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GRADUATE COLLEGE

BRINE DISPOSAL FROM SMALL OIL PRODUCTION SITES

A DISSERTATION

SUBMITTED TO THE GRADUATE FACULTY

in partial fulfillment of the requirements of the

degree of

DOCTOR OF PHILOSOPHY

BY

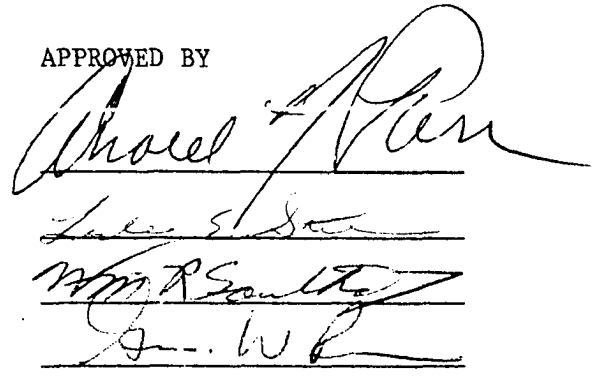
JUSTIN RAYMER SMITH

Norman, Oklahoma

1972

BRINE DISPOSAL FROM
SMALL OIL PRODUCTION SITES

APPROVED BY



DISSERTATION COMMITTEE

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As this dissertation was prepared in fulfillment of the requirements for the Ph.D. degree, all pertinent research data was included to support and justify the research topic. It should be noted that an edited version in manual form is under development for use by the Environmental Protection Agency. The research reported in this document was supported by EPA contract No. 14-12-873. The report requires revision and is not approved by EPA for publication in its present form.

ABSTRACT

The purpose of this research is to develop a methodology for the economic evaluation of oilfield brine disposal systems.

Specifically, a procedure is developed for the determination of the total unit cost of alternative systems. These unit costs are then compared in order to select the least expensive allowable brine disposal system.

The dissertation progresses from a discussion of the broad realm of resource economics to the more specific subjects of disposal mechanisms and disposal cost analysis. In addition, methods for obtaining necessary information to use in the analysis are discussed throughout the text.

In the Appendix section of this report, oil regulating agencies and water quality agencies for each state, by name and mailing address, are listed. The roles of these agencies in administering the brine disposal policies of each state are also explained.

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SECTION I

REGULATING RESOURCES

Three major interactive factors, which presently seem on a collision course, have been emerging within the oil industry. The first factor is industry. The character of America has changed from a primitive, agricultural land completely dependent on European industry for manufactured goods to a land whose industry dominates much of the world.

Second is energy. Concurrent with the development of industry, and the level of activity and mobility accompanying it, America developed a need for energy which surpasses that of any other nation in the world.

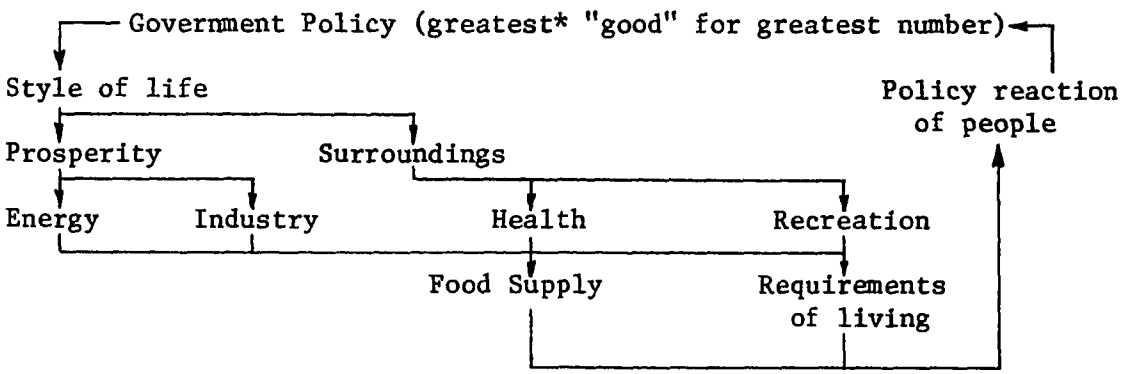
Third is environment. In her early days, America was blessed with rich, plentiful land. Wasteful agricultural and industrial processes were hidden by the availability of good, cheap land further west. But no longer is pollution generated by the activities of Americans so diluted by the relatively pure winds and rivers that it is reduced to virtual nonexistence.

As the United States has grown, the three factors of industry, energy, and environment have become more and more dominate, but, not in an equal balance. Until relatively recent times, the population and activities of the United States did not exert a dramatic demand on the environment, mainly because the extent of natural resources was so vast that once again the

demand was diluted by abundant supply. By the early 1960's it became so dramatically clear that the critical balance between the American and his surroundings was in serious danger of an irresversible upset that environment became a major national issue.

Why should anyone become alarmed by this imbalance? Perhaps basically because of the threat of two powerful "predatory" forces, broadly covered by economics and health. Put rather broadly, economics may be visualized as the cycle any living thing goes through in utilizing relativily limited resources for its own survival and growth. And health may be visualized as the struggle between different forms of life for critical resources.

How does this fit into the American Scene? Actually, rather simply. To provide the high standard of living most Americans enjoy, industry has developed to a high level those active elements critical to the needs of society and thus to the survival of the nation. The threat of the predatory forces of economics and health is basically that simple. If the use of natural resources is not controlled, and the balance of living things is not maintained, the quality of living is threatened by disease and the standard of living suffers the adjustment of re-evaluation of goods and services to the detriment of society and its influences. (See Figure 1.)



*Objectives
1. Prosperity
2. Security

Figure 1. Government Policy Cycle.

Legislatures decide, in effect, the style of life. The decision on the proper balance between resource utilization, and general style of living is a continuous political decision. (See Figure 2.)

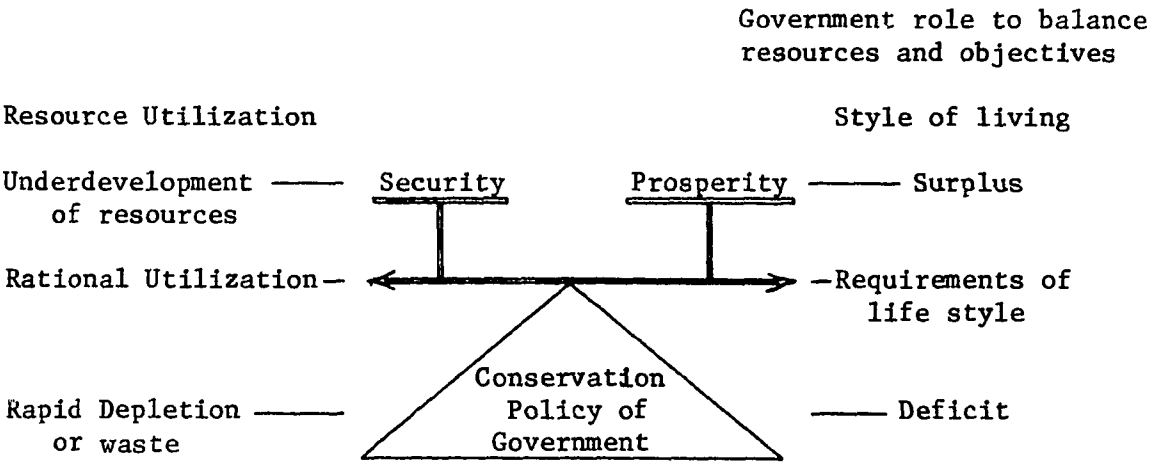


Figure 2. Resource Policy Balance

When the great mass of people are overly afflicted by economic deprivations that severly limit their prosperity level, they utilize political action to relieve these limitations. When, on the other hand, the people suffer because of health problems or the spoilage of their "eminent domain," the political emphasis is shifted the other way. The desired effect is a balance between the style or standard of living and resource utilization.

In real terms, prosperity, resource utilization, and environmental wholesomeness are extremely difficult to identify. However, to assure a reality in the "pursuit of happiness," someone or some group has to make decisions that will affect private interest concerns and establish national priorities. These decisions may seem to be "against" one or another private interest group. But if there is any validity to the American system (and the high level of success achieved by our society demonstrates that there is), then it must be due to the ability of the government, working with industry and the general public, to deal effectively with issues of the present and the future. This means that the emphasis on pollution and the environment is not an animosity against industry but a positive step to preserve or conserve natural resources whose value and/or natural state exceeds the value derived from their use, either in the present or future.

SECTION II

ENERGY AND THE OIL COMPANIES

In effect, the conflict between national goals is a continuous process of re-evaluation. The two basic objectives of security and prosperity still exist. In re-defining these objectives however, the trends emerging are an increased concern relative to the quality of living (harnessing technology to improve utilization, not necessarily expand it) and a de-emphasis of the conspicuous consuption trademark of the 1960's in America. One explanation of this shift in attitude is that the motivating force is not a fear of economic reprisal but a recognition that at some point lower individual consumption will be less of a burden on natural resouces and on the environment. On closer examination, there seems to be good reason for the fear of economic reprisal as well:

> The United States has consumed more minerals in the past 30 years than the entire world for all time before. Based on Bureau of Mine commodity forecasts, it is estimated that the mineral extracting industry will face a 50% increase in demand by 1975, as compared with 1967, a 100% increase by 1980, and at least double again by the turn of the century (1).

Consumption demands are generated by a prosperous population. In the United States, present per capita consumption seems to compound with a rapid trend toward urbanization; 1970 estimates (based on 1960 data) placed America's population at 70% urban (1,2). Some of the apparent drift to cities might be explained by the growth of small communities to a level

of 2,500 or more, the densely settled fringes of urban areas, and unincorporated concentrations of population with 2,500 or more inhabitants (3). This means that there may not be a substantial relocation of the populace but simply an increse in the population of small communities to the 2,500 level where their inhabitants are classified as urban dwellers. From 1880 to 1960, the percentage of total population living in urban areas increased at a rate of 1% per year, the number of communities classified as urban increased on an average of 2.1% per year, and urban population grew at a rate of 2.6% per year. Correspondingly, energy use from 1940 to 1960 increased at an average of 3.7% per year (4).

There are four main energy consuming areas in the United States: household and commercial, industrial, transportation, and electric utilities (5). (See Tables 1 and 2.)

Table 1. U. S. Energy Consumption.

Present (1968) and Future (2000)

Consumption Sector	1968(%)	2000(%);(multiple x) low	2000(%);(multiple x) high	% Increase per year 1968-2000 low	% Increase per year 1968-2000 high
1. Household and commercial	21.8	12.7;(1.6x)	17.0;(3.0x)	1.4	3.5
2. Industrial	31.6	19.9;(1.7x)	25.1;(3.0x)	1.6	3.5
3. Transportation	24.2	21.9;(2.4x)	22.1;(3.5x)	2.8	4.0
4. Electric utilities	22.4	45.5;(5.4x)	35.8;(6.1x)	5.4	5.9
	100%	100%	100%		

Table 2. U.S. Total Energy Needs (10^{12} BTU).

Present (1968) and Future (2000)

	1968(%)	2000 (%);(multiple x)		% Increase per year 1968-2000	
		low	high	low	high
Direct Fuel Primary Energy	62.4	166.0(2.7x)	239.1(3.8)	3.1	4.3

These statistics represent the approximate increase in requirements for energy and energy resources as our population, urbanization, and technology increase.

A closer look at the oil producing companies supplying most of these energy needs makes these statistics more meaningful. Basically, there are two types of oil companies, the majors and the independents, along with oil companies that are a possession of diversified conglomerates.

Generally the majors are multibillion-dollar asset corporations. In addition, they tend to be engaged in all aspects of petroleum operations: exploration and production, transportation, refining, and distribution. Their operations cover off-shore and on-shore drilling on a world-wide scale. Chase Manhattan Bank listed a group of 27 major oil corporations whose operations accounted for approximately 70% of all the crude oil produced in the United States, and nearly 60% of the total output of the rest of the world in 1969 (6,7). Geographically, major oil company

petroleum supply areas include the Middle East (6.57 million barrels per day), United States (6.42 million brls/day), Venezuela (2.57 million brls/day), Africa (2.29 million brls/day), Canada (799,000 brls/day), the Far East (670,000 brls/day), and other foreign countries (464,000 brls/day) (7).

Of the total free world production of roughly 38 million barrels per day produced in 1969, approximately 40% or 15.2 million barrels per day were consumed by the United States. Of this 15.2 million barrels approximately 80% was produced domestically and 20% was imported.

With regard to international petroleum production two situations should be recognized. First, the United States has become the largest importer of oil in the world; second, current high industrial output areas of Japan, Canada, and Western Europe are also beginning to exert a very powerful competitive demand on the oil, which increases year after year (8). The significances of these two factors to America's energy consumption becomes even more apparent when considered with some rather recent actions taken in the domestic coal and oil industries.

Domestic coal mine expansion for speculative production has been reduced to near zero due to several factors among which are the threat of nuclear power plant competition, the Federal Mine Safety Act, and air pollution laws. Many air pollution laws require coal with less than .5% to .3% sulfur, whereas most coals mined in the eastern U. S. (where 72% of the

national output originates) contains 3 to 4% sulfur (6). As a result, many of the major electric utility power plants, traditionally the biggest users of coal, are being converted to burn residual or crude oil.

Increases in the petroleum taxation policy in many of the states and increases in operating expenses have caused major oil companies to experience the first decline in net income since 1958 (7,9). Further examination reveals that the rate of return on average invested capital in the United States declined to 11.0% --below 12.1% for the foreign sector of their operations (actually the rate of return in the United States has been below that achieved in the foreign area in all but two of the past 20 years). This is substantially below the average return of 11.7% reported for all manufacturing industry in the United States (7).

Certainly a valid reaction to these factors appears to be emerging both in the size and complexity of the operations involving the major oil companies. Mineral companies today are becoming primarily large materials producers, often operating internationally and sometimes even developing a multinational identity in their direction and concept. Consequently, they can be expected to invest where the rate of return is greatest (1).

As a summary description of the majors, they are integrated corporations of massive size financially as well as operationally; whose economic realm of envolvement embodies the full spectrum of big business, big politics, and big policy. Furthermore, they compete to fulfill a basic need of the consumers they serve, predominately by supplying fuel in enormous quantities.

The second type of oil operations involves the activities of thousands of independent oil companies. These companies do not conform to a specific pattern as the major oil companies appear to; however, they too have a realm of major concentration. As a general rule these companies operate in the North American Continent--mainly in the United States. With regard to economic size and operation, independents tend to be much smaller than majors with operations oriented almost exclusively toward exploration and production. While independents have produced a substantial amount of the oil used in the United States, perhaps their largest contribution has been in the exploratory phase of oil production. One source has estimated that approximately 85% of the exploratory wells completed in the United States were drilled by the independents (10).

The exploratory phase is easily the riskiest part of oil company operations. While statistics vary as to just how risky exploratory drilling is in the United States, one source lists a 20% chance of discovering 50,000-100,000 barrel equivalents (10), and another lists approximately a 2% chance of finding recoverable reserves of 1,000,000 or greater barrel equivalents (11). In 1969, the average depth per "wildcat" (one type of exploratory well) was 5,924 feet and the average price of crude at the wellhead was $3.09 per barrel (12). If these figures are considered with a $10.60 per foot drilling cost at this depth, $874 per well lease hold cost, and $.99 per barrel of oil lifting and administrative expense (10), on a 50,000 barrel pool the revenue after major expenses would be $154,500-$113,168 = $41,332. From this amount would be deducted severance tax, income tax,

royalty payment, interest payments, etc., as well as conceivably the losses on the four other unsuccessful wells (assuming a 20% success figure). Also at an average of 5 to 10% withdrawl per year (rough U.S. average), the gross revenue could be spread out over 10 to 20 years.

For these and many other economic reasons the independents have resorted to such arrangements as promotional speculation, in which a package operation is funded by speculators. In addition there are many variations of business ventures such as one type in which the driller trades percentage, say 25% of any strike, in exchange for the fund supplier absorbing a proportion of the expenses, say 33% if three fund suppliers are involved. Thus, the capital for the undertaking, called "risk capital," is likely to be generated by individuals other than the exploratory well driller/operator. One study of independent oil operators in Oklahoma conducted for the Oklahoma Congressional Delegation revealed that approximately 70% of the operator risk capital was obtained from outside investors--95% of whom were in the 50% or higher income tax bracket (10).

On the production side, much of independent operations concerns stripper well operation (average daily production of 10 barrels or less per well--unless operation or special legislation artificially restricts production to this level) (13). Operating at this capacity, the independent may find himself in an economically marginal or infeasible zone, from the point of view of the major producers.

One statistical presentation revealed that the magnitude of stripper well production in 1969 involved supplying 454 million barrels of crude oil from 358,000 wells (an average of 3.5 barrels per well per day) (13).

As a summary description of the independents, generalizations might be made that they tend to be much smaller than majors, operate in the North American Continent (primarily in the United States), and function primarily in the exploratory and production zones of the oil production sector.

The combined services of the majors and independents currently supply approximately 75% of the total energy requirements of the United States, which comprises approximately 56% of the total value of all American mineral production (12).

Considering the modes and areas of operation of the majors and independents, a rather interesting configuration seems to be inferred linking production with demand. The majors, by definition, supply petroleum products to their consumers in usable form via the refining and distribution functions they perform. These companies bring the crude oil from production sites to the refineries by pipelines, trucks, railcars, ocean tankers, or a blend of these transport vehicles. However, approximately 15% of American oil production comes from production sites of the independents in the 32 oil producing states, and roughly 85% of the total exploratory drilling is done by independents. Combining these figures implies that (assuming a successful well is equally likely for an independent as for a major) much of the

supply of American production results from the initial exploratory efforts of the independents.

The implication is that while almost all of the oil used in the United States has been processed by at least one of the majors, of the 80% produced domestically, 15% has come from independent production, and 85% of the burden for discovering the remaining domestic production has come from the exploratory efforts of the independents. Further, if it is recognized that oil in place has no more value than gold or uranium in place--which is zero in reality--then the contribution of the independent is not quite so overwhelmed by the activities of the majors.

Comparing relative risks between drilling productive (not necessarily profitable) wells in 1969, 82.5% of all wildcat wells (presumably largely an area of independent operation) were dry holes, and 23.6% of all development wells (presumably largely an area of major operation) were dry holes (12). The net result is that the burden of on-shore exploratory drilling in the United States seems to fall on the independent. This domestic production, in addition to its national implications, supplies a significant portion of the revenue of almost every oil producing state in the nation in severance and other taxes, as well as offers employment to over 250,000 people.

In summary, one knowledgeable observer indicated that perhaps one of the major reasons for the present energy crisis is that there exists a

communication gap between the oil industry and policy makers regulating this industry such that insufficient economic data exist to permit rational evaluation of policy proposals (14). Without such information, "no case can be made which will convince anybody who is not convinced already, because there is no other way to figure the cost of an important restricting program, let alone demonstrate that it is worth its cost ...the (statistical) gap will be keenly regretted by the industry in the years to come ..." (15).

In this regard Table 3 is presented as a composite of information recently collected by the American Petroleum Institute and the Independent Petroleum Association of America (11), to better illustrate the relative positions of the oil production sector of the industry and the states.

Table 3. Contribution of the Petroleum Industry, by State.

(1967 or 1968 Statistics)

State (A)	Crude (B) M. BRL	Gas (C) B.C.ft.	Value (D) $M	Ratio (E) %	Prod. Emp. (F) No.	Pet. Emp. (G) No.	Sev. Tax (H) $M	Prod. Tax (I) %	Pet. Tax (J) %	Amt. Pet. St. Tax (K) $M
Alabama	7.3	0.2	19.5	7.9	318	13,000	1.2	.4	21.0	100.0
Alaska	74.1	87.3	227.3	86.2	3,218	3,500	4.1	6.3	56	33.9
Arizona	2.4	1.1	7.3	1.6	152	--	0	0	--	--
Arkansas	21.1	116.5	74.7	43	2,219	12,000	2.1	.8	23	66.1
California	460.9	714.9	1104.7	65	22,022	128,000	798.8	4.6	17	798.8
Colorado	31.9	121.4	110.6	35	5,432	15,000	1.4	.4	16	54.5
Florida	1.6	.1	3.6	2.0	103	30,000	.2	1.9	18	194.0
Illinois	56.4	4.4	173.7	32	6,882	60,000	0	0	16	275.2
Indiana	10.1	.2	30.1	14	1,129	33,000	.3	.2	19	144.0
Kansas	94.5	835.6	400.7	80	9,988	26,000	.7	.2	15	55.2
Kentucky	15.5	89.2	66.4	14	2,662	15,600	.2	0	19	86.9

Table 3 (Continued)

State (A)	Crude (B) M. BRL	Gas (C) B.C.ft.	Value (D) $M	Ratio (E) %	Prod. Emp. (F) No.	Pet. Emp. (G) No.	Sev. Tax (H) $M	Prod. Tax (I) %	Pet. Tax (J) %	Amt. Pet. St. Tax (K) $M
Louisiana (tot)	817.4	6.4	3783.3	93	49,300	73,000	223.1	33.8	51	355.3
Maryland	.2	1.0	.2	.3	--	18,000	0	0	14	90.5
Michigan	13.7	33.6	47.8	9	1,164	38,000	1.0	.4	16	237.8
Mississippi	58.7	135.1	187.0	84	4,987	14,000	9.6	3.0	28	90.4
Missouri	0	0	.2	0	118	23,000	0	0	16	97.5
Montana	48.5	19.3	126.2	51	1,853	7,000	2.4	2.3	26	27.2
Nebraska	13.4	8.4	38.2	52	658	10,000	.7	.5	38	52.1
Nevada	.2	0	.5	.5	97	--	0	0	--	--
New Mexico	128.6	1164.2	534.7	65	7,573	13,600	11.6	5.3	28	60.8
New York	2.0	3.8	10.2	62.8	1,934	66,000	0	0	7	300
N. Dakota	25.0	41	72.9	80	1,396	5,400	3.4	3.4	19	19.3
Ohio	9.9	41.3	41.4	8.6	3,715	49,000	0	0	24	274

Table 3 (Continued)

State (A)	Crude (B) M. BRL	Gas (C) B.C.ft.	Value (D) $M	Ratio (E) %	Prod. Emp. (F) No.	Pet. Emp. (G) No.	Sev. Tax (H) $M	Prod. Tax (I) %	Pet. Tax (J) %	Amt. Pet. St. Tax (K) $M
Oklahoma	223.6	1390.9	865.7	93	37,534	59,000	44.8	10.2	29	126.6
Pennsylvania	4.4	90.0	45.0	4.8	2,942	62,000	0	0	16	287.5
S. Dakota	.2	0	.5	.8	10	4,500	0	0	23	18.8
Tennessee	0	.2	.1	--	37	15,300	0	0	24	122.4
Texas	1133.4	7495.4	4462.6	91	108,652	207,500	240.7	18.8	40	513.5
Utah	23.5	46.2	70.1	16.4	951	7,000	1.2	.7	16	29.7
Virginia	0	3.8	1.2	.3	22	19,600	0	0	19	123.5
W. Virginia	3.6	211.5	65.2	69.8	2,780	9,000	2.8	1.0	17	46.5
Wyoming	144.2	248.5	416.9	76	6,369	11,600	.1	.2	21	14.3

A. State
B. Production crude oil, annual, (million barrels)
C. Production Nat. gas, annual, (billion cubic ft.)
D. Value of total petroleum production annual, (million dollars)
E. Ratio; dollar value petroleum: value total mineral, (%)
F. No. employees in petroleum industry (production)
G. No. employees in petroleum industry (total)
H. State and local production severance tax (million dollars)
I. % state revenue consisting of total petroleum production tax
J. % state revenue consisting of total petroleum tax
K. Amount total petroleum state tax (million dollars)

SECTION III

HYSTERICAL, POLITICAL, AND LEGAL POLLUTION

Having taken a cursory look at energy, oil operations and policy, and the oil operators, the next phase of this presentation will attempt to relate the industry and energy policies with that of preserving the environment.

A commonly accepted general definition of water pollution is any change in water quality that has an adverse effect on a beneficial use. It becomes rather immediately obvious at this point that a great deal of controversy surrounds the term "beneficial use."

Typically pollution makes itself known in four forms: Real Pollution, Legal Pollution, Political Pollution, and Hysterical Pollution. This section will deal with the last three of these topics in reverse order.

Hysterical Pollution (or Emotionally Defined Pollution)

Hysterical pollution is by far the best known--especially in laymen circles. Returning to the three factors of energy, industry, and the environment, industry usually values itself and competitively draws on the supply of energy. But how is the aggregate quality of societal surroundings, or environment, valued? In America, the goal of environmental quality is not a specific valuation result. Rather, it occurs as a legislative response

to the emotional reaction of the public at large to the believed results of a particular conservation policy. On the individual level, the exact meaning of this environmental conservation policy is specifically determined in court and the value and occurrence of a violation is defined through arbitration under the supervision of jurispurdence.

As an example, the Torrey Canyon oil tanker grounded off the coast of England in March 1967, spilling approximately 30,000 tons (147,300 brls) of Kuwait crude oil into the ocean and ultimately onto the beaches of France and England. Using $3 per barrel as a value of oil, approximately $460,000 worth of oil was spilled which ultimately cost the British Government an estimated $70 million to clean up (16,17)--and ultimately cost the company involved $7 million in damage claims (18).

Of note in this instance is that the decision to clean up the beaches was made primarily for aesthetic instead of health reasons. The political decision makers acted to reduce or eliminate the visual effect of the oil on public property, which is indicated by the use, in the cleaning operation, of many chemicals that were more harmful to the environment than the oil they were cleaning up but were not as visually obvious (17). The value of preserving the appearance of the beach areas was at least $77 million (price of clean-up and damages). Here the implication is that a great deal of the true value of environmental quality is set rather subjectively due to the emotions of the public at large. Some of the emotions are sincerely and universely felt, but others are generated and interpreted

by spokesmen, public or private minded, who make judgements on the future implications of present actions and policy--or on the value judgements of others (19,20,21,22).

Oilfield brine pollution is yet another type of hysterical pollution. However, in this case there isn't the obvious visual pollutant that lends itself to public sentiment as dramatically as surface oil spills do, although the undesirable effects of brine on the beneficial users of the water it pollutes can be at least as bad as those caused by oil. Perhaps the major element of brine pollution arises from the fact that the brine mixes thoroughly with the water rather than floating on the surface of the water making, in effect, more salt water. And to make matters worse, oilfield brine frequently contains undesirable or toxic substances extracted from the oil with which it was originally produced. Individual states, along with the Federal Government, have recognized the potential danger of oilfield brine--induced pollution hazards to the health of living things, industrial food and materials processing operations, agricultural activities, and the preservation of fresh water supplies and other natural resources.

The problem of oilfield brine disposal reached a climax a few years prior to 1935 (23). Damage claims (against oil companies) resulting from oilfield brines were taking a heavy toll from oil operators. Also in this period many state legislatures initiated legislation against indiscriminate dumping of oilfield brines, which had been an accepted disposal practice

until then. Here again the cycle of policy change in response to the public's reaction to an existing condition resulted in legislation. Perhaps one of the most meaningful policy reactions occurred in the adoption of water quality standards by each state. More recently, the Federal Water Quality Act of 1956 (24) was enacted to set a uniform national policy for enhancing the quality and productivity of interstate waters. This act specified that water quality would be expressed in terms of allowable limits on specific chemical, biological, radiological, and thermal elements of natural waters. Thus a viable alternative was established to constant litigation of defining beneficial uses of water.

Political Pollution

The next step in defining pollution is one of interpreting the true public sentiment from the emotional reaction of the public, in perspective with existing policies and objectives. In this political (or legislatively defined) pollution phase, the elected representative of the people effects just such an interpretation. Through legislative processes he attempts to develop an understanding of a broad view of reality, not only considering the immediate issue involved but also the impact of policy decisions on the existing and future physical environment and the oil industry, as well as the life style of society in his state. Only then can a reasonable arrangement of priorities be developed to satisfactorily achieve the objectives of all parties involved.

Continuing with the Torrey Canyon example, the United States became acutely aware of the magnitude of the problem of coordinating efforts to clean up massive oil spills. Ultimately this experience resulted in new laws and contingency measures being passed to prevent recurrence of this type of disaster, and new safety and prevention devices and procedures being required of vessels transporting or handling oil, as well as on- and offshore drilling operations.

Certainly the process of bringing about uniform water quality is not an instantaneous event but rather a planned and controlled cooperative effort between industry, the state governments, and the Federal Government. At present the individual oil producing states regulate brine disposal activities within their borders--with the Federal Government acting in an advisary supervisory capacity.

Legal Pollution

With pollution, or more specifically brine pollution, having been defined emotionally and politically, the next step should be a discussion of the emerging legal definition of pollution. Each state regulates its own brine pollution program. By setting forth the political intent of the legislature in terms of actual standards and specification, the legal definition of brine pollution is achieved.

The information in Appendix A is the compiled result of correspondence with each of the 50 states, January to June 1971. Basically the information has

been divided into five areas on each state: state oil regulation agency; publication of regulations (most recent title and date); other state agencies assisting in oil production and brine disposal; published allowable disposal methods; and disposal permit costs.

By general definition oil field brine disposal is defined as descarding produced brine so as not to jeopardize:

1. Surface and ground fresh water quality (Appendix B).
2. Other mineral extracting operations.
3. Agricultural operations.
4. Recreational activities and other natural resources.

As a rule, the state agency charged with regulating oil and gas production operations is also responsible for regulating oilfield brine disposal activities and is often assisted by other agencies such as the state health department, water quality control department, etc. However, specifications for allowable disposal methods differ as do state enforcement policies. In addition, many of the states contacted indicated that their brine disposal laws were being revised or that enforcement policies existed which were not covered in the current regulations publication. Thus any but broad attempts to summarize state regulations could lead to invalid interpretations. Therefore, the alternative recommended is that prospective brine disposal operators obtain an up-to-date copy of their state regulations and address any specific questions to the agency responsible.

SECTION IV

REAL POLLUTION

Water quality standards have been set up in each of the states (see Appendix B) to protect and preserve all of the following beneficial uses of water (see Table 4).

Table 4. Beneficial Uses of Water (25)

1. Domestic water supply.
2. Industrial water supply (including cooling water).
3. Agricultural water supply (irrigation).
4. Stock and wildlife watering (including refuge for water fowl).
5. Propagation of fish and other aquatic and marine life.
6. Shellfish culture.
7. Swimming, bathing, and other water-contact sports.
8. Boating and aesthetic enjoyment.
9. Water power and navigation.
10. Transport, dispersion, and assimilation of wastes.

Having defined pollution previously as a change in water quality that has an adverse effect on a beneficial use, there are three other basic terms which should be recognized before discussing brine pollution: environment, concentration, and toxicity. These three terms are closely connected with identifying real pollution.

Environment, which is generally associated with surroundings or nature, may be thought of as the aggregate or total of all external conditions and influences that affect life. Concentration is a ratio of the amount (by weight) of a specific chemical or chemicals in a solution, divided by the

unit volume of the solution. Parts per million (ppm) is a very common concentration term that was developed using the weight of chemical in milligrams (1/1000 gram) per liter of solution. At approximately $4^{o}C$, 1 milliliter (1/1000 liter) of water weighs 1 gram. Further, water-based solutions are assumed to approximate pure water (on a gross, physical level the addition of soluble chemicals to water does not appreciably change the density of water). Therefore, one milligram of material in a liter of solution is a concentration of essentially 1 part per million (ppm) of that material.

