% instead of its present 7.43% a number of added observations can be calculated:

$$n = \frac{(4)\ (1.645)^2\ (.15)\ (.85)}{(.05)^2} = \frac{1.38007}{.0025} = 552$$

Therefore, to meet the new accuracy requirements, 552 minus 250 or 302 additional observations of the work are needed to reduce the confidence interval to 5%.

After the waiting times are calculated, costs of waiting can be calculated and the value of reducing or adding haulage units evaluated. This type of analysis may also be useful in evaluating other production data, for example, what is th average number of hours before a cable breaks on the loading shovel, thus incurring additional costs due to delay? In the latter case there may be considerable statistical data to allow us to estimate the probability of a failure in the piece of equipment. It may also be possible to estimate the cost of a failure during operating hours versus preventative maintenance prior to failure during operation. The probability of failure times the cost of failure during operating can be compared to the cost of replacement prior to failure.

The concept of work sampling can be useful even if the results are not reduced to a specific statistical analysis. Most foremen are aware of delays and their cost even though no specific analysis is made. The work sampling technique is simply a more

quantitative analysis of any observable state of an operation. The technique is relatively inexpensive and convenient to perform and has the advantage that it can be undertaken without a stopwatch which often has the effect of altering a work pattern when it involves people.

## 8. COST CORRECTIONS FOR TIME, SIZE, AND LOCATION

### 8.1. Cost and Price Indexes

Order of magnitude and factored cost estimates make extensive use of past data. Detailed studies involve thousands of hours of effort and yield information on costs that can be updated and used in less comprehensive cost estimates.

A cost index is a ratio to estimate current costs from obsolete costs as follows:

$$\text{Cost}_{now} = \text{Cost}_{then} \times \frac{\text{Index}_{now}}{\text{Index}_{then}}$$

Example: a 100 horsepower, 24" x 36" primary jaw crusher for a concentrator cost $37,000 in 1970. What is its estimated cost today? The Marshall and Swift Cost Index was 300 in 1970 and rose to 553 in 1978. What is the estimated cost in 1978?

$$\text{Cost}_{now} = \frac{553}{300} \times \$37,000 = \$68,203$$

Cost indexes are a guide to the change in prices of a weighted mixture of equipment or commodities. They are used to update costs ranging from the price of a specific piece of equipment, raw material, or labor cost to the capital or operating cost of an entire plant.

The questions to ask when using one of the many existing cost indexes are:

1. What materials or items are included in the index? How do they correspond to the cost being updated?
2. What weighting method was used to construct the index?
3. Do the prices used in construction of the index reflect transactions or list prices?
4. Are recent changes in the mix of items included in the present index?
5. What correction is needed to account for changes in productivity of the equipment or production system? Is there a productivity factor included in the index?

The cost estimator will find existing indexes useful and frequently finds it of value to construct custom indexes tailored to a specific cost estimate. Such indexes are useful to reevaluate an estimate at a later date or for escalating costs over the construction period of a plant. For these purposes, some knowledge of cost index theory is needed.

Since many items are combined to form an index, there are different methods used to combine them.

Example: The Simple Aggregative Method

| Commodity | 1972 | 1977 |
|---|---|---|
| Milk, quart | $0.70 | $0.84 |
| Butter, pound | 0.80 | 0.85 |
| Eggs, dozen | 0.75 | 0.90 |
| Total | $2.25 | $2.59 |
| Simple aggregative price index (percent) | 100.00 | 115.1 |

Example: The Weighted Aggregative Method

| Commodity | Quantity Used 1972 | Unit Price 1972 | Unit Price 1975 | Price x 1972 Quantity 1972 | Price x 1972 Quantity 1975 |
|---|---|---|---|---|---|
| Milk, quart | 100 | $0.70 | $0.84 | $70.00 | $84.00 |
| Butter, pound | 20 | 0.80 | 0.85 | $16.00 | 17.00 |
| Eggs, dozen | 70 | 0.75 | 0.90 | 52.50 | 63.00 |
| Total | | | | 138.50 | 164.00 |
| Weighted aggregative index | | | | 100.0 | 118.4 |

$$\text{Formula:} \quad \text{Index} = \frac{\sum P_1 Q_0}{\sum P_0 Q_0}$$

The weighted aggregative method is by far the most common. Note that the weighted index holds the base year mix of the components ($Q_0$ constant and revises the index on the basis of changes in price. Actually, the mix of commodities does change. If the simple index shown is an index of food costs, the mixture of milk, butter, and eggs consumed at one point in time is probably different than at some later time. These changes in mix introduce an error into the index as a measurement of the actual changes in cost. Indexes are revised periodically to take account of the new mix. Additional error is introduced when the productivity of the new mixture of plant and equipment is different from the old mix.

## 8.2 Corrections for Time

There are hundreds of cost indexes in U.S. publications used by cost estimators. This section discusses a few indexes of particular interest for mineral and fuel evaluations. The appendix to this chapter includes plots and five year projections of some of the most useful indexes, including all of the index uses in the STRAMM Handbook and others commonly used for mineral or petroleum evaluation.

### 8.2.1 The Engineering News Record Indexes

The Engineering News Record, a McGraw Hill weekly publication for the engineering and construction industries, publishes two indexes of particular interest. The first, the Engineering News Record Construction Cost Index was created in 1921 to diagnose World War I price changes and evaluate their effect on construction costs. It is

a weighted aggregate index of constant quantities of structural steel, portland cement, lumbar and common labor. This hypothetical block of construction, repriced weekly, was valued at $100.00 in 1913 and $3,071.94 in August of 1979. The Construction Cost Index includes 200 hours of common labor priced at the average of twenty cities, 2500 pounds of structural steel shapes at a mill price average in twenty cities, 1.128 tons of portland cement and 1,088 board feet of lumber in the form of 2 x 4's.

The Engineering News Record Building Cost Index was created to evaluate the impact of skilled labor on construction cost trends. The Index represents a hypothetical construction block valued at $100.00 in 1913 prices, which reached $1,850.62 in August of 1979. The Building Cost Index includes 68.38 hours of skilled labor at the twenty-city average, 2500 pounds of structural steel shapes at the mill price of twenty-cities average and 1,088 board feet of lumber in the form of 2 x 4's.

A long term plot of the Engineering News Record Indexes can be found in the March issues of the magazines and the latest indexes can be found in the most recent copy of the Engineering News Record.

### 8.2.2 Chemical Engineering Indexes

Chemical Engineering Magazine publishes regularly the Marshall and Swift (M&S) Equipment Cost Index, the Chemical Engineering (CE) Cost Index as well as a series of current business indicators taken from government and non-government sources. The source of the chemical process industry (CPI) output index is the Federal Reserve Board and the Mc-Graw Hill Department of Economics. The source of the CPI value of output index is the U.S. Department of Commerce, Bureau of Census and the Mc-Graw Hill Department of Economics. The CPI operating rate index comes from the Federal Reserve Board and the Mc-Graw Hill Department of Economics. These three economic indicators can be found in Chemical Engineering, April 10, 1967, pages 197-198. The source of the construction cost index is based on new orders for chemical process equipment, chemical wholesale prices, industrial activity and the McGraw-Hill Department of Economics Equipment Cost Index.

After 1937 the consulting firm of valuation engineers, Marshall and Stevens, issued quarterly index numbers for comparative equipment in 47 different industries and commercial ventures. Later the index was known as the Marshall and Swift Index. The index includes eight process industries—cement, chemicals, clay products, glass, paint, paper, petroleum products, and rubber. Other related industries include electrical power, mining and milling, refrigerating, and steam power. Chemical Engineering, in November of 1947 (pgs. 124-6) provides details on the calculation of M&S numbers. The May 8, 1978 issue of Chemical Engineering provides a summary of M&S indexes from 1956 through 1978. Current issues of Chemical Engineering provide estimates of the M&S equipment cost index by quarters.

### 8.2.3 U.S. Government Statistical Abstract

The statistical abstract of the United States, published by the Superintendent of Documents, provides summaries of key indexes on an annual basis. Of particular interest are the wholesale price index and all of its components, which include such items as steel mill products, motor vehicles, tires and tubes, refined petroleum products, lumber, concrete products, coal, industrial chemicals, and electric power. The primary source of statistics in the statistical abstract are identified through the footnotes. For example, the producer price indexes come from the U.S. Bureau of Labor statistics and are published monthly and annually in a publication called Producer (formerly Wholesale)

Prices and Price Indexes. Information on U.S. consumer and producer prices is also published in the Survey of Current Business published by the U.S. Department of Commerce monthly and the annual report of the President and Council of Economic Advisors, published annually. The primary source of most data is the U.S. Department of Labor. The Bureau of Labor Statistics - Employment and Earning Statistics provides monthly data on the number of employees, production workers and weekly earnings in various industries.

The Bureau of Labor Statistics Wholesale Price Index - Construction Machinery and Equipment provides price movement data for eight classes of machinery including drag lines, shovels, air compressors, scrapers, graders, tractors and off-highway vehicles.

The Bureau of Labor Statistics Consumer Price Index measures average changes in the prices of goods and services for about 400 items bought by wage earners including necessities and some luxury items. Consumer and Wholesale Price Index is commonly available in all countries even if more detailed indexes are not available.

The Bureau of Labor Statistics Wholesale Price Index for all commodities measures monthly price changes in prices of commodities sold in primary markets. The U.S. Index is based on a sample of 2,300 items and is often used as a general purchasing index. This index increased at the same rate as copper production costs through the 1970-75 period. Specific commodity groupings are often useful to the estimator for example, explosives, industrial chemicals, tires, iron and steel, construction machinery and equipment. The Wholesale Price Index is a weighted average of price changes. Weights are based on the total net selling value and are revised each five years with data from the industrial censuses.

### 8.2.4 The STRAMM Indexes

The STRAMM Handbook is used to estimate mining and beneficiation costs. Eleven readily available indexes are used to update estimates from a July, 1975 base. The source of data includes the Engineering News Record (ENR) and the Bureau of Labor Statistics (BLS) as indicated in Table 7.

Table 7 STRAMM Indexes

| No. | Item | Cost Index | Source | Value July '75 |
|---|---|---|---|---|
| 1. | Mine and Plant Labor* | Mining Labor Table C-1 | B.L.S. | $5.89/hr |
| 2. | Construction Labor | Skilled Labor (BC) | E.N.R. | 1996.7 |
| 3. | Equipment & Repair Parts | Equipment Table 4 Code 11-2 | B.L.S. | 184.9 |
| 4. | Bits & Related Steel | Iron & Steel Table 4 Code 10-1 | B.L.S. | 197.3 |
| 5. | Timber & Lumber | Lumber Table 4 Code 08-1 | B.L.S. | 196.8 |
| 6 | Fuel | Petroleum Table 4 Code 05-7 | B.L.S. | 258.8 |
| 7. | Powder & Blasting Agents | Explosives Table 6 Code 067902 | B.L.S. | 177.2 |
| 8. | Tires | Tire Table 6 Code 07120105 | B.L.S. | 158.8 |
| 9. | Construction Materials | Materials (Denver) | E.N.R. | 185.0 |
| 10. | Industrial Materials** | Industrial Commodities Table 2 | B.L.S. | 171.2 |
| 11. | Transportation*** | Rail - Metallic Ore Table 14 Code 28 | B.L.S. | 185.7 |

*Rate does not include burden.

**Use for items not otherwise covered. Reporting in table 2 was discontinued by B.L.S. in March, 1978. Values given at beginning of Table 6 may be used thereafter.

***1969 was year of origin. Indexes prior to 1969 have been extrapolated. Usa for all transportation items.

### 8.2.5 Foreign Indexes

Because of the international nature of the mineral industry access to foreign and international indexes is important.

The United Department of Commerce, Industry and Trade Administration publishes "International Economic Indicators" monthly. This publication provides information on wholesale prices for all commodities for the United States and a number of other industrialized countries including France, the Federal Republic of Germany, Italy, the Netherlands, United Kingdom, Japan and Canada.

A publication called International Financial Statistics, published by the United Nations, is also useful for wholesale price information worldwide.

Publications such as the Engineering News-Record also publish international information. For example the September 16, 1971 issue of the magazine published materials prices and wage rates in Mexico City, Sao Paulo and Caracas. Foreign governments also publish more detailed statistical information. The service bulletin for the statistics of Canada (Ottawa, K1AOV5) publishes construction price statistics for that country.

To the extent that a project in South America is equipped with U.S. or Canadian equipment, U.S. and Canadian indexes are useful for cost estimation. The foreign exchange rate, if it is allowed to fluctuate freely, is inclined to adjust for the differences in the rate of inflation between countries. Thus it is possible that a project in a foreign country can be estimated in U.S. dollars at two points in time using U.S. indexes - then corrected using the rate of foreign exchange at each point. Most estimators are likely to have more confidence in an estimate where local costs are corrected using reliable local indexes and international costs are corrected with the appropriate international index.

The broadest indicators of price and cost changes in Peru are the Consumer Price Index and the Wholesale Price Index shown in Table 8.

TABLE 8 Peruvian Price Index

| MID YEAR | CONSUMER PRICE INDEX (1970 = 100) | WHOLESALE PRICE INDEX (1970 = 100) |
|---|---|---|
| 1970 | 100 | 100 |
| 1971 | 110 | 107 |
| 1972 | 118 | 115 |
| 1973 | 129 | 118 |
| 1974 | 165 | 242 |
| 1975 | 195 | 252 |
| 1976(Sept) | 268 | - |

Source: First National City Bank and U.S. Department of Commerce

The Consumer Price Index of Table 8 exhibits an average increase of 15% per year and the Wholesale Price Index 22% per year over the 1970-75 period.

Table 9 is an index more specifically tailored to Peruvian mining and milling costs. It is based on actual cost data from five major concentrators in Peru representing four million tons of ore-processing capacity.

TABLE 9 Index of Peruvian Milling Costs 1964-1975 (1970=100)

| YEAR | TOTAL COST | MATERIALS | LABOR and SUPERVISION | POWER SHOPS AND SERVICES | INDIRECT OPERATING EXPENSE |
|---|---|---|---|---|---|
| 1964 | 57 | 63 | 76 | 27 | 43 |
| 1965 | 61 | 70 | 78 | 27 | 46 |
| 1966 | 70 | 80 | 86 | 31 | 50 |
| 1967 | 66 | 72 | 82 | 34 | 50 |
| 1968 | 73 | 80 | 81 | 51 | 78 |
| 1969 | 83 | 90 | 79 | 71 | 61 |
| 1970 | 100 | 100 | 100 | 100 | 100 |
| 1971 | 110 | 81 | 98 | 133 | 296 |
| 1972 | 107 | 72 | 109 | 142 | 358 |
| 1973 | 112 | 88 | 131 | 113 | 383 |
| 1974 | 127 | 103 | 154 | 80 | 406 |
| 1975 | 182 | 172 | 166 | 110 | 513 |
| 1976 | 222 (*) | | | | |
| 1977 | 271 (*) | | | | |
| 1978 | 330 (*) | | | | |

*Projected at 22% per year based on the trend in wholesale prices.

The index shown is not exactly a weighted aggregative index as defined because it is based on actual changes in cost. The mix therefore is changing continually. For example, if an unusual amount of high-priced materials were purchased in any one year, it would be reflected in this index. In the absence of a more carefully prepared index, this is the closest measure we have for updating actual costs in Peru. Note that this index in 1975 is close to the level of the Consumer Price Index. Use of the Consumer Price Index would have given us a reasonable estimate of actual cost. The Wholesale Price Index would have been high.

The historical data shown in the table is projected through the year 1978 to make it useful to the cost estimator. The 1970-75 trend is at a rate of 10% per year, but it has accelerated reaching 42% between 1974 and 1975. Because it is not a true aggregative index, it may have been affected by irregularities in the mix. It would not have been unreasonable to turn to the Wholesale Price Index for a projection. In this case, the projection for the three year period is at a rate of 22% per year.

Bolivian indexes or actual mining costs are not available, but there is a published Consumer Price Index shown in Table 10

TABLE 10 Bolivian Consumer Price Index

| YEAR | CONSUMER PRICE INDEX |
|---|---|
| 1970 | 100 |
| 1971 | 112 |
| 1972 | 139 |
| 1973 | 145 |
| 1974 | 236 |
| 1975 | 255 |
| 1976 (1) | 311 |
| 1977 (1) | 380 |
| 1978 (1) | 463 |

(1) Projected at a rate of 22% per year, the 1970-75 trend.

The increase is close to that of the Peruvian Wholesale Price Index. It is projected at its 1970-75 trend rate of 22% per year.

The uncertainty created by runaway inflation can be appreciated from a review in the Chilean Price Index shown in Table 11

TABLE 11 Chilean Consumer Price Index

| YEAR | CONSUMER PRICE INDEX |
|---|---|
| 1970 | 100 |
| 1971 | — |
| 1972 | 162 |
| 1973 | 734 |
| 1974 | 5484 |
| 1975 | 27,518 |
| 1976 (est.) | 71,327 |

The rate of price change in Escudos (now Chilean pesos) makes it impossible to forecast costs. The 1970-76 trend is at an average rate of 236% per year. During 1975 the cost of living rose by 341%, in 1976 by 173%. The government of Chile uses daily mini-devaluations to keep their prices stable in dollar terms. During 1976 devaluation in relation to the dollar was 106%.

### 8.2.6 Price Fluctuation Due to Business Activity

Figure 5 indicates an important consideration when using cost indexes. The various indexes indicate a trend line over time but costs vary around this trend line due to general economic conditions that are specific to the type of cost involved. These fluctuations around the trend line can be extremely important to specific cost estimates and should be a part of the interpretation of the cost indexes.

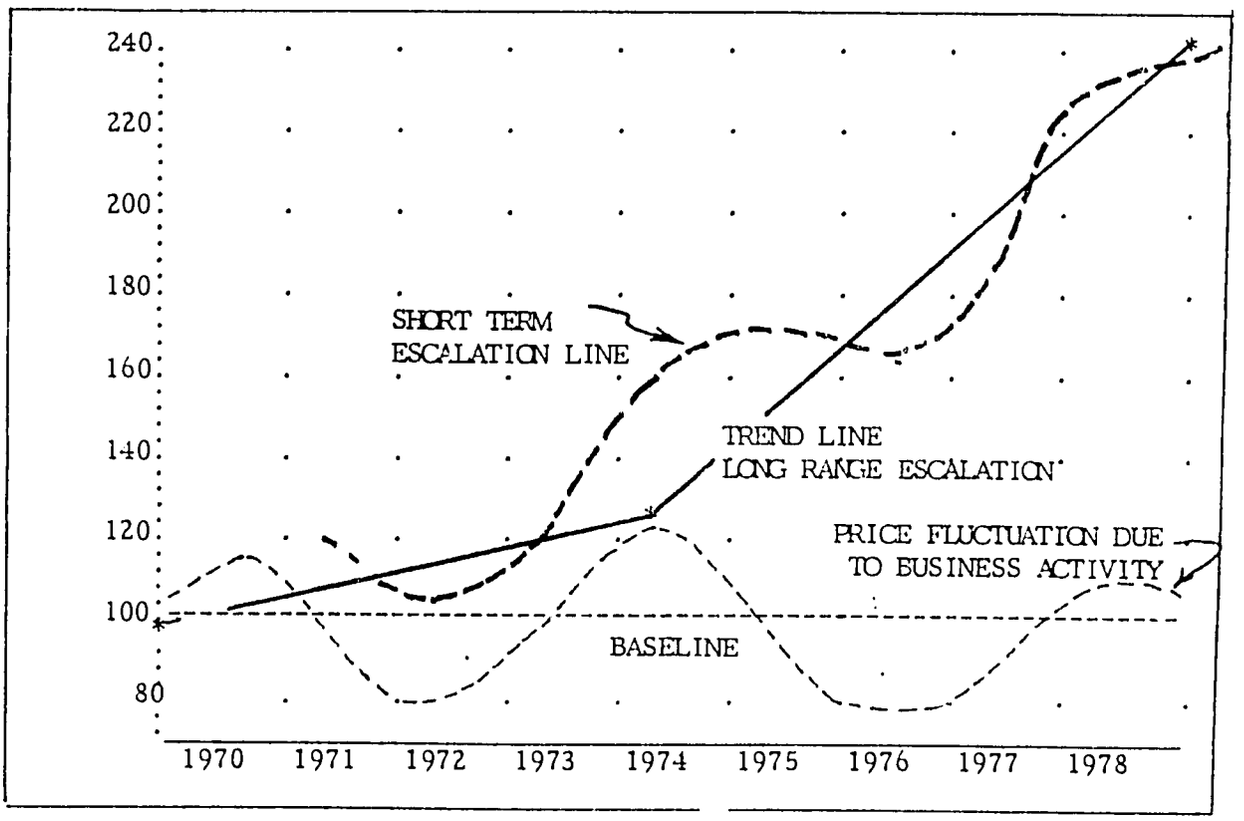



FIGURE 5 COST INDEX TRENDS AND VARIATIONS DUE TO BUSINESS ACTIVITY

### 8.3 Size Corrections

Capital cost data for processing equipment of different sizes is frequently summarized in the form of a power curve in the form

$$\text{Cost} = ax^b$$

In this equation x is the size variable, such as area, horsepower, capacity in cubic feet, gallons, tons per day, pounds or tons per hour, volume, length, width, diameter, feed size, depending on the type of equipment involved. The coefficient "a" makes the conversion between the units of size and the dollars of cost. Graphically this relationship results in the type of curve illustrated in Figure 1. The curve indicates the relationship between size and cost, then factors are used to correct for time, location and specific differences in physical conditions.