Toxicity is an adverse reaction to a change of the environment of a living thing. Living organisms function in the presence of a great number of external influences; however, due to different tolerances for single or combined changes, life processes may be slowed, altered, or stopped depending on how well the species can adjust to the new environmental conditions that the change produces. The common terms used to express toxicity are: minimum lethal dose (MLD), which is the minimum concentration required to kill one or more of the laboratory tests species (usually in 96 hours); and tolerance limit median (TLM), which is the concentration required to kill 50% of the tested organisms (usually in 24 hours). The toxicity of a material or group of materials on a particular species is dependent on the nature of the materials, the time of exposure in the life cycle of the organism, the duration of exposure, and obviously, the presence or absence of other essential environmental factors while the organism is exposed to the toxic material. In reality, so difficult are the toxic

effects of a material to define that except for an extreme set of circumstances in which there is an immediate, measurable change in the life pattern of exposed organisms--whether they are people, chickens, trees, or microorganisms--it may be several years or several generations after the initial exposure before the toxic effects begin to be noticed (25). This fact is one of the reasons why the general subject of pollution is presently so emotional. It is more than a remote possibility that future effects of pollution--which occur now with no noticeable effects--may be very serious.

Categories of Water Pollution

Water pollution may be divided into eleven catagories: salinity, pH, temperature, dissolved oxygen, petroleum products, turbidity and color, settleable solids and floating materials, tainting substances, nutrients, nuisance organisms, and toxic substances (26).

Salinity

The degree of saltiness affects the ability of an organism to retain fluids in its body tissue. Large salinity changes upset this osmotic tissue balance and the ability to live. Some margin organisms, such as the oyster, thrive in regions of reduced salinity because they are better able to survive than their predators or disease-causing organisms. Changes in the degree of saltiness caused by damming rivers, draining marches, or opening cuts can have drastic effects on a water-borne organism merely by changing salinity.

pH

Many waters are buffered by their carbon dioxide content, and their pH does not change under ordinary conditions. However, externally caused changes in pH are disastrous to fish life because the level of pH can directly affect the toxicity of other materials.

Temperature

Some waters normally have wide variations in temperature. Larval forms of many water-borne organisms are particularly sensitive to temperature changes. The optimum temperatures for tropical species are often only a few degrees below the lathal temperatures. Furthermore, it must be remembered that fish are not mammals and have very little regulation of their body temperatures. They also derive their oxygen from the water. As temperature increases, the dissolved oxygen content of the water decreases.

Dissolved Oxygen

Fish extract the oxygen dissolved in water by breathing just as mammals extract oxygen from air. Thus, when the oxygen concentration in the water falls below a given level, the fish suffocate. Consequently, anything that causes the oxygen content of water to diminish is hazardous to fish. Because the degradation of organic material uses up oxygen, waters containing a large quantity of such material (e.g., sewage or paper mill wastes) will be

depleted in oxygen and will kill fish, drive them away, or adversely affect their reproduction. Often, tragically, the lowered oxygen content occurs because organisms were killed by a toxic material and the dissolved oxygen was consumed by bacteria in the degradation and putrefaction of the dead organisms.

If the oxygen content is sufficiently low, some bacteria can use the organic matter and the sulfate in the water to produce poisonious hydrogen sulfide gas. Some natural ocean basins, such as the center of the Black Sea, are completely devoid of marine life because of sulfide content.

Petroleum Products

Petroleum is categorized separately from other materials because of the magnitude of the problems that have occurred with its transportation and use. Since petroleum products are not very soluble in water, the oil spreads as a film on the water's surface and collects on beaches, rocks, and any organism projecting above the surface. Toxic and carcinogenic substances may be dissolved into water from some types of crude oils. This type of surface pollution is highly visible and aesthetically unpleasant, in addition to preventing the transfer of oxygen into the water.

Turbidity

Turbidity results from the occurrence of small particles in the water that interfere with the transmission of light. Silt from erosion is a principal

cause of turbidity, but sewage and some types of industrial effluents can also increase the concentration of suspended particles. Turbidity interferes with the photosynthetic activity of plants and with the ability of some fixed organisms, such as oysters, to exist. Dredging often has adverse effects because of a resulting increase in turbidity.

Settleable Solids and Floating Materials

Solid materials entering waters include: products of forest industries such as sawdust, bark chips, and wood fibers; municipal-sewage solids, and many floating industrial wastes such as plastics and polymers. Floating materials are unsightly and hence objectionable even if they do not harm water-borne organisms. Settleable materials coat the bottom and prevent the growth of bottom-living organisms. Areas around sewage outfalls, for example, are usually covered with sewage solids, and only a few species of organisms can be found.

Under unusual conditions, discharged materials can precipitate out some of the dissolved substances in the water (by altering the pH or by chemical reaction). Titanium paint pigments and kraft-pulpmill wastes fall into this category.

Tainting Substances

Tainting substances are those that, while not causing the death of an organism, render water unfit for its beneficial use. Even small amounts of

some chemicals (such as phenols) and petroleum products (such as aromatics) will render fish inedible because of the production of offensive odors or objectionable tastes in their flesh.

Pathogenic bacteria and viruses discharged with human wastes can be accumulated in an organism such as the oyster, which is not in itself harmed but, because of the accumulation, is made unfit for human consumption. This type of pollution is extremely widespread and, indeed, is one of the major types of marine pollution now encountered.

Nutrients

The availability of nutrient materials such as phosphates and nitrates often determines the rate of growth and total production of water-borne organisms, especially the primary plant producers. Many municipalities and some industries discharge waters rich in nutrients into the nearby rivers, lakes, or ocean. These nutrients often cause a rapid growth of undesirable organisms, scums and algal blooms, which crowd out the more desirable species.

Nuisance Organisms

Nuisance organisms are closely related to the concentration of nutrients. Such organisms include algae and others which make recreation areas unattractive, produce unpleasant odors, and produce deposits that plug intake and effluent pipes, foul boat bottoms and water structures, and interfere

with more beneficial organisms. The growth of any nuisance organism can be enhanced by changes in the environment that upset nature's delicate ecological balance. The results are often only obscurely related to the causes and are often unpredictable with our present knowledge.

Toxic Substances

Toxic substances are those that directly affect a living organism. The organism need not be killed, and the results may be noticeable only through a lessening of the ability to resist other causes of death or by a reduced ability to perform the normal functions required to sustain life.

Relatively few of the potential toxicants have been studied in detail, but known substances that are toxic at some concentration include many metals such as silver, arsenic, copper, chromium, mercury, and zinc as well as ammonia, cyanides, flourides, household detergents, and many other relatively common materials. Indeed, many naturally occurring substances are toxic if discharged in sufficiently large amounts into the fresh water as well as coastal marine environments (26).

Oilfield Brine Pollution

While oilfield brines have been known to encompass all the above-mentioned pollutional areas, some of these areas may be combined or eliminated. This presentation will concentrate on salinity and petroleum products.

Salinity exists as both a tainting substance and a toxic pollutant. While salts are generally defined as ionic products of neutralization between an acid and a base, they may also occur due to the following reactions: of acids on the oxides of certain metals; between acids and certain metals; and between bases and the oxides of many non-metals (27). Perhaps the most serious oilfield brine-caused problems are caused by salts having various proportions of the cations (sodium (Na^{+}), calcium (Ca^{++}), and magnesium (Mg^{++})) and the anions (chloride (Cl^{-}), bicarbonate ($HCO_3^{=}$) and sulfate ($SO_4^{=}$)) because these chemicals generally constitute overwhelmingly the highest portion of the total dissolved solids in the brine.

The distinction between total dissolved solids and its frequent misnomer, total solids, is of major significance. The total solids value is determined by evaporating a sample of water to dryness at 103-105^{o}C. The weight of the dried residue and volume of the original sample are combined and expressed as ppm (parts per million) total solids concentration. (The recommended total solids upper limit for a source of drinking water is 1,000 ppm (28)). This dried residue is composed of essentially four types of solids--floatable, settleable, suspended, and dissolved--each of which may be either organic (volatile) or inorganic (fixed) (29). Since settleable and floatable solids are generally removable by ordinary mechanical means (primary flotation or settling), they are not considered to be as large a problem as dissolved solids. Dissolved solids (materials which have gone into solution, not merely suspended) are not removable under ordinary mechanical water treatment means (determined by filtering the liquid through

high quality filter paper with a maximum pore size of 5 microns) (29). However, some suspended solids--particularly clays--may also prove troublesome.

Table 5 is a general classification of water based on the concentration of dissolved mineral solids in ppm (30).

Table 5. Water Classification.

Description	Dissolved Solids (ppm)
A. Fresh	Less than 1,000
B. Slightly saline; brackish	1,000 - 3,000
C. Moderately saline	3,000 - 10,000
D. Very saline; marine (upper value)	10,000 - 35,000
E. Brine	More than 35,000

This classification, while adequate for most water quality considerations, does not encompass the full salinity range of oilfield brines.

As a comparison with sea water, oilfield brines have been chemically analyzed to contain the elements listed in Table 6 (31).

Table 6. Brine Concentration Comparison.

Chemical	Sea Water ppm	Oil Field Brine ppm (max)	Concentration Ratio, In Oil Field Brine: Sea Water
Chlorine	18,980	270,000	14.2:1
Sodium	10,560	150,000	14.2:1
Calcium	400	120,000	300:1
Magnesium	1,560	25,000	19.7:1
Potassium	380	10,100	26.6:1
Sulfate (s)	2,560	8,000	3.4:1
Bromine	65	5,500	84.6:1

Table 6 (continued)

Chemical	Sea Water ppm	Oil Field Brine ppm (max)	Concentration Ratio, In Oil Field Brine: Sea Water
Strontium	8	4,500	562:1
Iodine	.05	1,500	30,000:1
Barium	.05	1,000	20,000:1
Lithium	.18	150	836:1
Rubidium	.2	7	85:1
Bicarbonate	-	1,220	-

Concentrations of disolved substances in the oceans at the same depth vary relatively little; however, oilfield brines vary considerably. An oil brine will contain several or all of the listed chemicals, and the concentrations may vary significantly from well to well--even in the same field--or from one analysis to the next from the same well durng its productive years.

Typically oil brines occur in two ways, as a connate water in the oil bearing stata or as ground water partially surrounding the oil bearing zone. Connate water is frequently under such a great pressure that it exists in a state of compression to the extent of about one part in 2,500 per 100 psi (pounds per square inch) change in pressure (32). When a new reservior is developed properly, the compressed connate water expands, providing a natural water drive to force oil upward in the reservior and up the production well (33). During initial oil production, very little brine accompanies the oil because the connate water brine expands to occupy the void spaces in the production zone left by the displaced oil. As production progresses, the natural water drive is replaced by pumps. Along with this gradual transition from natural water drive to pumping, the brine-to-oil ratio of the

produced fluid increases and more brine partially connate water and partially the surrounding ground water, is pumped from the well. At some point the expense of handling the fluid exceeds the value of the oil being produced, and the well becomes economically unfeasible to operate. The progressive change in type and amount of produced brine is thus a significant factor in the "production life" of a well.

Considerable research has been done on the effects some of these constituents have beneficial uses of water. One of the most notable compilations of such research is Water Quality Criteria (25) by the California State Water Quality Control Board. Much of the remainder of this discussion on oilfield brine salinity will be composed of a brief mention of the effects of individual brine chemicals, followed by a discussion of the effects of salinity, in general, as dissolved solids.

Polluting Effects of Individual Chemicals Found in Brines

Bicarbonates (HCO_3^-) as a general group are seldom considered detrimental to health (25). Even though they may combine with carbonate ($CO_3^=$) and hydroxide (OH^-) to form alkalinity, the overwhelming predominance of bicarbonate in chemical analyses of brines done by the U.S. Department of Mines on oilfield brines of Alabama and Mississippi (34), Arkansas and Louisana (35), California (36), Kansas (37), Oklahoma (38), and Texas (39) indicates that oilfield brines rarely exceed a pH of 9. Although the pH may be as low as 5, a California source lists a general pH range of 7.3 to 8.9 (36). The exact upper limits for bicarbonate concentration--relative to the effects

on beneficial uses--are hard to determine; however, generally accepted values are less than 150 ppm for drinking water and less than 100 to 200 ppm for industrial water supplies and fresh waters (25). The general range of bicarbonates in the brines listed in the Bureau of Mines analyses was from 0 to 2,000 ppm.

Bromine (B_2) has wide application in medicinal compounds, as a disinfectant, and as an anti-knock compound in gasolines for automotive use. However, doses with concentrations greater than 10 ppm have proven fatal to fresh water fish, and concentrations greater than 75 ppm have proven violently irritating to marine fish (25).

Calcium (Ca^{++}) contributes significantly to hardness in water. While calcium in drinking water may exceed 1800 ppm with no apparent undesirable effects, high calcium concentrations in water used in industrial processes can result in scale accumulations in boilers and pipes and other problems. In addition, calcium has multiple effects--both beneficial and toxic--in water because of its capacity for a wide range of reactions with various combinations of other chemicals normally present in natural waters (25).

Chlorides (CL^-) occur in almost all natural waters. For industrial uses, permissible chloride values vary from 20 to 250 ppm. Chlorides in concentrations above 96 ppm impart a salty taste to water, and an upper limit of 250 ppm is suggested for drinking water. A general summary of allowable chloride limits depends the planned water usage combination with other

chemicals, and duration of exposure (25). Table 7 give general chloride limits for some common water supply usages.

Table 7. Chloride Concentration Limits.

Use	Suggested Limit
Domestic water supply	250 ppm
Industrial water supply	50 ppm
Irrigation	100 ppm
Livestock	1,500 ppm
Freshwater fish	170 ppm
Wildlife	1,500 ppm

Chlorine (Cl_2) should not be confused with chloride, in that while chlorides exist in most natural waters as an ion or combined as a salt, chlorine is almost always a gaseous by-product of a chemical reaction, and rarely occurs in natural waters. Having a taste threshold of 5.2 ppm in distilled water, chlorine is used as a municipal water disinfectant due to its capacity to be toxic to pathogenic microorganisms at fairly low concentrations. Humans experience strong physiological reactions at chlorine concentrations above 90 ppm. Some industrial process waters may become highly objectionable at chlorine concentrations above 2 ppm (25).

Iodine (I_2) is normally found in only trace amounts in natural waters. Concentrations of iodine in excess of 28.5 ppm have proven toxic to some freshwater fish (25).

Magnesium (Mg^{++}) constitutes approximately 2.1% of the surface of the earth. Due to its high chemical activity, however magnesium is rarely found in its

elemental state in nature. In domestic water supplies, high magnesium contents can have a laxative effect on humans, and many sources suggest a maximum allowable limit for drinking water of about 125 ppm. Like calcium (Ca^{++}), magnesium is a significant cause of "hardness" in water, and therefore generally has a lower limit for industrial water users than for human consumption. Table 8 gives suggested allowable magnesium limits (subject to use, combined form, and exposure) for water supply usage (25).

Table 8. Magnesium Concentration Limits.

Use	Suggested Limit
Domestic water supply	125 ppm
Industrial water supply	20 ppm
Irrigation	24 ppm
Livestock	500 ppm
Freshwater fish	14 ppm
Wildlife	500 ppm

Sodium (Na^{+}), like magnesium, constitutes approximately 2.8% of the earth's crust and rarely exists in its elemental form in nature due to its high chemical activity. Although sodium may be tolerated to concentrations up to 200 ppm in drinking water, much lower values are usually recommended. Industrial users vary in their allowable limits for sodium. The major undesirable effects of sodium are found in agricultural applications where as little as 69 ppm of sodium can cause leaf burn and defoliation in plants. Similarly, relatively low amounts of sodium applied to soils in irrigation water can accumulate to a level sufficient to cause the deterioration of soil quality. In addition sodium has a tendency to become toxic when combined with other chemicals, even at reasonably low concentrations. Suggested limits are summarized in Table 9 (25).

Table 9. Sodium Concentration Limits.

Use	Suggested Limit
Domestic water supply	10 ppm
Industrial water supply	50 ppm
Irrigation	50 ppm
Livestock	2,000 ppm
Freshwater fish	85 ppm
Wildlife	2,000 ppm

Sulfates ($SO_4^{=}$) occur naturally in waters (particularly in the western United States) as leaching of minerals or as the final oxidized states of sulfur compounds. While sulfate concentrations have been found in drinking water in North Dakota as high as 600 ppm, much lower values are suggested for drinking waters due to the laxative effects of high concentrations. Suggested limits are rather conservative due to the variance in effects that sulfate intakes can have on different species and under different circumstances (25). Table 10 gives suggested sulfate concentration limits.

Table 10. Sulfate Concentration Limits.

Use	Suggested Limit
Domestic water supply	250 ppm
Industrial water supply	50 ppm
Irrigation	300 ppm
Livestock	500 ppm
Freshwater fish	100 ppm
Wildlife	500 ppm

Natural Salinity

Natural salinity is a term generally applied to waters containing relatively high dissolved solids composed of the above-mentioned chemicals. The effects of salinity are thus a combined effect of many environmental factors, as well as characteristics of the particular species and the exposure duration. Early accounts indicated the undesirable effects of different concentrations of salts on livestock; however, the types of salinity and presence or absence of other environmental factors were not mentioned (39).

In 1929, a Bureau of Mines publication noted not only the effect of oilfield brines on fish and livestock but also described the effect of different salts at different concentrations on farm animals in the United States. It also mentioned that unless the salt water actually contained toxic material (such as barium salts), saline waters would have relatively little effect on livestock which also had access to a source of relatively good water. This is mainly due to the objectionable taste of salt waters, which becomes even more objectionable as the salt concentration increases. Thus, when an alternate sources of water with an acceptable level of salinity is available, the objectionable taste will normally drive farm animals from the saline water to the good water source before they drink enough amounts of salt water to experience toxic effects (40).

A later report related the results of controlled experiments on the effects of varied exposures, amounts, and types of salt waters on farm animals

having no other source of water (41). As to be expected, the report noted that different concentrations of different salts had varying effects on the farm animals tested. Generally the animals went without water for as long as possible before drinking the salt water (concentrations ranged from 10,000 to 20,000 ppm). After a period of time, depending on the temperature, they began drinking small amounts regularly and adjusted their bodily activities, including feeding, to a minimum. This was accompanied by a substantial loss of weight. After a period of adjustment--which could be several weeks--the animal either was able to live with the changes or it died. When the salt water was replaced with water having a total solids concentration of less than 1,000 ppm (fresh water), almost all the animals tested resumed their normal size and life patterns. A later publication listed livestock tolerance limits for brines composed of anions of chloride (CL^-), sulfate ($SO_4^=$), and bicarbonate (HCO_3^-), and cations of sodium (Na^+), calcium (Ca^{++}), and magnesium (Mg^{++}) (25). These are given in Table 11.

Table 11. Saline Water Tolerance.

Animal	Concentration
Poultry	2,860 ppm
Pigs	4,290 ppm
Horses	6,435 ppm
Cattle, dairy	7,150 ppm
Cattle, beef	10,000 ppm
Adult sheep	12,900 ppm

Similar experiments have been performed on agricultural crops. In this area the same chemicals constitute the major portion of analytical examination;

however, sodium and potassium concentrations expressed as exchangeable percentages, along with moisture content and pH, assume predominant roles as in indicators of the quality of saline soils. One publication, Diagnosis and Improvement of Saline and Alkaline Soil, explains the treatment and uses saline and alkali soils extensively. Further, the book demonstrates that lands may be successfully irrigated using waters with relatively high dissolved solids concentrations if proper leaching procedures are followed (42).

It is estimated that over 98% of the drinking water distributed through community water systems in the United States contains much less than 500 ppm dissolved solids. However, approximately 420 communities with populations greater than 1,000 have drinking water supplies with dissolved solids concentrations greater than 1,000 ppm (43). The water supply sources considered suitable for use as domestic drinking water generally contain dissolved solids in concentrations ranging from 500 ppm to 5,000 ppm. Of note is that as long as water doesn't contain excessive amounts of particularly undesirable chemicals or chemical combinations, relatively high amounts of dissolved solids may be tolerated in a source to be used for drinking water.

Polluting Effects of Materials Accompanying Oilfield Brines

A second major aspect of brine pollution is caused by the oil, dissolved gases, and other residual materials which may accompany the oilfield brine after it has been processed by the separater and poorly disposed of in a receiving body of water, or which may litter a production or disposal site if good housekeeping procedures are not followed. Under poor housekeeping

conditions, grazing animals may be attracted to small oil spills seeking salt in the brine accompanying the spilled oil. In the process of licking the oil and salt brine mixture, or grazing on grasses covered by the spilled fluid, the grazing animal may ingest a toxic amount of oil constituents. These spills are most likely to occur during well work-over, or at older oilfields where central pumping stations are maintained. Likely sites for problems with grazing animals exist where production, disposal, or trash gathering areas are unfenced and/or littered (44).

Polluting Effects of Oil

Oil which is somehow spilled onto fresh or marine water either lies on the surface of the water as a film or mixes with the water to form an emulsion. In either case this oil may interfere with the transfer of oxygen from the atmosphere into the water (essential for fish life), may coat the bodies of water birds and fish, may impart an objectionable taste to fish, may exert a direct toxic action on some organisms, or may interfere with the fish-food organisms in the natural food cycle. In addition, the oil may become adsorbed onto clay particles and settle to the bottom of the water where it can remain as a continuing source of pollution. Further, the adsorbed oil may be stirred up and refloated, or may leach the toxic elements into the water (25).

A common unit of measurement that indicates the amount of dissolved oxygen which will be used by a particular water-borne waste material is BOD_5

(Biochemical Oxygen Demand). Materials that originated from living things (termed organics) are either part of a living or dead organism. If the organism is alive, it continually synthesized food for energy and growth. However, the dead organism, or parts or discards from living organisms, begin a process of decay as soon as they cease to function as living organisms. This process may be visualized as a type of combustion that changes the form of the material and ultimately results in an inorganic ash, much the same as a burning match is changed to wood ash. And just as a match requires oxygen to support the flame, the microorganisms involved in the decaying process also require oxygen and therefore compete with fish who must breathe dissolved oxygen in the water to sustain life. Chemical oxidation adds another oxygen-consuming reaction to the water environment, depleting the dissolved oxygen reserve.

An oilfield brine containing even small amounts of oil can have a relatively high BOD_5. This means that, assuming a BOD_5 of 500 ppm for the brine (a reasonable figure), one million pounds (roughly 3,000 barrels) of brine would consume 500 pounds of dissolved oxygen in a stream or lake. Since many fresh waters have dissolved oxygen content of 8 ppm (saturated) or lower, the 3,000 barrels of brine with a BOD_5 of 500 ppm would require all the dissolved oxygen in approximately 62 million pounds of fresh water. However, water with no dissolved oxygen will contain no fish because fish require from 1-2 ppm (trash fish) to 8 ppm (trout). Thus, an oilfield brine containing both oil and organic material may ruin more than 62 times its volume of fresh water as far as the fresh water's ability to sustain a

balanced aquatic environment. Brine is also capable of destroying the oxygen balance in sea water, although not in the same ratios as in fresh water.

Some testing has been performed with oils to determine general toxicity levels. These levels of course vary according to conditions surrounding the exposure and the species involved, but generally it has been found that of the usual oil constituents aromatics are the most toxic, naphthenes and olefins are intermediate in toxicity, and straight paraffins are the least toxic. Within the above general groups, the low-boiling aromatics are the most toxic, as are generally the smaller molecular constituents (45).

It is difficult to gauge the magnitude of the pollutional significance of the oil accompanying the brine into a receiving body of water. While it is a fact that some portions of the crude oil as well as dissolved gas disposed of with the brine (literature reports oilfield waste waters contain as much as .1% to .33% oil by volume (45)) could conceivably be pollutants, it is suspected that the gaseous and aromatic fractions of the brine evaporate before they accumulate to toxic levels in receiving bodies of water. However, should the oil be present in the waste-water brine to such an extent that it leaves a visible slick, or accumulates in the water to as low a level as 3 to 5 ppm, it is very possible that toxic effects may be observed in freshwater fish, which seem to be especially susceptible to toxicity from oil constituents (46). In 1963, petroleum operations accounted for

nearly 44% of the fish killed by pollution from industrial operations, and 14% of the total reported pollution-caused fish killed (47).

Regrettably, the tremendous complexity of the environment, along with the present limited amount of information on the biological effects of environmental stresses, prevent the development of specific, universal anti-pollution criteria. As an initial procedure however, an oil operator should be aware that there is considerable evidence supporting the public's image of the oil man as a significant polluter of surface as well as underground water, in addition to thousands of acres of potentially valuable farm land. He should also realize that this public reaction has caused legislators to react in favor of strict anti-pollution laws which carry heavy fines. Each state now has defined water quality criteria as well as prescribed allowable disposal methods.

It should then be recognized that in describing the current energy situation in the United States some rather direct implications have been made for the need of a social cost mechanism. However the remainder of this dissertation is devoted to the problem of developing individual disposal costs; nor has any attempt been made to construct a socially optimum solution.

SECTION V

CONSIDERATIONS IN THE SELECTION OF BRINE DISPOSAL SYSTEMS

Introduction

The preceeding section discussed oilfield brine pollution by first introducing the beneficial uses of water and then describing the materials (constituents) normally found in oilfield brines. If these materials, chemical as well as physical, are present in amounts exceeding levels that potential users of the water (industrial, agricultural, or municipal) can tolerate, then the brine must be disposed of.

The last section of this report deals rather generally with byproduct recovery, which can offer additional profit under certain conditions. However, the small operator is almost always right in considering the salty brine produced along with oil as a necessary evil in oil production, not as an additional source of profit. Certainly the possibility exists that laboratory tests may reveal the presence of valuable materials in the brine (which technology may have or will soon develop a means of profitably extracting), but the overwhelming majority of oil well operators are unlikely to reap any of those benefits due to relatively high economic development costs.

A natural alternative to disposal would seem to be discharging the brine

into a stream with a sufficiently high flow to dilute the salt concentration; this alternative is illegal and unwise for at least two reasons. First, salts (especially chlorides) accumulate in a stream such that each salt water discharge into fresh water causes progressively higher levels of salt to exist in the stream, which can be extremely undesirable to downstream users who depend on the stream for drinking water. (Dissolved salts are among the most difficult and expensive materials to remove from water, and very few towns or cities are equipped to perform this level of treatment on their drinking water.) Second, streams in the United States do not flow at the same velocity and volume throughout the year. In fact, so wide is the variation in volume flow rates of some streams from month to month that spring and early summer flows may be primarily runoff while late summer flows may be only discharges from industrial and sewage treatment plants located along those streams. Thus, these streams cannot be relied on to adequately disperse the constituents of the discharges brine to a safe level.

The remainder of this report is oriented to explaining the existing disposal alternatives, as well as explaining brine-water treatment as a process which does not produce drinking water from oilfield brine but instead produces a brine which may be more efficiently disposed of by a particular disposal method.

Of primary concern in brine disposal is the protection of surface and subsurface fresh water. It is entirely possible for a relatively small amount

of a very salty brine to mix with a much larger amount of fresh water and render it unfit for consumption. One reference cites the possibility that 1 barrel of brine could cause 400 barrels of fresh water to be above the Public Health Service drinking water standards allowable limit for chlorides (48).

Generally there are three basic considerations that must be met prior to selecting an appropriate method of brine disposal: legal, physical, and economic. A fourth area, future legislation, should also be considered.

Legal specifications for disposing of oilfield brines have been set by oil regulating agencies in each of the states. In almost all states a prospective operator must apply for a disposal permit (at small or no cost) prior to the beginning of actual brine disposal operations. The application form generally allows the regulating agencies to investigate the suitability and legality of the proposed method of disposal, as well as its size and location. Not only does this assure a seasonable margin of safety in the protection of fresh water and other natural resources, but it permits the state to maintain up-to-date records on disposal operations to assure a reasonable balance in its resource utilization policies.

These state records are available to operators and can be especially valuable to small independent in judging the suitability of a proposed disposal site because they contain extensive information on the location, size, and type of geologic formation in which the well is located. It should be remembered

however that the responsibility for legally developing, operating, and abandoning a disposal or a production operation rests with the individual operator.

Physical Considerations

The physical suitability of the legal disposal alternatives available to the operator must be considered in relation to his particular site. Not only does this involve establishing and maintaining the appropriate disposal mechanism, but it may also involve water treatment and corrosion protection.

Economic Considerations

Once the operator strikes oil, he is forced to make decisions that will determine the economic success or failure of his current and future oil production-brine disposal operations. Basically, these decisions are based on analytical judgments relating value, capacity, and time made in a high-risk environment.

From a brine disposal point of consideration (which should be involved in the initial reservior development decision), the prospective disposal operator must adopt a plan which will effectively deal with an initial high rate of oil production, gradually decreasing, and an initial low rate of brine production, gradually increasing. Conceivably, this decision may involve a

multimillion dollar combined operation lasting in excess of 30 years.

Future Legislation

The processes of pollution abatement involve almost continual updating in legislation to keep pace with the changes in petroleum production technology as well as to improve the existing legal means of disposal. Many of the methods of pollution protection (or brine disposal) which at one time were legal have more recently been updated or outlawed to reflect these changes, and this trend should continue. Thus the existing and prospective oil operators would do well not only to keep informed of these changes but also to consider the intent of the law along with the letter of the law in his brine disposal operations. The real possibility continually exists that new legislation will be passed to alter or eliminate those practices that allow a significant pollution threat. (As an example, refer to the date of publication on most state regulations given in Appendix A.) A special effort has been made to point out these possibilities in the following discussion of disposal methods.

SECTION VI

BRINE DISPOSAL METHODS

Brine disposal methods exhibit wide variations in operation under actual field conditions. No general discussion can possibly deal with all the causes and effects of these variations individually. Therefore, the main features of each disposal method will be presented and appropriate references given. Figure 3 shows a typical production-disposal system layout, and Figure 4 is a block diagram of that layout.

Basic Information Required Prior to Selection of Disposal Method

Prior to the selection of an appropriate brine disposal system, the oil operator would be well advised to:

1. Obtain information on allowable disposal methods from the state oil regulation agency (see Appendix A).

2. Obtain a copy of the state's water quality standards (see Appendix B), a copy of any available chemical analyses of fresh and ground water in the general vicinity of the prospective production and disposal system the addresses of reputable water testing laboratories. This information will not only indicate water quality levels which must be compiled with but also will provide background information which could be valuable in event of a pollution claim (49).

3. Obtain a chemical analysis of the brine Chlorides (CL^-), Sodium (Na^+), Magnesium (Mg^{++}), Calcium (Ca^{++}), Sulfate ($SO_4^=$), Carbonate ($CO_3^=$), Bicarbonate (HCO_3^-), Barium (Ba^+), Strontium (Sr^+), Hydrogen Sulfide (H_2S), and suspended solids (ppm) (see Appendix C). These tests will help in the evaluation of disposal mechanism and in the anticipation of water treatment and corrosion problems. If the

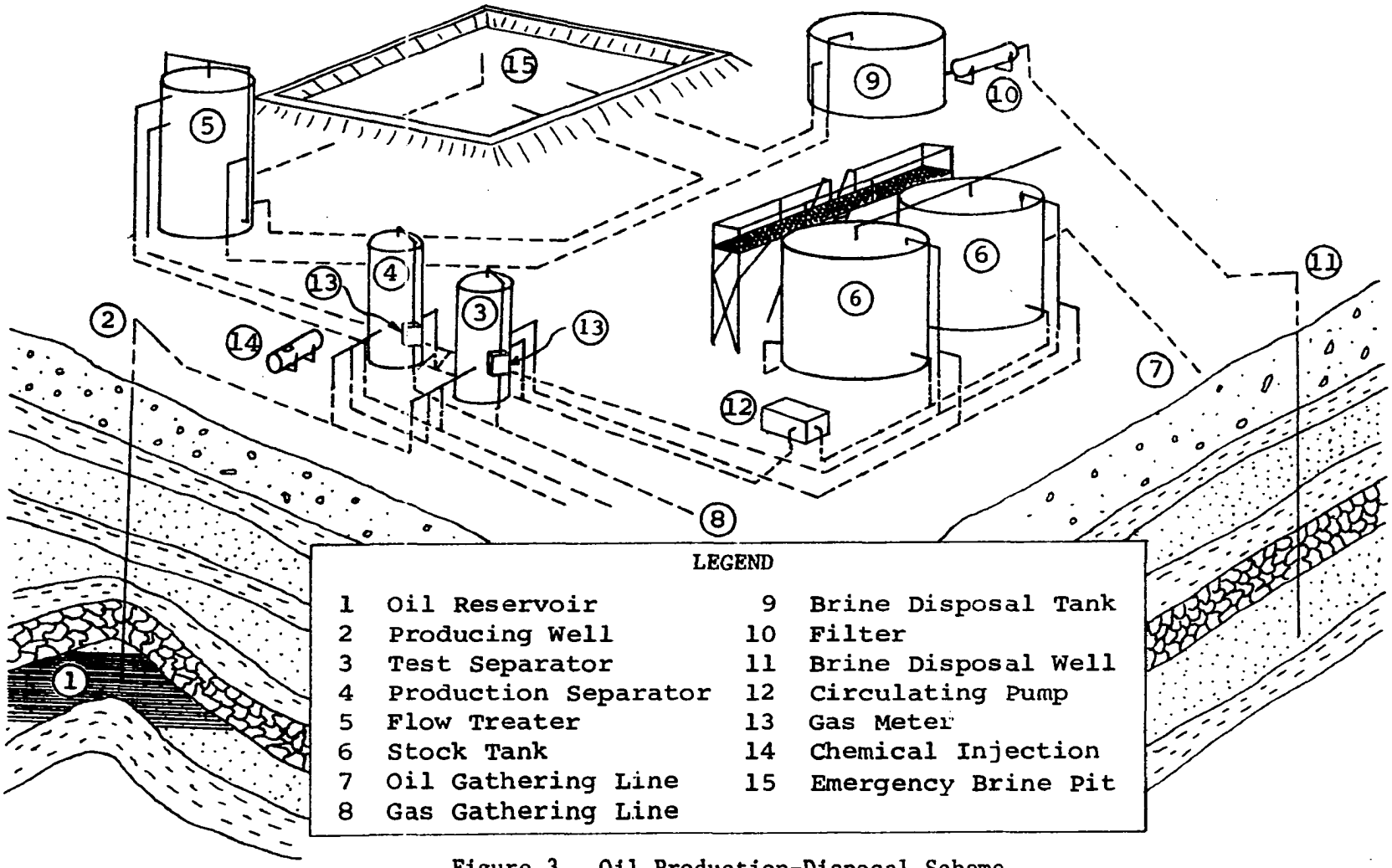


Figure 3. Oil Production-Disposal Scheme.

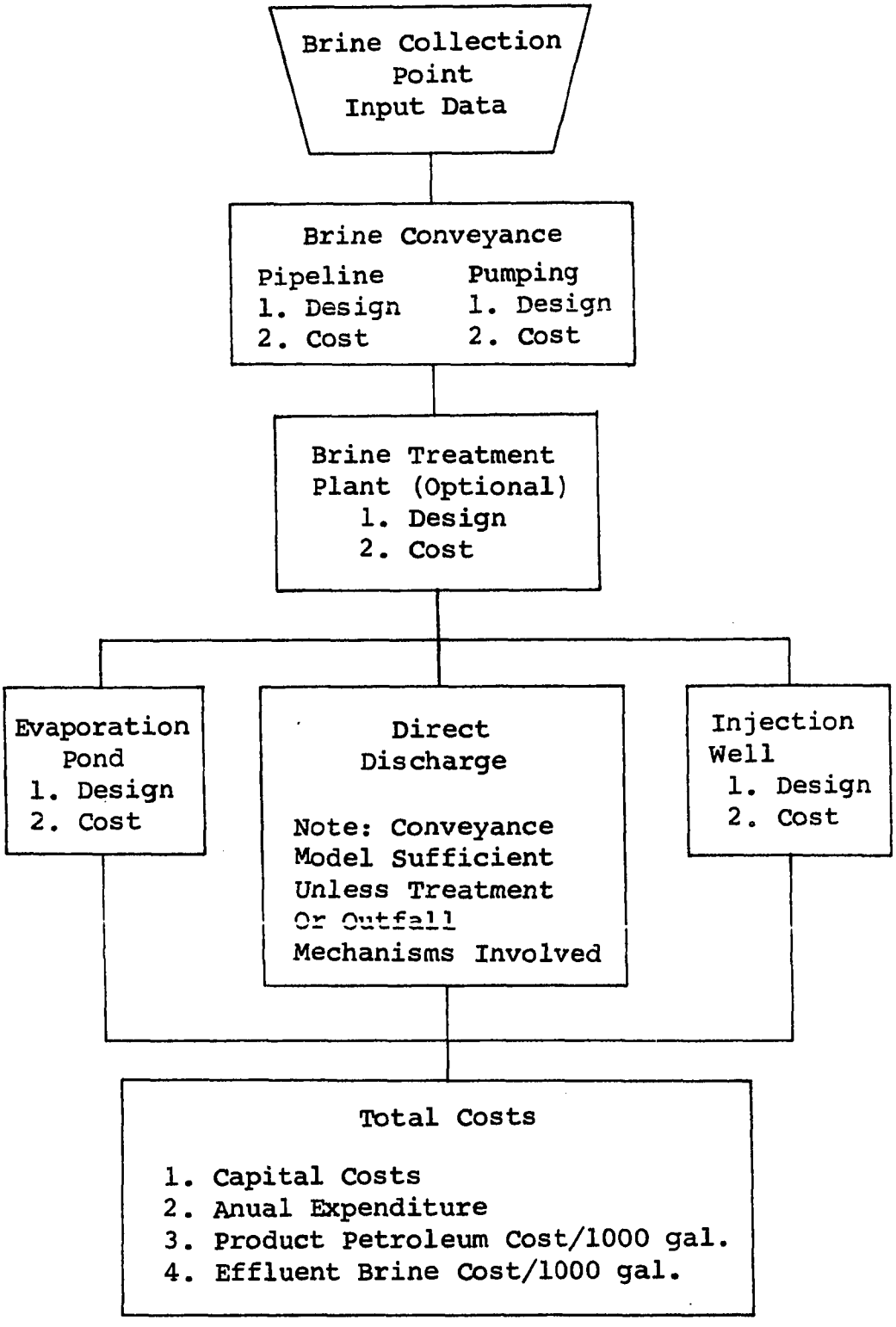


Figure 4. Disposal System Diagram.

> brine is to be injected, it should be tested with a sample of the water and material in the proposed disposal reservoir for chemical compatability.

These initial steps will prove extremely valuable in avoiding a large initial dolar outlay for an illegal, unsuitable, or unnecessarily difficult and expensive disposal mechanism.

Cementing-Completion and Plugging

Ultimately, the abandonment operation is the terminal phase in all drilling operations, whether drilling was successful or not. Proper completion and abandonment practices are perhaps the simplest of all disposal methods but can be the most polluting if improperly done. Almost all agencies contacted on brine pollution problems in their particular states indicated that the primary cause of their pollution problems was probably seepage from old, abandoned oil and gas wells. And small wonder! The Independent Petroleum Association of America reported that between 1859 and 1970 approximately 2.2 million wells have been drilled in the United States in search of petroleum. Of that number, roughly 0.6 million were still in operation in 1970 (12). This means that there has already been over 1.5 million abandonments in the United States.

During the early years of the petroleum production industry it was considered acceptable practice to stuff rags, logs, and other materials down an abandoned well as plugging. This practice was outlawed because it

permitted fluid migration up the annulus into other oil zones or freshwater zones. More recent practices required the operator to cement outer drilling casing from the surface through the freshwater zone (which generally extends to a 400-foot depth, but depths of 1400 feet are not uncommon in some areas) as well as any impervious strata immediately beneath the lowest freshwater zone. Current practice in most oil producing states requires cementing off of all producing zones in addition to the cement plug protection of fresh water. Thus, if corrosion does occur in the well casing or if the brine seeps into the abandoned well, the cement plug prevents brine seepage into other strata and protects against what is known as cross pollution. A further reason for proper abandonment procedures is that secondary recovery practices are becoming more widely adopted. In this regard it is to the financial advantage of the land owner as well as the oil operator that proper abandonment plugging is followed to prevent pressure leaks in plugged wells from destroying the secondary recovery potential of an oil or gas reservoir.

If the cement job in a completion is faulty, there may be a route of seepage for the brine around the plug. Therefore, good cementing techniques must be used, including the use of wall scratchers and centralizers, to ensure that the well bore is reasonably clean and that the casing is not laying against the side of the hole. The hole should be circulated (at a high rate) prior to cementing to ensure that channeling through the mud is not occurring. It is also necessary to displace the cement around the annulus at a reasonably high rate to prevent channeling.

In summary, for completion and abandonment operations to prevent seepage;

1. Use good cementing techniques.
2. Plug properly.
3. Consult state regulations to determine amount and extent of cementing.

Gathering System

A salt-water gathering system begins at the tank battery and ends in collection tanks or at the disposal site. Generally, the gathering system includes all flowlines and equipment connecting these two points. Three types of gathering systems are possible: a gravity gathering system, a pressure gathering system, or a combination of the first two. A gravity gathering system uses no pumps and depends on gravity to supply energy to the fluid. This means that flowlines must be laid out so as to conform to the natural drainage patterns of the land. On the other hand, a pressure system does not require as extensive a topographical survey because pumps supply the main driving force. Probably the most logical design would be a combination of the two systems to take advantage of the natural drainage as well as to reduce the number of flowline networks required in areas with undesirable drainage topography.

The gathering system should be designed and equipped not only to withstand the corrosive characteristics of brine but also to alleviate potential scaling problems which, along with oil, are more likely to accumulate in the high points. Where arches are unavoidable, vents should be used.

These can be constructed from a tee in the line with a riser above the hydraulic gradient (50). Figure 5 shows a disposal system layout.

In some sections of the gathering system it may be impractical to consider gravity flow, so pumps are necessary to move the fluid. Topography should still be considered, however, since each 100-foot increase in elevation requires approximately 50 psi additional pressure on the pumps and lines.

Size of Lines

Pipe sizing is based on maximum expected flow rates, available head, and head loss due to friction. Future brine production must be carefully estimated since an increase in line capacity is difficult to obtain. Line size is usually determined from the Hazen-Williams formula (see injection design analysis section) with a pipe-roughness coefficient of 100 because oilfield experience has indicated that 100 is a reasonable value for the type of pipelines used in salt water operations. The "C" values for new pipe may range from 120 to 150; however, since scale will accumulate to some extent and the maximum fluid flow rate will probably occur in the future, the lower value is usually used.

Materials

The type of pipe used in a salt-water gathering system depends on the operating pressure and temperature, the corrosiveness of the water, the life

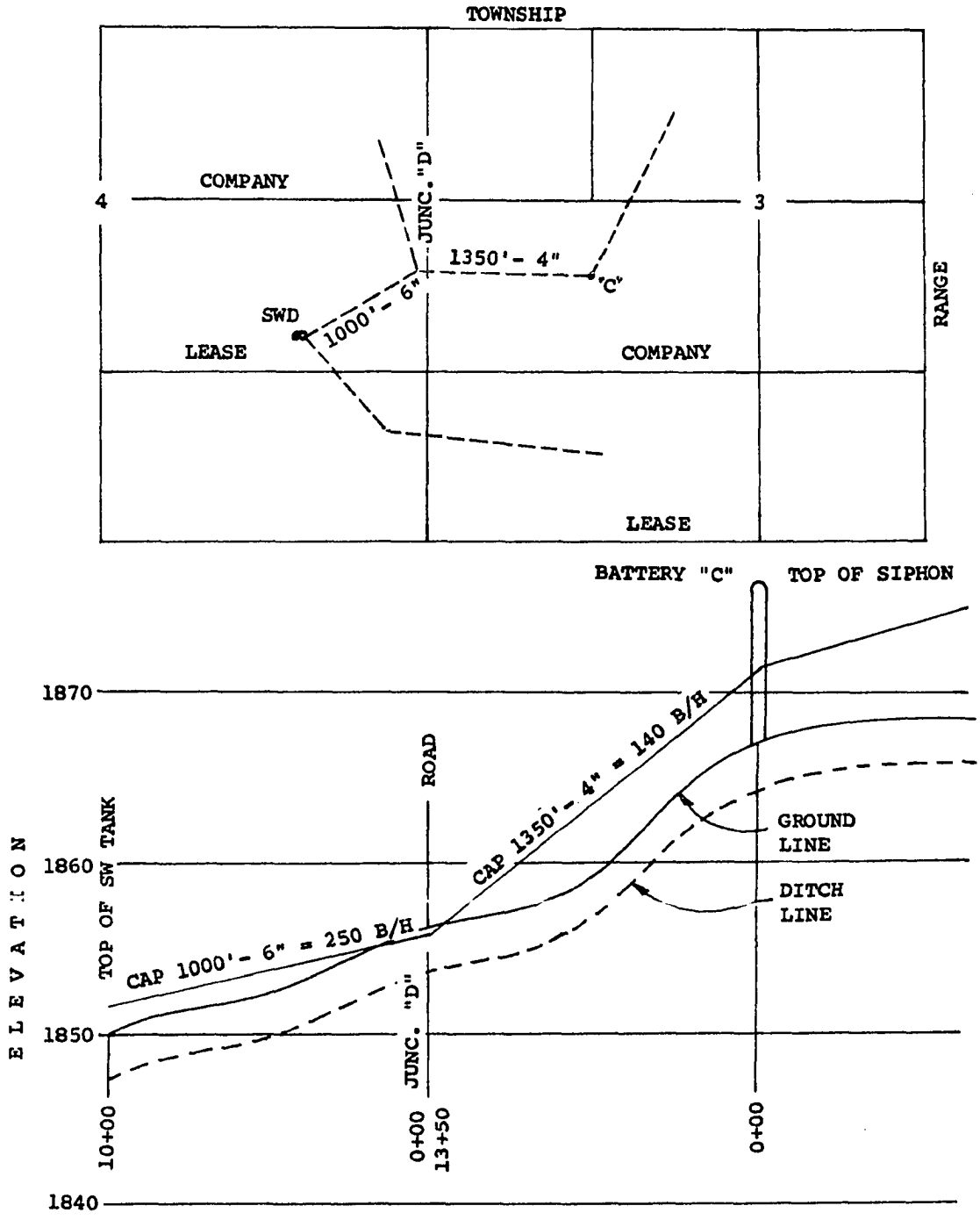


Figure 5. Plan and Profile of Disposal System Layout(51).

of the system, and the relative costs involved. In most systems corrosion is the predominant criteria. Table 12 shows the type of pipe used in salt-water gathering systems with their conditions of service. In installations where plastic pipe is applicable, savings in time and labor are possible. An example is a 12-mile installation of 3- and 4-inch polypropylene pipeline in the Person-Panna Maria field in Texas (52). The line was part of a salt-water disposal system and was completed in 11 days by a three-man crew. A heat-fusion process was used to weld the joints in less than 1-1/2 minutes each.

Table 12. Published Data on Pipe Generally Used in Salt-Water Gathering System Service (53).

Type of Pipe	Nominal Size, Inches	Working Pressure, Psi Rated at 80°F.	Working Pressure, Psi Rated at 150°F.	Applicable Service
Steel				
Schedule 40 Grade A	2-12 incl.	1,900-910	1,900-910	Noncorrosive
Continous-weld and lap-weld	2-12 incl.	750-490	750-490	Noncorrosive
Cement-lined	2-12 incl.	750-490	750-490	Corrosive
Plastic-lined	2-12 incl.	750-490	750-490	Corrosive
Asbestos Cement				
Class 100	3-12 incl.	100	100	Corrosive
Class 150	3-12 incl.	150	150	Corrosive
Class 200	3-12 incl.	200	200	Corrosive
150-ft. head	3- 8 incl.	65	65	Corrosive
Plastic				
Butyrate . . .	2	102	20	Corrosive
	3	73	11	Corrosive
	4	70	11	Corrosive
Vinyl	2	133	44	Corrosive
	3	103	32	Corrosive
	4	98	29	Corrosive

Table 12 (continued)

Type of Pipe	Nominal Size, Inches	Working Pressure, Psi Rated at 80°F.	Working Pressure, Psi Rated at 150°F.	Applicable Service
	2	500-1,000	360-775	Corrosive
Fiber-reinforced	3	350-1,000	270-775	Corrosive
epoxy	4	200- 500	150-360	Corrosive

The East Texas Salt Water Disposal Company has had experience in the use of several different types of pipe, including asbestos-cement-lined, cast iron, and plastic (53). The cast iron pipe was lined with a special Portland Cement mix and seal-coated with coal tar. Abestos-cement was used almost exclusively, but cast iron was preferred for lines exceeding 200 psi. The asbestos-cement pipe was resistant to brine corrosion but was rather fragil and required considerable care when installing. The cement-lined pipe had the disadvantages of large variances in the internal diameter and the possibility of damaging the lining, particularly while coupling the joints.

Scrapers

Sludge and scale build-up on the internal surfaces of the pipe line must be removed at regular intervals. The most common method is to flow a "scraper" or "pig" through the line, introducing and removing it at scraper traps. The scraper types vary, but the most common are the steel-ball, chained rubber ball, cementing plug with trailing wire-brush, go-devil with lead-end knives and cutter wheels, and the spiralbrush. The scraper traps consist of an arrangement of valves and fittings designed to facilitate

inserting and removing the scrapers. Quick couplings are normally used in traps. The traps are placed at strategic locations, such as the connection to a tank battery or a point of line size change. Care must be taken to prevent spilling brine when opening a trap.

In some cases scale builds up in the line to the point where conventional scrapers will not remove it. It then becomes necessary to acidize the line, or dismantle it and mechanically remove the scale. Acid has a disadvantage in that it attacks steel, cement-lined, and asbestos-cement pipe.

Pumps (53)

Centrifugal pumps are used extensively on salt-water gathering systems. They are ideally suited for this service because they can handle large volumes of fluid at the lower pressures usually associated with gathering systems, they are easily adaptable to electric motors, they are easily maintained, and they can operate under a shut-in head if necessary. Experience obtained in the East Texas oilfield has indicated that attention to suction conditions is one of the most critical considerations of design. Inadequate filling of the suction can seriously erode or cause cavitation of an impeller in a matter of days. Flooded suctions have been found to pay for the increased costs of installation by savings in maintenance cost. The suction line should be a straight run and as short as possible, with the line size at least twice that of the pump suction inlet.

Corrosion resistant pump parts are also a critical consideration in brine

service. The metallic materials used in pump construction should be close together in the electromotive series; otherwise corrosion will take place by galvanic action. Two examples of the metal combinations used in a centrifugal pumps for brine service are: all-bronze pumps with monel shafts and packing sleeves; and cast-iron cases with aluminum bronze impellers. Brand name alloys, such as Ampcoloy and Worthite, have also given excellent service.

Direct Discharge

Basically, direct discharge is a surface disposal mechanism in which the quality of the oilfield brine does not differ appreciably from the standards set for the receiving water, and thus the brine can legally be discharged directly into the receiving water with little or no treatment. Examples of brine meeting receiving water standards can be found in Wyoming and Southern California where the brine is used for irrigation and livestock watering (although it is very unusual for brine to approach quality levels permitting this type of beneficial use) and in ocean environments here low brine toxicity and high ocean circulation combine. Obviously, this disposal mechanism is open to relatively few on-shore oil well operators.

At present, considerable controversy surrounds ocean discharge of brine from on-shore as well as off-shore oil production operations. With desalination facilities being considered for many ocean-bordering cities,

studies have been made to investigate the impact of the concentrated brine from these processes on the environment adjacent to on-shore desalination plants. Results indicated that brine discharges in shore areas could significantly damage the marine environment in those areas if circulation patterns at the discharge site were too low to permit rapid dilution, if high concentrations of toxic or undesirable materials were present in the discharged brine, or if fish and shell fish used the waters at or near the discharge site for breeding or feeding purposes. And the probability of damage increased if bays or estuaries were the receiving waters.

Bays, estuaries, and relatively shallow continental shelf regions are the major habitats of shrimp and shell fish--sources of a multimillion dollar industry in Texas and Louisiana--as well as spawning grounds for important food fish in California (54). The major problems encountered in using bays and relatively shallow, sheltered, coastal areas for brine direct discharge are that circulation patterns in these types of marine environments are restricted. Rather than the rapid dispersal of pollutants expected in the deeper ocean, discharges into coastal marine environments may disperse relatively slowly. In some cases, dispersal patterns, rather than diluting the discharged waste material and sweeping it out to sea, channel the discharge stream adjacent to the coast line for a considerable distance (55). Thus undesirable constituents from brine discharges could conceivably inflict damage at the discharge area and to beaches and fish habitats along the coastline below the outfall.

Typically, oilfield brines contain much greater concentrations of individual constituents than does sea water; chlorides alone may be twice as concentrated in an oilfield brine as they are in the ocean (52). Other potentially harmful constituents of a discharged oilfield brine include oil, dissolved organics, and minerals such as aluminum and barium, plus thermal pollution effects. The basis of one major controversy surrounding direct discharge of oilfield brines into marine environments concerns the ability of marine animals to accumulate concentrations of dissolved minerals in their bodies many thousands of times greater than the concentrations in the surrounding water. Some accounts record these multiples of accumulation, known as enrichment factors, to be as high as 13,000 (New Zealand Oyster) (56). As an example, copper normally exists in the oceans in concentrations from .02 ppm to .005 ppm. Some marine animals have the capacity to accumulate this copper to toxic levels and thus are potentially lethal to other animals (including man) who feed on them. (Copper becomes toxic to many species of marine life at levels from .1 ppm to .5 ppm.) Oilfield brines normally contain several potentially toxic materials, but the heavy metals (chromium, copper, etc.) have been found only in low concentrations (the parts per billion range) which are within the range of existing sea water concentrations (57). Considerable study is continuing to determine the effects of reduced brine-sea water mixing in coastal areas. However, the pollutant factors of brine (elevated temperatures and salinities, the additional organic load, and dissolved and suspended metallic materials) have proven even more toxic in fresh water than they are in salt water, especially chloride salinity.

The real disposal mechanisms of a direct discharge system are the receiving bodies of water, which vary as to the type and amount of oilfield brine they can receive. Intrastate waters are regulated by the water quality administration policies of each state; the Environmental Protection Agency administers water quality standards of interstate waters; and the United States Army Corps of Engineers administers water quality standards for all coastal, navigable, and tributary waters. Both state agencies and the Corps of Engineers are assisted by the Environmental Protection Agency in establishing standards and criteria for water quality. If direct discharge is being considered as a disposal method, it is essential that the prospective operator contact the reasponsible water quality agencies prior to construction of his disposal system, not only to acquire the required registration permits but also to assure that the legal requirements do not mitigate against the disposal mechanism he has selected. The remainder of the direct discharge disposal system consists of the supply pipelines from the brine collection points treatment facilities (if required), pumps, and discharge pipelines to the disposal receiving water. In essence, this is identical to the transport and treatment portions (except, perhaps, for the degree of treatment) used in evaporation and injection disposal systems, and has been covered in the discussion of the gathering system and treatment, along with injection analysis. Table 13 summarizes the advantages and disadvantages of direct discharge disposal.

Table 13. Summary of
Direct Discharge Disposal.

Advantages	Disadvantages
1. May be very inexpensive to build and operate.	1. Impractical when long distance from ocean, or rough terrain boost pipeline and pumping costs.
2. May require minimum treatment.	2. Pipeline right-of-way cost may prove overly expensive.
3. Is not restricted by the amount of brine it can handle.	3. Treatment costs for agriculture or cooling use may be prohibitive.
4. Does not require extensive underground analysis for disposal zone.	4. Ocean discharge pipeline and requires extensive corrosion protection.
5. May be mixed with other water and diluted to a quality level which is acceptable for agricultural and cooling uses.	5. May require regular, extensive chemical testing which can prove expensive.
6. Does not depend on evaporation rate.	6. May require outfall off-shore to protect fish spawning areas.

Evaporation Ponds

Like direct discharge, evaporation ponds or pits are a surface means of oilfield brine disposal. Unlike direct discharge however, evaporation ponds depend on the ability of the atmosphere to withdraw the liquid portion of the disposed brine as water vapor, not on dilution and mixing of the brine with freshwater sources (except in the rare cases where the brine's relatively high quality enables its use as fresh water). Perhaps visualizing the atmosphere as a sponge with a limited capacity to absorb moisture will aid in understanding the function of an evaporation pond,

which is to act as a container of oilfield brine while its water content is absorbed by this "atmospheric" sponge.

Brine disposal by evaporation is harshly criticized by many water quality regulating officials because of the many recorded instances where damage was done to top soil and fresh water. In such instances, evaporation ponds functioned simply as holding tanks for brine prior to accidental or deliberate illegal direct discharges onto the land or into fresh water, or as infiltration devices through which the salty brine seeped into underground fresh water. In addition, cases have been recorded where the extremely saline residue from evaporation ponds was haphazardly covered and abandoned, allowing the concentrated salts to "leach" out of the evaporation pit and damage surrounding land and fresh waters for several years. Such incidents have resulted in legislation outlawing oilfield brine evaporation pits in several states (e.g., Texas) and in strong discouragement of their use in other states (e.g. Oklahoma).

To combat threats of brine infiltration and leaching, the majority of states still permitting evaporation ponds now require that the ponds be built on impervious strata or lined with some type of impervious material such as PVC or Hypolyn. As with other means of brine disposal, each state administers its own evaporation pond program and provides its own specifications for the legal design and operation of these ponds.

Determination of Evaporation Rate

The successful operation of an evaporation pond depends on an accurate calculation of an average annual evaporation rate, which is generally expressed in units of length (inches or centimeters) per day or per year. Evaporation rate is a rather elusive and highly variable concept to define. Meteorological agencies have erected stations throughout the United States at which special pans simulate evaporation from a standing body of water (such as a lake). After applying coefficients, the data collected is generally expressed as either gross lake surface evaporation (total evaporation loss from a unit area of lake surface obtained by applying the appropriate coefficient to the pan evaporation) or net lake surface evaporation (gross lake surface evaporation with adjustments for rainfall and normal runoff). The net lake surface evaporation figure is then assumed to be a reasonable approximation of the actual evaporation loss which would occur (58).

Figure 6 shows the average annual net evaporation rates for the United States by area. This and other related data may be obtained from The United States Weather Department, and the United States Bureau of Reclamation, or from publication such as Climatological Data, Annual Summaries (by the U.S. Weather Bureau), or Water Bulletins published by the International Boundary and Water Commission. These net lake surface evaporation rate values may be adequate bases for the majority of oilfield evaporation pond design criteria, but the designer should remember that this data was

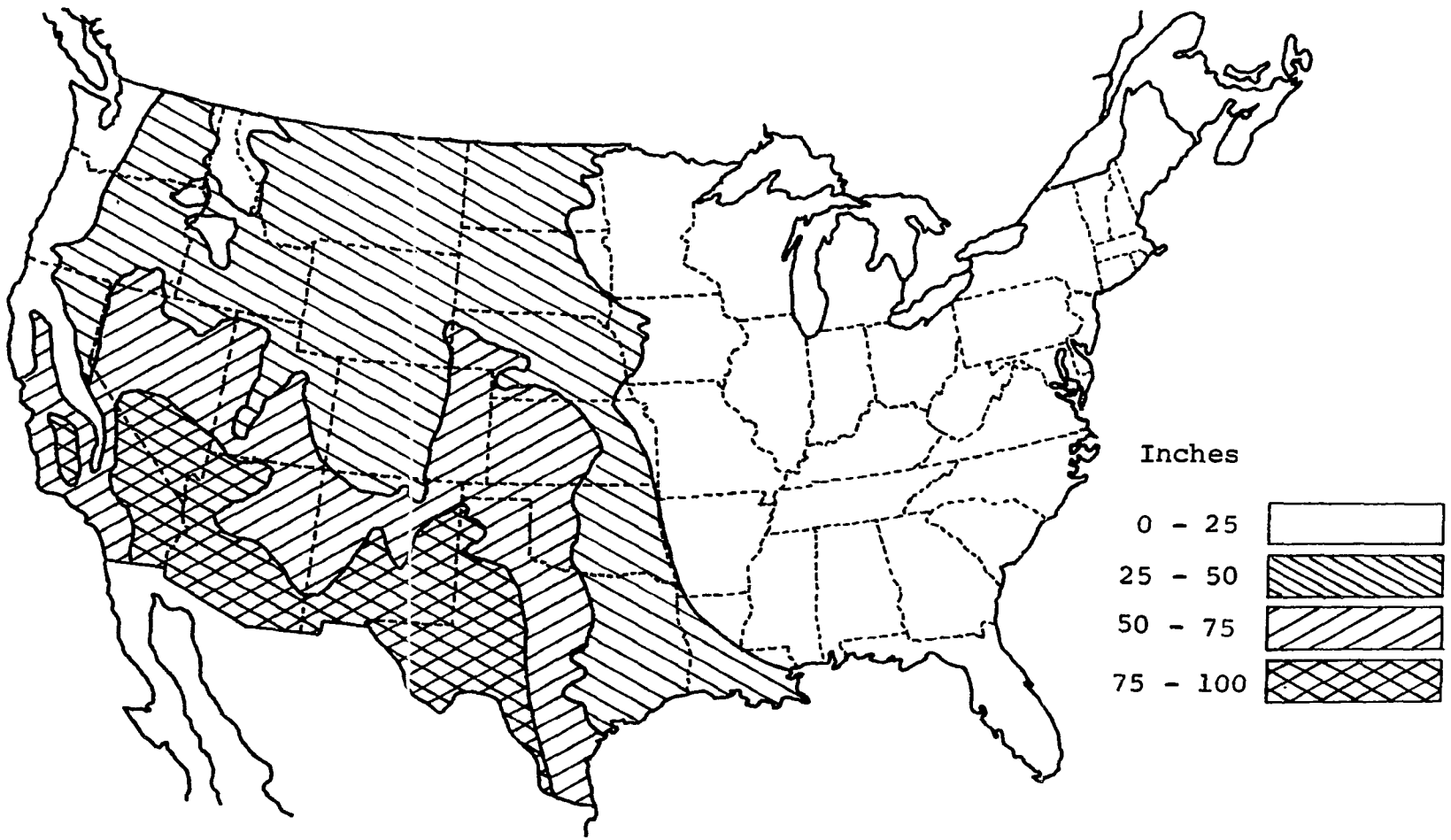


Figure 6. Map of Annual Net Evaporation in Inches (Pan Evaporation Minus Precipitation)(59).

taken from individual stations (which may be separated by many miles) measuring fresh water evaporation, not brine evaporation. If the magnitude of the disposal project is large due to brine volume, relatively high land costs, or expecially if conditions (elevation, climate, etc.) at the prospective brine evaporation pond site differ from those at the site at which the data was collected, the operator may wish to determine the approximate brine evaporation rate in his own area. Unfortunately, this may not be a simple task because analytically the evaporation rate is a net effect of several variables:

$$E = NU\ (e_o - e_a) \quad (60)$$

where:

E = evaporation in cm/day.

U = wind speed measured 2 meters above the ground surface in miles per hour (mph).

e_o = vapor pressure of saturated air in millibars (mb) at the brine surface temperature (available from meteorological tables).

e_a = vapor pressure of the air in mb at the 2-meter (6.5 feet) air temperature (meteorological tables).

N = mass transfer coefficient in cm/(day · mph · mb).