Capital cost curves are constructed using quotations from manufacturers or similar data from producers, feasibility studies or the technical literature. Individual data points are summarized in the form of a curve which describes the relationship between the variables.

Curves are fitted to actual cost data using standard regression techniques, for example, the power curve least square formulas result in a curve that minimizes the sum of the squares of the distances of the logarithms of the points to a straight line.

Assume that a set of data is collected in 1975 on the costs of a number of jaw crushers of various sizes. The result of the survey is shown in Table 12

TABLE 12 Jaw Crusher Costs

| JAW CRUSHER SIZE INCHES | AREA OF FEED OPENINGS (SQ. IN.) | COST, DOLLARS 1975 |
|---|---|---|
| 15 x 24 | 360 | 17,000 |
| 15 x 30 | 450 | 22,000 |
| 24 x 36 | 864 | 35,000 |
| 30 x 42 | 1260 | 50,000 |
| 48 x 36 | 1728 | 125,000 |
| 48 x 42 | 2016 | 152,000 |
| 60 x 48 | 2880 | 241,000 |

Marshall and Swift Index: 448
Prices include drive, and exclude motor.
Using the method of least squares, a power curve can be fitted to this data resulting in a curve of the form:

$$\text{Cost} = a\,x^b$$

where a=7.7099 and b=1.2833.

The coefficient of determination for the curve is 0.95. The curve and the original data points are plotted in Figure 6.

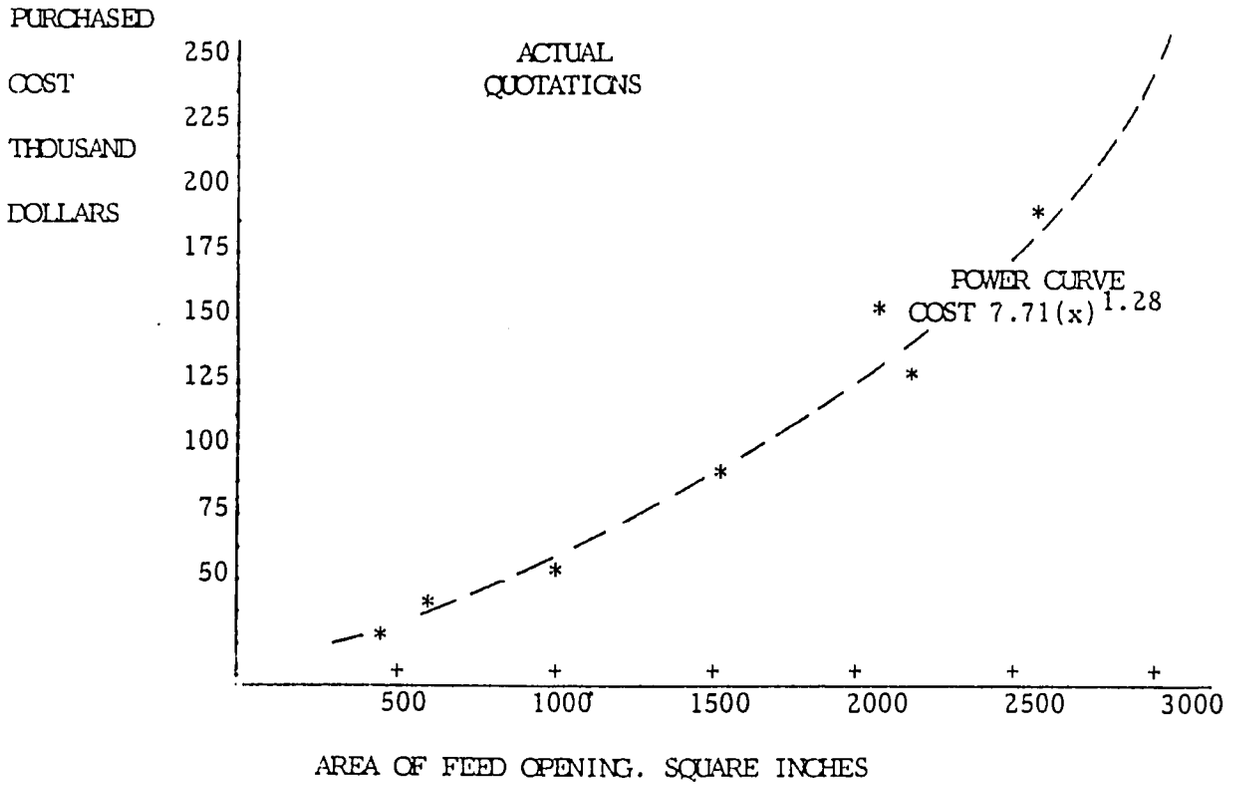



FIGURE 6 POWER CURVE FITTED TO JAW CRUSHER DATA

The coefficient of determination can be interpreted in this case as a "good fit," the curve "explains" 95% of the variation around the mean of the cost values. This curve relates cost and size of these jaw crushers, summarizing the cost information. This approach can be used on all types of process of mining equipment for sizing purposes where the key variable can be defined.

### 8.4 Corrections For Location

Cost data is generally specific to a location and must be corrected if we are making an estimate for a plant elsewhere. The location factor used in Peru, for example, is approximately 1.6 reflecting the costs shown in Table 13.

TABLE 13 Location Factor Example (1975 DATA)

Example: Importation of a cone crusher
Key Import Data U.S. Price: $200,000
Volume: 1200 cubic feet
Weight: 10 metric tons (10,000 kgs)
Exchange rate for freight cost: 43.38 Soles/$
Tariff: 32%
Freeport rights: 0/30 Soles/kg plus tariff
Law 19620: 3% of CIF (customs valuation)

Customs Valuation = $200,000 x 1.2 x 43.38
$10,411,200 Soles CIF

Freeport rights = ( 10,411,200 x .32 ) - ( 10,000 x .30 )
= 3,334,584 Soles

Law 19620 Tariff = .03 x 10,411,100 S/= 312,336 S/

Summary

| | Soles |
|---|---|
| FOB cost $200,000 x 38.70 soles/dollar = | 7,740,000 |
| Freight $150/mt x 43.38 soles/dollar x 10 mt = | 65,070 |
| Insurance | 10,000 |
| Freeport rights | 3,334,584 |
| Law 19620 | 312,336 |
| Total | 11,461,990 |

$$\text{Location factor} = \frac{7,740,000}{11,461,990} = 1.48$$

A knowledge of location factors makes it possible to utilize technical and cost information for plants constructed in other countries and to correct such estimates approximately to a cost abroad. The factor of 1.48 for Peru is approximate and in this case depends on a simple example. The average figure in Peru at the time was approximately 1.6.

At this writing, the U.S. Bureau of Mines has entered into a major contract to correct the capital and operating costs in the STRAMM Handbook for application to international locations. The obvious changes in operating cost include corrections for differences in wage rates, the exchange rate, and productivity. When wage rates are lower labor is likely to be substituted for capital equipment, thus the technical assumptions of the STRAMM book can be entirely wrong. Isolated locations, high labor turnover and lack of skilled personnel are reflected in different assumptions of productivity as well as the mix of equipment, materials and labor in a particular cost estimate.

## 9. U.S. METHODOLOGY

We do accurate guesswork!" This statement appears on the door of the cost estimating department of a major minerals firm in Colorado. The key word of course is "accurate." All costing is a blending of art and science but there are standard methods that minimize blunders in costing work.

The group that does the "accurate guesswork" passes on the following advice for cost estimators:

(1) Have a checklist. Omissions are a major source of error in cost estimation.

(2) Start with a mine plan or flow sheet or at least a sketch. Use it to develop the materials balance and the equipment, manpower, and supply lists. It is extremely important to make sure that the concepts behind the mine plan and the flow sheet are practical. There may be scale-up problems when processing is based on pilot plant testing. There may be problems with the mine plan that relate to characteristics of the rock. Are the products from the system the products that are demanded in the market or will there be problems with are reasonable or is there some uncertainty? If there is it should be tested in the sensitivity analyses on the project.

(3) Use the equipment list to develop your power requirements.

(4) Know something about your sources of supply of materials. Who will supply the required sulphuric acid? Where will the necessary electric power be purchased? Who will supply the grinding balls?

(5) Spend enough time on the estimate. Call the vendors on critical items in the estimate.

(6) Continuously develop sources of cost data from publications, symposiums, and internal sources.

(7) Develop some of your own indexes and factors to fit your projects.

(8) Be sure that the market assumptions for the product are correct.

## 9.1 Costing Techniques

Kennecott Ledgemont Laboratory procedures for estimating costs of metallurgical processes begin first with the technical analysis, then proceed to the economic analysis and the economic evaluation (Agarwal, 1973).

### 9.1.1 Evaluation Model

The Kennecott evaluation model is described (Agarwal, 1973) in terms of five phases.

(1) Identification of the problem
(2) Establishing the criteria to be used in the evaluation of the specific problem
(3) Information gathering
(4) Evaluation procedures
(5) Reporting and identifying critical technical and economic parameters.

The group feels that once the problem is successfully defined they are halfway to the solution. Definition of the problem also involves establishing the criteria for the evaluation which differs with various projects and processors. Available experimental results, previous experiences and literature sources are collected and analyzed.

In the area of problem identification the objective is to determine the technical and economic viability of a process at its present state of development and to identify and rank the critical, technical and economic parameters of a process. The group must then present the findings to management with recommendations for further action.

### 9.1.2 Technical Analysis

The technical analysis includes thermodynamic and chemical considerations, rate phenomena, raw materials requirements, containment and corrosion considerations, scale-up problems, product quality relative to product specifications, competing processes, emergency and safety considerations, and environmental considerations.

The product of the technical analysis includes the process description, a process flow diagram and plant capacity, heat and material balances, and the product quality specifications.

A preliminary analysis is likely to start with process chemistry. Based on the chemistry in the other technical considerations, a flow sheet is prepared which is used for equipment sizing and a conceptual lay-out. These technical considerations provide operating requirements and an estimated manpower requirement based on the complexity of the processing, safety requirements, previous experience and judgement.

### 9.1.3 Economic Analysis

The economic analysis first identifies and collects basic economic data including sources and prices of raw materials, utility and labor rates, product prices and by-product credits, depreciation, insurance and tax schedules, working capital and inventory requirements, and shipping and sales expenses. The products of the economic evaluation are the capital and operating cost estimates to which investment decision criteria are applied.

Establishing criteria for a preliminary evaluation involves reasonable assumptions for technical and economic parameters. Table 14 is an example of study criteria developed by the Kennecott group for evaluation of a ferric chloride leaching process for treating copper concentrates.

Table 14 STUDY CRITERIA

**Plant Factors:**

| | |
|---|---|
| Capacity: | 50,000 TPY Fire Refined Copper |
| Operation: | 330 days/year |
| Location: | Grassroot (Western U.S.) |

**Concentrate Analysis:**

| Components | % by weight | |
|---|---|---|
| Cu | 26.0 | |
| Fe | 25.0 | |
| S | 31.0 | |
| $SiO_2$ | 9.0 | |
| $Al_2O_3$ | 2.0 | |
| CaO | 0.5 | |
| Insols | 13.0 | |
| Ag | - | 3.6 ounces/Ton |

**Cost Factors:**

| | |
|---|---|
| **Fuel** | |
| Non-Interruptible natural gas | $0.40/$10^6$ Btu |
| **Utilities** | |
| Cooling water | $0.038/$10^3$ gal. |
| Electricity - purchased | 6 mills/KWH |
| Steam | 50¢/1000 lbs |
| **Process Supplies** | |
| Hydrochloric Acid (22, Be) | $35/Ton |
| Filter Aid | $0.05/lb. |
| Solvent | $0.10/lb. |
| Sponge Iron | $70.00/Ton |
| **Labor** | |
| Operating Labor | $6.40/man-hour |
| Supervision | 25% of oper. labor |
| Services | 20% of oper. labor |
| Repair and maintenance | 2% of investment |
| Technical, administrative and general expenses | 40% of total labor |
| **Repair and Maintenance** | |
| Supplies | 3% of investment |
| **Indirect Costs** | |
| Depreciation | 15 yrs. straight-line (6.7% of investment) |
| Property taxes | 2% of investment |
| Insurance | 0.1% of investment |

**Assumptions for Profitability Calculation**

| | |
|---|---|
| Toll charges | $400 per ton of copper |
| Income tax rate | 50% of operating income |
| General & Administrative Cost | 1.5% of Sales (Toll charges) |
| Sales Development Cost | 0.5% of Sales (Toll charges) |
| Selling price of Copper | $0.50 per pound |

Reference: U.S. Bureau of Mines RI 8484

### 9.1.4 Factoring The Capital Cost Estimate

The procedure for estimating capital costs at Kennecott's Ledgemont Evaluation Unit is as follows:

(1) Divide up the process flow sheets into major segments; for example, raw materials, unloading and storage, crushing and grinding, drying, flotation, reduction, smelting, refining, electrowinning, utility support. Block flow diagrams commonly used for process description are not suitable for process evaluation purposes and are misleading indicators of process engineering requirements. For some of the cost segments, operating costs will be fairly well known. These include unloading and storage, or tailings disposal estimated on the basis of dollars per ton of material handled.

(2) Size the required equipment from process flow sheets and estimate purchase costs. Use the company data bank, quick quotes from suppliers, or on special designs make detailed estimates in house or contract the estimate to an experienced group.

(3) Factor the equipment cost to installed equipment cost, then factor to plant cost with appropriate factors for piping, instrumentation, insultation, and electrical requirements as shown in Table 15. The factors are based on judgment and prior experience.

TABLE 15 ELEMENTS OF THE PHYSICAL PLANT COST

| | |
|---|---|
| 1. Installed Equipment | _____ |
| 2. Piping | _____ |
| 3. Instrumentation | _____ |
| 4. Insulation | _____ |
| 5. Electrical | _____ |
| 6. Plant Utilities | _____ |
| 7. Buildings | _____ |
| 8. Spare Parts | _____ |
| 9. Land and yard improvements | _____ |
| Total Physical Plant Cost | _____ |

Plant utilities are estimated based on the actual requirements of the plant; these can be obtained from the utility summary which is a part of the process engineering analysis. Buildings are estimated using standard costs after the preliminary space requirement is determined, for example, square feet times cost per square foot. The land and yard improvements are based on the layout requirements of the process.

The physical plant costs from Table 15 are in turn built up to take into account engineering, construction, fee, royalty, etc. A healthy contingency of up to 25% is generally allowed at the stage of preliminary evaluation.

An estimate of the offsite installations is also required. Sometimes this portion of the investment is ignored. For example, if an addition to an existing plant is made and a considerable quantity of electric power is required, the process engineering is likely to include substation costs required at the plant boundary limits but may ignore the costs necessary to increase the boiler and generating capacity at the central power generating station in the mother plant. If the power were totally purchased from a power company, ignoring this additional investment would be correct, but otherwise, offsite costs such as these can influence profitability of the project considerably.

The total of all this, plus an allowance for working capital, gives us the total investment cost for the plant, as indicated in Table 16.

TABLE 16 FACTORING PHYSICAL PLANT COST TO TOTAL INVESTMENT

| Item | Amount $ |
|---|---|
| 1. Physical Plant Cost (PPC) | _____ |
| 2. Engineering and Construction (% of PPC) | _____ |
| 3. Direct Plant Cost | _____ |
| 4. Contractor's Fee ( % of DPC) | _____ |
| 5. Contingency ( % of DPC) | _____ |
| 6. Offsites | _____ |
| 7. Fixed Captial Cost | _____ |
| 8. Working Capital | _____ |
| Total Investment | _____ |

### 9.1.4 Example Capital Cost Estimate

An example of a specific factored cost estimate follows. It is made from a concentrator flowsheet and an equipment list derived from that flowsheet. The detail is dependent on how much the estimator knows about the technology, how much time is available for the study, and how the resulting cost estimate will be used. A study of the chemistry (if a process), or the logistics (if a material handling system) precedes the plan or flow sheet. It is impossible to separate the research and engineering from the economics of the project. The plan or flow sheet must represent the best effort of the company scientists and engineers.

TABLE 17 EXAMPLE: FACTORED CAPITAL COST ESTIMATE FOR 2000 TON PER DAY COPPER-ZINC CONCENTRATOR

| | | | |
|---|---|---|---|
| 1. | Purchased equipment cost, U.S. dollars, 1976 | | |
| | Crushing | $213,000 | |
| | Grinding | 483,000 | |
| | Copper flotation | 288,000 | |
| | Zinc flotation | 528,000 | |
| | Total, equipment | | $1,512,000 |
| 2. | Installed equipment cost<br>1.43 times item (1) | | 2,162,160 |
| 3. | Process piping<br>10% of item (2) | | 216,216 |
| 4. | Instrumentation:<br>3% of item (2) | | 64,865 |
| 5. | Buildings and site development:<br>35% of item (2)<br>Mill, building, crusher building, assay laboratory, machine shop, office | | 756,756 |
| 6. | Auxiliaries: 5% of item (2)<br>Water supply, diesel standby power | | 108,108 |
| 7. | Outside electrical lines:<br>8% of item (2) | | 172,973 |
| 8. | Total physical plant costs:<br>items (2) through (7) | | 3,481,078 |
| 9. | Engineering and construction:<br>25% of item (8) | | 870,270 |
| 10. | Contingency: 25% of item (8) | | 870,270 |
| 11. | Offsite plant and equipment<br>(from plans) | | 500,000 |
| 12. | Fixed capital cost:<br>items (8), (9), (10), (11) | | 5,721,618 |
| 13. | Working capital: 10% of item (12) | | 571,162 |
| | Total capital investment | | 6,293,790 |

The total capital cost of this 2,000 tons per day concentrator is $6.3 million, or $3,150 per ton of daily capacity. Corrections would be made if the plant were located

outside the United States; for example, a factor of at least 1.6 would be applied to equipment costs in Peru. The result would be an estimate of $5,000 per daily ton of capacity.

### 9.1.6 Factoring the Operating Cost Estimate

Similar factoring procedures are used to develop operating costs for process plants. Following the Kennecott procedure, there are eight basic components to the operating cost estimate:

(1) Yield of the process
(2) Raw material costs
(3) By-product credits
(4) Utilities
(5) Labor-related charges
(6) Capital-related charges
(7) Sales and other related costs
(8) Plant availability or "on-stream" time

The raw material costs and credits for by-products can be estimated from the material balances performed in the technical evaluation. It is important to make a realistic estimate of the yield in the plant; otherwise, all of the costs would be understated. By-product credits should be estimated realistically with a proper market analysis as to the effect of these additional by-products on their salability. For example, although ammonium sulfate is a very desirable fertilizer, it is not always possible to sell it at the quoted price for ammonium sulfate. The components of the labor-related charges are:

a. Direct labor
b. Supervision
c. Services
d. Technical administration and general expense

The factors used in these labor-related charges are based on the kind of plant, and experience within the company. Required utilities are obtained from the utility summary produced in the technical evaluation. Capital-related charges are also estimated based on experience with similar plants and the company's depreciation, tax, and insurance structure.

The sales and other operating expenses are estimated depending upon the kind of product made and the sales effort it requires, while plant availability, or on-stream time, is dependent upon the projected materials requirement in the plant. A good guess generally can be made of this by reviewing analogous processes in other industries.

TABLE 18 OPERATING COST ESTIMATE

| Item | Amount $ Per Year |
|---|---|
| 1. Raw material Costs | _____ |
| 2. By-product Credits | _____ |
| 3. Labor-related Charges | _____ |
| a. Labor ($ per man-hour) | _____ |
| b. Supervision ( % of Labor) | _____ |
| c. Services ( % of operating labor) | _____ |
| d. Fringe benefits ( % of operating labor supervision + % of repairs and maintenance) | _____ |
| 4. Utilities | _____ |
| 5. Capital-related charges | _____ |
| a. Repairs and maintenance ( % of investment) | _____ |
| b. Plant supplies ( % of repairs and maintenance) | _____ |
| c. Depreciation ( % of Investment) | _____ |
| d. Taxes ( % of Investment) | _____ |
| e. Insurance ( % of Investment) | _____ |
| Total Operating Cost | _____ |

### 9.1.7 Example of an Operating Cost Estimate

The following example is based on the Kennecott evaluation of the ferric chloride process. The various components of the operating cost estimate are identified. Unit costs, daily costs, annual costs and the cost per pound of copper are calculated for evaluation purposes.