This evaporation rate can be expected to decrease as the quantity of dissolved solids increases as shown in Table 14.

Table 14. Concentration Adjustment (60).

	Concentration	Replace e_o by e'_o
At saturation	50,000 ppm NaCl	$e'_o = .97\ e_o$
	150,000 ppm NaCl	$e'_o = .91\ e_o$
	300,000 ppm NaCl	$e'_o = .80\ e_o$

Another study produced a different equation for brine temperatures varying from 76°F to 90°F (61). Basically this method uses a multiple regression equation relating evaporation (E) in centimeters per day with the user supplying the following information:

AT = air temperature (degrees Farenheit).

W = wind speed (miles per hour).

RH = relative humidity (percent).

C = concentration of NaCl in units of 50,000 ppm per unit (i·e·a/150,000 ppm solution of NaCl would be 3 units).

WT = brine temperature (degrees Centigrade) [°C = 5/9 (°F - 32)].

The actual equation is:

$$E = B_1\ (AT) + B_2\ (W) + B_3\ (RH) + B_4\ (C) + B_5\ (WT) + B_6\ (AT)^{1/2} + B_7\ (W)^{1/2} + B_8\ (RH)^{1/2} + B_9\ (C)^{1/2} + B_{10}\ (WT)^{1/2} + B_{11}\ (AT)\ (W) + B_{12}\ (AT)\ (RH) + B_{13}\ (AT)\ (C) + B_{14}\ (AT)\ (WT) + B_{15}\ (W)\ (RH) + B_{16}\ (W)\ (C) + B_{17}\ (W)\ (WT) + B_{18}\ (RH)\ (C) + B_{19}\ (RH)\ (WT) + B_{20}\ (C)\ (WT).$$

While the equation is long, the individual calculations are relatively simple. The B values refer to the following coefficients (rounded to the nearest .0001):

B_1 = -0.2276	B_8 = -0.6812	B_{15} = -0.0019
B_2 = 0.2426	B_9 = -0.0781	B_{16} = -0.0068
B_3 = 0.0874	B_{10} = 0.9523	B_{17} = 0.0017
B_4 = 0.2129	B_{11} = -0.0015	B_{18} = 0.0001
B_5 = -0.3424	B_{12} = -0.0003	B_{19} = -0.0011
B_6 = 1.8153	B_{13} = -0.0002	B_{20} = -0.0076
B_7 = 0.2063	B_{14} = 0.0046	

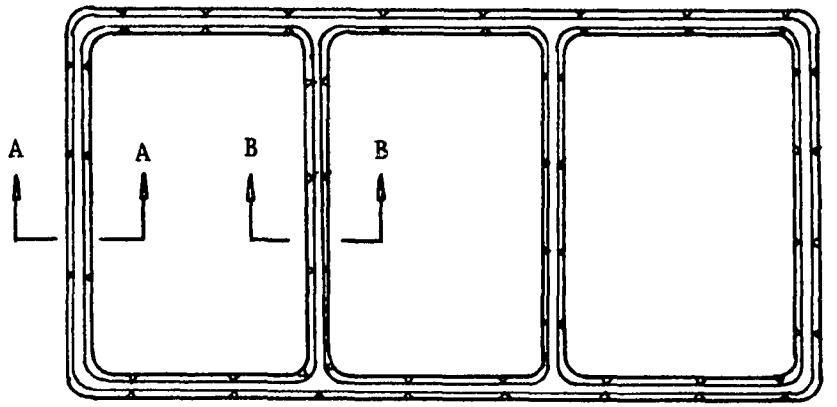
The reference cited indicated a very high correlation between values obtained using the above equation and actual measurements made of evaporation pond rates. Further, information from this reference also indicated generally that:

1. Evaporation decreased with an increase in relative humidity.
2. Evaporation decreased as the salt concentration increased.
3. Evaporation increased with an increase in wind speed.

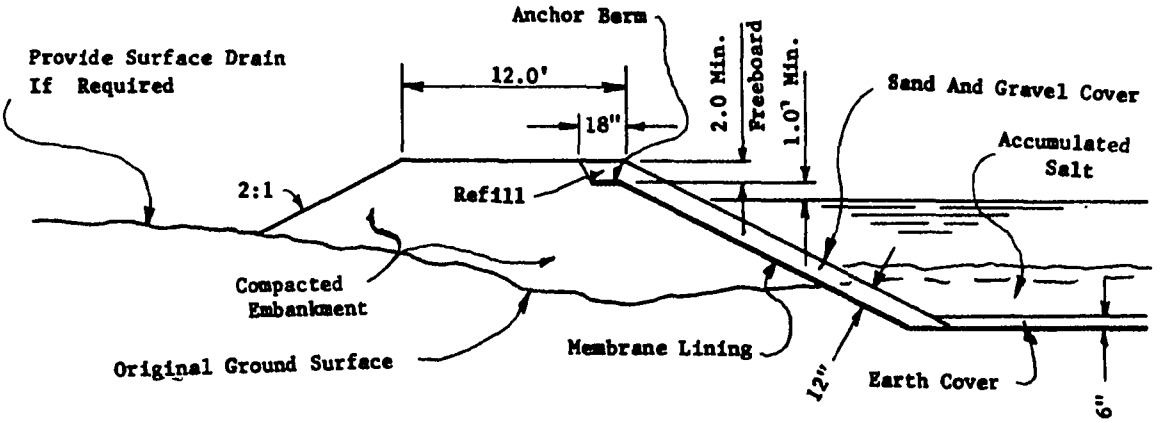
Another recent study in the general area of evaporation ponds for brine disposal also developed relationships for evaporation but in a more sophisticated manner (62). In addition to the evaporation equations

presented, the reference indicated several useful generalizations relative to the configuration and operation of evaporation ponds (see Figure 7):

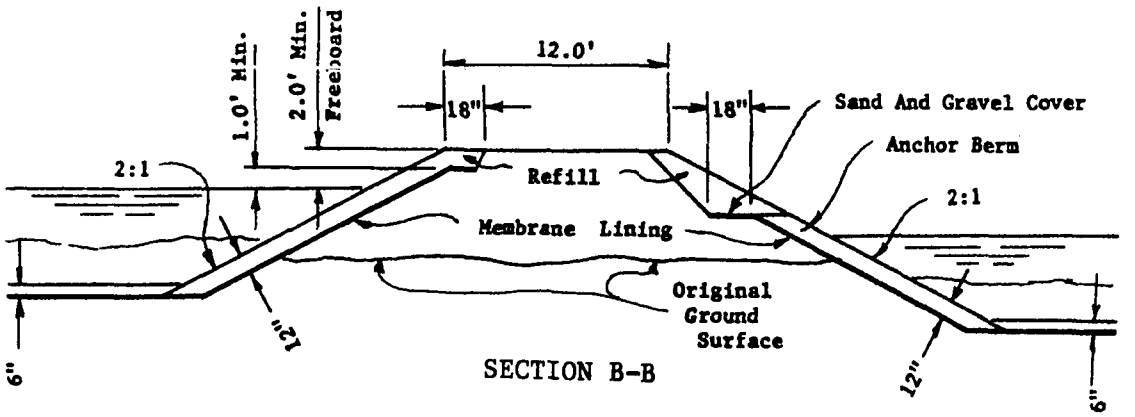
1. Maintain a uniform depth of brine (liquid) throughout the pond at from 1 to 1.5 feet. Evaporation rates increase as pond depths decrease due to the added beneficial effects of solar heating.
2. Shape the pond in a rectangular fashion so that the prevailing wind blows across the longest side of the pond, entering from the same side as the incoming (influent) brine.
3. The air mass over the pond (described earlier as operating in analagous maner to a sponge) approaches a maximum thickness of approximately 26 feet. Other dimensions, such as the length and width of this moisture-receiving air mass, depend on wind velocity and pond dimensions. This means that at increased humidities the air mass "sponge" over a pond would be considerably less absorptive than at low humidities.
4. The study recommended a downwind dimension (pond width) of at least 200 to 400 feet to allow adequate contact time between the moving air mass over the brine pond and the evaporated water vapor. For massive evaporation ponds however, the general configuration of the pond should conform to an approximate pond length-to-downwind



PLAN



SECTION A-A



SECTION B-B

Figure 7. Typical Plan and Sections for Brine Disposal Ponds(63).

(influent) length ratio of 2:1 (see the evaporation cost analysis section).

Evaporation Pond Design Considerations

Although state specifications on evaporation ponds differ, design considerations include the following major areas (63):

1. Evaporation rate.
2. Site location.
3. Pond size and shape.
4. Seepage control.
5. Structures.
6. Pond depth.
7. Banks.
8. Earthwork.
9. Environmental control.

Evaporation Rate

As discussed previously, evaporation rates may either be taken from United States Weather Bureau records, other government agency records, or developed from actual field measurements (59). The net lake surface evaporation rate is normally a reasonable value for use in evaporation pond design. Another useable evaporation rate is the standard evaporation pan value (taken from the data of surrounding stations where conditions approximate the ones at the proposed pond locations) multiplied by an appropriate correction factor (.7 is reported as a reasonable figure (63)). If values are to be calculated, the equations presented previously or others contained in the indicated references may be used to determine

the appropriate evaporation rate. Three items should be kept in mind. First, all the design equations have been developed for salt brines in which there was no oil, grease, or other surface-film materials. Second, weather evaporation rate data applies to fresh water. And third, actual evaporation rates vary constantly and thus average annual or seasonal rates are used. To convert fresh water rates to salt-water rates, adjust the data according to the following equation:

$$E' = \frac{E(e'_o - e_a)}{e_o - e_o} \quad (58)$$

where:

E' = adjusted evaporation rate in cm/day.

E = evaporation in cm/day (2.54 cm = 1 inch).

e_o = vapor pressure of saturated in mb. air at the water surface (air temperature)

e_a = vapor pressure of the air in mb at the temperature 2 meters (6.5 feet) above the water surface.

e'_o = an adjustment for salinity:

50,000 ppm NaCl:	$e'_o = 0.97\ e_o$
150,000 ppm NaCl:	$e'_o = 0.91\ e_o$
300,000 ppm NaCl:	$e'_o = 0.80\ e_o$

Site Location

The brine disposal pond should be located as close to the oil production

site as possible to eliminate pipeline and hauling expenses, and to minimize land right-of-way purchases. Level ground should be chosen outside natural drainage areas. This will minimize ground preparation by earth movers and the possibility of a washout during a rainstorm, a potential source of damage claims. The pond should also be located downhill from the production site to minimize pumping costs. In addition, the pond should be sheltered from dust storms as much as possible because a dust film on the water surface will reduce evaporation from the pond.

Pond Size and Shape

Ponds should be designed in a generally rectangular form with the longest sides at right angles (90°) to the direction of the prevailing wind. Pond width (downwind dimension) should be a minimum of 200 to 400 feet. The inflow to the pond should be parallel to the wind direction, and multiple baffle defices should be used to achieve a uniformly distributed inflow across the pond as much as practically possible. Allowance for freeboard (pond surface to embankment height of 2 feet is generally made to overcome the wave action caused by winds (up to 80 miles per hour across a 2,000-foot pond surface length). Therefore, a maximum of 2,000 feet is generally specified for the downwind dimension of the pond. (Realistically, the wind may gust to speeds of the 80-mph magnitude, so a 2,000-foot maximum pond width would probably prove sensible (63).) As indicated in Figure 7, the pond should also be divided into smaller ponds to minimize wave action, with an overall suggested ratio of 2:1, crosswind length-to-

downwind length. While some land leveling may be desirable to provide a uniform basin with a slight slope away from the upwind side of the pond, extensive earthwork should be avoided.

Seepage Control

Almost all states allowing evaporation pits require that they either be lined with some type of chemically resistant (to brine) liner material or be built in a naturally occurring bed of impervious material to eliminate dangerous leaching or percolation into ground water, farm lands, or fresh surface waters. Ponds should also be regularly maintained, and any damages to embankments resulting from errosion or scour should be made as soon as possible

Structures

Normally, structures associated with an evaporation pond are either flow regulating devices such as inflow piping, channels, and gates or embankment material. All structures should be made of wood or some other non-reacting material where possible to eliminate corrosion. Adjustments should be made in the flow regulating devices to reduce excessive flows into or between adjacent ponds--a frequent cause of scour or errosion. A freeboard of 2 feet is normally considered suitable for ponds having a surface area of 100 acres or less.

Pond Liquid Depth

Most references recommend a liquid depth of 1 to 1.5 feet in the pond. While a lesser depth would offer proportionately higher evaporation rates, extremely shallow ponds are subject to drying and cracking of the liners if for some reason inflow is intermittant. However, a greater liquid depth would lessen the beneficial effects of solar heating on evaporation, as well as be more prone to overflow and wash out the banks of the pond should a heavy rain storm occur.

Embankment Height

Pond depth is usually the sum of: 6- to 12-inch layer of cover material to keep the liner in place and protect it from weathering; a 2-foot freeboard; the depth of the accumulated salt precipitate over the life of the disposal pond (which depends on brine salinity/flow and pond life--about four feet); and at least 1 foot of soil cover on abandonment. Thus, an accumulated depth of approximately 8 to 10 feet should be adequate for most oilfield uses (assuming a 15- to 20-year life expectancy).

Embankment Dimensions

Banks surrounding the evaporation pit should slope approximately 2:1 (width to height). Like the bottom, the sides of evaporation pond should be lined and covered with a 6- to 12-inch layer of material. In addition, the top

of the banks should be wide enough to permit easy access by four-wheeled vehicles for maintenance of embankments and cover material over membrane linings, as well as weed control.

Earthwork

To obtain satisfactory pond soil stability, all embankments should be compacted. Further, compacted embankment and earth lining quantities should be multiplied by a compaction factor to obtain the amount of excavation required to produce the material necessary to make the embankment or lining cover. The compaction factor varies with the type of material and inplace density, and may also vary with depth at a specific site. Therefore, while this factor may be estimated for preliminary investigations, it should be supplemented in-place density tests before final design. The density of accumulated brine residue is approximately 83.5 pounds per cubic foot.

Environmental Control

To further assure that no brine is seeping out of the pond, underdrains may be installed at a depth of 1 to 2 feet under pond lining (under the sides and bottom) and should be checked regularly for seepage. Excessive seepage may indicate a break in the lining which could necessitate the pond being emptied into an adjacent pond while the break in the pond lining is located and repaired. Although regular maintenance and repair is

an additional expense, it is impractical to invest in pollution control devices to prevent damage claims then negate their effectiveness by improper maintenance. The obvious result could be a doubled expense.

It should also be pointed out that some brines, such as those with high sulfur content, are extremely corrosive to many liner materials. Therefore, a sample of liner materials should be sent with the brine for lab testing. One major operator indicated that the only material that the company had found suitable for liner uses was a 2-inch thick layer of gunnite (concrete sprayed over a wire mesh using a corrosion-resistant cement).

The final step in environmental control is abandonment. Common procedure is to install an impervious, corrosion-resistant liner over the dried residue of the pond, level with the bottom of the freeboard. Following this, the liner should be covered with a 2-foot cover of earth and top soil and lightly compacted. If the pond was build in a grassy or forested area, it should be seeded; whereas in an arid area, a layer of sand may prove more satisfactory. The reason for this procedure is that the salt package contains extremely high concentrations of materials which are poisonous to crops, wildlife, and agricultural animals, as well as ruinous to fresh water. Therefore, the pit must be sealed indefinitely. Further, by properly covering the abandoned pit, the land can be returned to its natural state and to beneficial use when the operation is completed.

Improvement of Evaporation Ponds

Several suggestions have been reported for devices to improve evaporation rates. These devices include additional removal of oil and other floatable materials, using dyes, and using spray devices.

Perhaps the best way to slow or stop the evaporation process is to allow enough oil to flow onto the pond to form a surface film. While specific information on the actual reductions in evaporation from brine evaporation ponds due to the formation of an oil slick was not obtained, it has been reported that oil film exist as thin as 1.5×10^{-6} inches, conforming to 25 gallons of oil per square mile of pond surface area (25). The exact effect on an oil film depends on wind and other meteorological conditions; however, for water vapor to form, there must be sufficient energy at the water surface to overcome the molecular surface tension at the water surface. Therefore, any material that strengthens this surface tension (such as an oil film) can be expected to significantly retard evaporation.

Another attempt at developing a mechanism for increasing brine evaporation consisted of the addition of dyes to the brine. While research is continuing in this area, earlier claims of increased evaporation have been more recently discovered to be economically and physically of questionable merit (62,63).

Using spray systems to increase evaporation rates has exhibited better

possibilities. The theory behind this method is that breaking the water into droplets increases the surface area of the brine and exposes more of it to meteorological effects. This theory was tested in an area with meteorological conditions similar to those in Phoenix, Arizona. The tests indicated that under certain conditions significant cost savings could be realized by the operation of spray evaporation system.

For example, assuming a quantity of 1.4 million gallons per day (33,333 brls/day), a performance level of approximately a 40% increase in evaporation rate could justify implementation of a spray system. However, such areas as spray nozzle size and type, system design configurations and capacities, and costs of corrosion-resistant materials, operation, and maintenance are being investigated further to determine the economic feasibility of such systems. As pointed out in a subsequent section, this method could prove beneficial in areas where land costs are high enough to justify the additional capital and operation costs of the spray system. Table 15 summarizes evaporation pond information. For a more thorough explanation of evaporation rates, see Evaporation for Brine Solutions under Controlled Laboratory Conditions (61) and Disposal of Brine by Evaporation: Design Criteria (62). Also, a very good guide to the construction and operation of an evaporation pond may be found in Brine Disposal Pond Manual (63).

Table 15. Summary of
Evaporation Pond Information.

Advantages	Disadvantages
1. Elevated brine temperature beneficial.	1. High land costs may make this method impractical.
2. Relatively quick to construct and easy to maintain.	2. Can be used only where high evaporation rates combine with low land costs.
3. Only oil and other film-creating floatable materials need be removed prior to disposal, implying minimal water treatment.	3. Breaks in dikes or seepage may cause land damage.
4. Very effective in relatively arid sections of the country, especially where land costs are relatively low.	4. Oil film on brine surface can seriously affect evaporation process.
5. Frequently least expensive brine disposal alternative, especially in areas of the western United States with high evaporation rates.	5. May be difficult to find a reasonably priced liner resistant to chemical degradation of some brines.
6. Brine quality (toxicity), except for film-causing floatable material, is not a major problem in the operation of an evaporation pond.	6. Source of continuing legal scrutinity because history of land and water damage.

Injection

Increased attention to pollution control and ecological principles has led to the adoption of more stringent federal and state brine disposal regulations and to stricter enforcement of those regulations, particularly the ones covering surface disposal methods such as evaporations pits and

direct discharge to streams. Thus, the alternative to surface disposal, subsurface injection (which has been used effectively for many years), is becoming legally more advantageous than surface disposal.

Subsurface injection of brines is also used in maintaining reservoir pressure and in secondary recovery by water flooding. Water injection for pressure maintenance is begun early in the life of an oil reservoir to curtail the drop in the original formation pressure and thereby retard the decline of oil production. Water flooding, on the other hand, is a secondary recovery operation that utilizes injected water under pressure to drive the oil to the producing well. Water flooding is normally begun late in the primary recovery period, usually after the formation pressure has declined (64). Both operations increase the recovery of oil in place, and both require sources of water. One of the logical sources of this water has been the brine incident to the production of oil.

The advantages of injecting brine back into its native formation, or a similar formation, are essentially two-fold. First, the returned brine is often compatible with the connate water in the reservoir. It should be remembered however, that reductions in pressure and temperature along with exposure to air will produce chemical changes that can limit complete compatibility between injected brine and the brine already in the formation. Second, "clean" brine (with relatively low total and suspended solids and oil content) has less tendency than fresh water to cause obstructions due to the swelling of certain clays associated with oil-

producing formations, thereby reducing the permeability of the disposal zone (65, 66).

Considerations for Injection

The following consideration-and-decision sequence appears plausible when investigating disposal by subsurface injection. These topics will be briefly summarized, then followed by a more lengthy discussion in the text of subsurface disposal.

1. Determine the legal constraints.
2. Select the appropriate disposal formation.
3. Determine the type of disposal wells necessary.
4. Determine the type and extent of water treatment necessary prior to injection.
5. Determine the economic feasibility of injection.

Legal Constraints

The legal constraints for injecting brine should be investigated for each specific application. Each state has different regulations regarding allowable disposal practices and it is not uncommon to find that a disposal method is legal in one state and illegal in another. (The legal and institutional aspects of brine disposal are discussed in a separate section of this report.)

Selection of Disposal Formation (65)

The disposal formation may be selected on the basis of secondary recovery

considerations, or it may be necessary to select a formation for injection only. The investigation of a formation should include general geological considerations, specific formation characteristics, and connate and waste water characteristics. These considerations are necessary to determine the injection capacity of the formation as well as the chemical compatibility of the injected brine and the connate water of the formation.

Disposal Wells (67)

Brine disposal wells may be old producers converted for injection purposes (with or without secondary recovery), recompleted abandoned wells, or new wells drilled expressly for disposal. In many cases it is more economical to use a converted well, since drilling and casing costs are minimal. However, the following disadvantages may eliminate using a converted well for disposal:

1. The expense of reconditioning and/or drilling an old well deeper to reach a suitable disposal formation may prove as great as the cost of drilling a new well.
2. The casing size in an old producer may be too small for use as an injection well.
3. Old wells are not always located in a suitable topographical or geological location (51).

A major advantage of drilling a new well, from a pollutional standpoint, is the assurance of a good cement job to prevent fluid migration and the use of corrosion resistant materials to lessen the opportunity for leaks. Many abandoned or older producing wells have very poor cement protection or none at all. The casing in these older wells often has corroded, with

the prospect of further, more rapid corrosion if used as a brine injection well.

Water Treatment (68)

The two types of water disposal systems currently in use are closed and open systems. The closed system prevents brine-air contact and thus helps maintain the fluid's chemical equilibrium by alleviating oxygen-induced corrosion scaling and chemical precipitation problems. (Other factors which may threaten chemical equilibrium are the pressure and temperature changes that occur when the fluid comes from the reservoir to the surface.) In a completely closed system the only treatment necessary is the removal of any entrained oil or suspended solids. There is some doubt as to the feasibility of maintaining a completely closed system in normal oil-field practice (69) because of the many points in a disposal system where air can leak into the system, but some operations can be designed with a minimum of air contact (semi-closed systems).

Open (presence of air) systems usually require more extensive treatment of the brine before injection because of oxygen-induced changes in the brine's chemical equilibrium. The treatment generally involves removal of the dissolved gases, removal of the suspended and dissolved substances, and possibly removal of the dissolved oxygen from the brine prior to injection.

The chemical and physical nature of the disposal formation in large measure

determines the degree and extent of the water treatment necessary prior to injection. Some limestone and dolomite formations will take untreated brine under a vacuum; some sandstone formations require that the brine be treated to a high degree.

Formation Analysis

The important regional geologic characteristics when considering a formation for disposal purposes are areal extent and thickness, continuity, and lithological character. This information can usually be obtained from geologic maps (if the areas under consideration have been geologically explored), such as those of a producing oil field. On a local basis it is necessary to know formation depth and thickness, stratigraphic position, lithology, porosity, permeability, reservoir pressure, and temperature. This information can be obtained or estimated from core analysis, examination of bit cuttings, drill stem test data, electric logs, and driller's logs (67).

Warner (70) states that the characteristics suitable for a waste injection formation are: and injection zone with sufficient permeability, porosity, thickness, and areal extent to act as a liquid-storage reservoir at safe injection pressures; and an injection zone that is vertically below the level of freshwater circulation and is confined vertically by rocks that are, for practical purposes, impermeable to waste liquids.

Vertical confinement of the potential injection zone is necessary to protect surface and groundwater resources, as well as other undeveloped oil formations and mineral resources, from brine contamination. Knowledge of the lateral movement of fluids in a disposal formation is also necessary for pollution control.

Two type of intraformation openings common in reservoir formations are (1) intergranular and (2) solution vugs and fracture channels. Formations with openings in the first category are usually made up of sandstone, limestone and dolomite formations often have vugulor or cavity-type porosity. Also, limestone, dolomite, and shale formations may be naturally fractured. The second type of formation opening is often preferrable for wase disposal because fracture channels are relatively large in comparison to intergranular openings. These larger channels may allow fluids high in suspended solids to be injected into the receiving formation under minimum pumping and with a minimum amount of water treatment at the surface.

Warner further indicates that a suitable location for waste disposal could depend on the local incidence of earthquakes, which cause movement along faults and can damage wells in the area. Earthquakes have thus far not been a problem in conjunction with oilfield brine disposal; however, the injection of liquid wastes at the Rocky Mountain Arsenal near Denver, Colorado may have been the cause of numerous earthquakes in that area since 1962. This indicates that fault zone aspects should not be completely ingnored.

Many mathematical relationships have been derived from fundamental flow theory considerations and have been used to predict the receptivity of a formation to injected fluid (50, 53). Relationships are also available to calculate the change in intake rate per unit of time (71). It must be emphasized, however, that the conditions on which these and other general formulae are based do not all exist in an injection situation, thus, the answers determined through their use should be regarded as approximations.

Injection Pressures

As a general rule, the pressure exerted on lower formations by overburden is considered to be in the order of 1 psi per foot of well depth is conceded to be the maximum pressure some formations can withstand before fracturing. To maintain a factor of safety, the recommended bottom hole pressure in an injection well is usually considerably lower than the 1 psi per foot value. Conversations with state regulatory agencies have indicated that a bottom hole injection pressure of 0.5 psi per foot of depth is usually the maximum recommended. In the case of deep wells this pressure level may be reduced to 0.4 psi per foot od depth. The purpose of these safety factors from a pollution point of view is to prevent any possible escape of the brine, through vertical fracturing, into fresh water or other mineral producing zones. It is not uncommon for a formation to take water under vacuum conditions at the surface.

Connate Water Characteristics

The reservoir water already in place (connate water) is a determinate of a formation's ability to receive a waste-water stream. If the injected water is not chemically compatible with this connate water, chemical precipitates can form and eventually plug the formation in the vicinity of the well bore. Further discussion of a compatibility can be found in the section on water analysis.

Capacity Index (68) and Injectivity Index (71)

A disposal well may be converted oil well or abandonment, or it may be a new well drilled expressly for disposal purposes. After a disposal well is completed, injection capacity tests should be run to better determine a well's ability to receive injected brine. Injection capacity depends on the permeability of the formation, the bottom hole pressure available, and the friction in the tubing or casing due to the fluid flow.

A phenomonon known as transient back pressure may cause a backflow in a well when injection is stopped suddenly, and the well is opened to the atmosphere. This backflow is the result of a small amount of free gass in the formation that expands under the decreased pressure and drives the fluids back to the well bore. To properly determine the injectivity index of a well, the transient back pressure must be controlled so that its effect is negligible.

The capacity of a well is usually expressed in terms of a capacity index or an injectivity index. These indices are measurements of the effective permeability of the disposal well and disposal formation as a whole. The capacity index is defined as barrels per hour injected divided by the increase in bottom-hole pressure (psi). This value can be determined by measuring the static bottom hole pressure and the bottom hole pressure at the maximum possible flow rate, and dividing the quantity injected by the corresponding pressure change. The tubing or casing should be kept filled, if possible, during the test, and flow should be continued until a stabilized rate is established. A well taking fluid under vacuum indicates that the formation is capable of fluid injection at a higher rate than that being delivered, but this is not necessarily an indication of the capacity of the well.

Injectivity index is similar to capacity index. It is defined as the change in the number of barrels per day of gross liquid injected into a well divided by the corresponding pressure differential between mean injection pressure and mean formation pressure, referring to a specific subsurface datum (usually this is the mean formation depth).

One way to determine the injectivity index is as follows. Shut down the well until the transient back pressure is falling very slowly, which probably will take several hours. This means that the pressures in the formation near the well bore have become equalized. Begin injection, maintaining a steady pressure for a short period of time (e.g. 5 minutes). Record

the volume injected during the period--or if possible record the instantaneous rate at the end of the period--then raise the pressure in equal increments (e.g. 100 psi) and take other readings. Follow this procedure until enough points are obtained to establish the relationship between intake rate and pressure. The resulting graph should be a straight line, the slope of which is the injectivity index. Capacity index tests should be performed periodically (e.g., monthly) on each well to determine any changes in the injection capacity. A simple plot of injectivity index versus time can indicate when the injection formation is plugging and that remedial action is necessary.

Drilling and Completion

New disposal wells that are drilled in a conventional manner normally utilize rotary tools. Several different procedures are followed in drilling and completing a convention well through the disposal formations. The American Petroleum Institute (72) lists the following accepted techniques:

1. Drill a full-sized hole to total depth and set the well casing through the porous disposal zone or zones. This method is recommended for unconsolidated formations subject to sloughing or caving.

2. Drill a full-sized hole through all porous zones or to where circulation is lost and set the casing immediately above the porous disposal zones.

3. Drill a full-sized hole to immediately above, or to the top of, the disposal formation and set the casing at this point. Then drill a reduced sized hole through all the porous zones or until circulation is lost. If possible,

clear water should be used for drilling fluid in drilling the reduced hole to prevent plugging from mud and lost circulation material.

4. Drill a full-sized hole to immediately above, or to the top of, the disposal zone, then drill a reduced-size hole to total depth and set the casing at the point where the hole size has been reduced. After the casing has been set, ream the rat-hole or reduced hole to remove the mud or invaded zone, using water for the drilling fluid. If the casing and hole size permit, the rat-hole may be reamed with a larger-diameter bit in a conventional manner. If conventional reaming cannot be done, the rat-hole may be underreamed.

Liners should be used when converting an old well for injection purposes, if deepening is required, to protect freshwater and other mineral bearing formations. Open hole completions are preferred in consolidated formations due to increased permeability and ease of cleaning, while an unconsolidated formation may require that casing be set through the formation and perforated. Other possibilities in the case of unconsolidated formations include a gravel pack or screened liner. It may be possible to improve the well permeability (ease of flow) of the formation face and mud invasion zone by circulating clear water, scratching or reaming the open hole, or swabbing to induce a backflow of fluid from the formation. Often it is necessary to increase the permeability in the vicinity of the well bore by acidizing in the case of limestone or dolomite formations or by hydraulic fracturing.

Completion Practices

There are many methods of completing injection wells for the disposal of

brine or other liquid wastes. The wells can be completed with or without a packer (a special tool usually used to seal off the annulus, between the tubing and casing). Packers are sometimes necessary to protect the casing from high injection pressures and are also used to protect the annulus from the corrosive effects of the brine. After setting the packer, the annulus should be filled with a noncorrosive fluid such as kerosene, diesel oil, naphtha, crude oil, or chemically treated water, although it is also possible in many cases to use these fluids in the annulus without the benefit of a packer. The purpose of this operation is to replace the water that normally fills the annulus of the well with a noncorrosive fluid in a quantity sufficient to balance the brine in the tubing at static conditions. If the static fluid level in the tubing is not high enough to support a column of noncorrosive fluid in the annulus, a packer must be used. Corrosion and unseating difficulties in brine injection wells make the use of packers desirable only when absolutely necessary. As injection commences, resistance to flow in the tubing and formation causes the fluid in the tubing to rise, with a subsequent rise of the fluid in the annulus. A record of casing-head pressure along with injection rates taken at bimonthly intervals can reveal the following indicators in the operation of an injection well:

1. A constant injection rate and an increase in pressure indicate the formation is becoming plugged.

2. A decrease in injection rate at a constant pressure or a decrease in pressure indicates an increased friction head in the tubing due to scale formation.

3. A constant rate or a greatly increased rate and a sudden decrease in pressure indicate a tubing or casing leak with possible pollutional consequences.