TABLE 19 OPERATING COST ESTIMATE, FERRIC CHLORIDE PROCESS, 1973
Scheduled Operation: 350 days per year
Anticipated On Stream Time: 330 days per year

| Item | Units | $/Unit | Units/Day | $M/year | $/lb of Copper |
|---|---|---|---|---|---|
| Process Material | | | | | |
| Sponge Iron | Tons | 70 | 80 | 1,848.0 | |
| Make up HCC | Tons | 35 | 4 | 46.0 | |
| Solvent | lbs | 0.10 | 11,630 | 384.0 | |
| Filter Aid | lbs | 0.05 | 3,000 | 49.5 | |
| Total | | | | 2,327.5 | 2.32 |
| Utilities & Fuel | | | | | |
| Electricity | KWH | 0.006 | 205,400 | 406.7 | |
| Natural Gas | MMBTU | 0.40 | 2,105 | 277.9 | |
| Cooling Water | M.Gal. | 0.038 | 3,212 | 40.3 | |
| Total | | | | 724.9 | 0.73 |
| Labor Dependent | | | | | |
| Direct Labor | Man-hr | 6.40 | -- | 1,625.8 | |
| Supervision | 20% of Direct Labor | | | 325.2 | |
| Services | 25% of Direct Labor | | | 406.4 | |
| Plant General & Administrative (40% of Direct & Maint Labor) | | | | 905.3 | |
| Total | | | | 3,262.7 | 3.26 |
| Capital Dependent | | | | | |
| Maintenance Labor | | 2.0% (1) | | 637.7 | |
| Maintenance Supplies | | 3.0% (1) | | 956.5 | |
| Operating Supplies | | 0.5% (1) | | 159.4 | |
| Depreciation | | 6.7% (1) | | 2,136.3 | |
| Property Taxes | | 2.0% (1) | | 637.7 | |
| Property Insurance | | 0.1% (1) | | 32.0 | |
| | | | | 4,559.6 | 4.56 |
| Total Operating Cost | | | | 10,874.7 | 10.87 |

(1) of Depreciable Capital

**9.1.8 Sensitivity Analysis**

The flow sheet is divided into major areas. In some areas costs are fairly well known, for example, the cost of unloading, storing and moving minerals and ores is well known and for preliminary evaluation can be estimated on the basis of dollars per ton of materials handled. Similar estimates can be developed for utility costs and tailings disposal facilities.

The remaining costs are estimated first by sizing the required equipment from the process engineering flow sheets, then estimating purchase costs and factoring up equipment costs to give installed equipment costs. These are in turn factored for piping, instrumentation, insulation, electrical and other requirements to arrive at a physical plant cost.

Factors affecting the economic viability of a project are not equally important and are usually ranked with respect to their impact on operating cost and return on investment. Since the Kennecott group is oriented toward metallurgical research and development sensitivities are directed toward determining where the R & D effort will do the most good. If an increase in investment has a major effect on return on investment and if utility consumption has a minor impact then the group concentrates on decreasing investment at the expense of higher utility costs. Sensitivity analysis, when used in this context, is a powerful tool to identify economically important items that can be improved.

Figure 7 shows the sensitivity of total operating cost to changes in the various components of capital and operating cost. The lines with the steepest slopes identify those factors that have the greatest impact on total cost including amortization of the investment. In the diagram fuel and power costs have very little effect on total costs costs, while materials, labor, and investment in that order are increasingly significant. These sensitivities lead to recommendations for further research or for alternative technical approaches to processing.

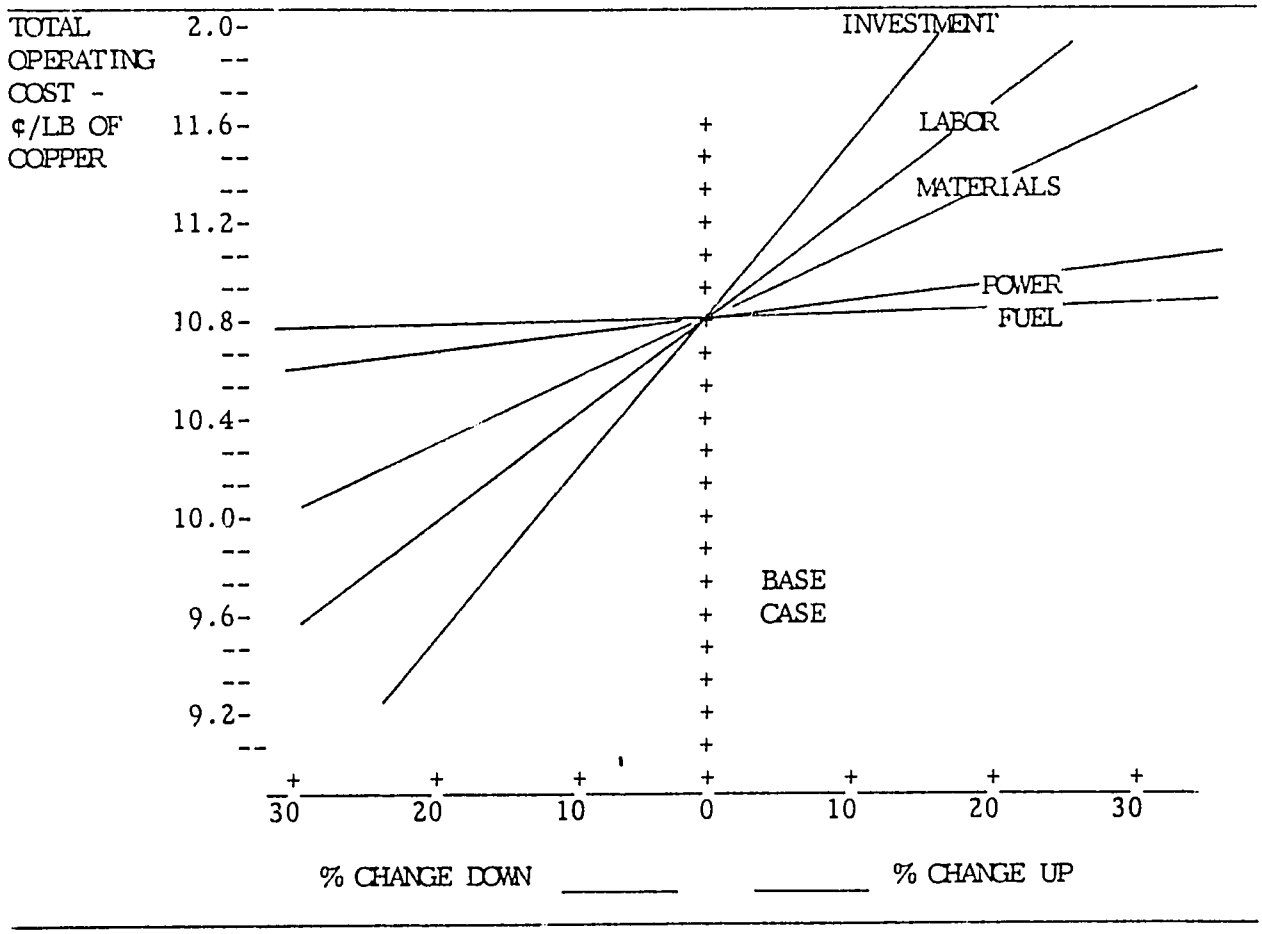



FIGURE 7 RESULTS OF SENSITIVITY ANALYSIS

## 10. QUALIFICATION OF COST ESTIMATES

Estimate qualifications and clarifications are essential and an extremely important part of any estimate. The following section is based on Stearns-Roger procedures. Components of an estimate that have a large effect on estimated costs are listed in the statement of qualifications even though they are listed elsewhere in specifications and job documents. All significant items affecting the estimate that have not been defined elsewhere are listed in the qualification statement. Particular attention is paid to items that are different from a typical installation.

One of the first things the project estimator does when beginning an estimate, is to start the list of estimate qualifications. He must not trust his memory and attempt to remember all of these at the conclusion of the estimate. Jot down these qualifications as they are recognized throughout the duration of the estimate. The completed list becomes an integral part of the estimate and must be included whenever the estimated project cost is discussed or published.

Following are some typical subjects that need to be clarified in the estimate qualifications when applicable. This is not intended to be an all-inclusive list, but it does cover many of the commonest items.

1. What is the time frame of the costs? Are all costs escalated using the project schedule as a basis, or are the costs all based on a particular calendar date?

2. When future escalation is included, indicate the annual rates used for each category of costs.

3. Upon what schedule is the estimate based? List the construction work mechanical completion date along with any other important milestones.

4. Is the engineering and construction work based on a normal 40 man-hours per week or will some scheduled overtime be required?

5. Will the construction labor be merit shop or union?

6. List the plot plans, flow sheets, specifications, equipment lists, etc. that were used as a basis to prepare the estimate. Indicate drawing and revision numbers where applicable.

7. If this is a plant addition, define any work to be done outside of the project battery limits. Tie-in points for utilities and process piping need to be defined.

8. Grassroots plants must define where utilities are obtained, who applies for environmental permits, whether wastewater, sewage treatment, or special off-site facilities are included, etc.

9. For remote projects, note that no infrastructures are included and whether craft subsistence or a construction camp is required.

10. Exclude any possible rock excavation and define unusual foundation conditions, i.e., piling is required or an entire area must be mucked-out and backfilled with purchased material.

11. Define special sitework included, such as; paved roads and plant areas, landscaping, special buildings, etc.

12. List the major work categories that are estimated as being subcontracted.

13. List all client furnished items that have not been included in the estimate.

14. What start-up costs are included?

15. Are any catalysts, royalties, spare parts, all-risk insurance, or bonds included?

16. Are any special items or plant areas not included in the estimate?

17. Note any special labor conditions that have been considered, such as availability or labor, bad regional productivity, project size, or congested work areas.

18. State the percent contingency, the probability of the actual costs overrunning it, and accuracy range of the estimate, e.g., a 5.3% contingency was used with a 30% probability of overrun and an accuracy range with an 80% confidence level of +5% and -3%.

## 11. PROJECT LOGISTICS

Most of the case studies in this book include a logistic curve showing the spending between the initial exploration and the project start-up. The following curves are based on Stearns-Roger information and relate man-hours expended in various phases of a project. They are the basis and underlie the total project expenditure curve.

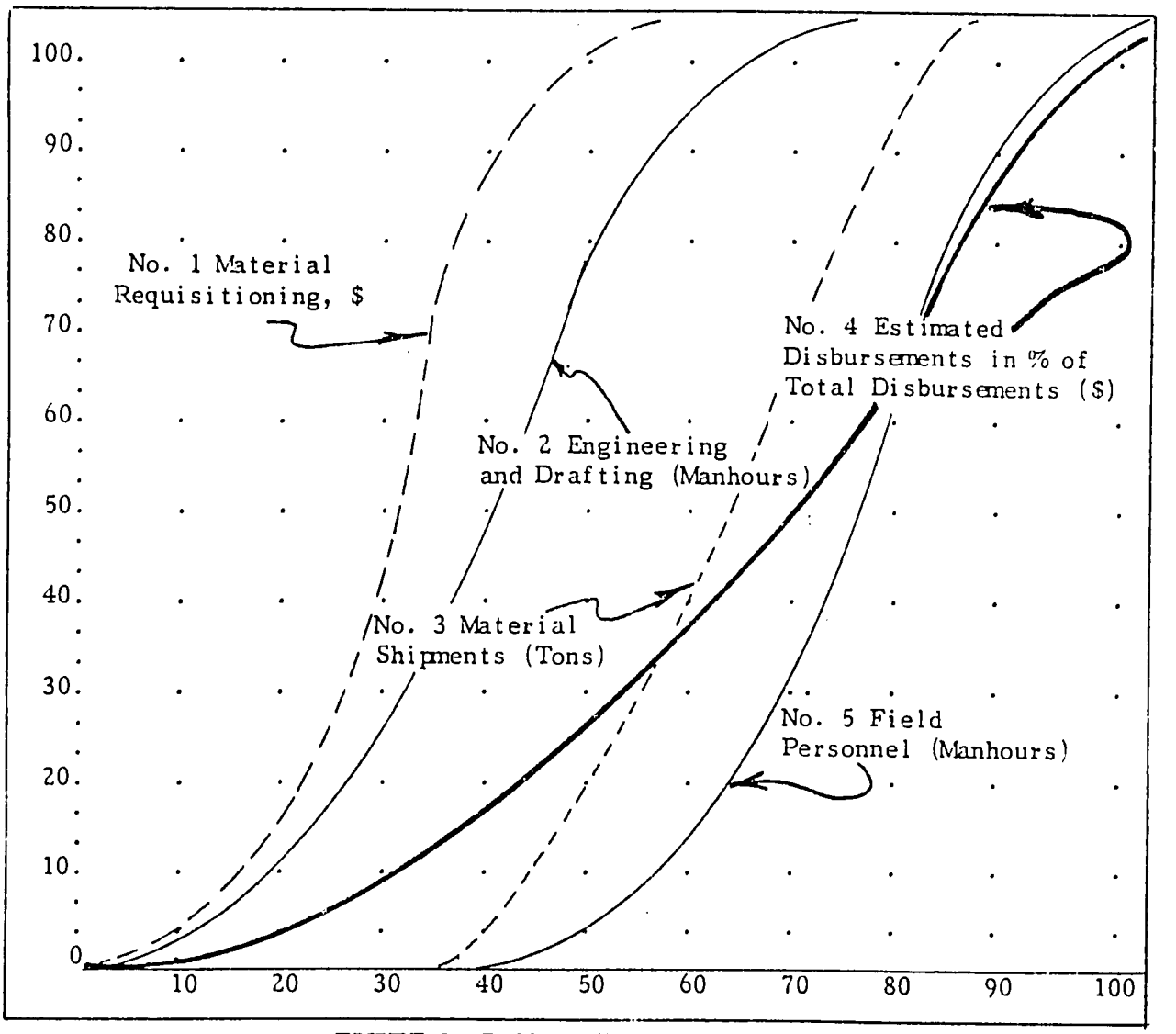



FIGURE 8 PROJECT PLANNING CURVES

## 12. COST ENGINEERING TERMINOLOGY

Accounts Payable : The value of goods and services available for use on which payment has not yet been made. See also taxes payable.

Accounts Receivable : The value of goods shipped or services rendered to a customer on which payment has not yet been received. Usually includes an allowance for bad debts.

Administrative Expense : The overhead cost due to general direction of the company, above the plant manager level. Generally includes top management salaries, and the costs of legal, central purchasing, traffic, accounting, and other staff functions.

Average Annual Cost : The conversion by an interest rate and present worth technique, of all capital and operating costs to a series of equivalent equal annual costs. As a system for comparing proposal investments, it requires assumption of a specific minimum acceptable interest rate.

Battery Limit : Geographic boundaries, imaginary or real, enclosing a plant or unit being engineered and/or erected, established for the purpose of providing a means of specifically identifying certain portions of work as being related groups of individual times or associated facilities. Generally refers to the processing area only unless specified to the contrary.

Book Value (Net) : Current investment value on the books calculated as original value less depreciation accruals. New asset value for accounting use. Also, the value of an outstanding share of stock of a corporation at any one time.

Breakeven Point : The percentage of capacity at which incomes of a company or facility just cover all fixed and variable costs. Depreciation normally included. See Shutdown Point.

Burden : The percentage of cost used for maintaining, staffing and furnishing of an office with staff other than operating personnel. In contracts with some Governmental agencies these items are included in indirect cost.

Capital Budgeting : A systematic procedure for classifying, evaluating, and ranking proposed capital expenditures for the purpose of comparison and selction, combined with the analysis of the financing requirements.

Capital, Cost of : The weighted evidence of (1) the after-tax cost of long term debt, (2) the yield on any outstanding preferred stock, and (3) the cost of common equity capital.

Capital, Fixed : The total original value of physical facilities which are not carried as a current expense on the books of account and for which depreciation is allowed by the Federal Government. It includes plant equipment, building, furniture and fixtures, transportation equipment used directly in the production of a product or service. It includes all costs incident to getting the property in place and in operating condition, including legal costs, purchased patents, and paid up licenses. Land, which is not depreciable, is often included. Characteristically, it cannot be converted readily into cash.

Capital, Sustaining : The fixed capital requirements to (1) maintain the competitive position of a project throughout its commercial life by improving product quality, related services, safety or economy, or (2) required to replace facilities which wear out before the end of the project life.

Capital, Working : The funds in addition to fixed capital and land investment which a company must contribute to the project (excluding startup expense) to get the project started and meet subsequent obligations as they come due. Consists of the difference between current assets (cash, receivables, and inventories) and current liabilities (accounts, notes, and taxes payable). Characteristically, these funds can be converted readily into cash. Working capital is normally assumed recovered at the end of the project without loss.

Capitalized Costs : The present worth of the cost of renewing and operating a facility perpetually. As a system for comparing proposed investments, it requires assumption of a specific minimum acceptable interest rate.

Cash Flow : The net flow of dollars into or out of the proposed project. The algebraic sum, in any time period, of all cash receipts, expenses, and investments. Also called cash proceeds or cash generated.

Cash Return, Percent of Total Capital : Ratio of average depreciation plus average profit, to total fixed and working capital, for a year of capacity sales. Under certain limited conditions, this figure closely approximates that calculated by profitability index techniques where it is defined as the difference, in any time period, between revenues and all cash expenses, including taxes. The sum of net profit after tax and the depreciation used in calculated by profitability index techniques where it is defined as the difference, in any time period, between revenues and all cash expenses, including taxes. The sum of net profit after tax and the depreciation used in calculating net profit.

Contingencies : Specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that, statistically, unforeseeable events which will increase costs are likely to occur. It may or may not include allowance for escalation.

Contracts : Legal agreements between two or more parties, which may be of the type enumerated below:

1. In Cost Plus contracts, the Contractor agrees to furnish to the Client services and material at actual cost, plus an agreed-upon fee for his services. This type of contract is employed most often when the scope of services to be provided is not well defined.

a) Cost Plus Percentage Burden* and Fee : The Client will pay all costs as defined in the terms of the contract, plus "burden and fee" at a specified percent of the labor costs which he is paying for directly. This type of contract generally is used for engineering services.

* In contracts with some Governmental agencies these items are included in indirect cost.

b) Cost Plus Fixed Fee : The Client pays costs as defined in the contract document. Burden on Reimbursable Technical Labor Cost is considered in this case as part of the cost. In addition to the costs and Burden, the Client also pays a fixed amount as the contractor's "fee".

c) Cost Plus Fixed Sum : The Client will pay costs defined by contract plus a fixed sum which will cover "non-Reimbursable" costs and provide for a fee. This type of contract is used in lieu of a Cost Plus Fixed Fee contract where the Client wishes to have the contractor assume some of the risk for items which would be Reimbursable under a Cost Plus Fixed Fee type of contract.

d) Cost Plus Percentage Fee : The client pays all costs, plus a percentage for the use of the contractor's organization.

2. Fixed Price types of contract are ones wherein a Contractor agrees to furnish services and material at a specified price, possibly with a mutually agreed upon escalation clause. This type of contract is most often employed when the scope of services to be provided is well defined.

a) Lump Sum : Contractor agrees to perform all services, as specified by the contract for a fixed amount. A variation of this type may include a Turn-Key arrangement where the contractor guarantees quality, quantity, and yield on a process plant or other installations.

b) Unit Price : Contractor will be paid at an agreed-upon unit rate for services performed. For example, technical manhours will be paid for at the unit price agreed upon. Often, field work is assigned to a Sub-Contractor by the Prime Contractor on a unit price basis.

c) Guaranteed-Maximum (Target Price) : A Contractor agrees to perform all services as defined in the contract document guaranteeing that the total cost to the Client will not exceed a stipulated maximum figure. Quite often, these types of contracts will contain special share-of-the saving arrangements to provide incentive to the Contractor to minimize costs below the stipulated maximum.

d) Bonus Penalty : A special contractural arrangement usually between a Client and a Contractor wherein the Contractor is guaranteed a bonus, usually a fixed sum of money, for each day the project is completed ahead of a specified schedule and/or below a specified cost, and agrees to pay a similar penalty for each day of completion after the schedule date or over a specified cost up to a specified maximum either way. The penalty situation is sometimes referred to as liquidated damages.