A variety of types of completions are presently being used for injection service; however, not all of these are satisfactory from a pollution-control standpoint (73). Slimhole techniques have been employed where relatively low volumes of water are injected. In one such project in Oklahoma and Kansas, a 6 1/4-inch hole was drilled to total depth, and then a 2 7/8-inch plastic-coated tubing was cemented to the surface. The average well depth was 1250 feet. The tubing was perforated and the formation acidized. Injectivity tests indicated that the wells and sandstone formation would take from 60 to 90 bbl/hr. (71). In a more conventional injection project in the East Texas oilfield, the wells were completed with 10 3/4-inch surface pipe to at least 100 feet, and a 7-inch long string was set below a substantial shale break located below the original oil water contact of 3,320 feet below sea level. These wells have been completed with and without tubing. In the latter case the 7-inch casing had to be plastic-lined or cement-lined to prevent corrosion (74). Figure 8 illustrates both open and closed hole well completions.

Materials

Brine is extremely corrosive, particularly when the fluid contains dissolved oxygen. Tubing and casing should be internally lined with plastic or cement to prevent the bare metal from contacting the brine; in some instances epoxy resin tubing has been used successfully (68). The plastic-lined tubing and epoxy resin tubing show improved flow characteristics over unlined steel tubing, as well as more resistance to the accumulation of scale.

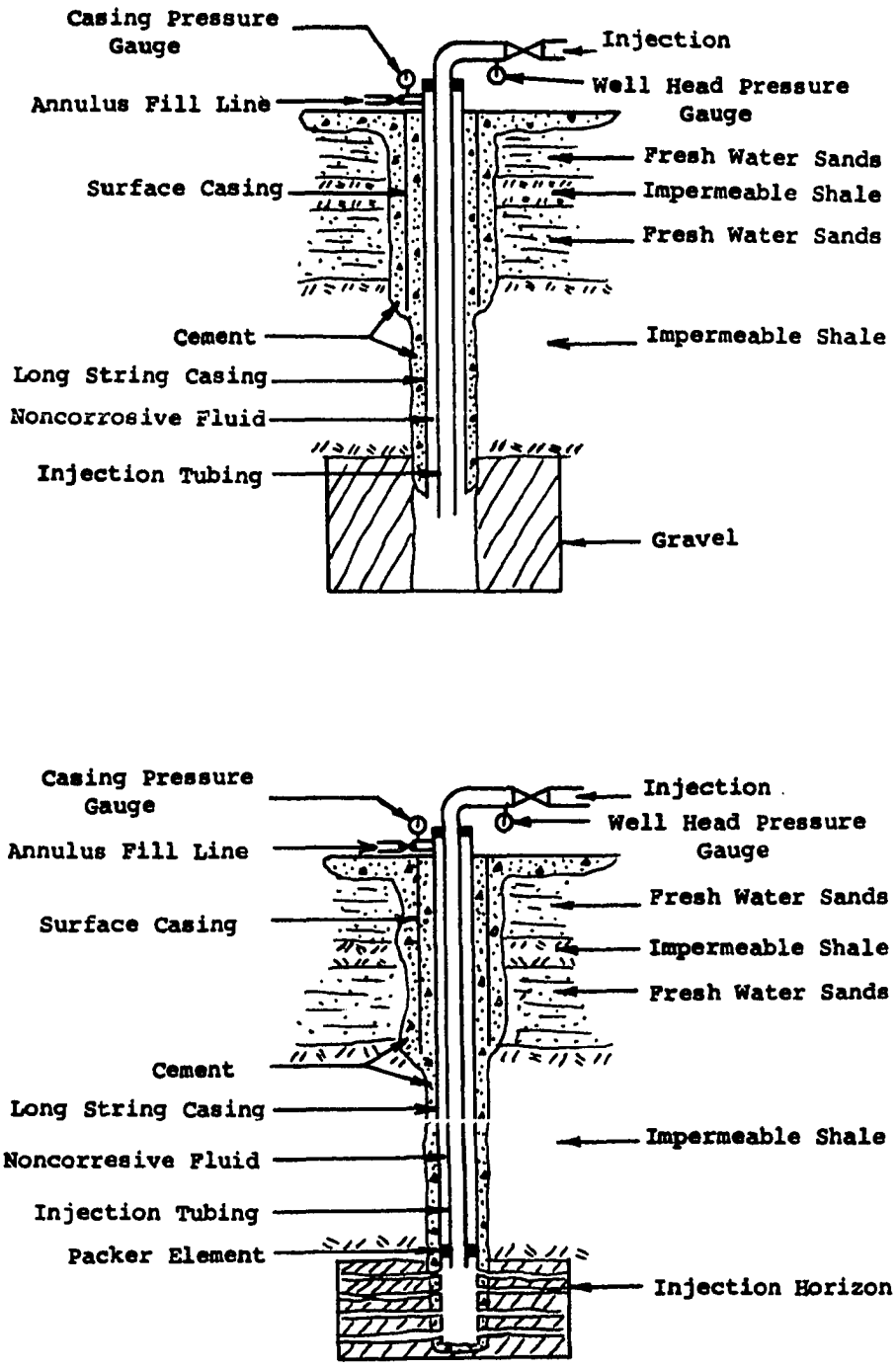


Figure 8. Open and Closed Hole Injection Well Completions (75).

Care must be exercised when handling or running tools in the lined casing to prevent cracks or breaks in the lining. The pipe should be carefully inspected before being run.

Injection Pumps

Two type of pumps are used for fluid injection. Centrifugal pumps are used for high volume service where the injection pressures are less than about 300 psi, and reciprocating, positive displacement pumps are necessary for pressures greater than 300 psi.

The piston-type duplex pump and the plunger-type inverted triplex are used in the East Texas oilfield (76). Duplex piston pumps are generally used for pressures up to 500 psi, whereas the triplex pumps are suited for high-pressure operations. A primary consideration in pump design is the selection of the proper materials for salt-water service. The usual oilfield fittings such as pistons, liners, rods, valves, sents, and packing cannot be used in brine service because the salt water provides little lubrication and is extremely corrosive. The East Texas Salt Water Disposal Company reports that liners made from "Janney 30," monel, and "ni-resist" are fully satisfactory from both the corrosion and wear resistance standpoint (53). In the same operations, rods made of 303 stainless steel, with valves and seats of aluminum-bronze and magnesium-bronze, have also proved satisfactory.

Cleanout and Remedial Techniques (68)

Injection well capacity may decrease over a period of time as a result of formation plugging; the formation can become plugged with suspended solids and precipitates or hydrocarbons. Capacity may also decrease due to scale forming in the flowlines or in the well tubing. The following methods can be used to increase capacity.

1. Acidizing. Hydrochloric acid will remove most scales with the exception of barium sulfate, strontium sulfate, and calcium sulfate which may have to be removed mechanically by scraping or reaming with a drill bit. Hydroflouric acid will dissolve sand, clay, or mud if these are the plugging agents. A detergent may be added to the acid to help remove oil films from the reservoir and allow the acid to react with as much rock as possible.

2. Hydraulic fracturing. In this technique, a fracturing fluid can be introduced into the formation with sufficient pressure to induce horizontal fractures in the formation, thereby increasing permeability. A material, such as coarse sand, should be pumped with the fluid to ensure permanent permeability after the pressure is released. Brine, which is normally injected into the formation, is the logical "hydrofracing" fluid. Care must be taken not to apply excessive injection pressures which could cause vertical fractures into freshwater or other oil zones.

3. Backflowing. Under certain conditions wells can be backflowed in order to clean the formation face. Occasionally special strings of tubing are used to facilitate this operation.

4. Mechanical cleanout. In cases where large deposits of hard scale are formed on the formation face, tools such as reamers and bits may be used to restore permeability.

5. Chlorine and other chemicals. The injection of chlorine has in some instances doubled the rate of input into injection wells (77). The reasons for this improvement were theorized as:

a. Chlorine forms hypochlorous acid in solution with water.

b. Chlorine is a powerful oxidizing agent.

c. Chlorine kills bacteria and thus reduces bacteria-caused plugging.

Carbon bisulfide has been used as a solvent for free sulfur, which can collect on the formation face. However, the toxicity and highly flammable nature of carbon bisulfide make it extremely dangerous to handle.

Pollutional Problems in Injection Wells (78)

Projects disposing of fluids into non-productive zones in Texas, as of January 1, 1966, numbered 4,367; the number of other fluid injection projects was 3,471. Other oil-producing states could probably show similar figures in proportion to the amount of oil produced. Overall, this indicates that there is a vast potential for the pollution of fresh waters from brine migration if proper disposal methods are not used.

As mentioned previously, discussions with regulatory officials in several states indicate that improperly plugged, abandoned wells are the major sources of brine pollution. Many of these wells either do not have cement plugs or have a top plug and no bottom plug. If improperly plugged, the well may leak at the ground surface, in which case it will probably be detected and remedied. A single top plug or a faulty cement job is extremely difficult to detect and poses a continuous threat to fresh groundwater.

There are many possible migration patterns of a fluid due to mechanical failures in wells or due to excessive hydraulic energy in the disposal formation. A review of the various types of completions presently being used for injection are shown in Figure 9. The type D completion is encouraged for brine injection because it can be effectively controlled and checked by surface tests. The following recommendations are presented for effective subsurface injection operations:

1. Design well completions for fluid injection and salt-water disposal service that may be effectively monitored and controlled by surface tests.

2. Give due consideration to environmental conditions in the project area.

3. In the design of salt water disposal systems, select zones that have sufficient reservoir volume to accept the present and expected volume of produced water without developing overcharged conditions in the formation.

4. Control operating conditions of injection systems to avoid mechanical failure.

5. Encourage field personnel to be zealous in their checking of operating systems so that trouble may be detected and remedied at an early date.

6. Attempt to design water treatment programs that will also control failures due to corrosion.

7. Keep detailed records of injected volume and produced volume so that anay loss of injected fluid might be detected and remedied at an early date.

Techniques to Detect Salt-Pollution Problems

An article by Roschhe, Smith and Wills (77) presents a series of techniques that can be used to detect and isolate salt-pollution

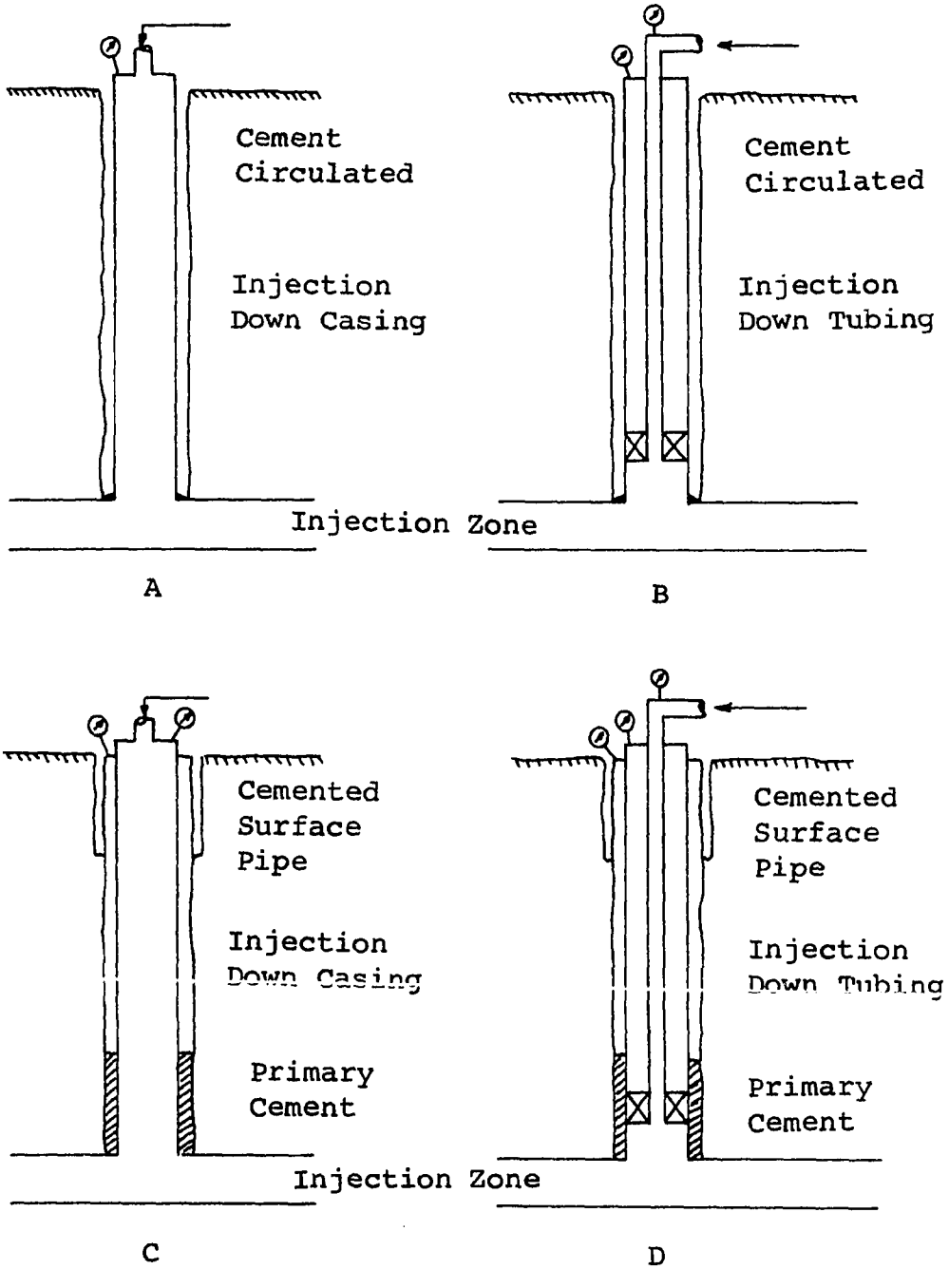


Figure 9. Typical Injection Well Completions(79).

problems, particularily in injection systems. Combinations of these techniques are recommended for each individual pollution problem:

1. Review Pollutional History in Area. This will answer the questions: How long has the problem existed? How widespread is the problem? Has there been a similar problem in the area? Do salt-pollution problems in the area follow any characteristic pattern or trend? Could the problem be a naturally occurring phenomenon? Is there any apparent time relationship between the problem and any system operating in the area?

2. Study Salt-Water Disposal Systems in the Area. The purpose of this study is to evaluate the general effectiveness of salt-water disposal systems in the area.

3. Wellhead Surveys. These surveys will determine the extent of localized overcharged sand, the presence of injection-well casing leaks, and injection well channeling.

4. Mapping. Outcrop, topographic, isobaric, isochloride, soil, and subsurface maps and aerial photographs are useful in data presentation, relating the data, fixing the extent of the problem, finding the size of disposal sands under flood, determining the nature of the surface beds (as well as the formation zone dip and strike,) and prediction of migration.

5. Water Analysis Pattern Studies. Chemical composition may be a clue to the origins of a contaminate. Pattern studies, based on geometric similarity, have been found useful for sample identification (formation or origin), relationship between samples, determining degree of contamination, and finding evidence and degree of dilution or chemical change. The three patterns used were star, milliequivalent, and log style.

6. Injection Well Tests. Injection well tests include:

    a. Interference Test. Simultaneous pressure measurements of the injection pressure and the casing head pressure, for example, could indicate a casing leak or channeling.

    b. Additive Tracer Test. Dyes are added to injected water and observations made in seepage areas.

c. Pressure Falloff Test. This is a test to further detect a casing leak, or channeling, by comparing several wells operating under similar conditions.

d. Injection Well Performance. Overcharging of the injection zone can be detected by running performance tests at intervals (e.g., every 6 months) throughout the life of the well. The test is run over a 48- to 72-hour period with alternating shut-in, injection, shut-in cycles. An increasing shut-in pressure indicates overcharging with possible pollutional consequences.

e. Relative Injectivity Tests. Two methods are available:

   (1) Plot the location of the injection wells on a map with their respective injection ratios (i.e., injection pressure/injection rate). Any large deviations can indicate casing leaks or channeling.

   (2) A graph of rate-pressure profiles for several different wells should show similar shopes. Any large deviation in slope is evidence of a casing leak or channeling.

f. Subsurface Tracer Surveys. Tracers such as dyes or radioactive material are injected into the disposal formation; a corresponding detection test run in the casing can indicate casing leaks and channeling.

g. Wire-Line Plug Method. It may be possible to pump a cement plug down the well and have it stop at a point just below a casing leak by checking the well pre-sure as the plug is lowered.

h. Temperature Survey. Changes in temperature may indicate a possible casing leak.

i. Pipe-Inspection Logs. These may be used to detect holes in casing.

j. Subsurface Pressure Gauge. Running a pressure profile may show a shift in the graph just below the leaks.

k. Packer and Tubing Test. A packer which has been set up to allow pressure in the tubing, casing, and annulus could be set at various points in the casing. This procedure would divide the pressure fall-off section of the annulus from the section where pressure doesn't fall off, thus isolating a leak.

7. Selective Shutdown Method. If several systems are operating in an area with a pollution problem, each system in turn could be taken out of operation to observe the effect.

8. Test-Hole Drilling.

9. Soil-Sample Study.

Table 16 summarizes the advantages and disadvantages of brine disposal by injection methods.

Table 16. Summary of Disposal by Injection.

Advantages	Disadvantages
1. Only way to remove oilfield brine from the land surface.	1. Can pollute fresh ground water with little possibility of detection.
2. Can handle large amounts of very saline brine.	2. Requires well-administered regulating program as well as conscientious disposal well operators.
3. Old wells can often be converted for disposal purposes at nominal cost.	3. May require high degree of water treatment, particularly if "dirty" brine is used.
4. Can substantially increase a reservoir's oil yield if used in conjunction with secondary recovery.	4. May involve high initial cost to drill or convert a disposal well.

Table 16 (Continued)

	Advantages		Disadvantages
5.	Does not require large amounts of land to accomodate an injection system.	5.	Often requires extensive reservoir engineering and laboratory analysis to select and install injection system competently.
6.	Suitable for inland areas where rough terrain make other methods impractical.	6.	May require extensive corrosion control.
7.	One injection well may handle the brines from as many as 60 production wells (80).	7.	Should not be used when a fault zone occurred in the reservoir.

SECTION VII

BRINE WATER TREATMENT

Put rather simply, oilfield brine water treatment is a process whereby the brine is in some way altered to reduce the unwanted effects of scaling or corrosion, or to remove any other conditions that might hinder disposal. While brine water treatment is predominantly the problem of the injection system operator, scale and corrosion effects are of general importance to all operations that involve the separating, transporting, and/or handling of oilfield brine.

Although more specifically explained in electrochemical terminology, corrosion might be visualized as a phenomena that occurs when a constituent in the brine has a stronger attraction for an element in the material of the brine handling container (pipeline, tank, etc.) than the container has. Thus, the element is literally pulled out of the container and combines with the material in the brine that exerted the stronger attraction. As would be expected, corrosion damage normally appears in the form of holes or similar depressions in the inside surface of the brine container, usually in areas of higher fluid velocity. Treating brine to prevent corrosion involves either removing the strongly attractive brine constituent or altering the nature of the brine to reduce the strength of or eliminate the corroding agent. An alternative to brine treatment for corrosion is to line the inside of all brine containers and piping with a non-reactive material.

Scaling, on the other hand, may be visualized as the opposite effect of corrosion. Scaling generally occurs as a result of conditions in the brine that cause some type of excess with regard to the chemical constituents. Therefore, the materials which are present in excess tend to "fall out of solution" or precipitate. Scaling damage is normally in the form of mineral deposits on the inside surfaces of the brine containers or pipes, usually at areas of lowered fluid velocity. These deposits gradually clog up the pipe openings increasing the amount of pumping necessary to move the fluid. Treating brine to prevent scaling broadly involves removing the potential scale-forming brine constitutents or altering the nature of the fluid to keep the potential scale formers in solution (dissolved).

Another factor that might create disposal problems and require treatment of the brine is fluid incompatibility. Like corrosion and scaling, incompatibility is predominantly a chemical effect. Unlike those problems however, incompatibility is most troublesome in brine injection reservoirs. Generally, incompatibility occurs when one or more of the chemicals in the brine reacts with chemicals in the existing reservoir fluid to cause an undesirable effect, such as precipitation. Precipitation damage resulting from incompatible fluids is usually in the form of plugged pore spaces in the injection zone. Treating brine to prevent incompatability consists of reducing the strength of or removing the reactive element, or altering the nature of the injected fluid. Alternatives to treatment include selection of another disposal method or another injection zone.

The last two brine handling/disposal problem areas are suspended solids and excessive amounts of oil. Suspended solids may be organic or inorganic material. If the solids are organic, then bacteria may also be present in the brine, especially if the organic material is present in relatively high amounts. These bacteria can prove excessively troublesome not only at the injection well interface but throughout the entire brine gathering system. Damaging effects of bacterial action include release of hydrogen sulfide (H_2S), oxygen (O_2), and other reactive gases as well as physical clogging of injection reservoir pores. Treatment usually takes the form of filtering and the addition of a good bactericide. If high amounts of dissolved and suspended organic materials are present, more elaborate treatment devices or alternate disposal methods may be required. Inorganic suspended material may cause the same brine disposal problems as precipitation and scaling.

The addition of oil magnifies disposal problems considerably. Even in amounts as small as 50 ppm oil can form a film on the surface of evaporation ponds and significantly reduce the evaporation rate from the pond. In disposal wells, oil coagulates around inorganic solids and binds them together. The effect is to produce a type of gel which can ruin an injection system. Treatment may consist of removing the inorganic solids by filtering or some type of chemical-aided settling, or by removing a higher percentage of the oil before it gets to the disposal system--even to the point of withdrawing a small amount of brine with the oil from the oil separater.

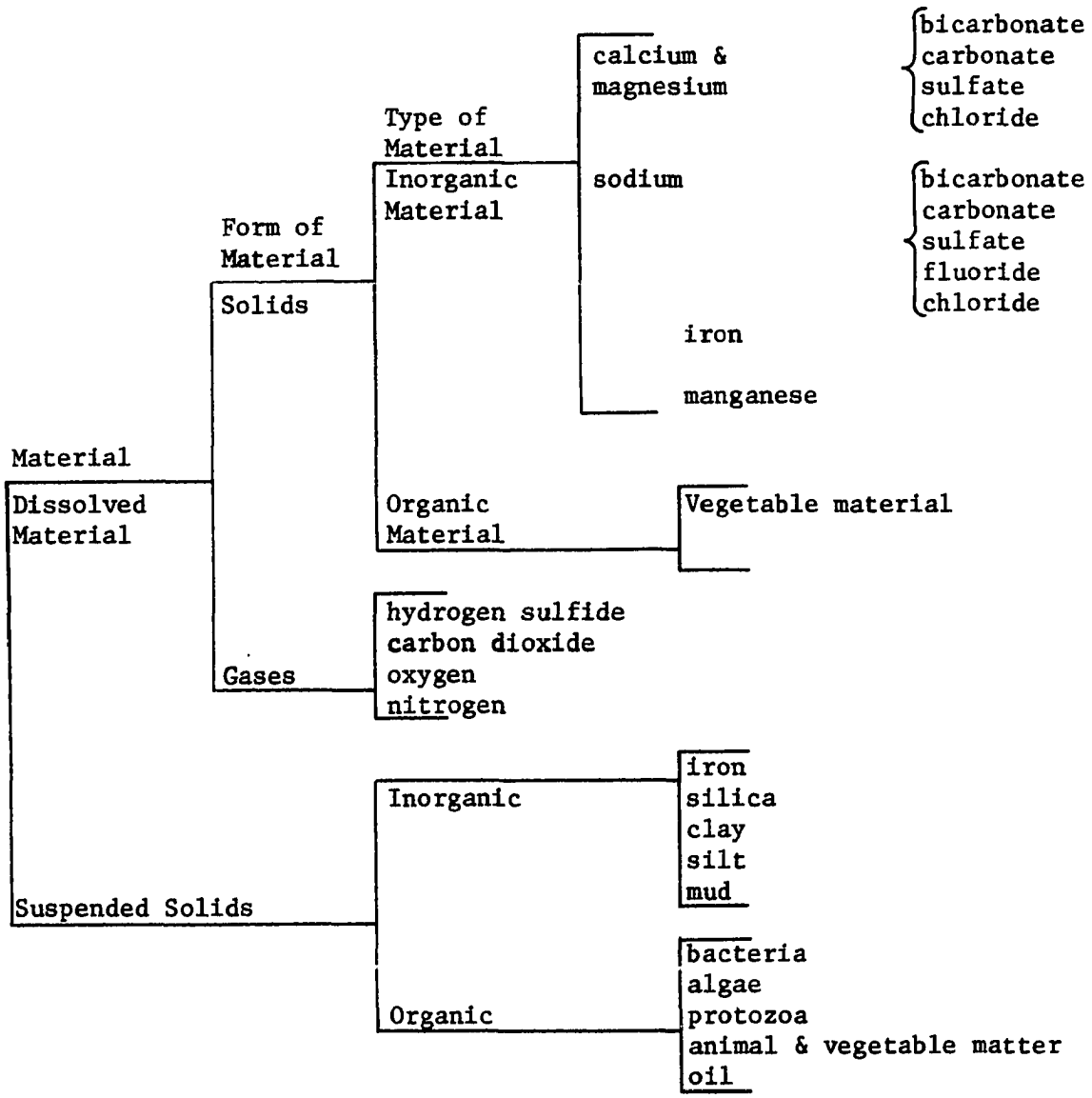
Degree of Water Treatment (68, 81)

The degree of water treatment required in a brine disposal project depends on the constitutents in the water, the type of disposal system (open or closed), the type of disposal mechanism, the kind of materials used in the well equipment, and the characteristics of the disposal formation (in the case of injection). (Secondary recovery generally requires a higher level of treatment than injection for disposal only (82).) In some instances, the combination of these factors is such that no water treatment, or at most a minimum of water treatment, is required. A closed system injecting a high quality brine into a very permeable formation may only require the addition of one or two chemicals to help prevent precipitation or corrosion. In other cases, the factors compound and require more elaborate treatment facilities. In all cases, a laboratory analysis of the brine must be made before the design of water treatment process can proceed. The common impurities of brine are shown in Table 17.

Analytical Tests

The analytical tests that are normally run on brine to be injected are listed in Appendix C. The analytical procedures, reagents, and preparation of reagents for these tests are well described in Standard Methods (84). A Bureau of Mines publication by Watkins also describes many of these tests giving field test procedures (85). As Watkins explains, "In some of the tests extreme accuracy, such as required in an analytical

Table 17. Common Impurities in Brine (83)



laboratory, has been sacrificed for rapidity and convenience. However, for most of the tests, the methods described herein are accurate enough for plant-control purposes (85).

In addition to the tests listed in Appendix C, it is often desirable to run corrosion tests to determine the weight loss for various metals expected to be used in the gathering system and disposal wells. This is accomplished by flowing the brine past a corrosion coupon (sample of the metal to be tested) that is rigidly suspended in the stream. The rate of corrosion is determined by weighing the coupon at various time intervals. Visual examinations of these coupons can also indicate the type of corrosion in some instances.

Membrane filtration tests are often used in determining the overall plugging tendencies of the suspended solids in water being injected. Membrane filters are made of cellulose ester or polyethylene and range in pore size from about 10 microns to 0.45 microns (the 0.45 micron size is used in the membrane filter test). The membrane filtration test is usually carried out at 20 psi pressure, and the volume of filtrate is determined as a function of time. From these tests, a graph of flow rate versus cumulative volume is obtained, the slope of which indicates the quality of water. A horizontal line indicates perfect water for injection purposes, while a slope greater than 1.8 indicates poor water.

Microscopic examination is also advisable to determine the presence of

microorganisms. Bacteria are the primary microbial offenders in the disposal systems of oilfield brines and can be a source of both corrosion and formation plugging. If a microscope reveals the presence of appreciable quantities of microorganisms, a more detailed examination should be conducted in a suitable laboratory to determine the nature of appropriate treatment devices.

Formation Plugging and Scaling

One of the major objectives in brine treatment is to prevent the deposits of solid material in the gathering system or, in the case of injection, in the formation surrounding the well bore.

As brine is produced from an oil well, its temperature and pressure decrease. An increase in temperature increases the solubility (tendency of a dissolved material to remain in solution) of most salts and gases. On the other hand, a decrease in pressure decreases the solubility of gases. Therefore, the usual overall effects of bringing the brine to the surface are the precipitation of salts and the release of gases from solution.

In injection, the compatibility of injected water and water already in the formation must be considered because a reaction between the chemical constituents of the two different waters may form insoluble compounds which precipitate. This condition could also occur if incompatible waters from different reservoirs or surface sources are to be mixed prior to injection.

Deposits

To deal effectively with chemical and biological deposited materials, the operator must be familiar with their specific natures and reactions. The substances most commonly deposited by oilfield brines are:

1. Calcium carbonate or calcite ($CaCO_3$); scale.
2. Magnesium carbonate ($MgCO_3$); scale or sludge.
3. Calcium sulfate ($CaSO_4$); scale.
4. Barium sulfate ($BaSO_4$); sludge.
5. Iron compounds; corrosion products.
6. Biological deposits.

Calcium Carbonate ($CaCO_3$)

The solubility of calcium carbonate in oilfield waters is influenced by the partial pressure of carbon dioxide (relative amount of the CO_2 gas dissolved in the brine compared to the amount in the atmosphere), brine temperature, and the concentration of other salts in the brine. Dissolved calcium carbonate does not exist in solution as calcium ions (Ca^{++}) and carbonate ions (CO_3^{--}) but as calcium ions and bicarbonate ions (HCO_3^-). Calcium carbonate is formed according to the equation:

$$Ca(HCO_3)_2 \rightleftharpoons CaCO_3 + H_2O + CO_2.$$

Decreasing the pH or increasing the carbon dioxide partial pressure would drive the equation to the left (i.e., increasing the concentration of calcium bicarbonate and decreasing the amount of calcium carbonate scale). Likewise an increase in the brine pH, corresponding to a decrease in the

carbon dioxide partial pressure, would cause calcium carbonate to be deposited. The latter condition usually exists when pressure is released as the brine is produced from an oil production well.

The loss of carbon dioxide from solution in brines is a function of the pH changes in the solution. If the pH of the water is near 8.0, the calcium carbonate will exist in solution as about 2% carbonate ion, 93% bicarbonate ion, and 5% hydrated carbon dioxide gas dissolved in water. If the pH were at 7.0, there would be only a trace of carbonate ions, 80% bicarbonate ions, and 20% hydrated carbon dioxide gas dissolved in the water. As discussed previously, most brines rarely exceed pH = 9.0. In fact, the usual range is pH 5.5 to pH 8.0.

The decrease in temperature and pressure in produced waters coming to the surface decreases the solubility of calcium carbonate, but in nearly all instances the loss in pressure exerts the greater effect. A decrease in the temperatures of brine being injected into a well decreases the solubility of calcium carbonate. This partially explains plugging and scaling problems encountered by injecting brine at surface temperatures into lower temperature formations.

Several equations are available for predicting the calcium carbonate scaling tendency of water. One of these is the Stiff and Davis Stability Index (65) which is an extension of the Langelier method developed specifically for oilfield brines:

$$SI = pH - K - pCa - pAlk$$

SI is the stability index value. A positive value indicates scaling conditions, whereas a negative value indicates corrosion. The ideal condition is to maintain the stability index at zero so that neither scaling nor corrosion will occur. Values for K, pCa, pAlk are obtained from graphs. The reader is referred to the Appendix section of Introduction to Oilfield Water Technology by A.G. Ostroff (65) for a more complete explanation of the method.

Magnesium Carbonate ($MgCO_4$)

Magnesium carbonate can be deposited as a scale or sludge, and its solubility in water is affected by the same factors as calcium carbonate. The difference is that magnesium carbonate is about four times as soluble as calcium carbonate. Since most waters contain both calcium and magnesium, calcium carbonate would precipitate first, thereby reducing the carbonate ion content. Thus, magnesium carbonate is not likely to precipitate unless the magnesium content is extremely high. At high temperatures magnesium carbonate decomposes into magnesium hydroxide (and other reaction products) which may form deposits in the tubing in deep, high temperature wells.

Calcium Sulfate ($CaSO_4$)

Calcium sulfate is common to oilfield brines and deposits as a scale rather than a sludge. It is more difficult to remove than calcium carbonate. Temperature variations do not influence calcium sulfate solubility as much as they do calcium carbonate, but decrease in temperature may decrease the calcium sulfate solubility causing scaling. Carbon dioxide does not affect the solubility of calcium sulfate as it did with calcium carbonate.

Calcium sulfate exists in nature as gypsum ($CaSO_4$, $2H_2O$) or anhydrite ($CaSO_4$). The anhydrite form exits at high temperatures and may be found in deep wells. Stiff and Davis have also developed a method for predicting the approximate solubility of calcium sulfate in oilfield brines (65).

Barium Sulfate ($BaSO_4$)

Barium sulfate is very insoluble and very difficult to remove once formed. The solubility of barium sulfate increases with increases in temperature and other salts concentrations. An estimate of the solubility of barium sulfate is given by the equation:

$$((Ba^{++}) - X)\ ((SO_4^{=}) - X) = K'sp$$

The barium and sulfate concentrations are determined by water analysis, and the K'sp (solubility product) found from an appropriate chemistry

table. The symbol X represents the molal concentration of barium sulfate precipitated (65).

Iron Deposits

Iron deposits in disposal systems come from two sources, the water itself or the corrosion of iron or steel in the system. These deposits may form scale or remain in the water as colloids (suspended particles). Precipitates from iron and hydrogen sulfide reactions can cause iron sulfide scales. The presence of large amounts of dissolved oxygen can cause hydrated ferrous hydroxide and ferric hydroxide scales or deposits. Dissolved carbon dioxide can cause ferrous bicarbonate scales, which are loosely held on metallic surfaces and can flake off with resultant plugging of the injection formation.

Iron in natural waters exists in such oxidation states as ferrous (Fe^{++}) ions or ferric (Fe^{+++}) ions, or as complex ions. The pH of the water influences the solubility of the ionic form; that is, at pH values higher than 3.0 the ferric ions combine with hydroxide ions to form ferric hydroxide. The solubility of the ferrous ion may be controlled by the hydroxide (OH^-) ion concentration or the bicarbonate (HCO_3^-) ion concentration. Formation waters containing dissolved iron can deposit ferrous carbonate, ferrous sulfide, ferrous hydroxide, ferric hydroxide, and/or ferric oxide.

The oxidation state of dissolved iron (ferric or ferrous form) is useful in predicting its deposition tendencies. By using a method based on the oxidation-reduction potential of the water, the pH of the water, the bicarbonate ion concentration of the water, and an iron stability diagram, the maximum permissible concentration of dissolved iron can be estimated (65).

Biological Deposits

Certain microorganisms which grow in disposal systems are able to corrode steel and form precipitates. Biological growths can also plug the injection reservoir formation face and such surface equipment as filters (77). Algae and bacteria are the primary offenders; however algae require sunlight and are able to grow only in open treatment systems. Fortunately, oilfield brines do not usually contain the necessary nutrients (chemical food materials) to support large bacterial growths.

Scale Prevention

Treatment for scale prevention may be either physical or chemical.

Physical methods include (66,81):

1. Separation of incompatible water.
2. Prevention of conditions causing supersaturation (the chemical "excess" condition which must exist prior to precipitation and scale formation).
3. Elimination of air entry.
4. Use of some type of settling or filtration mechanisms.

Treatment mechanisms require careful design and regular maintenance, and thus care should be used in their selection. Planning and analysis are necessary if the mechanism selected is to be installed without major modifications at the disposal site or in the brine gathering system.

Certain scale preventing chemicals are often added to brines as part of the treatment process. These chemicals are particularly useful in closed systems where it is necessary to avoid the precipitation of insoluble compounds. In chemical treatment the prevention of scale deposition involves either removal of the anion or cation of the scale forming combination, or the addition of a chemical scale inhibitor which ties up the scale forming cation. The inhibitor usually chelates or complexes the cations so that they remain in solution and cannot combine with the appropriate anions. The process of trying up the anions in this manner is called sequestration (86). Probably the most popular sequestering agents are the inorganic polymetaphosphates which are absorbed on the surfaces of crystal nuclei and prevent their growth. Organic chelates known as EDTA (ethylene-diaminetetracedic acid) are also useful in scale inhibitation. EDTA forms stable soluble complexes with magnesium, calcium, strontium, barium, and other divalent metals. Iron sequesting agents such as citric acid, galveonic acid, and their sodium salts have also proven useful.

Softening the water by the lime and soda ash process can remove ions such as calcium carbonate, calcium sulfate, barium sulfate, strontium sulfate, and ferrous carbonate that cause scaling.

Case (66) reports that stabilization processes consiting of coagulation (mixing), settling in open basins, and filtration can prove expensive and difficult to control--to the point of being impractical. If such is the case (or for other reasons, chemical scale inhibitors may prove a more satisfactory answer to scaling problems. One major operator reported that after extensive testing:

1. Scale-preventing chemicals only worked on chemicals that yield a crystalline form (inorganic).
2. The most effective of the scale inhibitors tested were organic polyphosphonates.
3. Combined corrosion and scale inhibitors were relatively ineffective in reducing either scale or corrosion.

Case further points out that the disposal system operator should insist on regular check-tests by chemical suppliers to assure that the scale inhibitors are performing properly.

Corrosion

The corrosion of metals in a brine disposal system is usually caused by electrochemical reactions (87). In this type of reaction an anode (electron donor) and cathode (electron acceptor) must exist in the presence of an electrolyte (ionic solution) and an external circuit. Anodes and cathodes can exist at different points on the steel surfaces with the steel providing the external circuit. A brine solution provides an excellent electrolyte. Thus, an electric circuit can be set up in the unprotected, brine-handling pipelines with iron being oxidized at the

cathode with a loss in iron ions, or corrosion, at the anode.

Corrosion damage can occur uniformly or as a gradual thinning of the anode, or it can occur in the form of pitting where localized electrolytic cells are set up. It can also occur when a difference in potential exists between the grain boundary and grain of a metal, or as galvanic corrosion when two different metals come into contact and form an electrolytic cell.

Dissolved gases (such as oxygen, carbon dioxide, and hydrogen sulfide) along with many dissolved salts are instrumental in corrosion from oilfield brines. Other influences on corrosion are pH, temperature, and the velocity of flow.

Dissolved oxygen is probably the worst corrosion producer. Oxygen-induced corrosion is the result of differences in oxygen concentrations in the system which cause an electrochemical potential difference. While oxygen is normally absent in formation waters, it is almost unavoidably absorbed from contact with air in the production-disposal cycle of oil operations.

Dissolved carbon dioxide (CO_2) is not as corrosive as dissolved oxygen, assuming equal concentrations. Carbon dioxide is present in water as an integral part of the carbonate system; however, any carbon dioxide above that necessary to keep bicarbonate in solution is termed "aggressive" carbon dioxide and is free to dissolve in water and act as an acid. Thus, the pH decreases and the corrosion rate increases with an increasing partial pressure of carbon dioxide. Water containing both oxygen

and carbon dioxide is more corrosive for equal concentrations than water containing either by itself. Carbon dioxide exerts a major influence on the solubility of calcium and magnesium carbonates. The partial pressure of carbon dioxide can be such that calcium or magnesium will form scales on metallic surfaces; however, water with aggressive carbon dioxide will not deposit a protective coating but will instead be corrosive.

Hydrogen sulfide (H_2S) is soluble in water and, when dissolved, behaves as a weak dibasic acid. Brine with dissolved hydrogen sulfide and oxygen may even be corrosive to acid-resistant alloys. The corrosion rate of mild steel when exposed to a hydrogen sulfide solution is a maximum at around 400 ppm H_2S, then drops off and becomes fairly constant to about 2500 ppm H_2S. Corrosion rates for metals exposed to hydrogen sulfide in brine are higher than those exposed to hydrogen sulfide in distilled water. And carbon dioxide is present, the corrosion rates are greater yet. Different types of steel alloys have also exhibited different corrosion rates when exposed to hydrogen sulfide.

Dissolved salts greatly affect the corrosiveness of water. Sulfate ($SO_4^{=}$), chloride (Cl^{-}), and bicarbonate (HCO_3^{-}) ions are among the most common ions in water, with the sulfate ion having the greatest effect on corrosion. The effect of ions on corrosion depends on the metal and the ion's ability to penetrate the protective coatings formed on the metal. The order of decreasing penetrating power of common anions is, progressing from most to least penetrating: chloride, bromide, iodide,

flouride, sulfate, nitrate, and monohydrogen phosphate. Similarly, the order of decreasing corrosiveness of cations (positive ions) is: ferric, chromic, ammonium, aluminum, potassium, sodium, lithium, barium, strontium, calcium, manganese, cadmium, and magnesium. The corrosiveness of waters with dissolved salts usually increases with increasing salt concentration up to a maximum, then it decreases. The decrease is due to a decrease in oxygen solubility, resulting in a decreased rate of depolarization.

The pH of the electrochemical solution influences the corrosion rate of most metals to a large extent; however the corrosion rates of the noble metals are unaffected by pH. Amphoteric metals, which form insoluble hydroxide coatings at a neutral pH but dissolve in alkaline or acidic solutions, have a U-shaped corrosion rate curve as shown in Figure 10. This class of metals includes aluminum, zinc, and lead. Metals of the class containing iron, nickle, cadmium, and magnesium have soluble hydroxides at low pH but commence precipitating and forming protective coatings at neutral pH and higher.

Temperature can affect the corrosion rate in a rather complex manner; however, the corrosion rate generally increases with an increase in temperature. The corrosion rate due to dissolved oxygen and a corresponding rise in temperature will increase, reach a maximum, then decrease. The decrease is due to an appreciable decrease in the solubility of oxygen.

Figure 10. Corrosion Rate Versus pH for Metals(72).

The effect of velocity on corrosion rate can be complex. The corrosion rate has been observed to increase as the velocity increased in small diameter pipes, possibly due to the effect of turbulence.

Bacteria can also cause corrosion in brine disposal systems with sulfate-reducing bacteria being the most damaging. These bacteria are anerobic, which means they grow in oxygen-free environments. They can, however, survive in the presence of some oxygen. In disposal systems bacteria grow under scale or other debris. Sulfate reducing bacteria often utilize hydrogen that has collected on the anode of an electrochemical cell. Hydrogen polarizes the anode, thereby decreasing or stopping electron current flow. However, the bacteria stripping the hydrogen from the anode depolarizes it and allows an increased flow of current and accompanying corrosion. In the same process a sulfate ion is produced that can combine with ferrous ions at the anode giving ferrous sulfide. Hydrogen sulfide can also be produced, which is itself corrosive. Other bacteria that contribute to corrosion in disposal systems are the iron bacteria and slime formers. These bacteria form on metallic surfaces causing oxygen concentration cells or environments for sulfate reduction.

Prevention of Corrosion

Corrosion can be prevented or at least reduced by certain brine treatments. De-aeration will remove oxygen, degasification will remove dissolved gases such as carbon dioxide and hydrogen sulfide, and water softening

will remove dissolved calcium and magnesium hardness.

Chemical substances called inhibitors are often added to reduce or prevent corrosion. However caution should be exercised in selecting a specific inhibitor because some of the inhibitors added in the incorrect concentrations can cause a corrosive condition themselves. These substances are both organic and inorganic in nature. The organic compounds usually form films on the metallic surface. Many inhibitors contain surface active agents that will remove loose scale when added for the first time and may cause plugging if precautions are not taken.

Corrosion can also be prevented by the use of coatings. Metallic coatings can be noncorrosive or sacrificial. The latter type protects cathodically, which is an electrochemical reaction that is imposed so that current and sacrificial metallic ions flow in a direction opposite to that which would normally occur. Other coatings used are vitreous enamels, cement, phosphate coatings, oxide coatings, paint, enamel, lacquer, and plastic. The correct choice of metals for brine service will prevent corrosion and reduce maintenance costs. Metals such as brass and monel do very well in salt water service.

Cathodic protection is often used to protect metallic surfaces below the water. In the protection of the submerged areas of equipment such as tanks and filters, an external current is applied so that the current enters all areas of the metallic surface that were previously anodic.

Sacrificial anodes such as magnesium and zinc are used in the protection of pipes and tanks.

Treatment Systems

Brine disposal systems are usually classified as closed (absence of air) or open (presence of air), although some systems employ features of both. Figure11 illustrates a typical oilfield brine disposal scheme.

Closed System

A closed system does not ensure a stable water for reasons discussed under the topics of scaling and corrosion; however by eliminating oxygen, precipitation of insoluble compounds and corrosion problems are usually minimized. In pressure vessels where oil water separation and emulsion treating are carried out, a closed system would be advantageous. In a closed system, an effort is made to maintain a blanket of natural gas or oil over the brine in all of the pipelines and tanks, but experience has shown that complete air exclusion is very difficult. A complete closed system usually consists of residual oil removal, probably in the form of a skimming tank, filtration and backwash, filtered water storage, and injection.

Open Systems

Open systems usually occur when the oil is separated from the water in

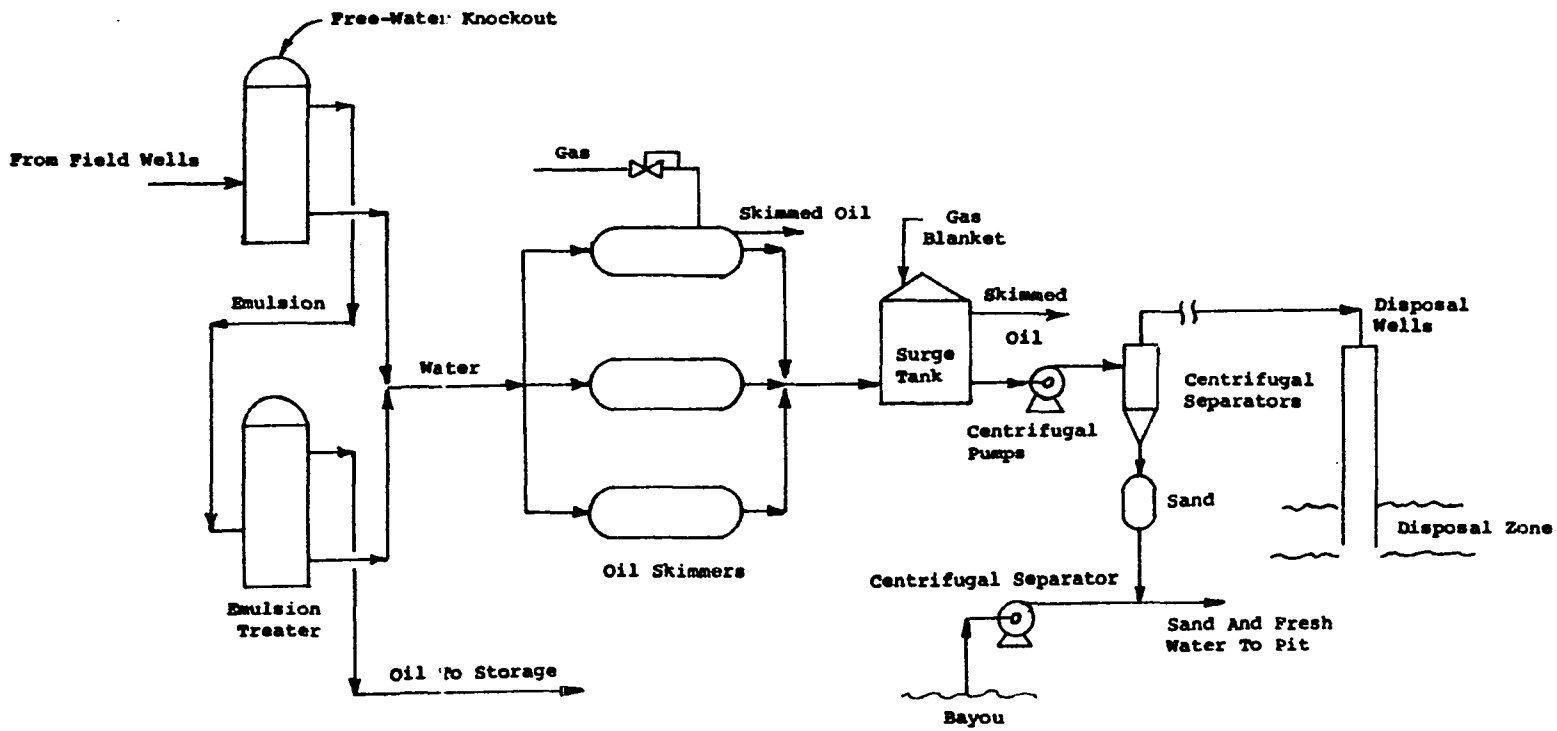


Figure 11. Typical Oilfield Brine Disposal Scheme (Bayou Sorrel SWD System - Shell)(88).

open gun-barrel type separators or when the water is stored in open pits or tanks prior to its being introduced into the disposal system. A cooperative disposal system with many operators is usually open since a variety of techniques and equipment is used to separate and store the water, much of which is open to the air. A completely open system usually consists of residual oil removal, aeration and degasification, chemical treatment including coagulation settling, filtration and backwash, storage, and injection. The additional treatment is necessary since exposure to air results in a change in the carbon dioxide partial pressure, which may cause precipitation, as well as corrosion due to free hydrogen sulfide and dissolved oxygen. Algae and aerobic bacteria are also free to enter open systems.

Oil Removal

Primary separation of oil from water is usually accomplished in free water knockouts, gun-barrel separators, or heater treaters. The efficiency of these processes are not always sufficient to ensure relatively oil-free water for introduction into the disposal system.

The ease of removing oil from water is greatly influenced by the chemical treatment or physical handling of the oil-water mixture before separation (66). Examples include:

1. Overtreating producing wells with certain scale inhibitors can stabilize emulsions.

2. Certain types of corrosion inhibitors act as emulsifying agents when used in slug treatment.

3. Certain emulsion breakers can give very clean oil, but also very stable emulsions of oil in water.

4. Centrifugal pumps can form oil-in-water emulsions.

Gravity separators are generally used in disposal systems to remove as much residual oil as possible from the water. (Horizontal pressure vessels are often used in closed systems.) One section of the separator vessel has a filter media which screens out large droplets of oil and smooths out the flow. Another section of the vessel is used for gravity separation. The oil rises and is skimmed off through a riser. Open systems often utilize large open concrete basins with baffles and slotted-pipe collectors to accomplish the separation and skimming. These basins are often similar to the conventional API separator used in oil refineries and may be wood or steel tanks. A typical skim tank is shown in Figure 12. A vertical baffle aids in gravity separation and the floating oil is skimmed off through a trough. Skim tanks are suited for both open and closed systems. Wood tanks are preferred in many instances for their corrosion resistance.

Flotation is a highly efficient method to remove oil from water, providing the load is less than 100 parts per million and an emulsion does not exist (66). Flotation is a process in which gases are dissolved in the water under pressure. On release of the pressure, bubbles form, become attached to the oil and particulate matter, and then float the oil matter

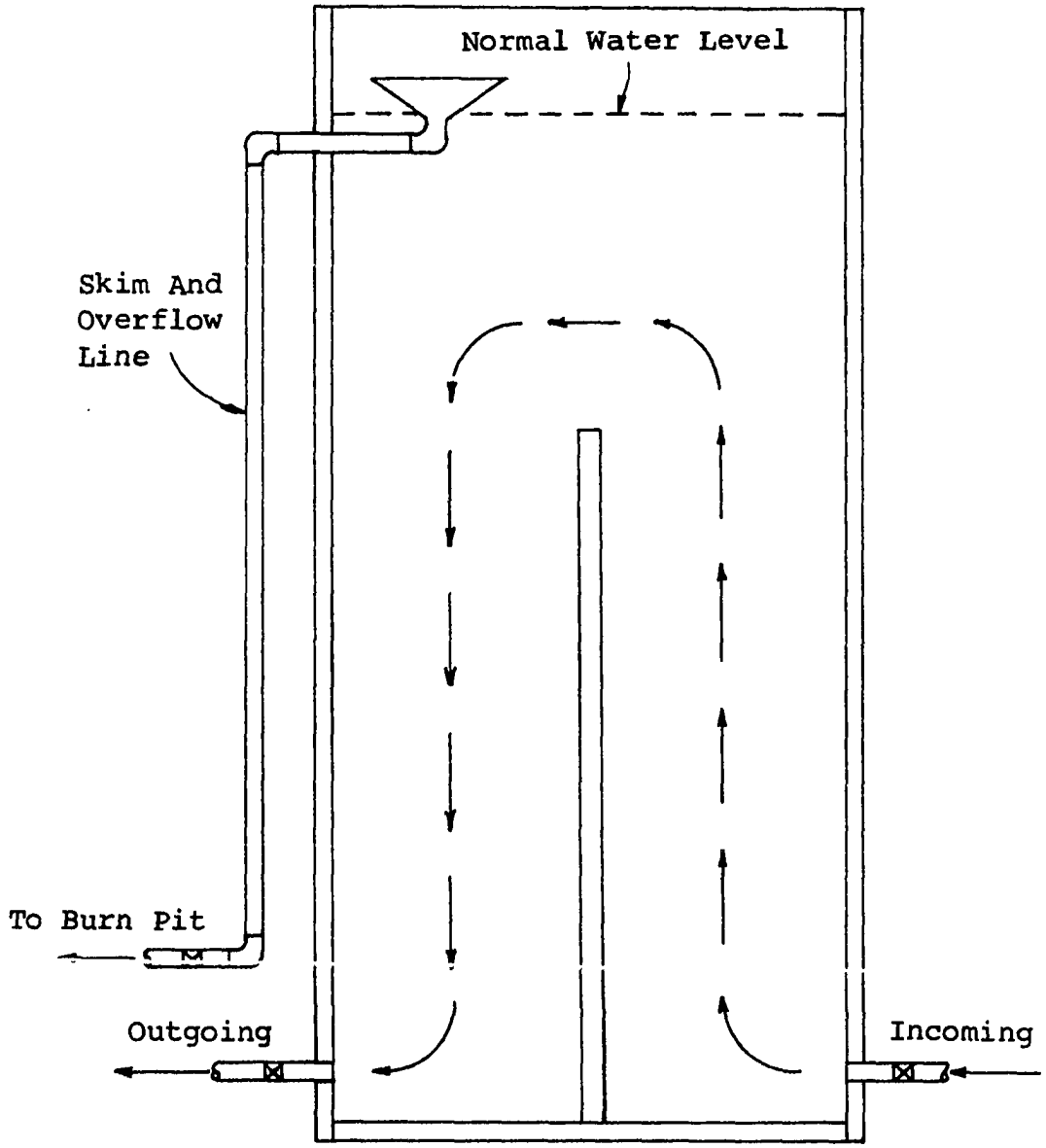


Figure 12. Sectional View of Skim Tank(53).

to the surface where it can be skimmed off. If the flotation unit becomes overloaded when oil or emulsions are present, the addition of absorbent clays followed by a polyelectrolyte is recommended. Alum, a coagulant used in municipal water treatment, will also aid a flotation cell that is overloaded or receiving emulsions.

Oil can also be removed by filtration. This process is usually incorporated in brine disposal systems to remove suspended solids and can, therefore, serve a dual purpose. It should be remembered however, that a filter cannot be overloaded with oil or it will rapidly plug up.

Aeration and Degasification

In open systems brine is aerated for two primary purposes. The first purpose is to drive all acid causing gases (carbon dioxide and hydrogen sulfide) out of solution and reduce corrosion. The second is to oxidize iron and form precipitants which will be retained in the settling basins or on the filters, which prevents these precipitates from coming out of solution in another part of the system or in the formation. If manganese is present, it will also be oxidized and precipitated. Aeration has one disadvantage in that oxygen is dissolved in the water and will cause corrosion downstream in the system. For this reason excess aeration should be avoided.

Aeration equipment usually consists of spray nozzels, atmospheric towers where the water cascades over a series of splash trays, forced draft

blowers where air is forced countercurrent to a flow of water cascading over splash trays, or free-fall or step-type aerators where the water falls on a spreader or tumbles down a series of steps.

Aeration is the most popular method of degasification in open brine disposal systems; however, carbon dioxide and hydrogen sulfide can also be removed in stripping towers or by vacuum degassing.

Coagulation and Sedimentation

Coagulation and sedimentation processes are used in open treatment systems to remove the suspended solids and precipitates that have formed due to equilibrium changes and aeration. In some disposal systems, sedimentation is employed without the help of chemical aids. The settling process in this case is known as plain sedimentation. The design of settling basins is based on the settling velocity of the smallest particle specified. The settling velocity of a particle in a liquid is function of the specific gravity and viscosity of the liquid and the specific gravity, size, shape, and possibly concentration of the particles. The sedimentation basin can be rectangular or circular in shape with the fluid flow being either horizontal or vertical. A term generally used in the design of sedimentation basins is called the loading rate or flow rate per unit of surface area (Q/A). The average value for loading rate is between 600 and 1,200 gallons per day per square foot of sedimentation surface area, and the outlet weir loading rate usually is set at 30,000 gallons per day

per foot of weir length (70). Experience has shown that these rates ensure an even distribution throughout the basin if it is properly designed to prevent fluid short circuiting (fluid flow directly from inlet to outlet with no settling time).

Chemicals called coagulants are often added prior to sedimentation to speed up and increase the efficiency of the process. This allows for smaller sedimentation basins and lower initial cost. Coagulation consists of feeding the chemicals, followed by a rapid mix of about 2 minutes, and then by a slow mix called flocculation for about 30 minutes. The chemicals or coagulants used are aluminum sulfate (alum), ferrous sulfate, ferric sulfate, ferric chloride, and sodium aluminate. Coagulation is designed mainly to remove minute, suspended particles called colloids in the size range of 1 to 200 millimicrons. Colloids are essentially nonsettleable because of their small size and cannot be removed by plain sedimentation. Colloids may be both organic and inorganic. The colloids of particular interest in a treatment system are compounds of iron such as ferric hydroxide. The addition of coagulants in the rapid mix phase involves the neutralization of the predominantly negatively charged colloids by adding an excess of positively charged particles. These are usually hydrous oxide colloids formed by the reaction of the coagulant with ions in the water. The hydrous oxide particles form flocs which attract the negative colloids. During the flocculation or slow-mix phase, the fine floc particles are collected into larger floc particles that can settle out more rapidly. Slow mixing must be done at very low fluid velocities to prevent physically breaking the floc particles.

The various coagulants will only operate effectively within certain pH ranges. The pH range for alum is 5.5 to 8.0 with 6.0 to 7.0 being optimal. Hydrated lime is usually added to adjust the pH of this range. Other chemical additions may include compounds called coagulation aids which are sometimes used in conjunction with the basic coagulating chemicals. Coagulation aids include such compounds as activated silica and polyelectrolytes which aid in the formation of larger, stronger, and denser flocs.

Coagulation, flocculation, and sedimentation can be accomplished in three different tanks or basins; however, in municipal and industrial water treatment there is often a combination basin employed. These combined units are referred to by such brand names as "Cyclator," "Accelator," or "Precipitor" and employ upflow sedimentation.

Centrifugal separators (desanders) have also been used to supplement gravity separation in the removal of solids from injection water (70).

Filtration

Filtration is a treatment process usually included in both closed and open systems. In closed systems it is the primary means of removing suspended solids whereas in open systems it is used to remove floc particles that were not removed in the sedimentation process. The types of filters used in brine disposal systems are the slow sand filter, the rapid sand filter, and diatomaceous earth filters.

Slow Sand Filters

Slow sand filters are composed of sand bedding with the top layer of sand used as the filtering media. A disadvantage of this type of mechanism is that the sand bedding material can not be back-washed or cleaned; rather it must be removed and replaced after clogging.

Wright (72) indicates that the slow sand filter has been superseded by the rapid sand filter in all new installations built in recent years because slow sand filters are relatively inflexible and require too much surface area.

Rapid Sand Filters

Rapid sand filters are classified as gravity sand filters or pressure sand filters. The gravity filter is usually open to the atmosphere, whereas the pressure filter is enclosed in vessels and operated at elevated pressures which can increase the flow rate and prolong the filter cycle. Gravity filters are usually operated at a rate of 2 gallons per minute (gpm) per square foot of filter surface area, whereas pressure filters may be operated at 3 gpm per square foot. Rapid sand filters usually have a layer of sand on layers of graded gravel; however, in some instances coal or "anthrafil" has been used in place of the sand, or as another layer on top of the sand. Filtration does not occur on the top layer of a rapid filter as it does in a slow filter. Instead, the particulate matter is adsorbed on the sand at different depths.

The filter media must be periodically back-washed to remove the filtered sediment. This means that when the pressure drop through a filter exceeds a certain value it is taken off line and backwashing is commenced. The reverse flow of water up through the filter media must expand the bed in the order of 30 to 50 percent of its normal depth to provide enough permeability for the wash water to thoroughly remove entrapped sediment. The back-wash rate is in the order of 12 to 15 gallons per square foot of filter surface area per minute and is applied for about 5 minutes. The backwash cycle stratifies the sand, arranging the fine sand on top and the coarse material on the bottom of the filter bed.

The theory and design of filters, as well as the other unit operations involved in water treatment are fairly complicated to design and operate; however these proceedures are well documented (89). See Figure 13.

Diatomaceous Earth Filters (70)

Diatomaceous earth filters consist of screens on which a pre-coat of asbestos fibers and diatomaceous earth is laid. A slurry of diatomaceous earth called filter aid, body feed, or slurry feed is then added continuously to the fluid. These filters can deliver a high quality water with less than 1.0 ppm suspended solids when properly run.