Construction Cost : The sum of all costs, direct or indirect, inherent in converting a design plan for material and equipment into a project ready for operation, i.e., sum of field labor, supervision, administration, tools, field office expense and field purchased material costs.

Cost Control : Is the application of procedures to follow the progress of design and construction projects as well as manufacturing operations in order to minimize cost with the objective of increasing profitability and assuring efficient operations. There are three essential elements of control. The first is to establish the optimum condition, the second is to measure variation from the optimum condition, and the

third is to take corrective action in order to minimize this variation. The application of these procedures attempts to limit costs to those authorized per capital projects or cost standards, focuses control efforts where they will be most effective, and achieves maximum control at minimum operating costs.

Cost Index (Price Index) : A number which relates the cost of an item at a specific time to the corresponding cost at some arbitrarily specified time in the past.

Depletion : The allocation of the value of the quantity of natural resources extracted from a deposit (applying to resources not replaceable by human beings). A non-cash expense, but allowed tax deductions. See Depreciation.

Depreciation : The allocation of the cost of fixed capital assets less salvage (if any), over the estimated useful life of the unit, in systematic and rational manner (straight line, sum of the digits, double declining balance, etc.). A non-cash flow tabulation used in various profitability measures, depreciation is important only as an allowed deduction from income taxes.

Development Costs : Those costs specific to a project, either capital or expense items, which occur prior to commercial sales found necessary to evolve the potentialities of that project for consideration and eventual promotion. Major cost areas include process, product, and market research and development.

Direct Cost : Dollar/unit of time for the manufacturing expenses which may be affected by production rate. Manufacturing direct costs are generally assignable to a specific product or process area and includes the following:

Input Materials, Operating, Supervision, and Clerical Payroll including Fringe Benefits.

Maintenance:
a. Payroll and benefits
b. Materials and supplies

Utilities

Catalyst, Chemicals and Operating Supplies, Miscellaneous (Royalties, Services, etc.)

In construction direct costs include the costs of direct materials which will become a permanent part of the project and direct labor which is expended to install the direct material.

Discounted Cash Flow : See Profitability Index.

Escalation : The provision in actual or estimated costs for an increase in the cost of equipment, material, labor, etc., over those specified in the contract, due to continuing price level changes over time.

Estimate : An evaluation of all the costs of the elements of a project or effort as defined by an agreed-upon scope. Three specific types based on degree of definition of a Process Industry Plant are:

1. Order of Magnitude Estimate : An approximate estimate made without detailed engineering data. Some examples would be: an estimate from cost-capacity curves, an estimate using scale up or down factors, and an approximate ratio estimate. An estimate of this type would be accurate within plus 50% or minus 30%.

2. Budget Estimate : Budget in this case applies to the Owner's Budget and not to the Budget as a project control document. A budget estimate is prepared with the use of flow sheets, layouts and equipment details.

3. Definitive Estimate : As the name implies, this is an estimate prepared from very defined engineering data. The engineering data includes as a minimum, fairly complete plot plans and elevations, piping and instrument diagrams, one line electrical diagrams, equipment data sheets and quotations, structural sketches, soil data and sketches of major foundations, building sketches and a complete set of specifications. This category of estimate covers all types from the minimum described above to the maximum definitive type which would be made from "Approved for Construction" drawings and specifications. An estimate of this type would be accurate within plus 15% and minus 5%.

Expansion : Any increase in the capacity of a plant facility or unit, usually by added investment. Scope of its possible application extends from the elimination or problem areas to the complete replacement of an existing facility with a larger one.

Fee : The charge for the use of the contractor's organization for the period and to the extent specified in the contract.

Field Cost : All those costs expended in the field involved in producing a finished project. Field cost includes but is not limited to: all material costs, all labor costs, the cost of all distributable items, the cost of field administration, tools, consumables, etc.

Fixed Costs : Those costs independent of short term variations in output of the sytem under consideration. Includes such costs as labor, maintenance, technical service and laboratory expense, taxes and insurance, plant overhead, and administrative, selling and research expense. For the purpose of cash flow calculations, depreciation is excluded (except in income tax calculations).

Fringe Benefits : Employee welfare benefits: expenses of employment not paid directly to the employee, such as holidays, sick leave, S.U.B., social security, insurance, etc.

Home Office Cost : Those necessary costs involved in the conduct of everyday business which can be directly assigned to specific project, processes or end products, such as Engineering, Procurement, Expediting, Inspection, Estimating, Reproduction, Telephone, Telegraph, etc.

Incremental Costs (Revenues) : The cost and revenue differences between two alternate courses of action. These should be based on changes which can actually be foreseen as occuring rather than having accounting conventions to approximate overheads, etc. Costs refer both to investment and annual operating costs. In narrower sense, the cost of the last unit produced at a given level of production.

Indirect Cost : In a construction project, all costs other than direct costs which do not become a final part of the installation, but which are required for the orderly completion of the installation and may include, but not be limited to, starting costs, contractor's fees, insurance, taxes, etc.

In manufacturing, those costs not directly assignable to the end product or process, and which may include plant overhead, material handling and maintenance charges, etc.

In Government contracts, it is often calculated as a fixed percent of direct payroll costs.

Interest, Compound : The rate earned by money expressed as a constant percentage of the unpaid balance at the end of the previous accounting period. Typical time periods are yearly, semi-annually, monthly and instantaneous.

Interest Rate of Return : See Profitability Index.

Inventory : The value of raw materials, products in process, and finished products required for plant operation. Also, other supplies, i.e., for maintenance, catalyst, chemicals, spare parts.

Labor Cost, Manual : The salary plus all fringe benefits of construction craftsmen and general labor on construction projects and labor crews in manufacturing or processing areas which can be definitely assigned to one product or process area or cost center.

Labor Cost, Non-Manual : Non-manual labor in the field, normally refers to personnel other than craftsmen and includes Field Administration and Field Engineering.

Leverage (Trading on Equity) : The use of borrowed funds of preferred stock in the intent of employing these "senior" funds at a rate of return higher than their cost in order to increase the return upon the investment of the residual owners.

Maintenance : The expense, both for labor and materials, required to keep equipment or other installations in suitably operable condition. Maintenance does not usually include those items which cannot be expended within the year purchased that must be considered fixed capital.

Manufacturing Cost : The total of operating costs chargeable to productions of a given product, usually expressed in cents or dollars per unit of production. Includes direct expenses such as ingredients, labor utilities, and also such fixed or allocated charges as maintenance, depreciation (a non-cash expense), insurance and property taxes. Overheads within the plant are usually considered within manufacturing costs: sales, administrative and research overheads, and freight are usually not included.

MAPI Method : A system of analysis based fundamentally on the discounted cash flow procedure. By formula approach it compares making an investment now with going on without investing for one more year. Easy to apply but should not be used where the assumptions built into the formula do not fit a particular situation.

Material Cost : The cost of everything of a substantial nature that is essential to the construction of operation of a facility, both of a direct or indirect nature. Generally includes all manufactured equipment as a basic part.

Maximum-Out-of-Pocket Cash : The highest year-end negative cash balance during project life.

Net Profit : Earnings after all operating expenses (cash or accrued non-cash) have been deducted from not operating revenues for a given time period.

Net Profit : Earnings after all operating expenses (cash or accrued non-cash) havv been deducted from net operating revenues for a given time period.

Net Profit, Percent of Sales (Profit Margin) : The ratio of annual profits to total sales for a representative year of capacity operations. An incomplete measure of profitability, but a useful guidepost for comparing similar products and companies.

Offsite Facilities : Facilities located outside the Battery Limits which provide support for the process units. These include but are not limited to utilities, storage tankage, administration facilities, and the like.

Operating Costs : Charges for labor, material, and contracted services which can be assigned, or allocated, to a specific manufacturing operation.

Opportunity Cost : The profits from alternative ventures that are foregone by using limited facilities for a particular purpose.

Optimum Plant Size : The plant capacity which represents the best balance between the economics of size and the cost of carrying excess capacity during the initial years of sales.

Order of Magnitude Estimate : See Estimate Order of Magnitude.

Overhead : A cost or expense inherent in the performing of an operation, i.e. engineering, construction, operating or manufacturing, which cannot be charged or identified with a part of the work, product or asset and therefore, must be allocated on some arbitrary basis believed to be equitable, or handled as a business expense independent of the volume of production.

Payout Time : The time required to recover the original fixed investment from profit and depreciation. Usually, but not always, after taxes and based on capacity operation. Most recent practice is to base payout time on an actual sales projection. Also called pay-off or payback period. It is simple to calculate and can be used for evaluating many projects. It is not satisfactory for comparing projects with different lives or patterns of cost and earnings.

Plant Overhead (Factory Expense) : Those costs in a plant which are not directly attributable to any one product or processing unit and therefore can be allocated on some arbitrary basis believed to be equitable. Includes plant management salaries, payroll department, local purchasing and accounting.

Present Value (Present Worth) : The discounted value of a series of cash flows at any arbitrary point in time. Also, the system of comparing proposed investments which involves discounting at a known interest rate (representing a cost of capital or a minimum acceptable rate of return) in order to choose the alternative having the highest present value per unit of investment. This technique eliminates the occasional difficulty with PI of multiple solutions, but has the troublesome problem of choosing or calculating a "cost of capital" or minimum rate of return.

Productivity : Relative measure of labor efficiency, either good or bad, when compared to an established base or norm as determined from an area of great experience, which may be either an increase or decrease in cost.

Profitability : A measure of the excess of income over expenditure during a given period of time.

Profitability Index (PI) : The rate of compound interest at which the company's outstanding investment is repaid by proceeds from the project. All proceeds from the project, beyond that required for interest, are credited by the method of solution, toward repayment of investment by this calculation. Also called discounted cash flow, interest rate of return, investor's method, internal rate of return. Although frequently requiring more time to calculate than other valid yardsticks, PI reflects in a single number both the dollar and the time values of all money involved in a project. In some very special cases, such as multiple changes of sign in cumulative cash position, false and multiple solutions can be obtained by this technique.

Project Life (Economic Size) : Total years of operation for any facility. Sometimes, but not necessarily, equal to depreciable life.

Rate of Return on Investment : The efficiency ratio relating profit or cash flow incomes to investment. Several different measures of this ratio are in common use. See return on average investment, return on original investment, profitability index.

Replacement : A facility proposed to take the place of an existing facility, without increasing its capacity, caused either by obsolescence or physical deterioration.

Research Expense : Those continuing expenses required to provide and maintain the facilities to develop new products and improve present products.

Return on Average Investment : The ratio of annual profits to the average book value of fixed capital, with or without working capital. This method has some advantages over the return-on-original investment method. Depreciation is always considered; terminal recoveries are accounted for. However, the method does not account for the timing of cash flow and yields answers that are considerably higher than those obtained by the return-on-original investment and profitability index methods. Results may be deceiving when compared, say, against the company's cost of capital.

Return on Original Investment : The ratio of expected average annual after tax profit (during the earning life) to total investment (working capital generally included). Similar in usefulness and limitations to payout.

Risk : The degree of dispersion or variability around the expected or "best" value which is estimated to exist for the economic variable in questions: e.g. a quantitative measure of the upper and lower limits which are considered reasonable for the factor being estimated.

Sales Profile : The growth or decline of historical or forecast sales volume, by years.

Sales Price : The revenue for a unit of product. Gross sales price is the total amount paid. Net sales are gross sales less returns, discounts, freight and allowances. Plant Netbacks are net sales less selling, administrative and research expenses.

Selling Expense : The total expense involved in marketing the product in question. This normally includes direct selling costs, advertising, and customer service.

Shutdown Point : The production level at which it becomes less expensive to close the plant and pay remaining fixed expenses out-of-pocket, rather than continue operations; that is, the plant cannot meet its variable expense. See breakeven point.

Site Preparation : An act involving grading, landscaping, installation of roads and siding, of an area of ground upon which anything previously located had been cleared so as to make the area free of obstructions, entanglements or possible collisions with the positioning or placing of anything new or planned.

Startup Costs : Presale operating costs to bring the plant on stream. Includes employee training, equipment tests, process adjustments, as well as the usual manufacturing costs. It is generally assumed that no revenue is obtained from products made during this period. Frequently, part of this startup cost is capitalized.

Sunk Cost : Money which was spent before today and cannot be recovered.

Taxes Payable : Tax accruals due within a year.

Turnover Ratio : The ratio of annual sales to investment. Inclusion of working capital is preferrable, but not always done. Considered by some to be a reasonable basis for a guesstimate of facilities costs, for new products similar to existing products. Ranges around 1.0 for many chemical plants. The product of turnover ratio and profit margin on sales gives a return on investment measure.

Uncertainty : Unknown future events which cannot be predicted quantitatively within useful limits; e.g., accidents which destroy invested facilities, a major strike, a competitor's innovation which makes the new product obsolete, etc.

Unit Cost : Dollar/unit of production. Usually total cost divided by units of production, but a major cost divided by units of production is frequently referred to as a unit cost; for example, the total unit cost is frequently subdivided into the unit costs for labor, chemicals, etc.

Variable Costs : Raw materials costs, by-product credits, and those processing costs which vary with plant output (such as utilities, catalysts and chemical, packaging, and labor for batch operations).

## GLOSSARY OF FINANCIAL TERMS

Amortize : To liquidate on an installment basis; an amortized loan is one in which the principal amount of the loan is repaid in installments during the life of the loan.

Annuity : A series of payments of a fixed amount for a specified number of years.

Capital Budgeting : The process of planning expenditures on assets whos returns are expected to extend beyond one year.

Capital Structure : The permanent long-term financing of the firm represented by long-term debt, preferred stock, and net worth (net worth consists of capital, capital surplus, and retained earnings). Capital structure is distinguished from Financial Structure; which includes short-term debt plus all reserve accounts.

Capitalization Rate : A discount rate used to find the present value of a series of future cash receipts; sometimes called Discount Rate.

Carry-Back; Carry-Forward : For income tax purposes, losses that can be carried backward or forward to reduce federal income taxes.

Cash Budget : A schedule showing cash flows (receipts, disbursements, and net cash) for a firm over a specified period.

Compensating Balance : A required minimum checking account balance that a firm must maintain with a commercial bank. The required balance is generally equal to 15 to 20 percent of the amount of loans outstanding. Compensating balances can raise the effective rate of interest on bank loans.

Composite Cost Of Capital : A weighted average of the component costs of debt, preferred stock, and common equity. Also called the "weighted average cost of capital,' but it reflects the cost of each additional dollar raised, not the average cost of all capital the firm has raised throughout its history.

Compound Interest : An interest rate that is applicable when interest is in succeeding periods is earned not only on the initial principal but also on the accumulated interest of prior periods. Compound interest is contrasted to Simple Interest, in which returns are not earned on interest received.

Compounding : The arithmetic process of determining the final value of a payment or series of payments when compound interest is applied.

Continuous Compounding (Discounting) : As opposed to discrete compounding, interest is added continuously rather than at discrete points in time.

Correlation Coefficient : Measures the degree of relationship between two variables.

Cost Of Capital : The discount rate that should be used in the capital budgeting process.

Cut-Off Point : In the capital budgeting process, the minimum rate of return on acceptable investment opportunities

Debenture : A long-term debt instrument that is not secured by a mortgage on specific property.

Debt Ratio : Total debt divided by total assets.

Degree Of Leverage : The percentage increase in profits resulting from a given percentage increase in sales. The degree of leverage may be calculated for financial leverage, operating leverage, or both combined.

Devaluation : The process of reducing the value of a country's currency stated in terms of other currencies; e.g., the British pound might be devalued from $2.30 for one pound to $2.00 for one pound.

Discount Rate : The interest rate used in the discounting process; sometimes called Capitalization Rate.

Discounted Cash Flow Techniques : Methods of ranking investment proposals. Included are (1) internal rate of return method, (2) net present value method, and (3) profitability index or benefit/cost ratio.

Equity : The net worth of a business, consisting of capital stock, capital (or paid-in) surplus, earned surplus (or retained earnings), and, occasionally, certain net worth reserves. Common Equity is that part of the total net worth belonging to the common stockholders. Total Equity would include preferred stockholders. The terms "common stock," "net worth," and "common equity" are frequently used interchangeably.

Exchange Rate : The rate at which one currency can be exchanged for another, e.g., $2.30 can be exchanged for one British pound.

Expected Return : The rate of return a firm expects to realize from an investment. The expected return is the mean value of the probability distribution of possible returns.

Financial Leverage : The ratio of total debt to total assets. There are other measures of financial leverage, especially ones that relate cash inflows to required cash outflows. In this book, the debt/total asset ratio is generally used to measure leverage.

Financial Risk : That portion of total corporate risk, over and above basic business risk, that results from using debt.

Financial Structure : The entire right-hand side of the balance sheet - the way in which a firm is financed.

Fixed Charges : Costs that do not vary with the level of output, especially fixed financial costs such as interest, lease payments, and sinking fund payments.

Floating Exchange Rates : Exchange rates may be fixed by government policy ("pegged") or allowed to "float" up or down in accordance with supply and demand. The market forces are allowed to function, exchange rates are said in accordance with supply and demand. When market forces are allowed to function, exchange rates are said to be floating.

Incremental Cash Flow : Net cash flow attributable to an investment project.

Internal Financing : Funds made available for capital budgeting and working capital

expansion through the normal operations of the firm; internal financing is approximately equal to retained earnings plus depreciation.

Internal Rate Of Return (IRR) : The rate of return on an asset investment. The internal rate of return is calculated by finding the discount rate that equates the present value of future cash flows to the cost of the investment.

Investment Tax Credit : Business firms can deduct as a credit against their income taxes a specified percentage of the dollar amount of new investments in each of certain categories of assets.

Liquidity : Refers to a firm's cash position and its ability to meet maturing obligations.

Marginal Cost : The cost of an additional unit. The marginal cost of capital is the cost of an additional dollar of new funds.

Marginal Revenue : The additional gross revenue produced by selling one additional unit of output.

Net Present Value (NPV) Method : A method of ranking investment proposals. The NPV is equal to the present value of future returns, discounted at the marginal cost of capital, minus the present value of the cost of the investment.

Operating Leverage : The extent to which fixed costs are used in a firm's operation. Break-even analysis is used to measure the extent to which operating leverage is employed.

Opportunity Costs : The rate of return on the best ALTERNATIVE investment that is available. It is the highest return that will NOT be earned if the funds are invested in a particular project. For example, the opportunity cost of NOT investing in bond A yielding 8 percent might be 7.99 percent, which could be earned on bond B.

Payback Period : The length of time required for the net revenues of an investment to return the cost of the investment.

Rate Of Return : The internal rate of return on an investment.

Reinvestment Rate : The rate of return at which cash flows from an investment are reinvested. The reinvestment rate may or may not be constant from year to year.

Required Rate Of Return : The rate of return that stockholders expect to receive on common stock investments.

Retained Earnings : That portion of earnings not paid out in dividends. The figure that appears on the balance sheet is the sum of the retained earnings for each year throughout the company's history.

Risk : The probability that actual future returns will be below expected returns. Measured by standard deviation or coefficient of variation of expected returns.

Risk-Adjusted Discount Rates : The discount rate applicable for a particularly risky (uncertain) stream of income: the riskless rate of interest plus a risk premium appropriate to the level of risk attached to the particular income stream.

Risk Premium : The difference between the required rate of return on a particularly risky asset and the rate of return on a riskless asset with the same expected life.

Salvage Value : The value of a capital asset at the end of a specified period. It is the current market price of an asset being considered for replacement in a capital budgeting problem.

Sensitivity Analysis : Stimulation analysis in which key variables are changed and the resulting change in the rate of return is observed. Typicaly, the rate of return will be more sensitive to changes in some variables than it will in others.

Blank Simulation : A technique whereby probable future events are simulated on a computer. Estimated rates of return and risk indexes can be generated.

Weighted Cost Of Capital : A weighted average of the component costs of debt, preferred stock, and common equity. Also called the "composite cost of capital."

Working Capital : Refers to a firm's investment in short-term assets - cash, short-term securities, accounts receivable, and inventories. GROSS WORKING CAPITAL is defined as a firm's total current assets. NET WORKING CAPITAL is defined as current assets minus current liabilities. If the term "working capital" is used without further qualification, it generally refers to gross working capital.

Yield : The rate of return on an investment; the internal rate of return.

## GLOSSARY OF RESOURCE TERMS

Resource : A concentration of naturally occurring solid, liquid, or gaseous materials in or on the earth's crust in such a form that economic extraction of a commodity is currently or potentially feasible.

Identified Resources : Specific bodies of mineral-bearing material whose location, quality, and quantity are known from geologic evidence supported by engineering measurements with respect to the demonstrated category.

Undiscovered Resources : Unspecified bodies of mineral-bearing material surmised to exist on the basis of broad geologic knowledge and theory.

Reserve : That portion of the identified resources from which a usable mineral and energy commodity can be economically and legally extracted at the time of determination. The term ore is also used for reserves of some minerals.

The following definitions for measured, indicated, and inferred are applicable to both the Reserve and Identified-Subeconomic resource components.

Measured : Material for which estimates of the quality and quantity have been computed, within a margin of error of less than 20 percent, from analyses and measurements from closely spaced and geologically well-known sample sites.

Demonstrated : A collective term for the sum of materials in both measured and indicated resources.

Inferred : Material in unexplored but identified deposits for which estimates of the quality and size are based on geologic evidence and projection.

Identified-Subeconomic Resources : Known deposits not now mineable economically.

Paramarginal : The portion of subeconomic resources that (a) borders on being economically producible or (b) is not commercially available solely because of legal or political circumstances.

Submarginal : The portion of subeconomic resources which would require a substantially higher price (more than 1.5 times the price at the time of determination) or a major cost reducing advance in technology.

Hypothetical Resources : Undiscovered materials that may reasonably be expected to exist in a known mining district under known geologic conditions. Exploration that confirms their existence and reveals quantity and quality will permit their reclassification as a Reserve or identified-subeconomic resource.

Speculative Resources : Undiscovered materials that may occur either in known types of deposits in a favorable geologic setting where no discoveries have been made, or in as yet unknown types of deposits that remain to be recognized. Exploration that confirms their existence and reveals quantity and quality will permit their reclassification as reserves or identified-subeconomic resources.

## 13. BIBLIOGRAPHY - COST ESTIMATION

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# 14. APPENDIX - REQUIRED COST INFORMATION

INFORMATION REQUIRED FOR DIFFERENT TYPES OF PROJECT ESTIMATES (STEARNS-ROGER, P&P DIV.)

| Type of Estimate (Use) Accuracy<br>Required Information | Order of Magnitude<br>(Prelim. Econ. Evaluation)<br>±20% to ±40% | CAPES (Normal)<br>(Studies, Fee, Scope)<br>±10% to 20% |
|---|---|---|
| Process Definition (2) | Block or Rough Sketch | Issue 2 or Equivalent |
| Heat & Material Balance (2) | Feed or Effluent Capacity Recovery or Conversion Required | Preliminary |
| Equipment List | Plant Unit Operation or Process | Preliminary |
| Mechanical Flow Sheets - Process (1) (2) | No | No |
| Mechanical Flow Sheets - Utility (1) (2) | No | No |
| Mechanical Flow Sheets - Other (1) (2) | No | No |
| Equipment Data Sheets | No | Equipment Type, Sizes & Materials of Construction |
| Equipment Quotations | No | Preliminary Vendor Quotes For Very Large or Unique Equipment |
| Equipment Estimate Sheets | No | No |
| Utility Balance (2) | Based on Ratios from Process Requirements | Sufficient to Size Equip. |
| Instrument Data Sheets | No | No |
| Instrument Quotations | No | No |
| Instrument Estimate Sheets | No | No |
| Electrical Motor List | No | No |
| Plot Plan | Plant Location | Preliminary |
| Equipment Arrangement | No | No |
| Engineering Items Data Sheet (Non-D&N Account) | No | Preliminary Building & Major Structure Sizes and Specs |
| Engineering Items Quoted (Non-D&N) | No | No |
| Electrical Single Line Diag | No | No |
| Structural & Foundation Specs | No | No |
| Piping Specs | No | No Identify any Unusual |
| Electrical Specs | No | No Requirements |
| Insulation Specs | No | No |
| Non-Engineered Items Takeoff | No | No |
| Engineering Estimate | Ratio from Similar Jobs | Ratio or Semi-Definitive |
| Cost of Preparing Estimate (% of Definitive Est. Cost | 1/2% to 3% | 5% to 15% |

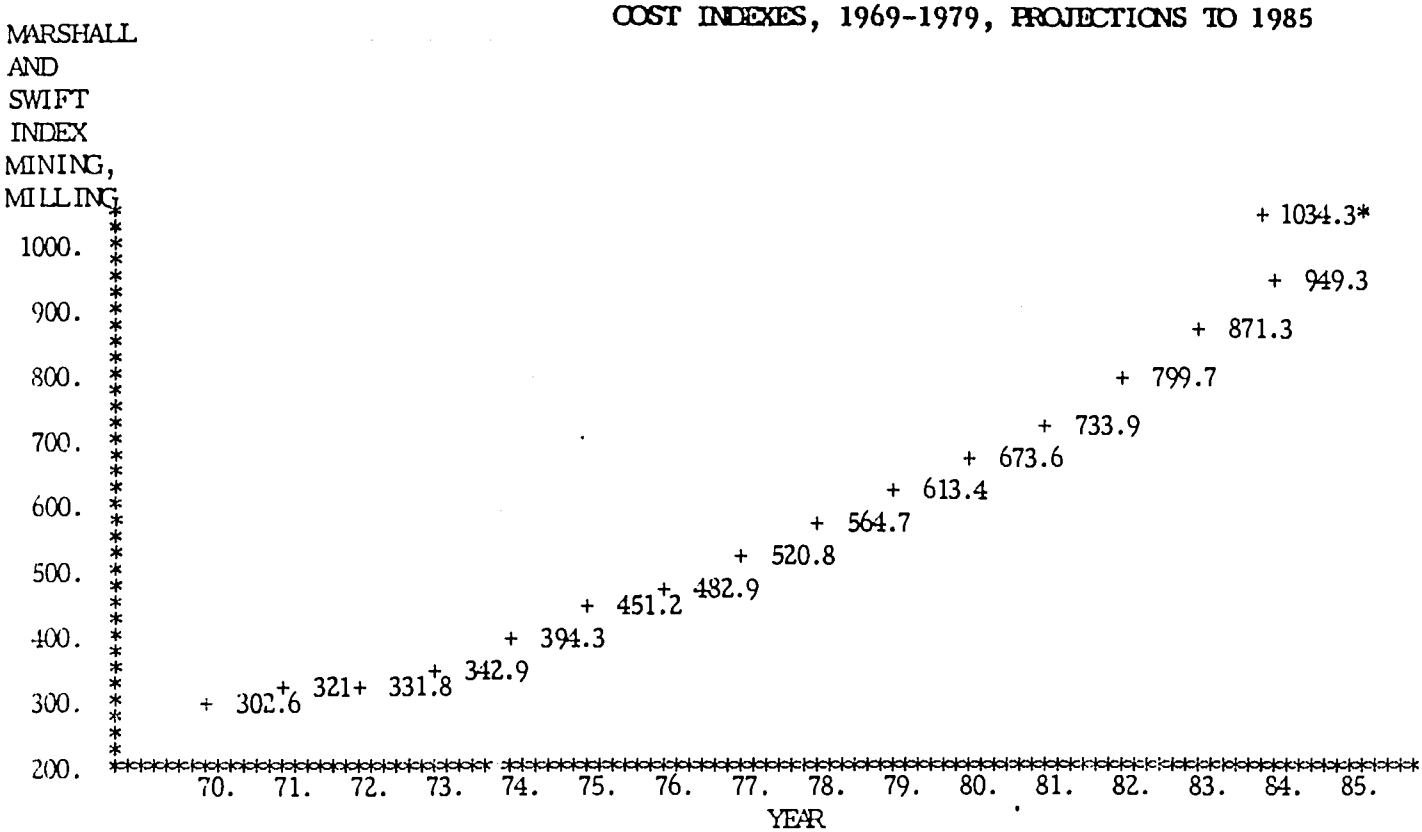
Notes: (1) See "Guide for Mechanical Flow Diagram Development & Information Status, Rev. #1" for required items.
(2) Needed before information required directly by estimating can be developed.

INFORMATION REQUIRED FOR DIFFERENT TYPES OF PROJECT ESTIMATES (CONTINUED)

| Type of Estimate (Use) Accuracy<br>Required Information | Semi-Definitive (Budget or AFE) ±7% to ±12% | Definitive (Firm Bid & Proj. Contrc ±3% to ±6% |
|---|---|---|
| Process Definition (2) | Issue 4 of Process Flow Sheet | Iss. 5 of Proc. Flow She |
| Heat & Material Balance (2) | Complete | Complete |
| Equipment List | Process Equipment-Complete<br>Utility Equipment-Preliminary | Complete |
| Mechanical Flow Sheets Process (1) (2) | Issue 4 | Issue 5 |
| Mechanical Flow Sheets Utility (1) (2) | Issue 4 | Issue 5 |
| Mechanical Flow Sheets Other (1) (2) | Preliminary | Issue 5 |
| Equipment Data Sheets | Based on Available Information (2) | Based on Vendor Selectio (2) |
| Equipment Quotations | At Least 1 Firm Quote on All Major Items | Complete Competitive Quotes Fully Evaluated |
| Equipment Estimate Sheets | As Complete as Possible | Complete |
| Utility Balance (2) | Based on Available Vendor Information | Based on Vendor Selectio |
| Instrument Data Sheets | Instrument List Only | Major Items Based on Vendor Selection, Minor Items Listed |
| Instrument Quotations | Major Items Quoted | Major Items Quoted & Eva uated; Minor Items-Catal Prices |
| Instrument Estimate Sheets | Preliminary | Complete |
| Electrical Motor List | Preliminary | Based on Selected Equip. |
| Plot Plan | Interim | Final |
| Equipment Arrangement | Preliminary | Complete (Not Dimensiona |
| Engineering Items Data Sheet (Non-D&N Account) | Based on Available Information | Based on Vendor Selectio |
| Engineering Items Quoted (Non-D&N Account) | Major Items Quoted | Complete & Fully Evaluat |
| Electrical Single Line Diag | Preliminary | Complete Based on Select Equipment |
| Structural & Foundation Specs | Preliminary | Complete |
| Piping Specs | Preliminary | Complete |
| Electrical Specs | Preliminary | Complete |
| Insulation Specs | Preliminary | Complete |
| Non-Engineered Items Takeoff | Preliminary | Complete |
| Engineering Estimate | Definitive | Updated Definitive |
| Cost of Preparing Estimate (% of Definitive Est Cost) | 80% | 100% |

Notes: (1) See "Guide for Mechanical Flow Diagram Development & Information Status, Rev. #1" for required items.
(2) Needed before information required directly by estimating can be developed

COST INDEXES, 1969-1979, PROJECTIONS TO 1985

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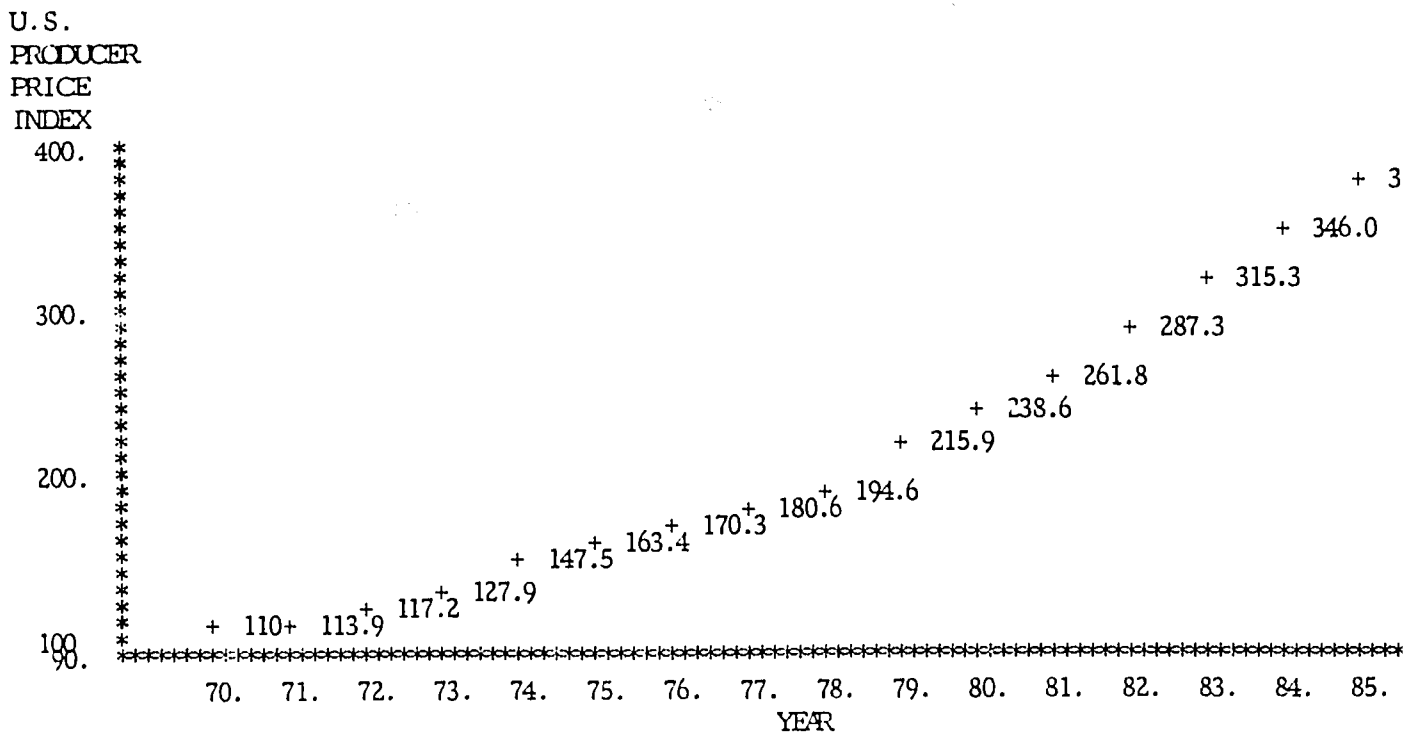


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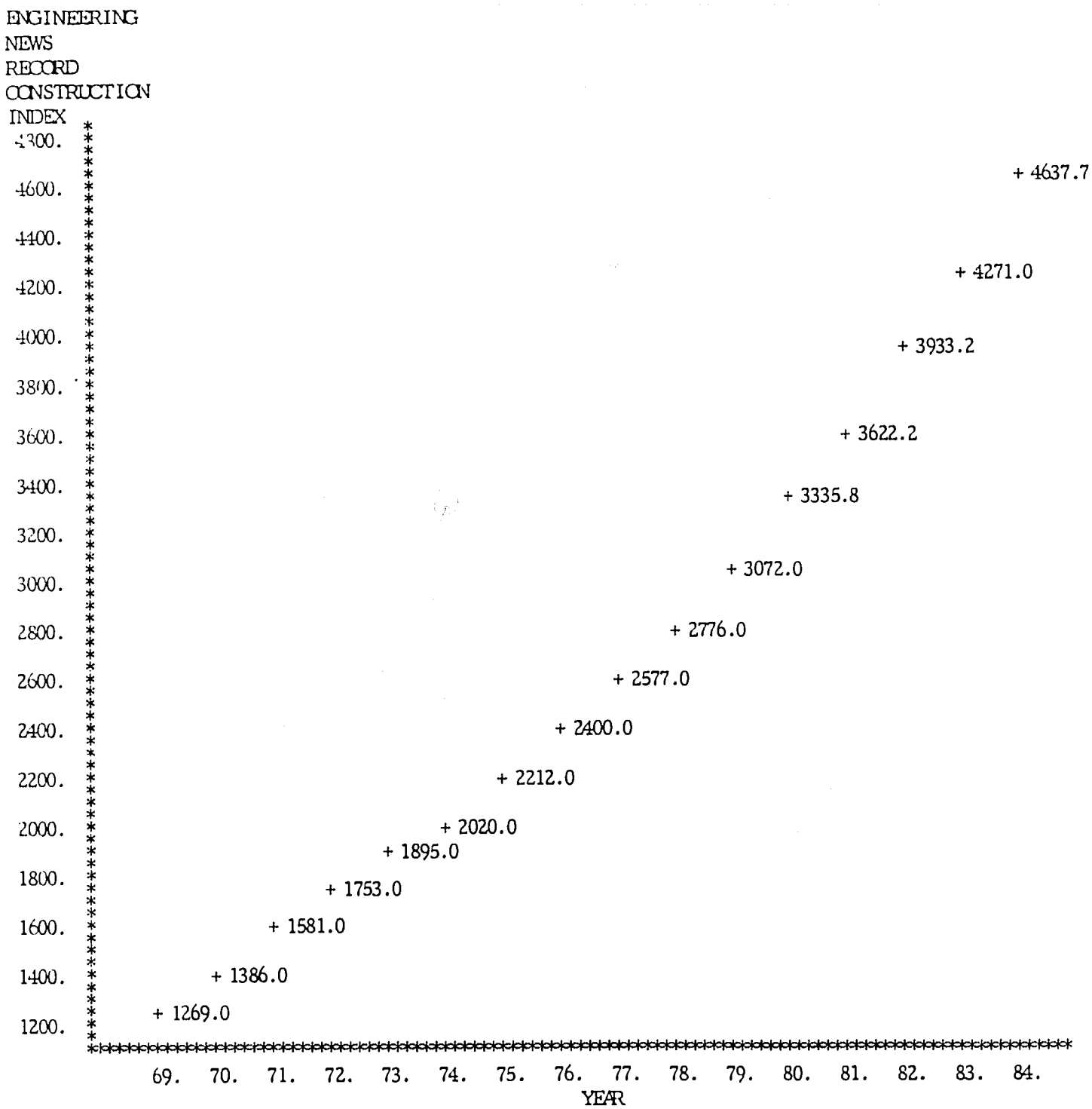


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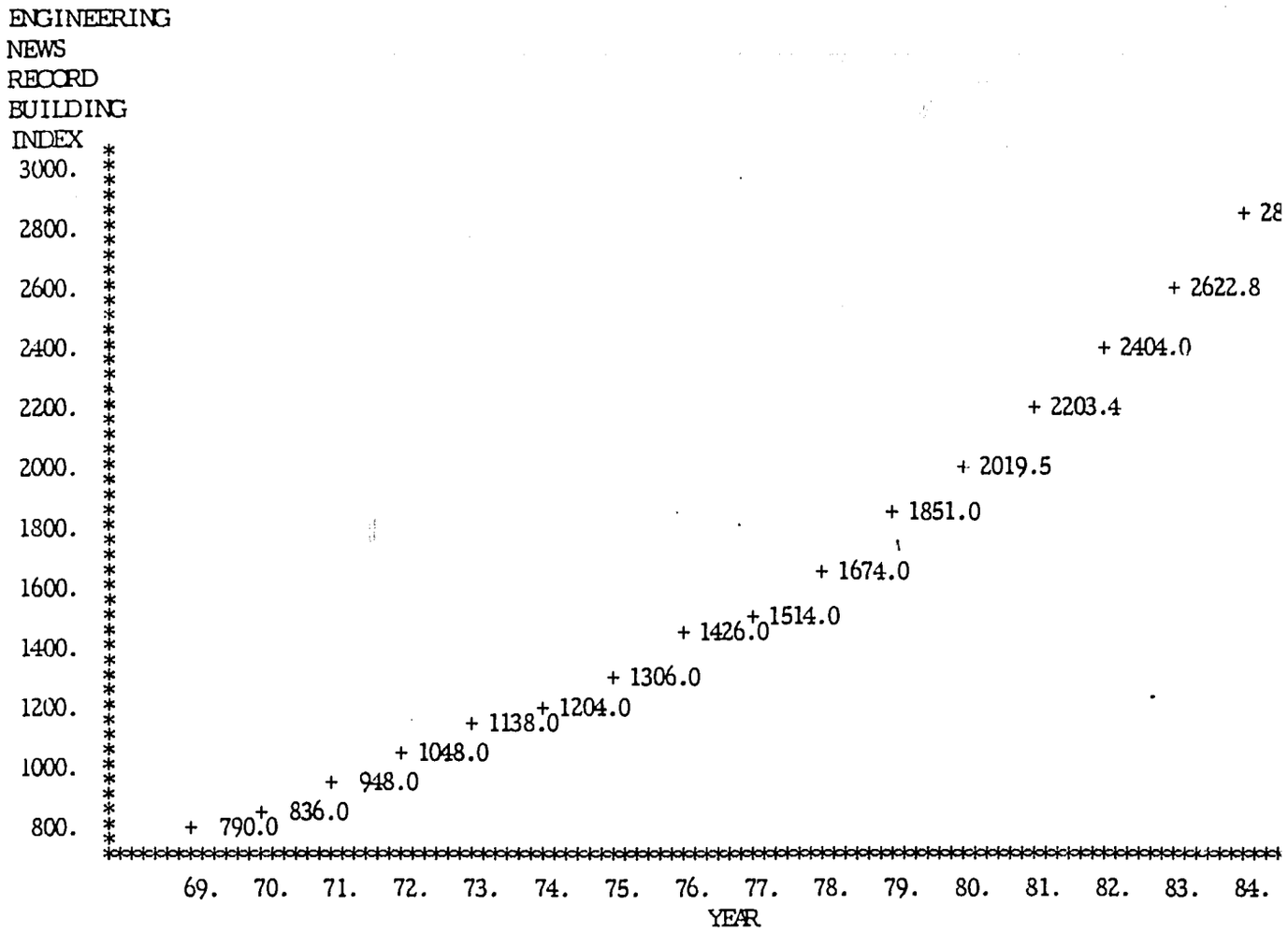