Diatomaceous earth filters have been used extensively in water treating plants in California (72). Wheeler has indicated the following advantages of diatomaceous earth filters over sand filters:

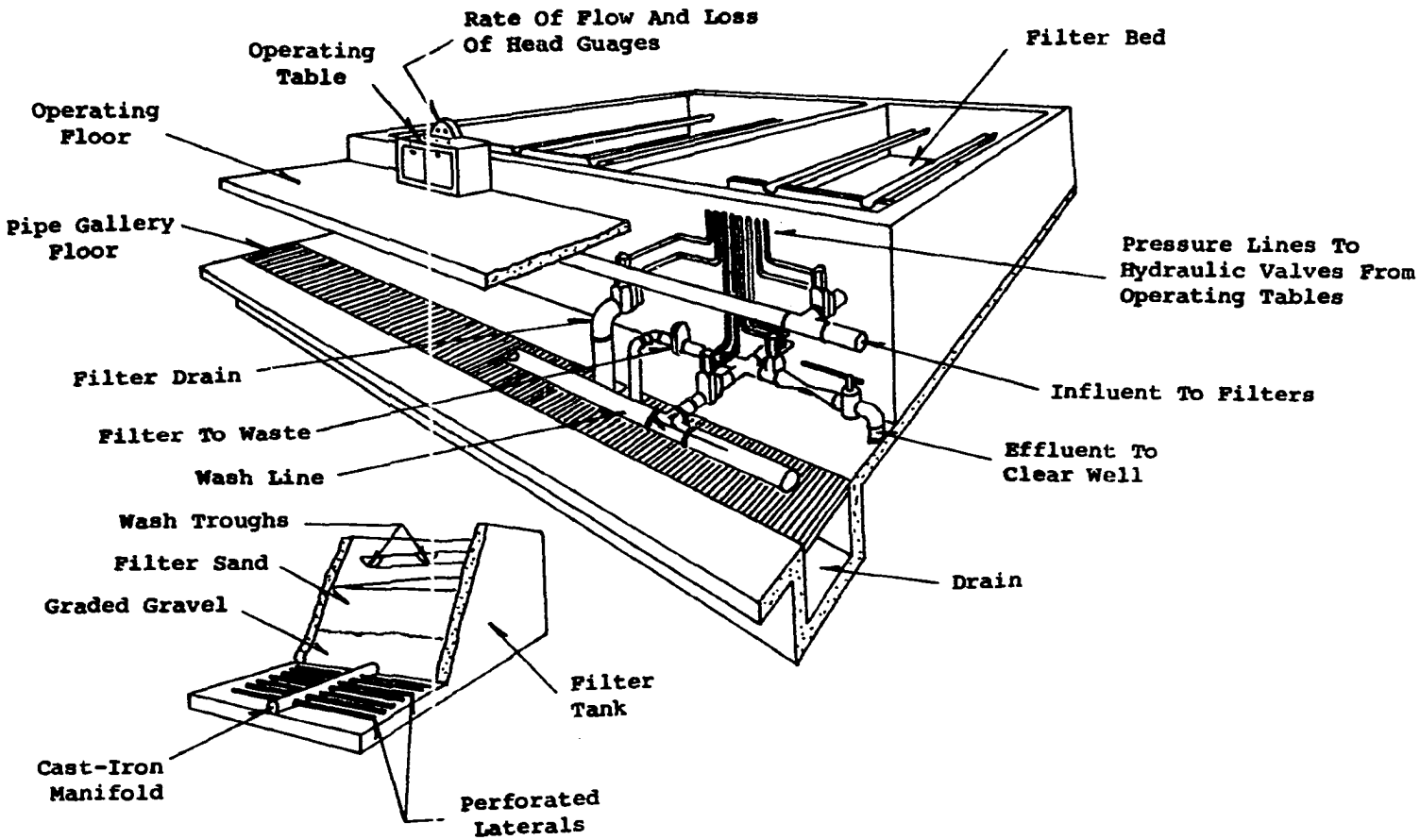


Figure 13. Rapid Filter and Accessory Equipment(89).

1. They require considerably less backwash water to clean the filter.

2. They can handle a small amount of oil that would, under the same circumstances, plug a sand filter.

3. They contain more filter area per unit volume, and are therefore smaller and more compact.

In some disposal application, proper brine water treatment can be the most difficult phase of the entire operation, as well as the most expensive. The previous section treated generally with the major topics involved, and the prospective operator would do well to refer to Introduction to Oilfield Water Technology (65) and Water Problems in Oil Production, An Operator's Manual (66) for a more complete presentation brine water treatment.

SECTION VIII

ANALYSIS OF DISPOSAL ALTERNATIVE

At this point the prospective brine disposal mechanism operator should begin to consider his own disposal needs (90). In this regard, the assumption is that he will have to answer two basic questions:

1. What type of disposal system do I need?
2. How much will it cost me to construct and operate an appropriate disposal system on an annual basis?

The answer to the first question is provided, basically, by the specifications of the oil regulating agency in each state as well as the physical considerations of each system. Specific design arrays of brine disposal systems from desalination processes have been developed in other publications in a manner which can be extremely useful (91). These arrays will be presented, after conversion to appropriate terminology, in this section.

Although the methods were not developed for oilfield brine disposal per se, the data and design information used either came from actual oil operations or from general groundwater and seepage relationships which were adapted to brine disposal activities. As a further note, a special effort has been made to present these analytical methods in a logically consistent manner, supplemented by clarifying instructions, to result ultimately in realistic, relatively simple, easy to follow procedure. In addition, a computer program (Appendix E) has been prepared for calculating new construction general configuration designs and costs. The derivations of

formulaic relationships used in these analyses are developed in Appendix D. Along with each calculation are the necessary terminology and explanations to complete the cost analyses. However, the analyst may also find the accompanying summary helpful in keeping track of the analysis steps.

Analysis for Direct Discharge or Conveyance

Basically this analysis develops the design configuration of pure water flowing in a pipeline from the point of brine collection to the direct discharge site or to the brine water treatment plant if this operation is necessary. In function, the supply pipeline and pumping analysis is that of simple fluid transport and remains the same whether used to transport the brine to the direct discharge site, evaporation pond or pit, injection site, or to another piece of equipment such as a treatment system or storage tank. Of course, many areas use tank trucks to haul the brine from the production site to the disposal site, and discharge either directly into the disposal mechanism or into a holding tank or small water treatment plant. If such is the case, the cost in dollars per barrel will already be known and can be added to disposal mechanism cost in determining total and annual disposal costs, in place of the pipeline and pump cost figures used in this analysis.

Direct Discharge Analysis

The following information is required before beginning the analysis:

1. Quantity of brine to be disposed of in gallons (42 gallons per barrel) per day (X_B): _____gpd

2. Quantity of oil in gallons per day produced with brine (X_o): _____gpd

3. Number of years of project (Y): _____years

4. Company's average cost of capital or discount rate (i): _____decimal fraction

5. Length of pipeline in miles from brine collection point to discharge point (F'): _____miles

6. Discharge elevation in feet above (-) or below (+) brine collection point (EL): _____ft.

7. Cost of right-of-way (assume a 30 foot wide strip at a land cost of $109/acre--unless better cost can be obtained) (ROW): _____$

8. Cost of pipe per foot (CPU): _____$/ft.

9. Cost of cement pipe lining per foot (CCU): _____$/ft.

10. Cost of pipe installation per foot: _____$/ft.

11. Cost per kilowatt hour of electricity (ECU): _____$/KWH

12. Current year Engineering News Record Building Cost Index (ENRBCI): _____

13. State specifications for design.

Direct Discharge

1. If the pipe requires a cement liner, calculate the inside diameter required (I.D.), assuming a liner thickness of .25 inch:

$$I.D. = (X_o^{.45})\ (.017) + .50$$ _____I.D., inches

if no liner:

$$I.D. = (X_B^{.45})\ (.017)$$

2. Enter O.D. corresponding to cement-lined:

$$O.D. = (1.07)\ (I.D.) = I.D. + \tfrac{1}{2} \text{ inch}$$ _____O.D., inches

3. Enter weight per foot (total) of pipe: _____lb/ft.

4. Enter yield pressure of pipe used (P_s): _____psi

5. Calculate head loss due to friction (H_f) for water flowing through a cement-lined pipe:

$$H_f = (.003)\ (5{,}280)(F')$$ _____ft.

6. Calculate the required pumphead (H_p):

$$(H_p) = \text{discharge elevation} - H_f$$

$$H_p = E - H_f$$ _____ft.

7. Calculate the required pump discharge pressure (which is also the minumum allowable yield pressure for the pipe):

Pump discharge (P_D) = .434 pumphead (H_p) _____psi

8. If calculated for more than one size of pipe, compare the pipe yield pressure (P_s) with the

calculated yield pressure (P_D) and select least expensive pipe whose yield pressure (spec) $\geq P_D$

9. Pump requirement? _____yes _____no

(A pump will be required if H_p is (-).)

10. Pump power requirements:

a. Hydraulic horsepower = HHP = $\frac{(X_B)\ (P_D)}{(2.468)\ (1{,}000{,}000)}$

_____HHP

b. Brake horsepower = BHP = $\frac{\text{Hydraulic horsepower}}{\text{Pump efficiency}}$

_____BHP

(Assume pump efficiency = .85 if not stated.)

c. Kilowatt hours = KWH

$$KWH = \frac{\text{(Brake horse power) (.7457)}}{\text{(Motor efficiency) (BHP)}}$$ _____KWH

(Assume motor efficiency = .93 if not stated.)

11. Calculate pump capacity:

Pump capacity = gpm = $\frac{X_B}{1440}$ _____

Data Summary

1. Supply pipeline and pump:

a. Length of line _____F, feet

b. Pipe size (cement-lined): _____I.D., inches

c. Pipe size (cement-lined): _____O.D., inches

d. Pipe grade, weight per foot: _____lb/foot

e. Pump required: _____yes _____no

2. Pump power requirements

   a. brake horsepower: _____BHP

   b. kilowatts: _____KWH

Cost Procedure for Direct Discharge

1. Cost of pipe:

   a. Cost per foot (CPU): _____$/ft.

   b. Cost of Pipeline (CP) = (F) (CPU): _____$

2. Cost of cement lining (see Figure 14):

   a. Cost of cement lining per foot (CCU): _____$/ft.

   b. Cost of lined pipe (CC) = (F) (CCU): _____$

3. Subtotal (ST_1):

   ST_1 = CP + CC: _____$

4. Construction cost subtotal (ST_2):

   a. Piping installation cost (CI) = (F)

      ($/foot installed) _____$

   b. Cost of right-of-way (ROW):

      Cost of right-of-way=(ROW) = (F)

      ($/foot right-of-way) _____$

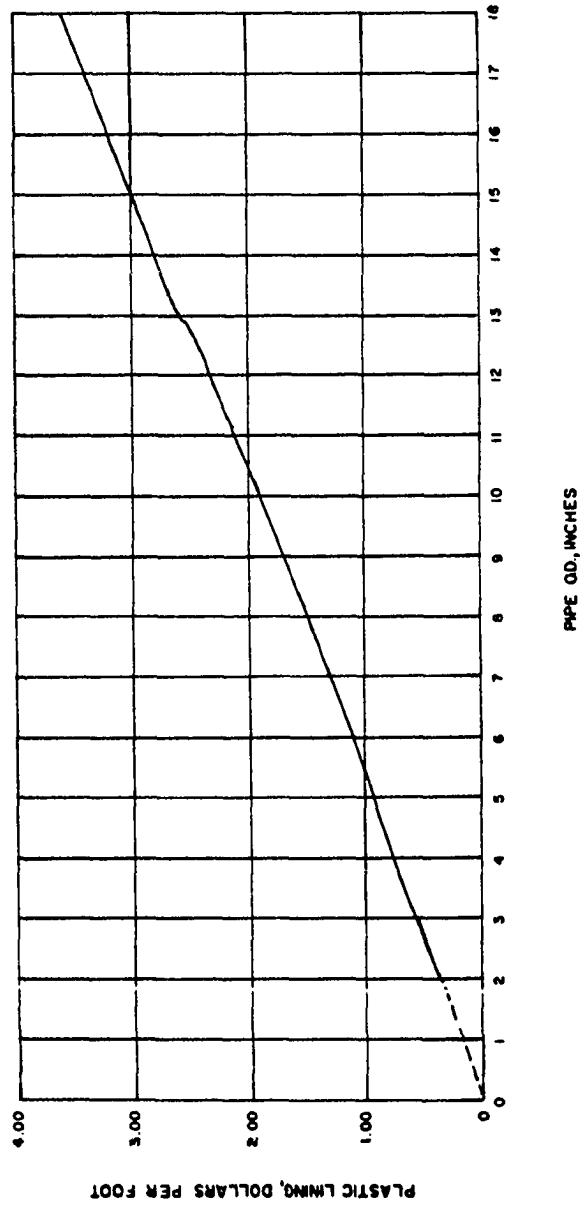
5. Pipeline Construction cost (ST_2):

   $ST_2 = ST_1 + CI + ROW$ _____$

Supply Line Cost

1. Capital cost:

   a. Cost of pipeline (ST_2) _____$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 14. Cost of Plastic or Cement Lining of Pipe in Dollars per Foot Versus Outside Diameter of Pipe in Inches(92).

b. Contingencies (.10) (ST_2):

(Assume 10% of pipeline cost.) _____$

c. Engineering (.10) (ST_2 + contingencies):

(Assume 10% of pipeline and contingencies cost.) _____$

d. Interest on construction (i_c):

(Assume 1.625% of cumulative capital costs.)

$i_c = (.01625)\ (ST_2 + \text{contingencies} + \text{engineering})$ _____$

e. Capital cost (CC_p):

$CC_p = ST_2 + \text{contingencies} + \text{engineering} + i_c$ _____$

2. Annual expenditure ($/yr):

a. Annual amortized expenditure (A_p):

$$A_p = (CC_p)_2 \left[\frac{i\ (1+i)^Y}{(1+i)^Y - 1} \right]$$ _____$/yr.

b. Operation, Maintenance, and Supplies (O_p):

(Assume .25% of capital cost.)

$O_p = (.0025)\ (CC_p)$ _____$/yr.

c. Interest on working capital (i_{wc}):

(Assume .7% of all annual expenditures.)

$i_{wc} = (.007)\ (A_p + O_p)$ _____$/yr.

d. Total annual expenditure = TAE_p:

$TAE_p = A_p + O_p + i_{wc}$ _____$/yr.

Pump Station Cost

1. Capital cost (knowing brakehorsepower, determine cost of pump and motor; see Figure 15).

   a. Cost of pump (P_{cu}): _____$

   b. Contingencies (.10) (P_{cu}):
   (Assume 10% of pump cost) _____$

   c. Engineering (.10) (P_{cu} + contingencies):
   (Assume 10% of pump cost and engineering) _____$

   d. Interest on construction (i_c):
   (Assume 1.625% of cumulative capital costs.)
   $i_c = (.01625)$ (P_{cu} + contingencies + engineering) _____$

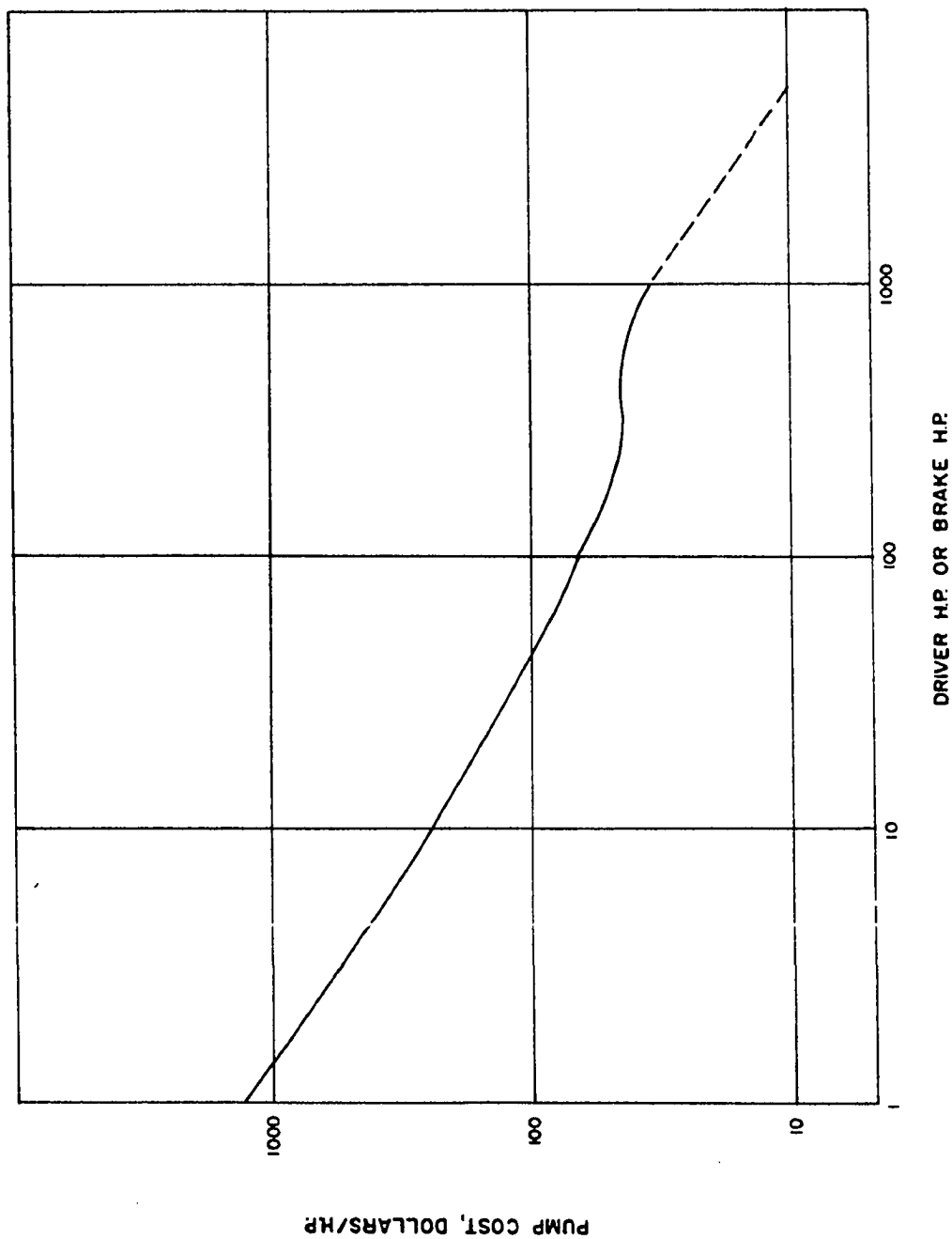
   e. Capital cost (CC_{PS}):
   $CC_{PS} = P_{cu}$ + (contingencies + engineering + i_c) _____$

2. Annual expenditure ($/yr):

   a. Annual amortized expenditure (A_{PS}):
   $A_{PS} = (CC_{PS}) \left[\frac{i(1+i)^Y}{(1+i)^Y-1}\right]$ _____$

   b. Materials and supplies (M_{PS}):
   (Assume .25% of capital cost.)
   $M_{PS} = (.0025)\ CC_{PS}$ _____$/yr.

   c. Power cost (EC):
   EC = (KWH) (ECU) 8760 hr/yr _____$/yr



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 15. Cost of Installed Centrifugal Pump and Motor in Dollars per Horsepower Versus Brake Horsepower(92).

d. Operations and maintenance (OM):

(Obtain estimate from curve in Figure 16.) _____$/yr

e. Payroll overhead (PO = (.15) (OM):

(Assume 15% of operations and maintenance cost.) _____$/yr

f. General and administrative (GA):

(Assume 30% of operation and maintenance, and payroll overhead cost.)

$GA = (OM + PO)\ (.30)$ _____$/yr

g. Interest on working capital (i_{wc}):

(Assume 7% of other annual costs.)

$i_{wc} = (.007)\ (A_{PS} + M_{PS} + EC + OM + PO + GA)$ _____$/yr

h. Total annual expenditure (TAE_{PS}):

$TAE_{PS} = A_{PS} + M_{PS} + EC + OM + PO + GA + i_{wc}$ _____$/yr

3. Total unit cost of supply pipeline and pumping per barrel of oil (TUC_{OPPS}):

$$TUC_{OPPS} = \frac{(TAE_P + TAE_{PS})\ (42)}{(X_o)\ (365.)}$$ _____$/brl oil

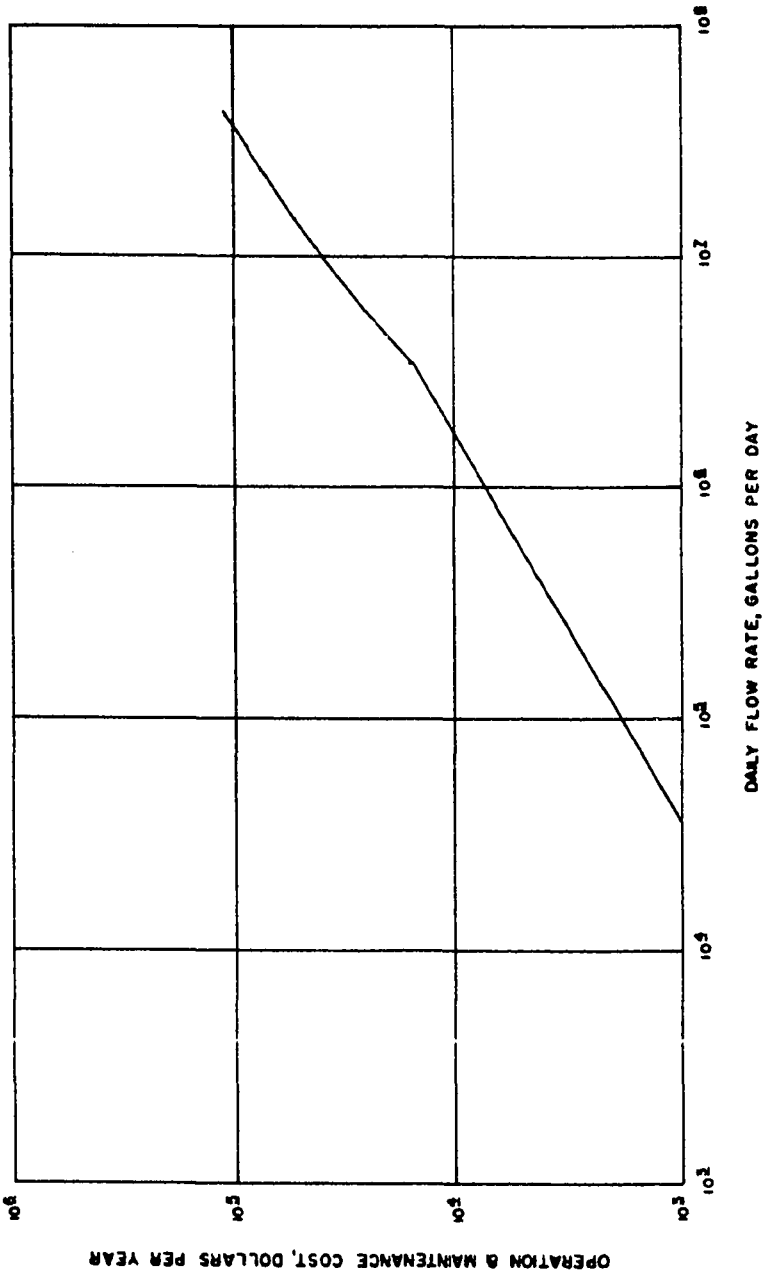
4. Total unit costs of supply pipeline and pumping per barrel of brine handled (TUC_{BPPS}):

$$TUC_{BPPS} = \frac{(TAE_P + TAE_{PS})\ (42)}{(X_B)\ (365.)}$$ _____$/brl brine

Total Direct Discharge System Cost (Pipeline + Pumping)

1. Total capital cost (TCC_{PPS}):

$TCC_{PS} = CC_P + CC_{PS}$ _____$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 16. Estimated Operation and Maintenance Cost for Pump Station Station or Well Field in Dollars per Year Versus Daily Flow Rate in Gallons per Day(93).

2. Total annual expenditures (TAE_{PPS}).

   $TAE_{PPS} = TAE_P + TAE_{PS}$ _____$/yr.

3. Total unit cost per barrel of oil produced (TUC_{OPPS}): _____$/brl oil

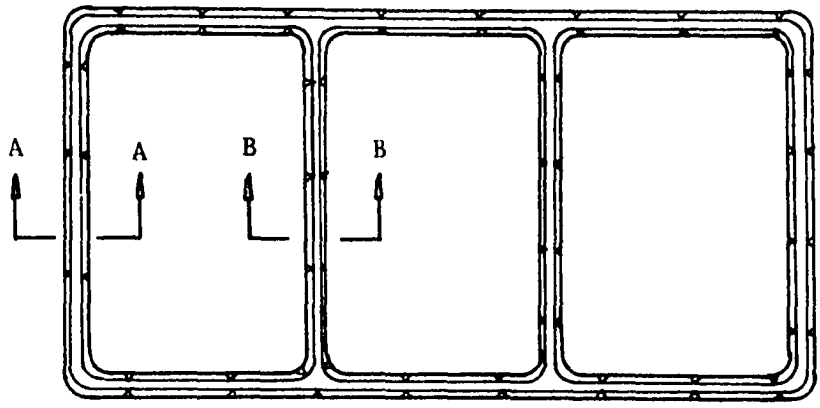
4. Total unit cost per barrel of brine handled (TUC_{BPPS}): _____$/brl brine

Analysis for Evaporation Pond or Pit

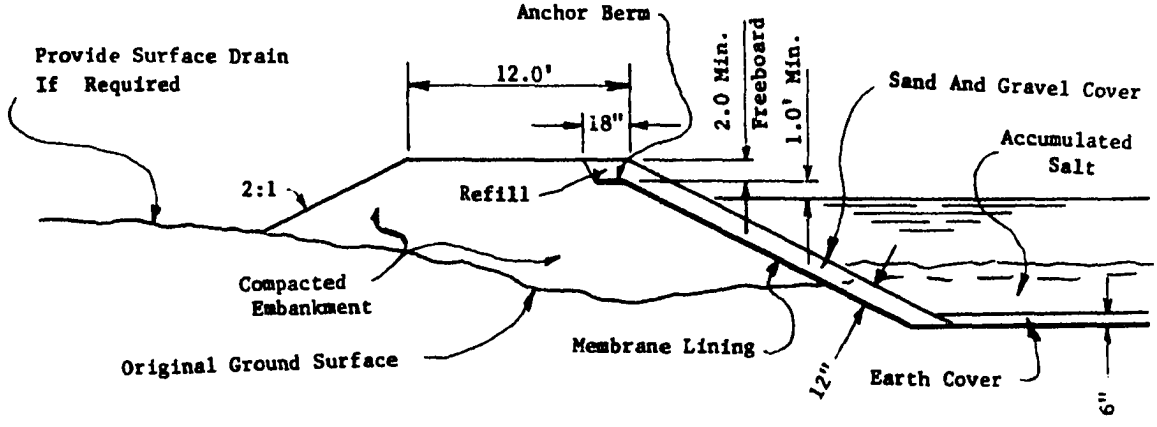
This analysis considers only the design configuration and associated approximate costs necessary to develop an appropriate evaporation pond (see Figure 17). The evaporation unit is assumed to be installed at the discharge end of the pipeline previously developed in the direct discharge analysis; i.e., the complete evaporation system would involve both the direct discharge analysis from the point of brine collection to the inlet of the evaporation pond and the analysis for the evaporation pond. From a cost point of view, this means that the total evaporation system cost equals the sum of the costs associated with the pipeline and pumping, those associated with the evaporation pond, and those associated with any treatment and/or storage units which might be needed.

Evaporation Pond

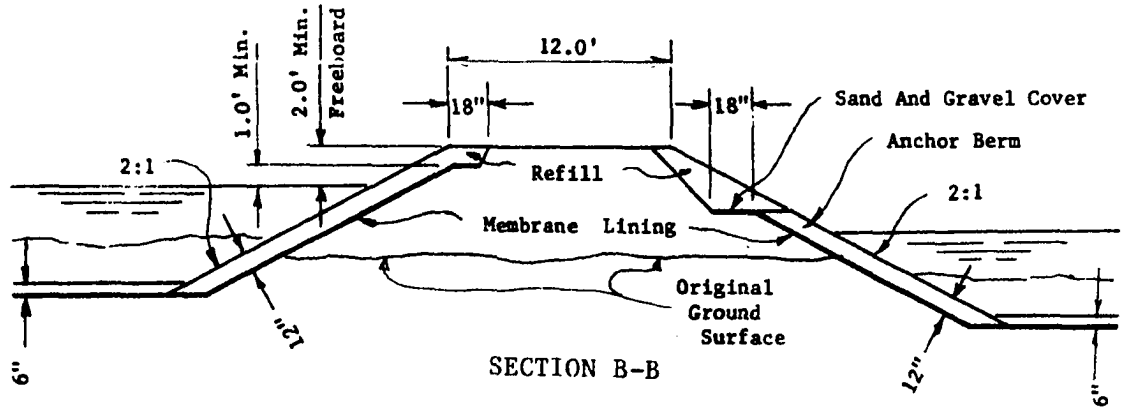
Assuming the brine is piped to the evaporation site, the following information is required before beginning the analysis. From pipeline and pump (Direct Discharge):



PLAN



SECTION A-A



SECTION B-B

Figure 17. Typical Plan and Sections for Brine Disposal Ponds(63).

1. Total capital cost (CC_{PPS}): _____$

2. Total annual expenditure (TAE_{PPS}): _____$

3. Total unit cost per barrel of brine handled (TUC_{BPPS}): _____$/brl brine

4. Total unit cost per barrel of oil produced (TUC_{OPPS}): _____$/brl oil

The following information will also be used in the analysis.

1. Average quantity of brine in gallons per day to be disposed of (X_B): _____gpd

2. Total dissolved solids in brine (Q_B): _____ppm_{TDS}

3. Quantity of oil in gallons per day produced with the brine (X_o): _____gpd

4. Number of years of project (Y): _____yrs

5. Campany's average cost of capital or discount rate (i): _____(decimal fraction)

6. Land cost (CLU): _____$/acre

7. Cost of electricity per kilowatt hour (ECU): _____$/KWH

8. Net evaporation rate (NER)
(See disposal pond section for evaporation rate calculation methods.) _____in./day

9. 24-hour point rainfall depth for 50-year recurrence (storm) interval: _____ft.

10. Liner cost installed if liner used (or assume $.031/$ft^2$): _____$/ft^2

11. Cost of clearing land (or assume \$100/acre): _____\$/acre

12. Cost of liner fill if liner used (or assume \$.40/yd^3): _____\$/yd^3

13. Cost of excavating dike (or assume \$1.00/yd^3): _____\$/yd^3

14. Current year Engineering News Record Building Cost Index (ENRBCI): _____

15. State specifications for design.

Evaporation Pond Analysis

1. The actual number (or fraction) of acres required for the pond depends on the evaporation rate, depth of brine to be maintained in the pond (combined with the flow rate of the incoming brine), and the general amount of land available either due to physical or economic limitations. In effect there is a balance between capacity and land area, with overriding topological considerations. In addition, the average daily amount of brine flowing into the pond (X_B) is assumed to be constant and contain insufficient oil to form an evaporation retarding film on the surface of the pond. (As little as ½ pint of oil form a film on an evaporation pond with a surface area of one acre.)

$$SA = \text{Surface area required (acres)} = \frac{X_B}{*NER\ (\ 2.72 \times 1.0^4)}$$

*It should be pointed out that the net evaporation rate (NER) should be adjusted for brine salinity as indicated in the earlier section on evaporation.

Although the recommended average evaporation pond liquid depth is 1 to 1.5 feet, the operator may want to increase the liquid depth to accomodate much higher brine quantities being produced than anticipated, long periods of humid weather with no wind decreasing the evaporation rate, or excessive rainfall. Thus, he may actually maintain the 1 to 1.5 foot level but increase the liquid depth capacity to 2 feet or even 4 feet.

Design pond brine liquid depth capacity_____feet

2. Another factor to consider is that as the water is evaporated from the brine, the suspended and dissolved material accumulate at the bottom of the pond as a residue. The depth of this accumulated residue may be obtained in the following manner.