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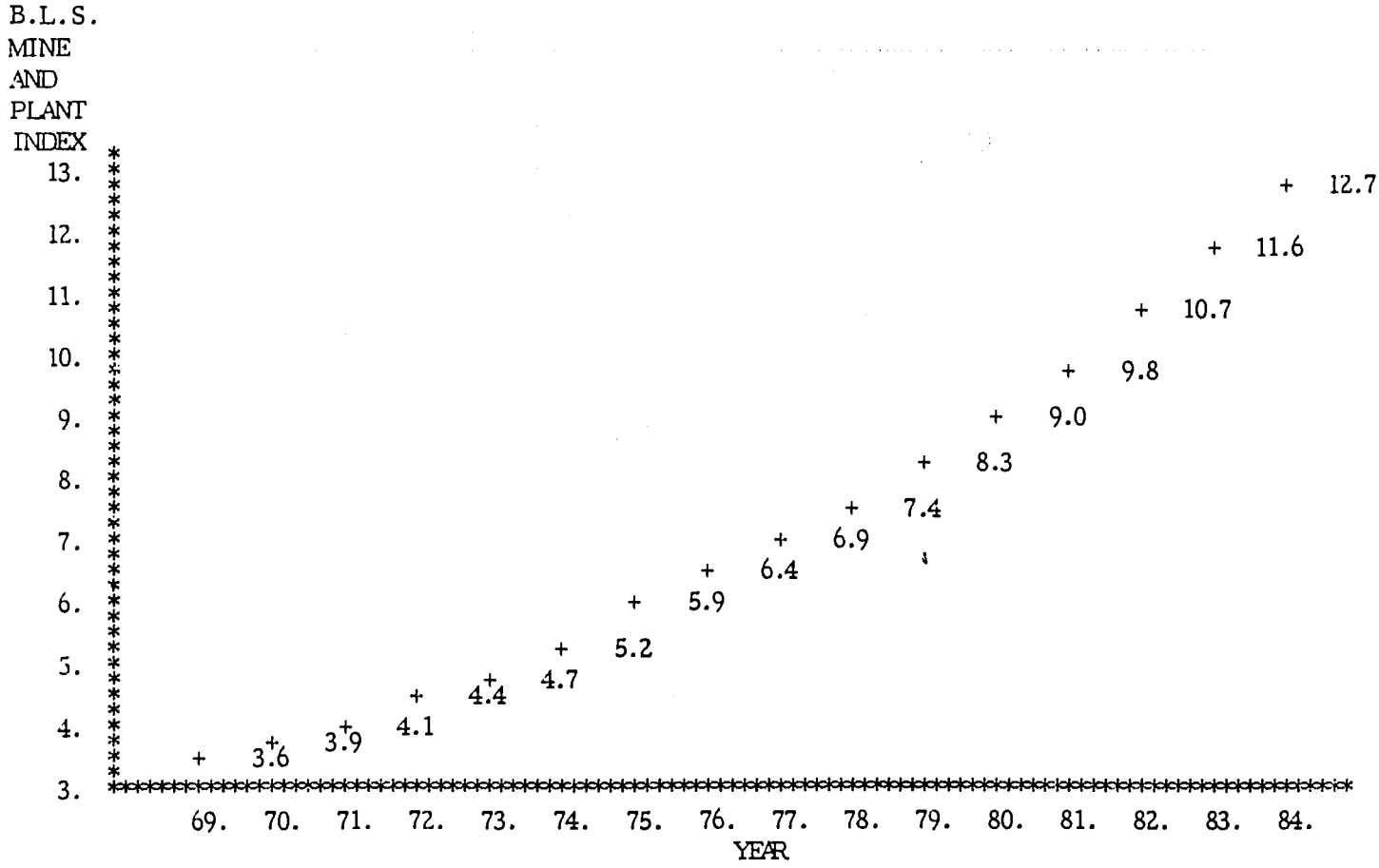
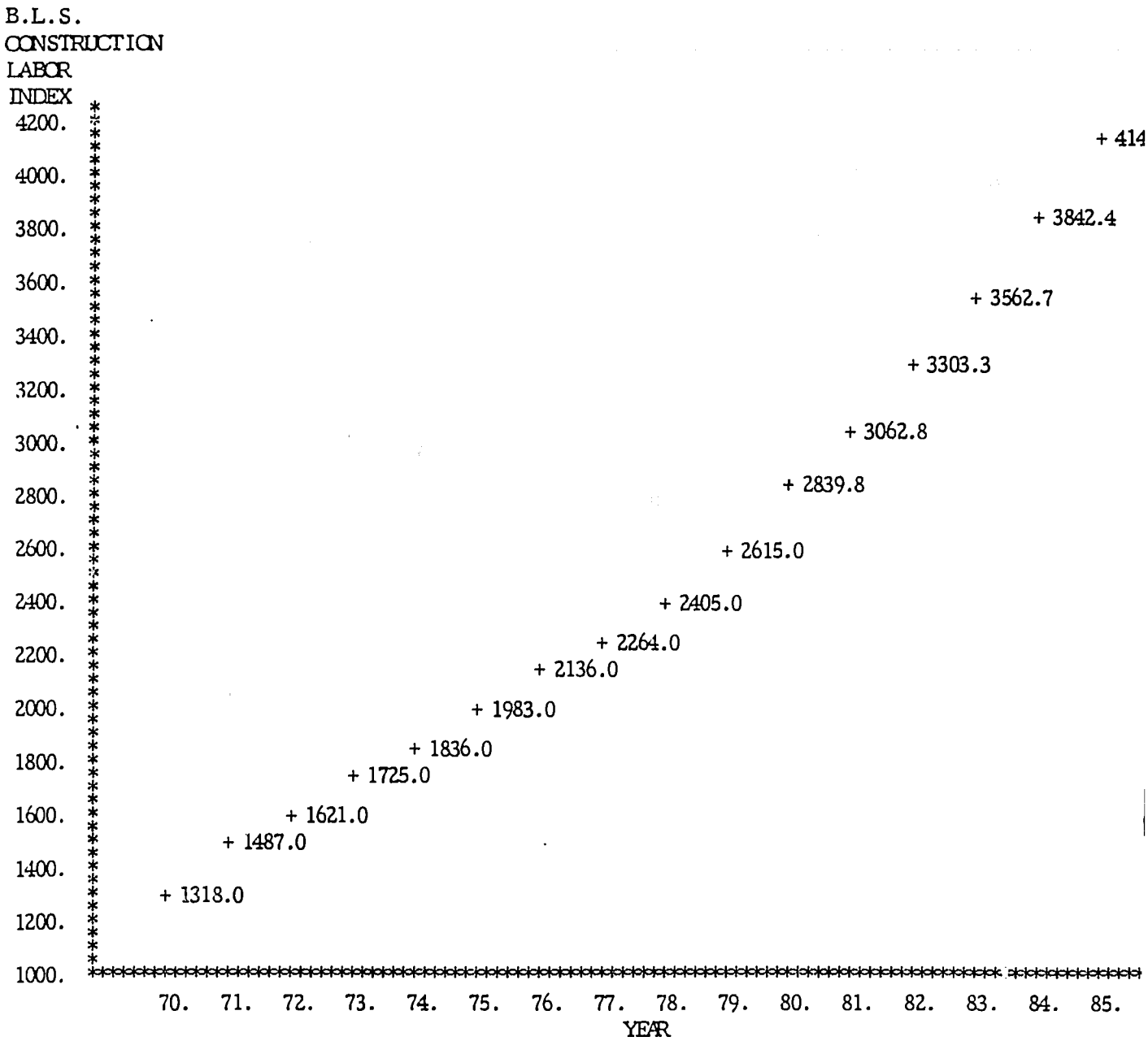
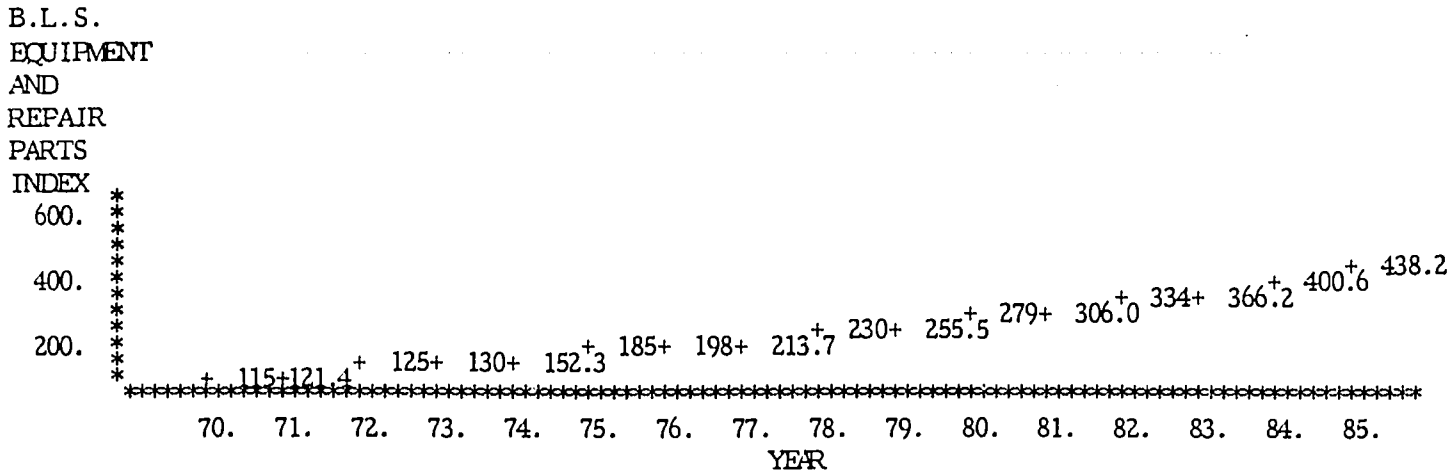


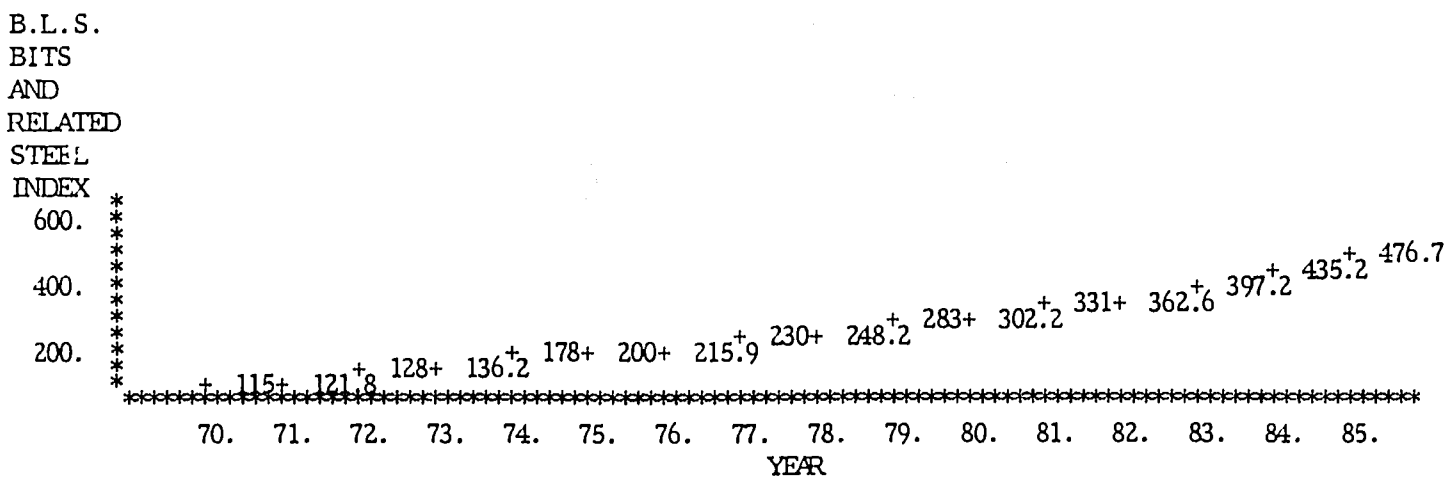

PROJECTION 1979 TO 1984. BASED ON 8.9 % AVG. AN. CHANGE, LAST 3 YR.



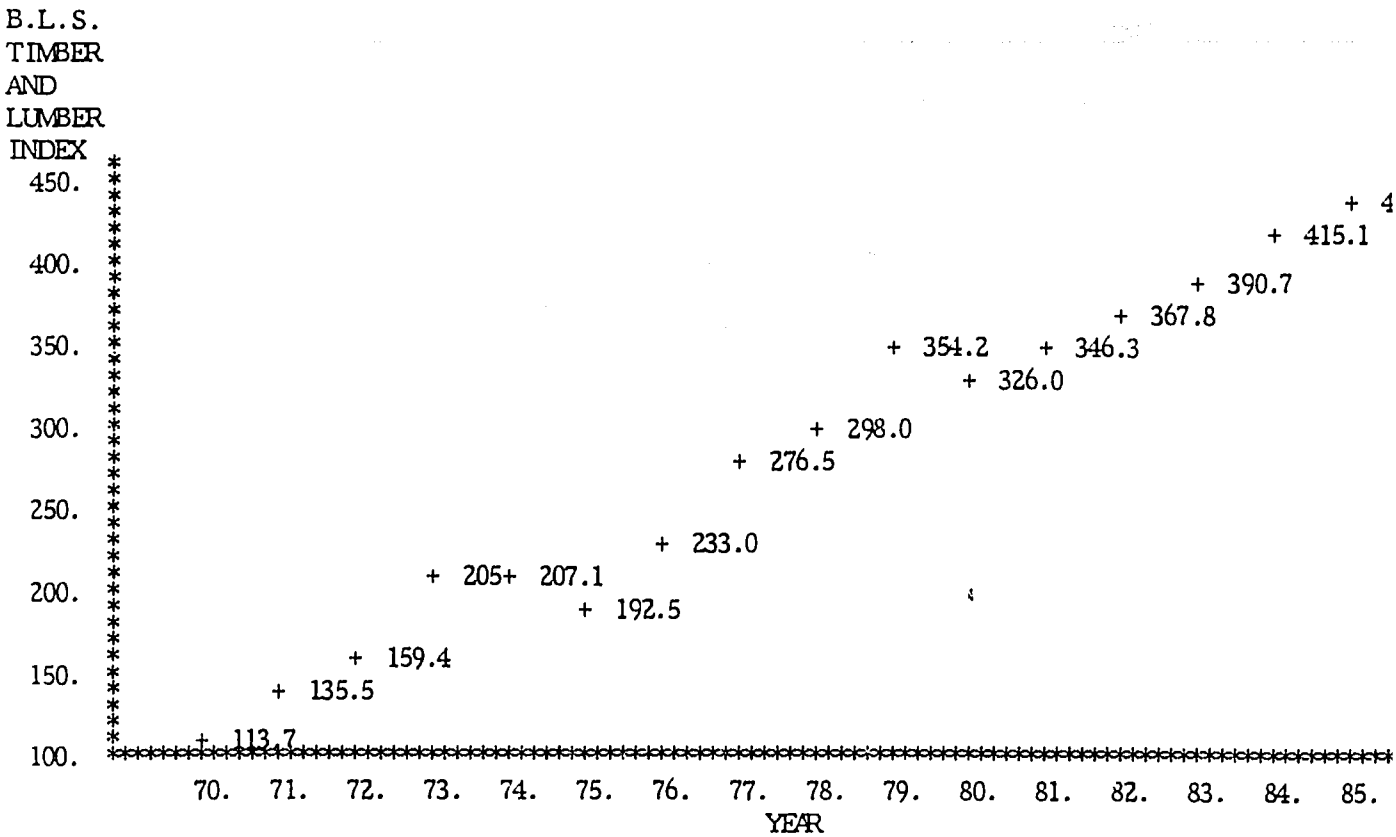

PROJECTION 1980 TO 1985. BASED ON 7.9 % AVG. AN. CHANGE, LAST 3 YR.



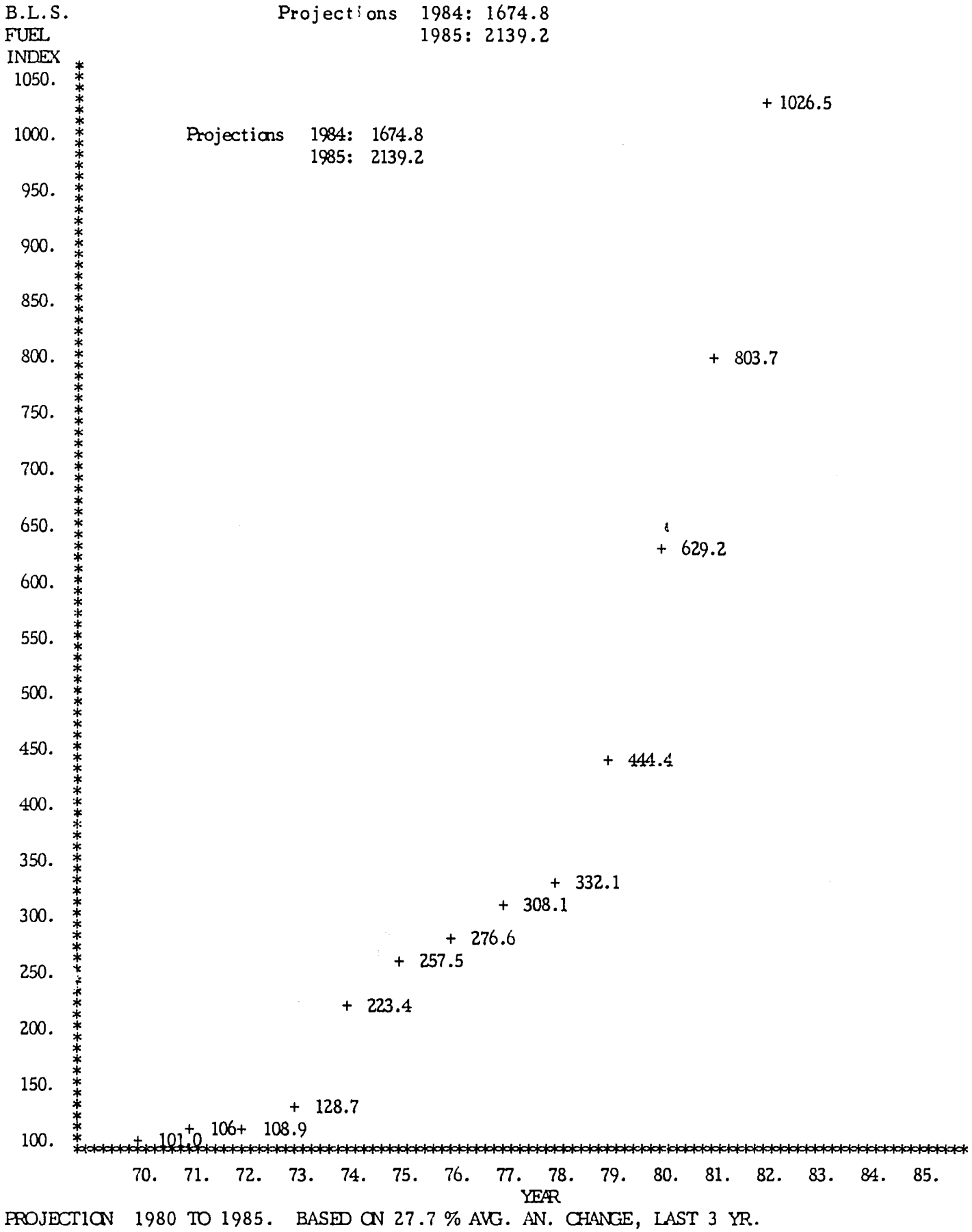

PROJECTION 1980 TO 1985. BASED ON 9.4 % AVG. AN. CHANGE, LAST 3 YR.



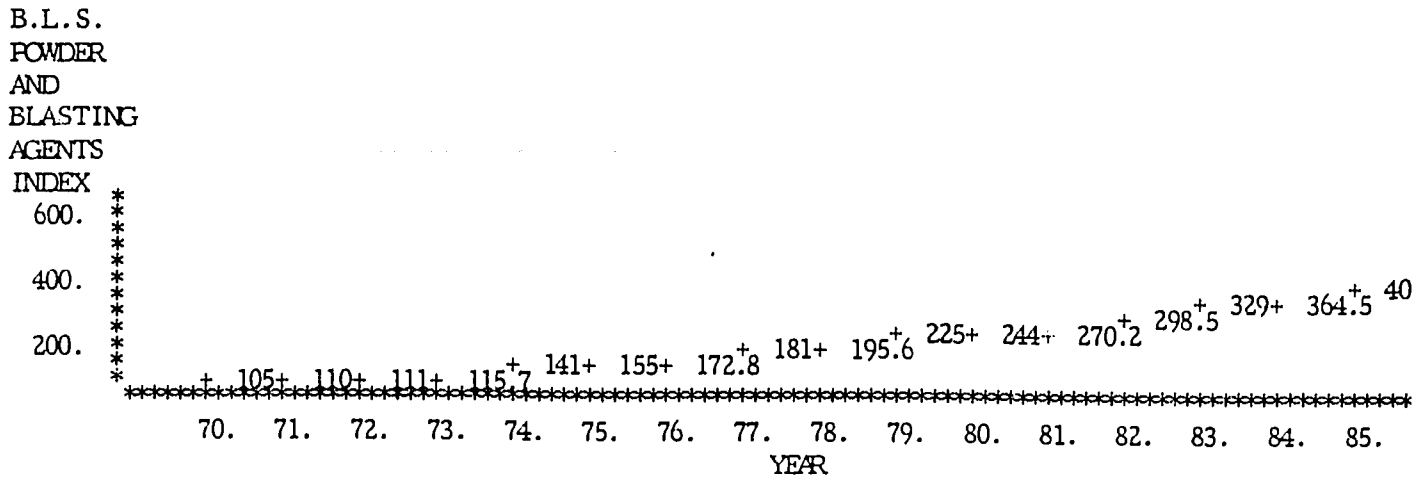

PROJECTION 1980 TO 1985. BASED ON 9.5 % AVG. AN. CHANGE, LAST 3 YR.



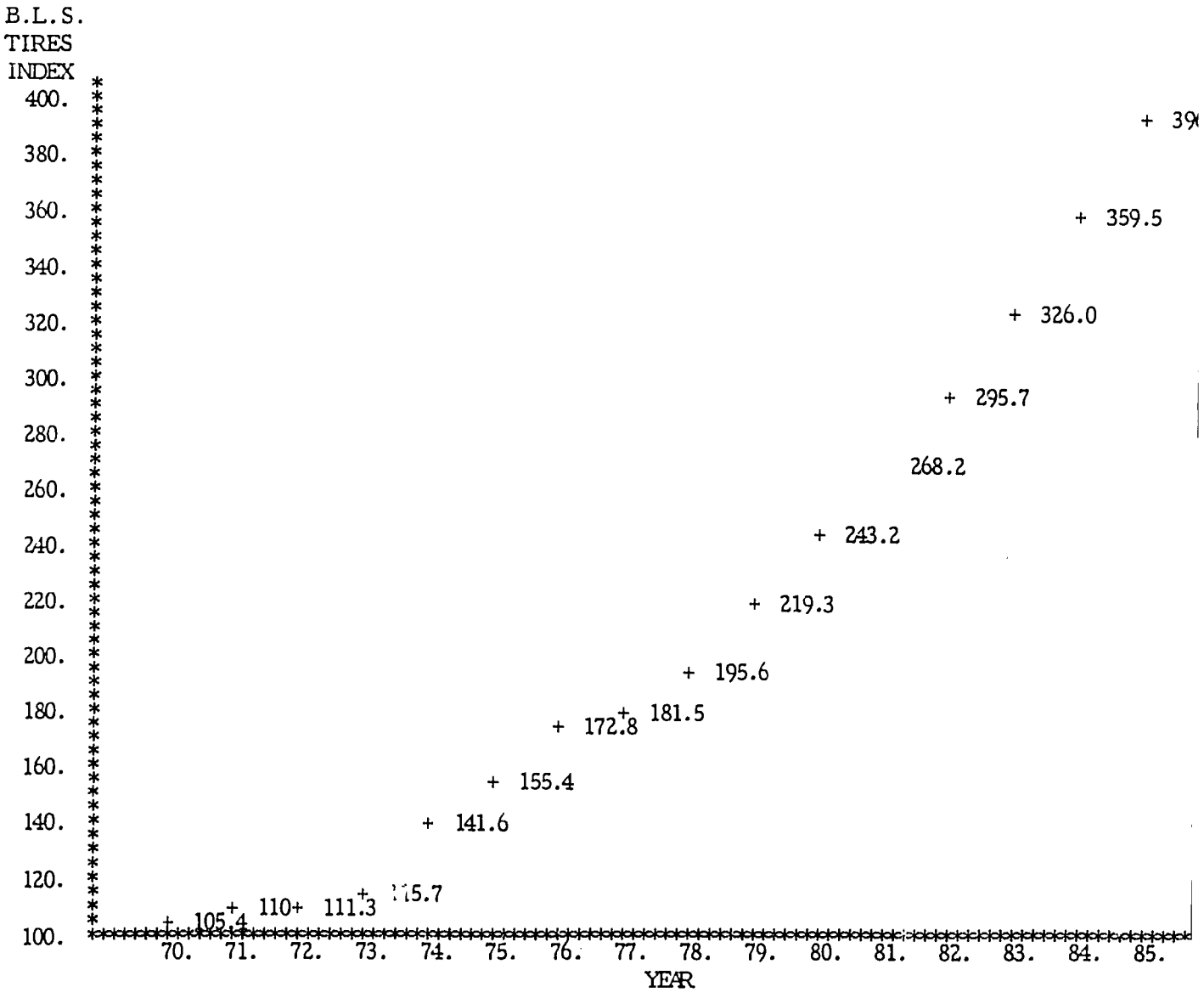

PROJECTION 1980 TO 1985. BASED ON 6.2 % AVG. AN. CHANGE, LAST 3 YR.



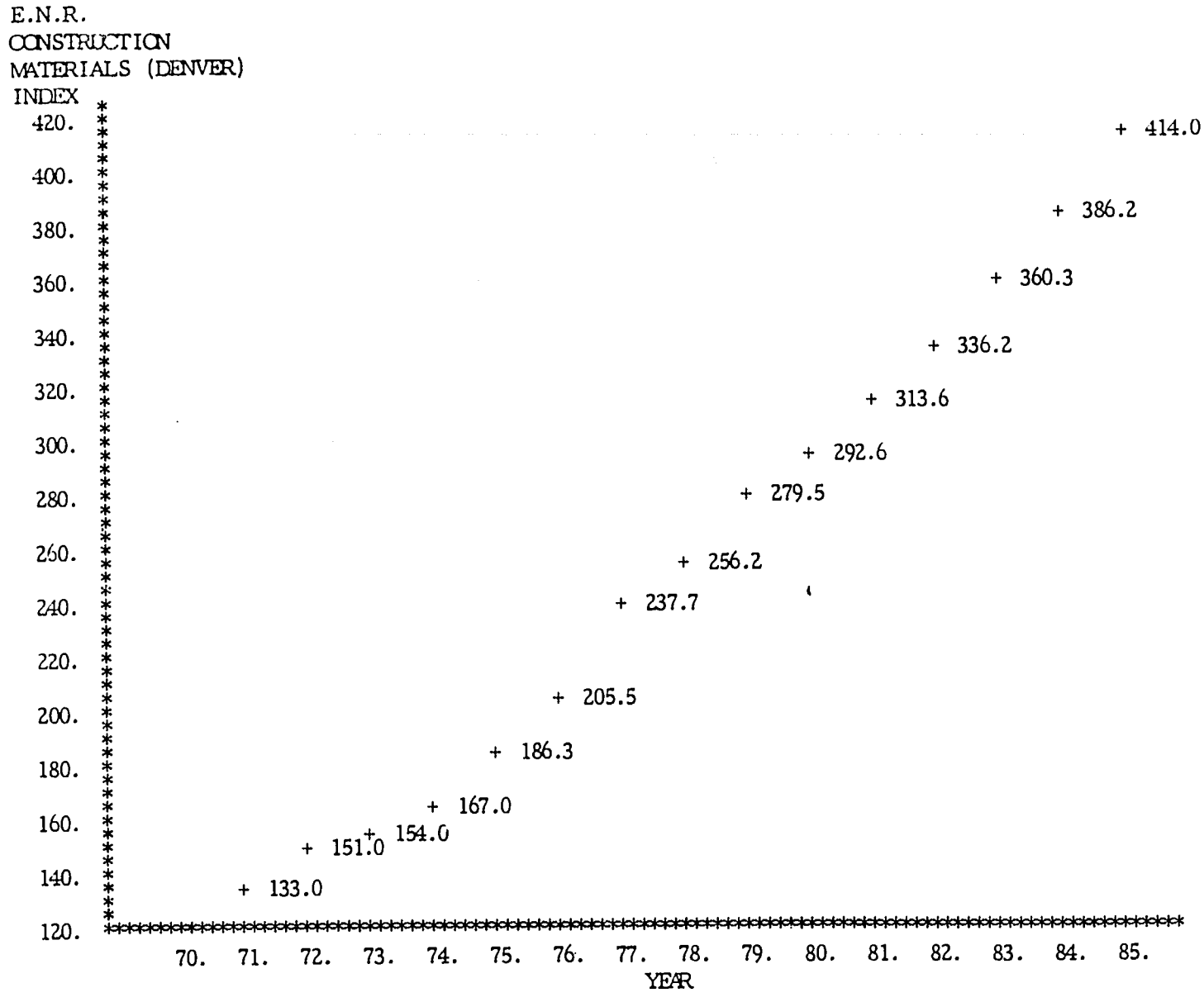

PROJECTION 1980 TO 1985. BASED ON 27.7 % AVG. AN. CHANGE, LAST 3 YR.



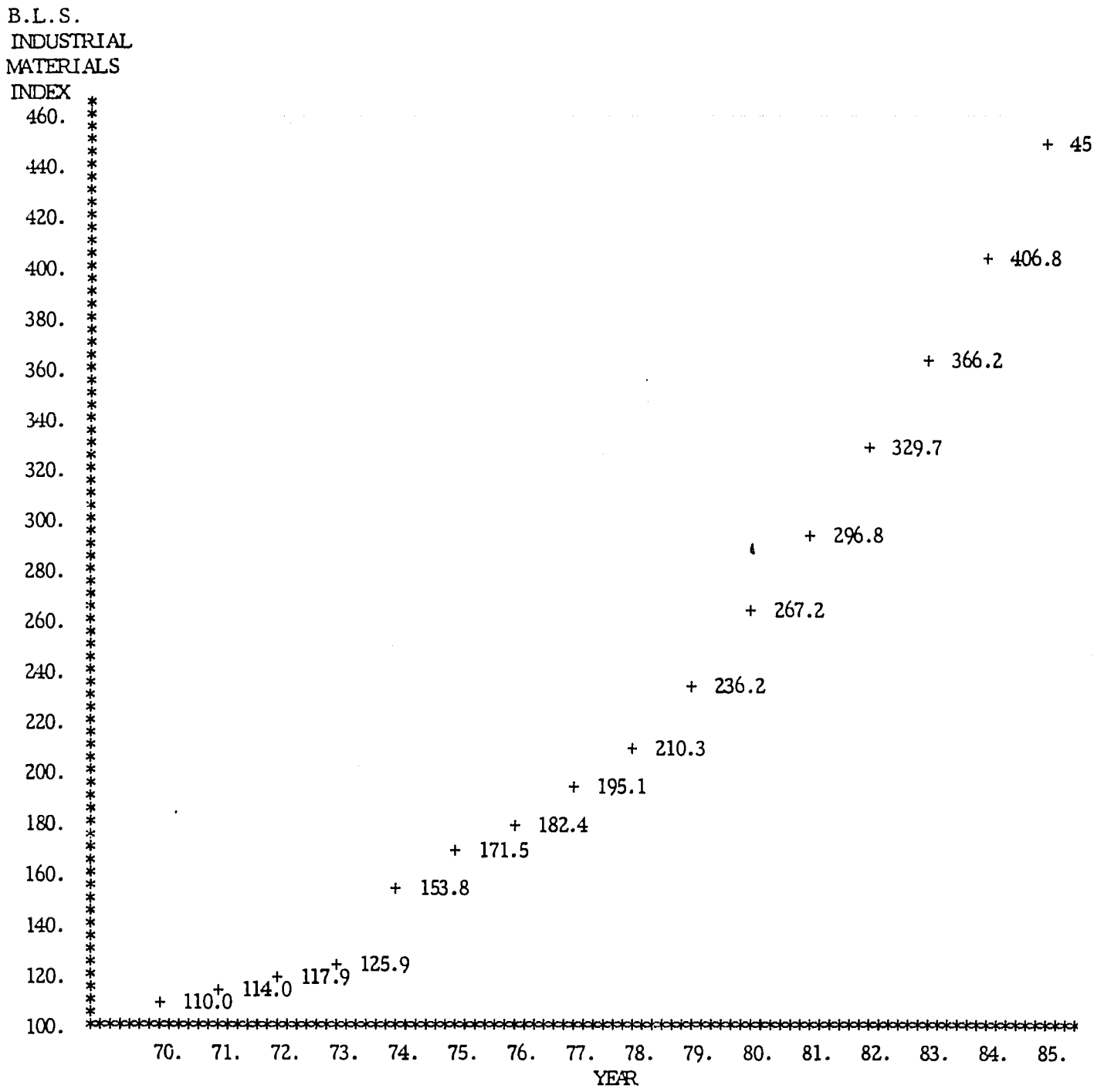

PROJECTION 1980 TO 1985. BASED ON 10.5 % AVG. AN. CHANGE, LAST 3 YR.




PROJECTION 1980 TO 1985. BASED ON 10.3 % AVG. AN. CHANGE, LAST 3 YR.

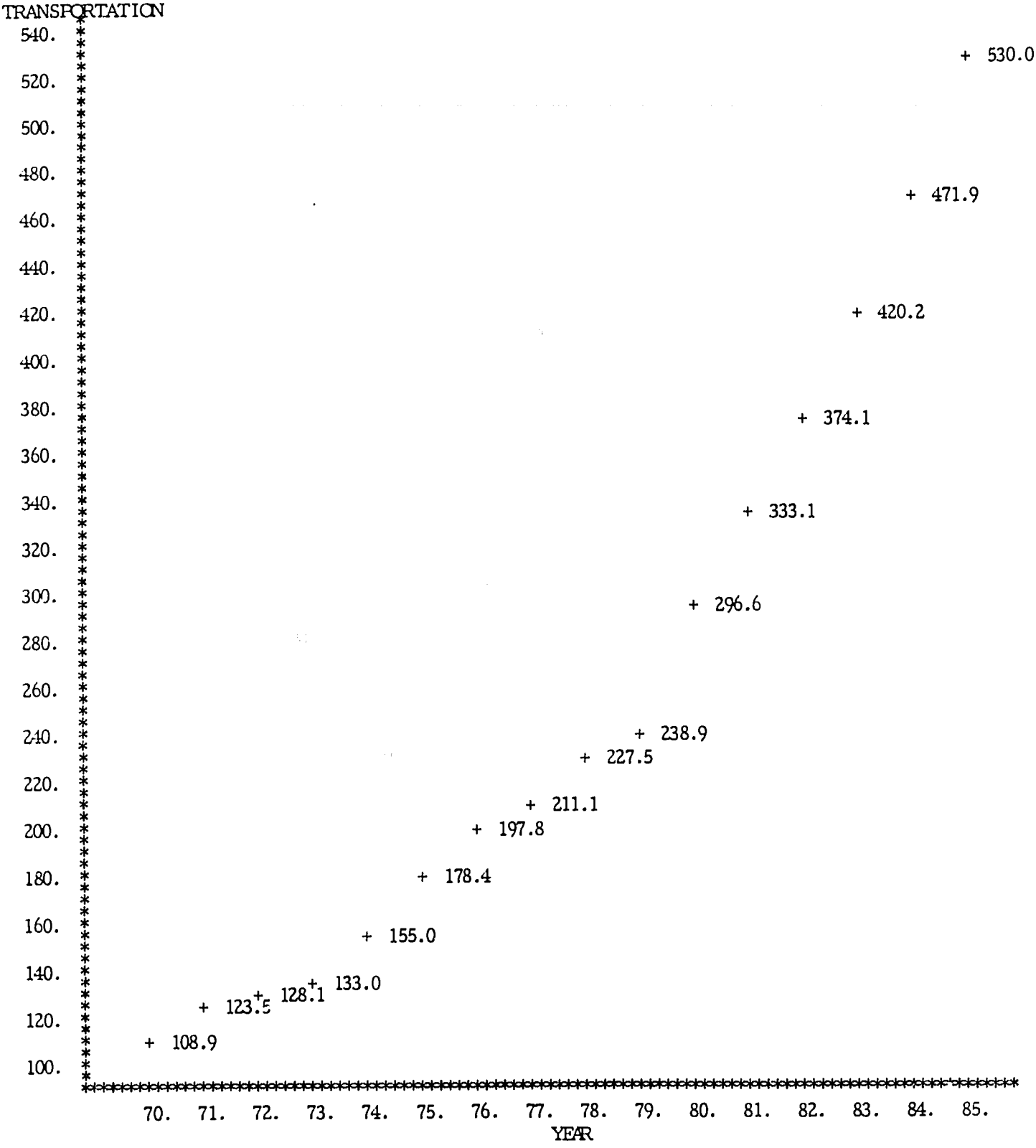



PROJECTION 1980 TO 1985. BASED ON 7.2 % AVG. AN. CHANGE, LAST 3 YR.

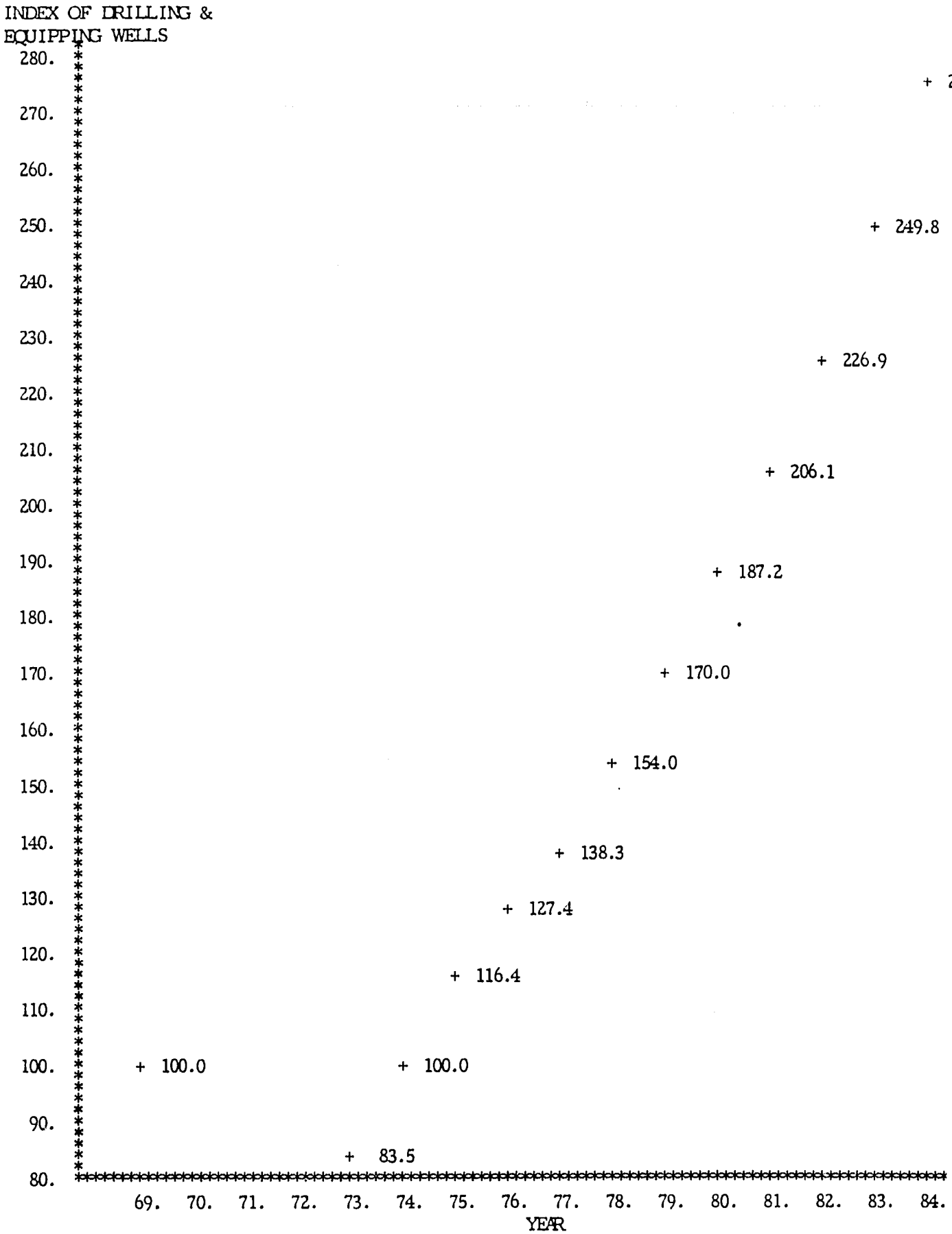



PROJECTION 1980 TO 1985. BASED ON 11.1 % AVG. AN. CHANGE, LAST 3 YR.

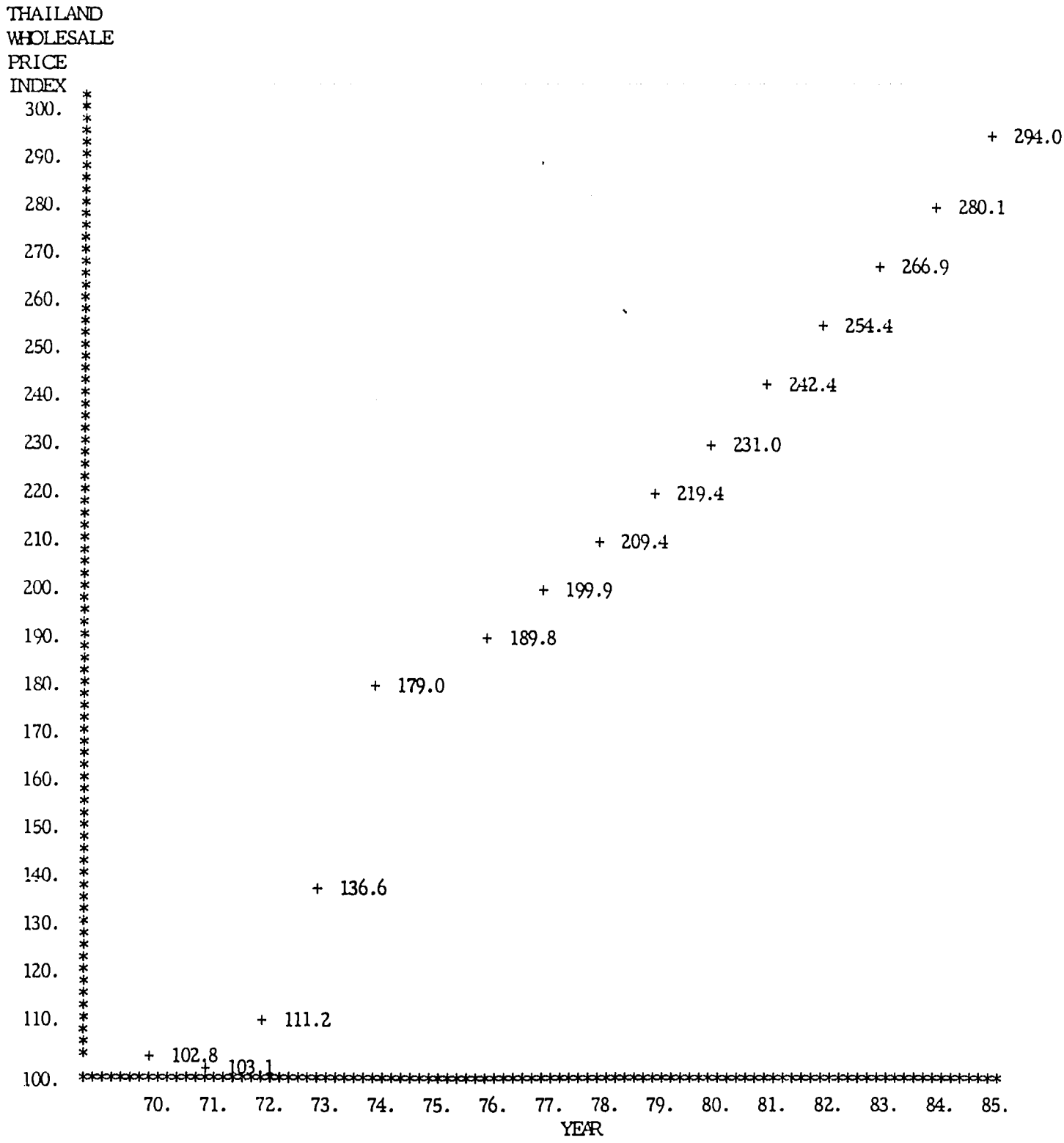
B.L.S.
TRANSPORTATION




PROJECTION 1980 TO 1985. BASED ON 12.3 % AVG. AN. CHANGE, LAST 3 YR.

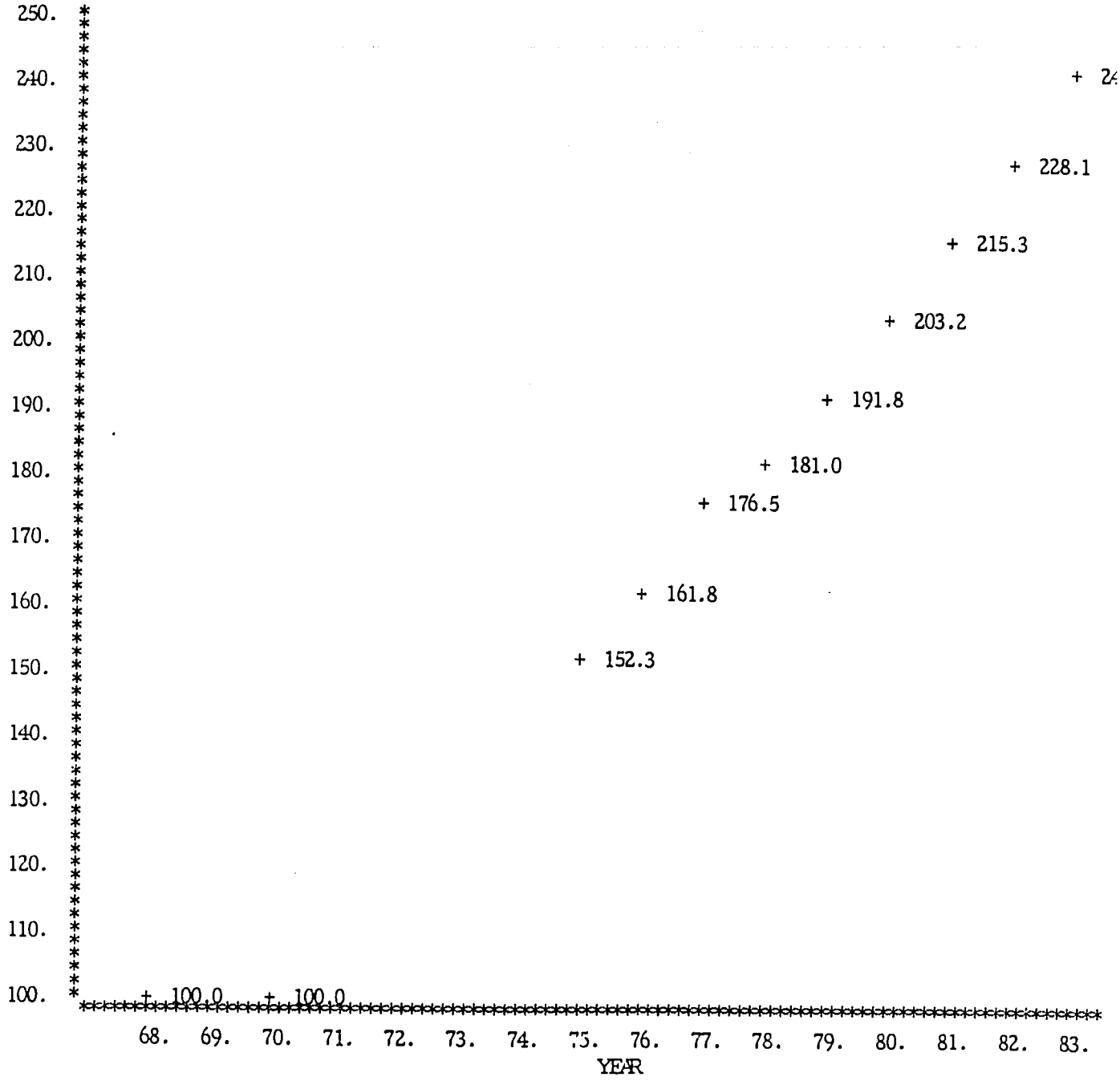



PROJECTION 1979 TO 1984. BASED ON 10.1 % AVG. AN. CHANGE, LAST 3 YR.




PROJECTION 1980 TO 1985. BASED ON 4.9 % AVG. AN. CHANGE, LAST 3 YR.

DOMINICAN REPUBLIC
GDP DEFLATOR




PROJECTION 1978 TO 1983. BASED ON 6.0 % AVG. AN. CHANGE, LAST 3 YR.

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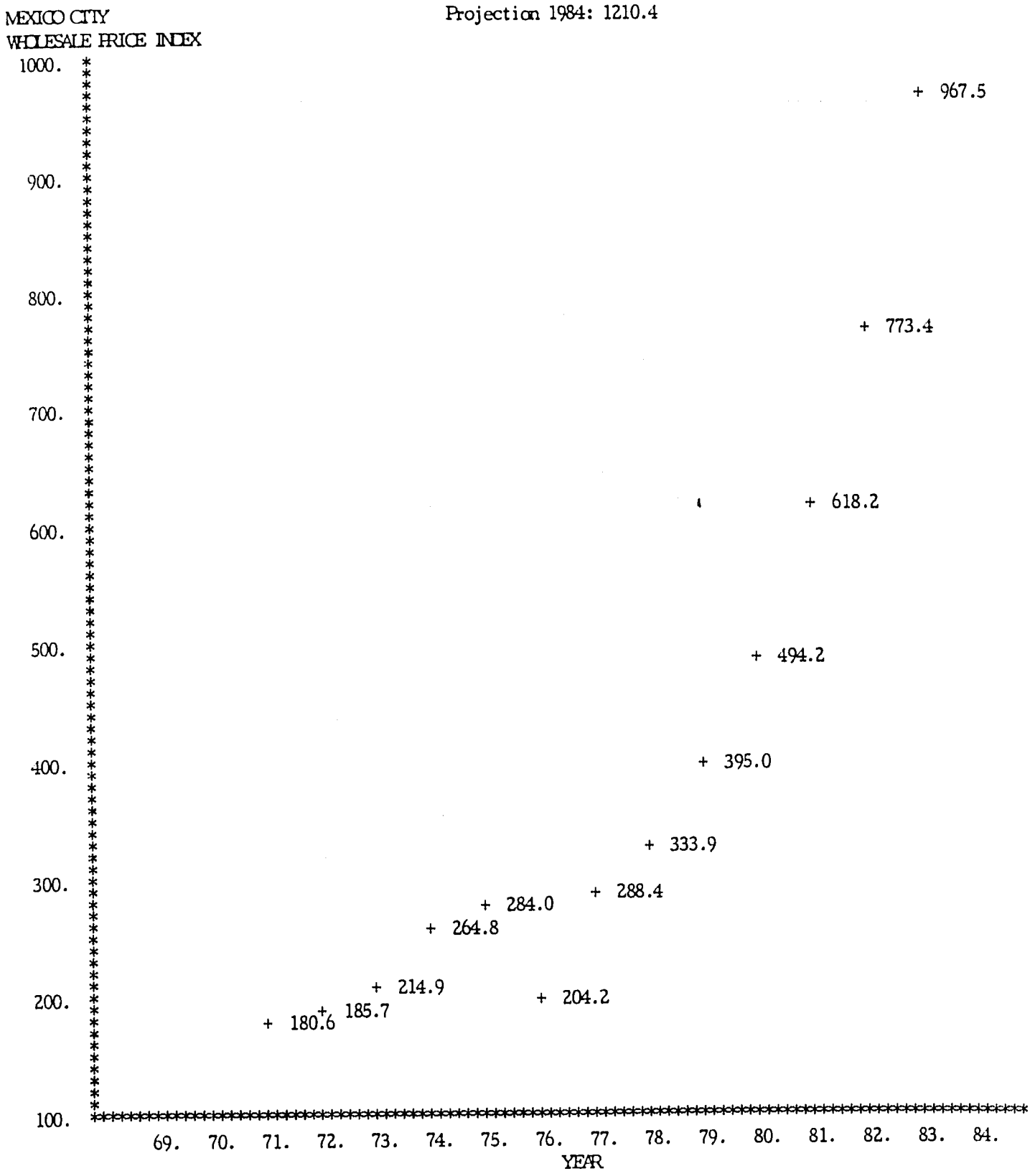
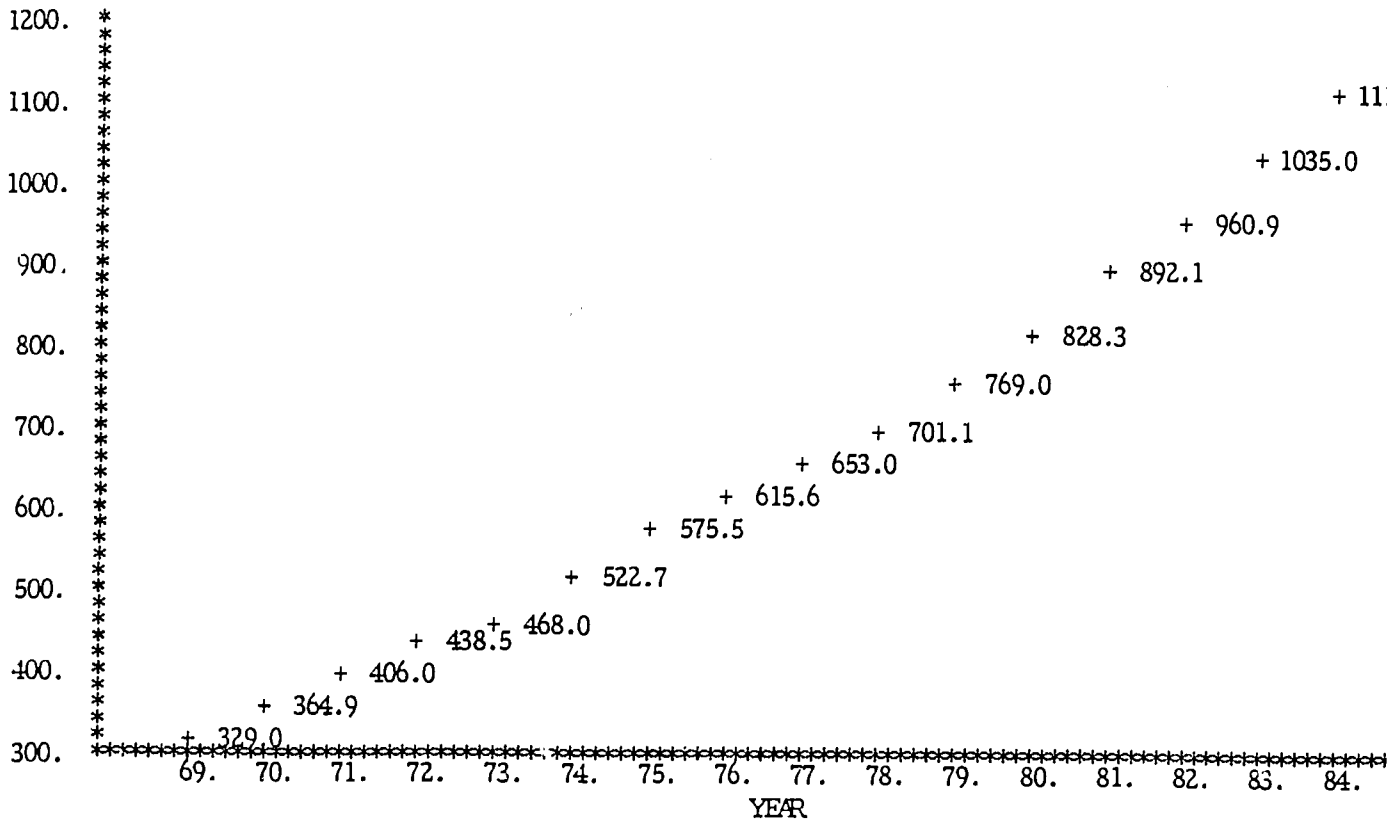


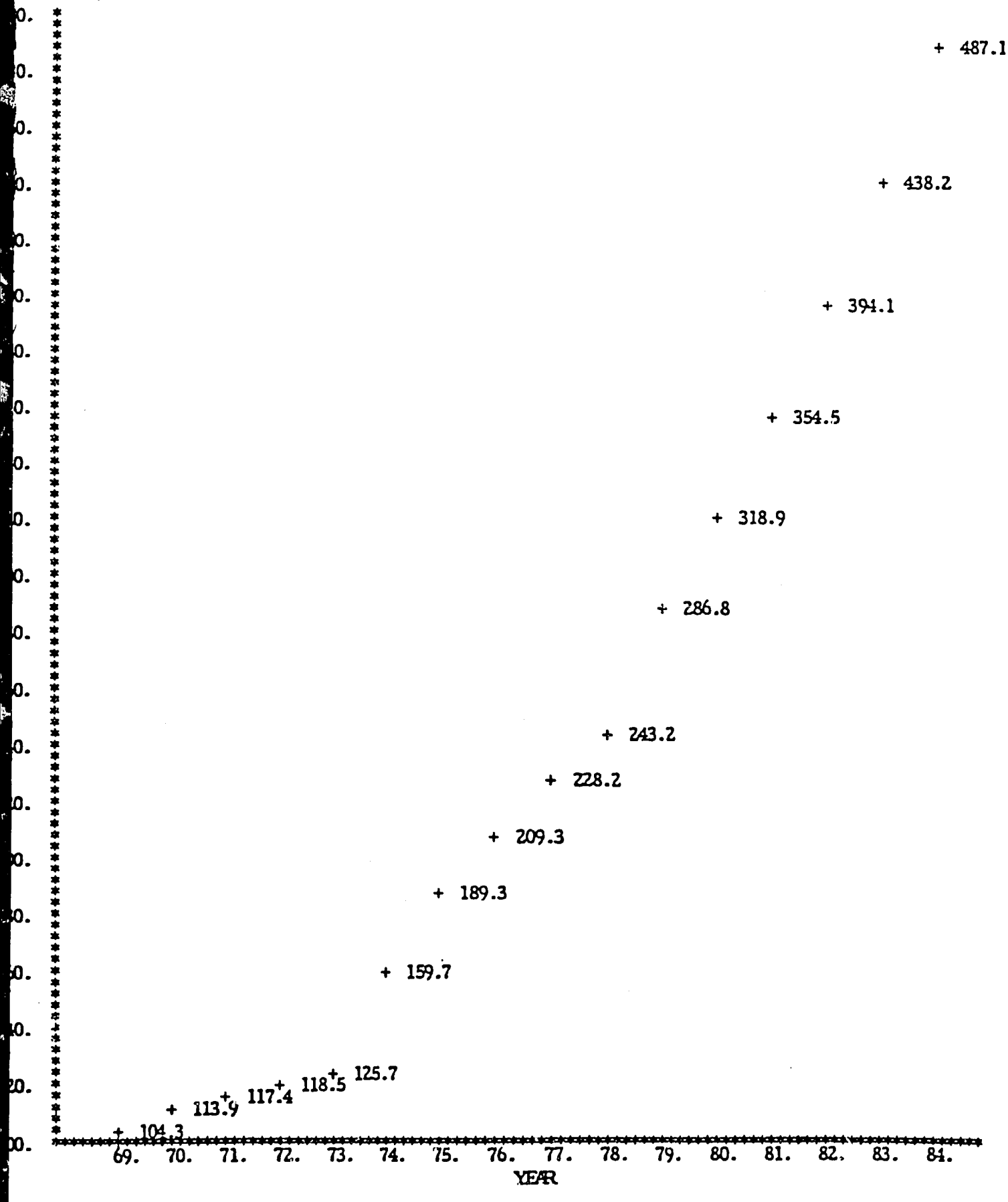

PROJECTION 1979 TO 1984. BASED ON 25.1 % AVG. AN. CHANGE, LAST 3 YR.

NELSON REFINERY
CONSTRUCTION (INFLATION)
INDEX (1946 BASIS)




PROJECTION 1979. TO 1984.BASED ON 7.7% AVG.AN.CHANGE,LAST 3 YR.

LSON OPERATING
ST INDEX
56 BASIS)




OJECTION 1979 TO 1984. BASED ON 11.2 % AVG. AN. CHANGE, LAST 3 YR.