First, having obtained the brine salinity by chemical analysis, locate the decimal fraction of deposit per foot of brine depth per year corresponding to the salinity of the inflowing brine from Figure 18. Next, knowing the inflow volume of brine in barrels per day, (X_D) (42), and the surface area of the evaporation pond in acres, locate the depth of brine per year from Figure 19. This depth, when multiplied by the decimal fraction of residue per foot of brine previously determined, gives the number of feet of residue which can be expected to accumulate each year in the evaporation pond. Assuming that the brine flow rate and salinity remain constant over the life of the evaporation pond, multiply the project life, in years, by the number of feet per year of residue

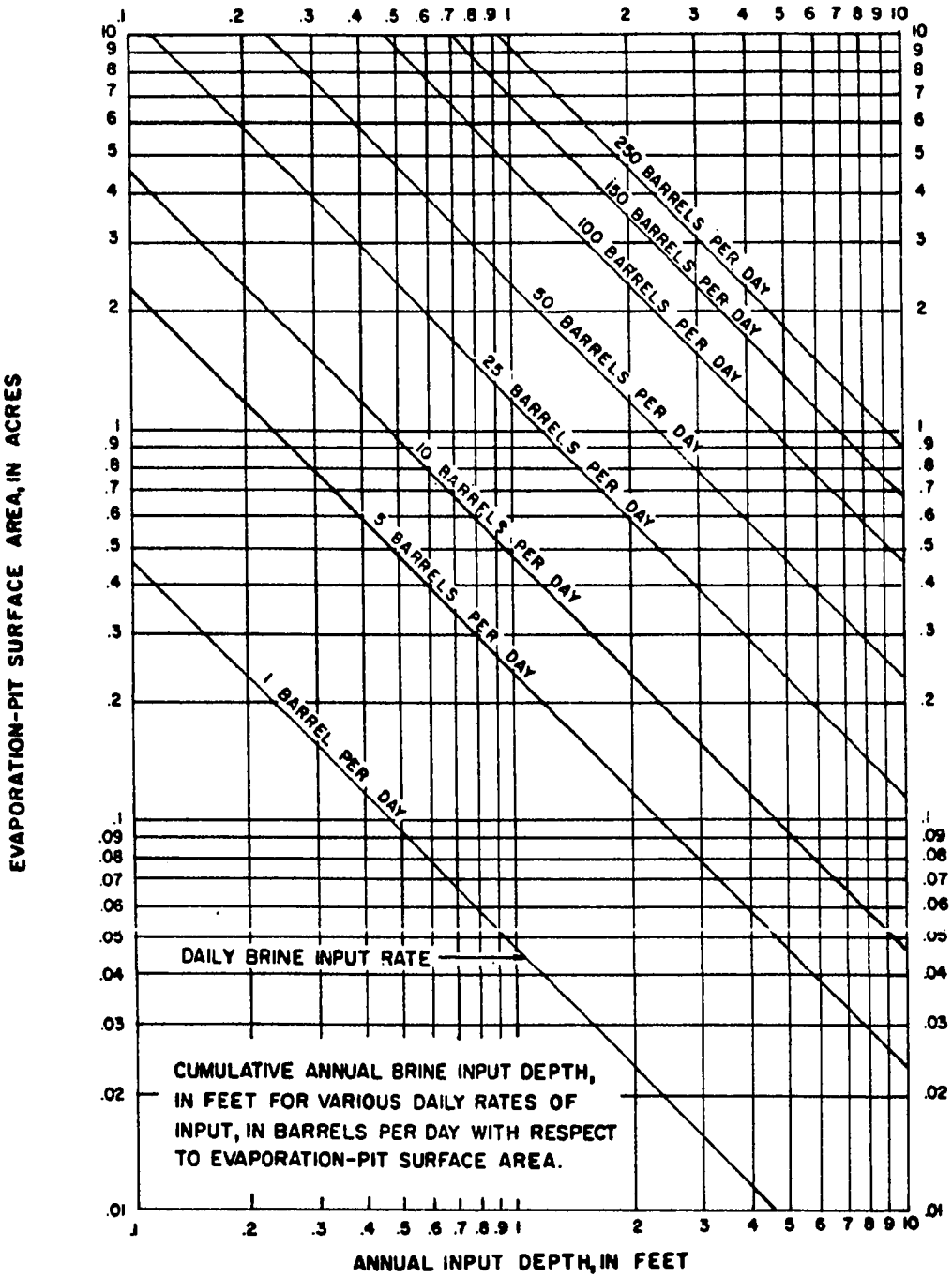


Figure 18. Evaporation Pond Surface Area in Acres Versus Annual Input Depth in Feet for Determining the Depth of Precipitate Deposited in One Year for Various Daily Rates of Input(63).

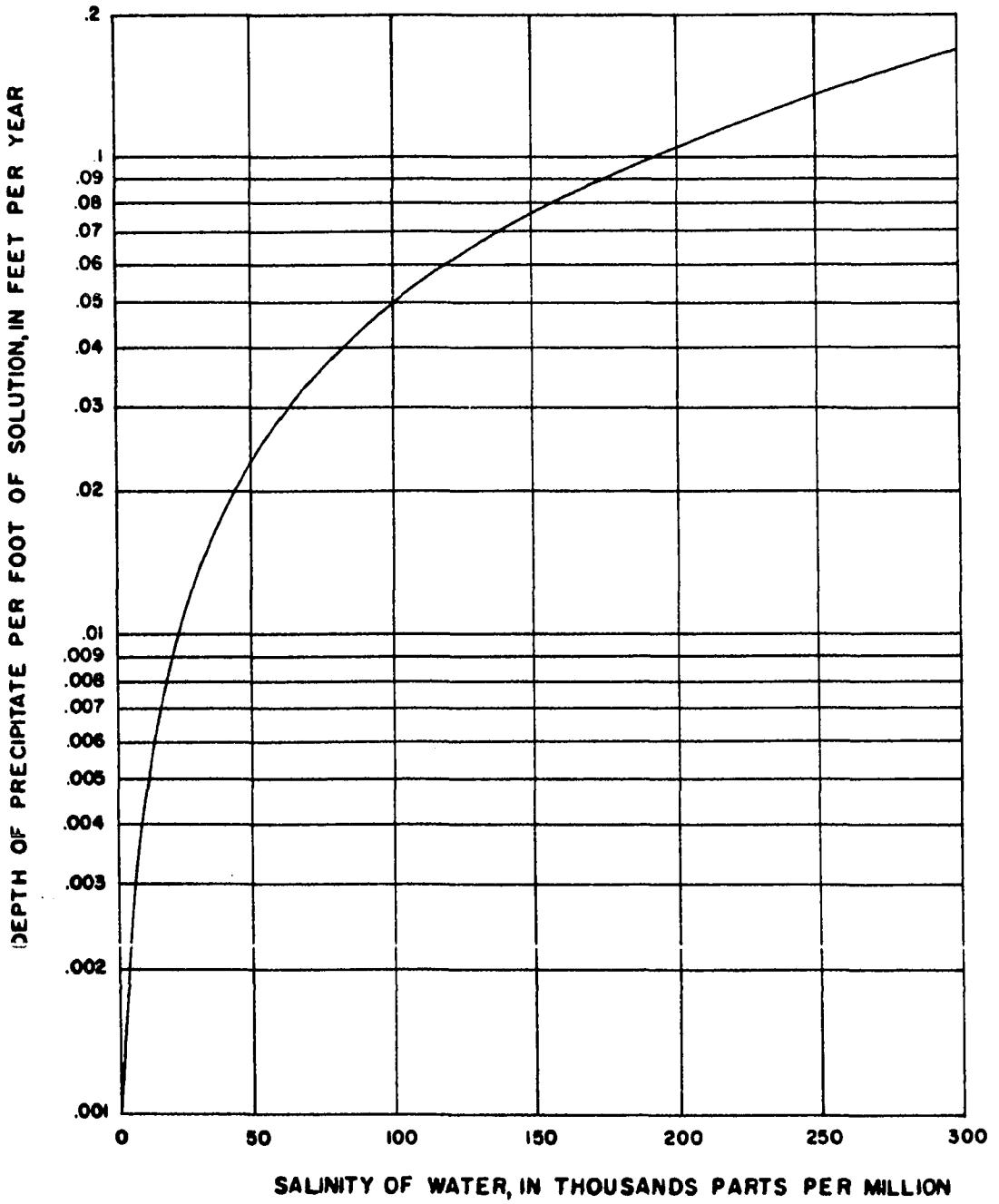


Figure 19. Depth of Precipitate per Foot of Solution in Feet per Year Versus Salinity of Water in Thousands of Parts per Million(94).

accumulation. This value is the expected total residue build-up over the life of the project.

Total residue _____feet

3. Next, determine the 24-hour maximum point rainfall depth for a recurrence interval of 50 years (storm) from the weather bureau for the vicinity of the evaporation pond.

Maximum rainfall _____feet

4. Assume a freeboard of 2 feet. This value is good up to an 80 miles per hour wind blowing over a pond with a downwind length of 2,000 feet.

Total freeboard 2 feet

5. Assume a 1-foot soil cover over the pond liner (if not surrounded by impervious soil).

Soil cover _____feet

6. The total pond depth, measured from the bottom of the pond to the top of the dike, is the sum of these depths (Dike height, H):

Liquid capacity _____feet

Total Residue _____feet

Maximum rainfall in a 24-hour, 50-year storm _____feet

Total freeboard _____feet

Soil cover over liner _____feet

Total pond depth (H) _____feet

Note: The dike is assumed to have 4-foot crest with a 2:1 slope on the toe and a 3:1 slope on the heel.

7. The next step is to determine the length of the dike necessary to enclose the pond. To obtain this value, add the lengths of the sides of the pond; i.e., the perimeter (EP).

   Total pond perimeter (EP) _____yards

8. From Figure 20, determine the volume of dike material, in cubic yards, required per linear yard of dike. Normally, material for dikes is obtained from pond excavation materials.) For example, a pond with a dike height of 10 feet would require 32 cubic yards of material per yard of dike length.

   Total volume of dike material (VT) _____yds^3

9. Next, determine the amount (square feet) of liner material (ALA) required. (Omit this step if the soil is impervious and a liner is not required by the state.)

$$ALA = \text{Area of liner required} = \frac{(.0111\ SA+6)(H-5) + (1.0111)(SA)}{(10)}$$

_____ft^2

10. Finally, calculate the quantity of fill (VF) neccessary to cover the liner with one foot of cover.

$$VF = \text{Cover fill} = \frac{(35\ SA+15{,}000)(H-5)}{10} + (1625)(SA) + 5{,}000$$

Data Summary

1. Evaporation area (SA): _____acres
2. Dike height (H): _____feet
3. Length of dike (EP): _____yards
4. Volume of dike material (VT): _____yds^3

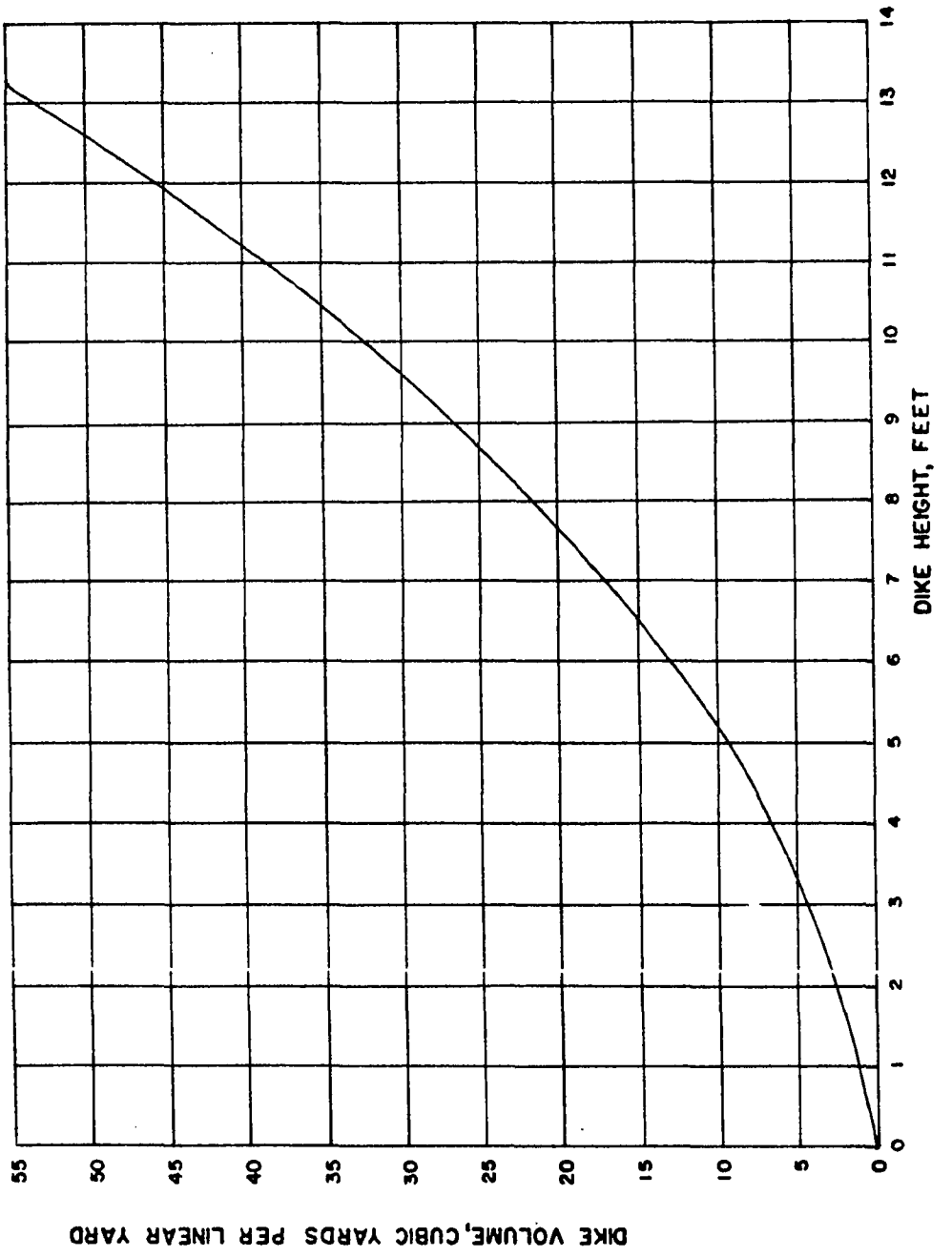


Figure 20. Dike Volume in Cubic Yards per Linear Yard Versus Dike Height in Feet(94).

5. Liner area (ALA): _____ ft^2

6. Volume of liner fill (VF): _____ yds^3

Evaporation Pond System Cost Analysis

1. Land Cost (LC) = (cost per acre)(number of acres): _____ $

2. Cost of stripping the land (CS):

   (Assume $100 per acre.)

   CS = ($100)(number of acres) _____ $

3. Liner cost (CLL)--omit if necessary:

   (Assume $.031 per ft^2.)

   CLL = (ALA)(.031) _____ $

4. Cost of liner cover fill (CF):

   (Assume $.40 per cubic yard for labor, material, and equipment.)

   CF = (VT)($.40) _____ $

5. Dike cost (CD):

   (Assume $1.00 per cubic yard for labor, material, and equipment.)

   CD = (VT)($1.00) _____ $

6. Subtotal, evaporation pond cost (ST_E):

   ST_E = LC + CS + CLL + CF + CO _____ $

7. Capital costs:

   a. Evaporation pond cost (ST_E): _____ $

b. Contingencies (CE): $(ST_E)(.10)$

(Assume 10% of pond cost.) _____$

c. Engineering (E_E): $(E_E)(.10)(ST_E + C_E)$

(Assume 10% of pond cost and contingencies) _____$

d. Interest on construction (I_{CE}) :

$$I_{CE} = (.01625)(ST_E + C_E + E_E)$$

(Assume 1.625% of cumulative capital costs.) _____$

e. Capital cost (CC_E):

$$CC_E = ST_E + C_E + E_E + I_{CE}$$ _____$

8. Annual expenditure:

a. Amortization expense (A_E):

$$A_E = CC_E \quad \frac{i(1+i)^Y}{(1+i)^{Y-1}}$$ _____$/year

b. Operation and maintenance (OM_E):

(Assume .5% of capital cost.)

$$OM_E = (.005)(CC_E)$$ _____$/year

c. Payroll overhead (PO_E):

(Assume 15% of operation and maintenance.)

$$PO_E = (.15)(OM_E)$$ _____$/year

d. General and administrative (GA_E):

(Assume 30% of operation and maintenance, and payroll overhead.)

$$GA_E = (.30)(OM_E + PO_E)$$ _____$/year

e. Interest on working capital (I_{WE}):

(Assume .7% of all annual expenditures.)

$$I_{WE} = (.007)(GA_E + PO_E + OM_E + A_E)$$ _____$/year

f. Total annual expenditure (TAE_E):

$$TAE_E = (I_{WE} + GA_E + PO_E + OM_E + A_E) \quad _____ \$/year$$

9. Total unit cost of evaporation pond per barrel of oil (TUC_{OE}):

$$TUC_{OE} = \frac{TAE_E\ (42)}{(X_o)(365.)} \quad _____ \$/brl\ oil$$

10. Total unit cost of evaporation pond per barrel of brine (TUC_{BE}):

$$TUC_{BE} = \frac{TAE_E\ (42)}{(X_B)(365.)} \quad _____ \$/brl\ oil$$

Total Evaporation System Costs (Evaporation Pond + Pipeline + Pump)

1. Total capital cost (TCC_{ES}):

$$TCC_{ES} = CC_E + CC_P + CC_{PS} \quad _____ \$$$

2. Total annual cost (TAE_{ES}):

$$TAE_{ES} = TAE_E + TAE_P + TAE_{PS} \quad _____ \$/year$$

3. Total unit expense per barrel of oil produced (TUC_{OES}):

$$TUC_{OES} = TUC_{OE} + TUC_{OPPS} \quad _____ \$/brl\ oil$$

4. Total unit expense per barrel of brine disposed (TUC_{BES}):

$$TUC_{BES} = TUC_{BE} + TUC_{BPPS} \quad _____ \$/brl\ brine$$

Injection

The question of what to do with the brine produced with oil is often

conveniently answered by injection disposal. It should be recognized that secondary recovery does often exist as an injection alternative in that from a pollution point of view using brine for secondary recovery fluid is disposal. However, due to treatment costs which may be necessary to prepare the brine for injection into a production strata (that may contain water chemically incompatable with the brine, or be of such a reduced permeability and porosity that extensive extra pumping is required) or for other reasons, a separate, non-productive strata is often selected for brine disposal.

The two basic options in subsurface disposal are to drill a new well or to convert an old well. The following analysis may be used for either case. As in previous analyses, basic values are assumed to simplify the analysis procedure. If better values are obtainable, they should be substituted for the assumed values in the cost or design configuration analysis.

Basically an injection disposal system is a combination of some type of brine handling device, a treatment plant, and an injection well. The brine handling device consists of either trucking or pipeline and pumping (from the direct discharge analysis). To the capital and/or annual costs of brine handling must be added the costs of storage facilities (if used), treatment facilities (if used), distribution piping and pumping, and the injection well.

Put rather simply, the injection process is one of moving a fluid (brine or other injection liquid) down a vertical tube and then dispersing the fluid

within a porous reservoir formation. Thus the design analysis of an injection well involves fluid and reservoir mechanics.

The injected fluid encounters a fluid friction force with the walls of the tubing and exerts a static pressure head (height-force) which is essentially the weight of the column of fluid in the tubing. The static pressure head aids injection; however, the fluid friction force along with the pressure of fluid already in the formation resists injection. The amount of resistance to flow depends on such factors as the inside diameter of the injection tube (the smaller the diameter, the greater the friction force on the fluid), the amount of flow, and the viscosity of the brine. In the reservoir, resistance to flow is influenced by the depth, thickness, porosity, and permeability of the formation. The calculations for these factors are given in Appendix D.

Assuming the brine is piped to the injection site, the following information are required before beginning the analysis. From pipeline and pump:

1. Total capital cost (CC_{PPS}): _____$
2. Total annual expenditure (TAE_{PPS}): _____$/year
3. Total unit cost per barrel of brine handled (TUC_{BPPS}): _____$/brl brine
4. Total unit cost per barrel of oil produced (TUC_{OPPS}): _____$/brl brine

In addition to the information supplied in the conveyance or direct discharge analysis, the following must also be provided:

1. Quantity of brine to be disposed of in gallons (42 gallons per barrel) per day (X_B): _____gpd
2. Quantity of oil in gallons per day produced with brine (X_o): _____gpd
3. Number of years of project life (Y): _____years
4. Company's average cost of capital or discount rate (i): _____decimal fraction
5. Cost of right-of-way (assume a 30-foot wide strip at a land cost of $109/acre unless better cost can be obtained)(ROW): _____$
6. Cost per kilowatt hour of electricity (ECU): _____$/KWH
7. Current year Engineering News Record Building Cost Index (ENRBCI): _____
8. Disposal formation lithology requirement (Li) (0 closed hole, 1 open hole): _____
9. Total disposal well depth (L): _____feet
10. Disposal formation porosity (ϕ): _____(decimal fraction)
11. Disposal formation permeability (K): _____Darcy
12. Disposal formation effective height (h): _____feet
13. Disposal formation reservoir pressure (P_r): _____psi
14. State specifications for design.

Design Limitations on Casing and Tubing

1. Set surface casing thru base of fresh water sand (D_{sc}): _____feet

2. Maximum casing head pressure (P_{ch}):

$$P_{ch} = .5(L)$$ _____psi

3. Minimum tubing I.D. = 2 inches

(to prevent excessive friction)

Injection Well Field Design Procedure

1. Select tubing I.D. (but do not exceed maximum in Figure 21)(d): _____inches
2. O.D. of external upset tubing of I.D.: _____inches
3. Tubing coupling O.D.: _____inches
4. Minimum collapse resistance of production casing = (2) (L): _____psi
5. Production casing I.D. equal tubing coupling O.D. plus 2 inches minimum (check collapse resistance; must be equal to or greater than minimum): _____inches
6. Production casing O.D.: _____inches
7. Production casing coupling O.D.: _____inches
8. Bottom hole diameter (production hole diameter), equal to production casing coupling O.D. plus 2 inches: _____inches

Fluid Mechanics (See Appendix D for Derivations)

1. Well radius (R_w) = 1/24 (bottom hold diameter): _____feet
2. Well diameter = Tubing I.D. = d _____inches

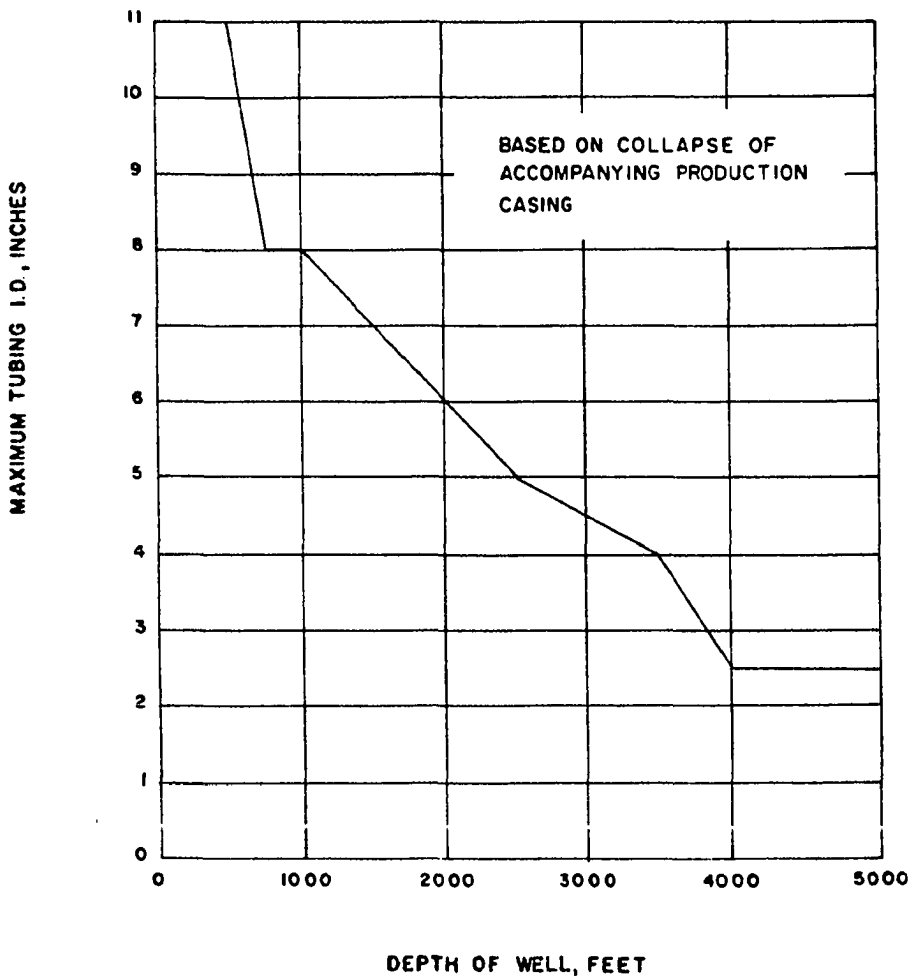


Figure 21. Maximum Tubing Inside Diameter in Inches Versus Depth of Well in Feet(91).

3. Number of injection wells (N) (usually 1): _____

4. Flow rate per well = $X_{Bi} = \frac{X_B}{N}$ _____gpd

5. Velocity of injected fluid (V):

$$V = (2.84)\ (10^{-4})\ \frac{X_{Bi}}{d^2}$$ _____ft/sec

6. Reynolds Number (N_{RE}):

$$N_{RE} = (7.75)\ (10^3)\ (d)\ (V)$$ _____

7. Enter friction factor (f) from Figure 22 (use N_{RE}): _____

8. Friction loss (P_f):

$$P_f = (32.36)\ (10^{-2})\ (f)\ (L)\ (V^2)/(d)$$ _____psi

9. Fluid radius at end of project (r_e):

$$r_e = (124.6)\quad \left[\frac{(X_{Bi})(Y)}{(1{,}000)(h)(\phi)}\right]$$ _____feet

10. Well spacing (2 r_e): _____feet

11. Bottom hole driving pressure (P_d):

$$P_d = \left[\frac{(X_{Bi})\log\left[\frac{r_e}{r_w}\right]}{(128.9)(k)(h)}\right]$$ _____psi

12. Static fluid pressure (P_c) = .434 (L) _____psi

13. Calculated casing head pressure (P_{ch}):

$$P_{ch} = P_d + P_r + P_f - P_c$$ _____psi

14. Allowable maximum P_{ch} = (.5) (L): _____psi

Note: If Calculated P_{ch} is greater than allowable limit (.5)(L), repeat steps 2 through 12 assuming 1 more well each time until P_{ch} is less than or equal to (.5)(L). Also recheck for design limitations above.

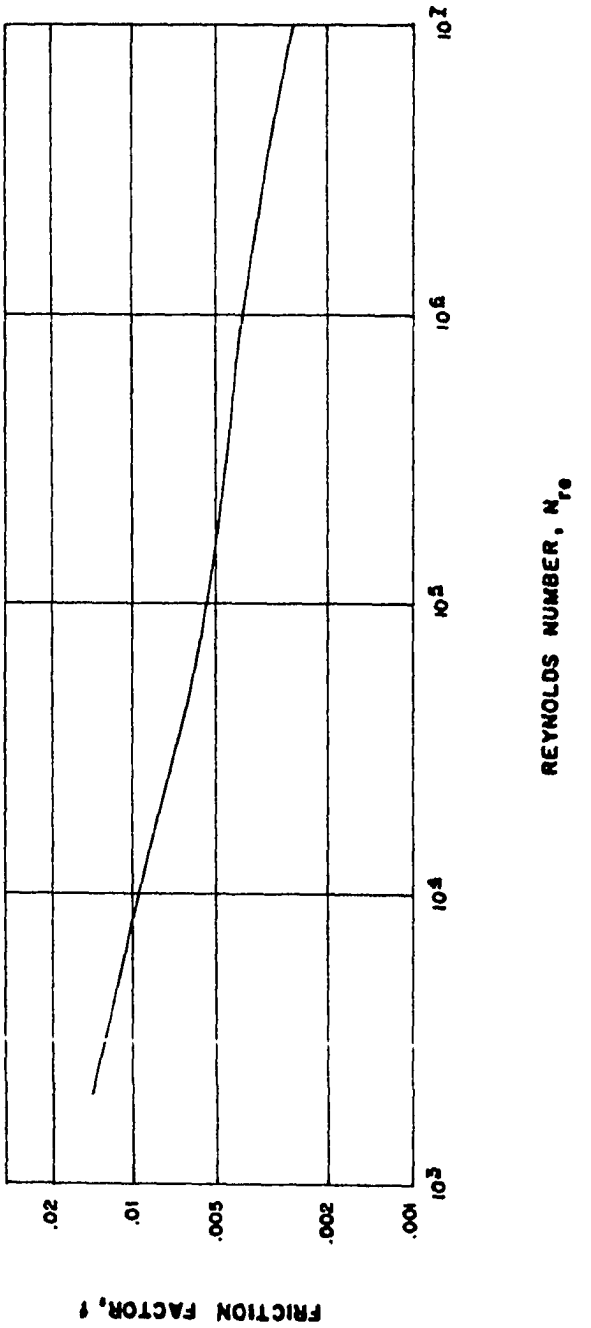


Figure 22. Friction Factor Versus Reynolds Number(95).

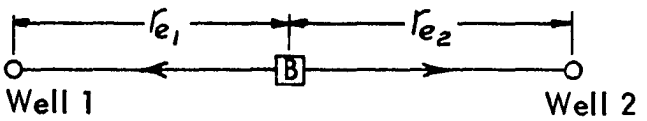
Distribution Piping - Cement-Lined

1. Arrange wells around injection pump so that the minimum distance between any two wells is at least (2) (r_e) of the wells.

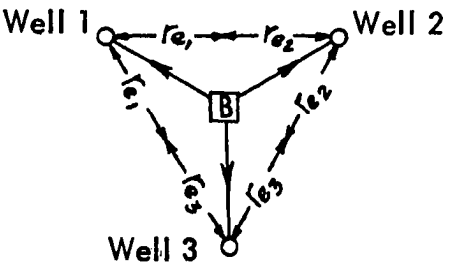
Note: 1 well.



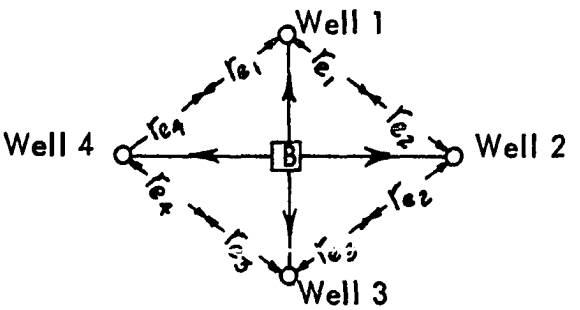
2 wells.



3 wells



4 or more wells on branches.



2. Determine the pipe size (d) of the line from the pump to each well:

   $d = (1.7)(10^{-2})(X_{Bi}^{.45})$ where X_{Bi} is the flow of brine in gpd in the line being sized. _____inches

3. Add ½ inch to d for cement lining (d') _____inches

4. Minimum yield pressure from previous section (P_{ch}): _____psi

5. With I.D. = d', consult Yield Pressure Tables: _____psi
   Must be equal to or greater than minimum in table (see Halliburton Cementing Tables, Halliburton Company, Duncan, Oklahoma).

6. Complete following table for each distribution pipe:

d	d'=I.D.	O.D.= I.D.+½ in.	lb/ft	Type of pipe

7. Friction loss in line connection distribution pump and most distant well ($\overline{FL}$) = (.0013)(length,ft): _____psi

Injection Pump and Power Requirements

1. Injection pump discharge pressure (P_i):

$$P_i = P_{ch} + \overline{FL}$$ _____psi

2. Hydraulic horsepower (HHP):

$$HHP = \frac{(X_B)(P_i)}{(2.468)(10^6)}$$ _____HP

Note: if only 1 well, $X_B = X_{Bi}$

3. Brake horsepower (BHP):

$$BHP = \frac{HHP}{.85}$$

(Assume pump efficiency is .85 if not stated): _____HP

4. Kilowatts KWH_i:

KWH = (BHP)(.802) _____KWH_i

(See derivation in Appendix D)

5. Pump head (P_h):

KWH(BHP)(.802) _____feet

6. Required pump capacity =

$$\frac{X_B}{1440}$$ _____gpm

Injection Well Field Cost Estimates

1. Well Cost:

a. Enter the cost of pipe ($/ft): _____$/ft

b. Obtain total cost of well pipe ($/ft)(L): _____$

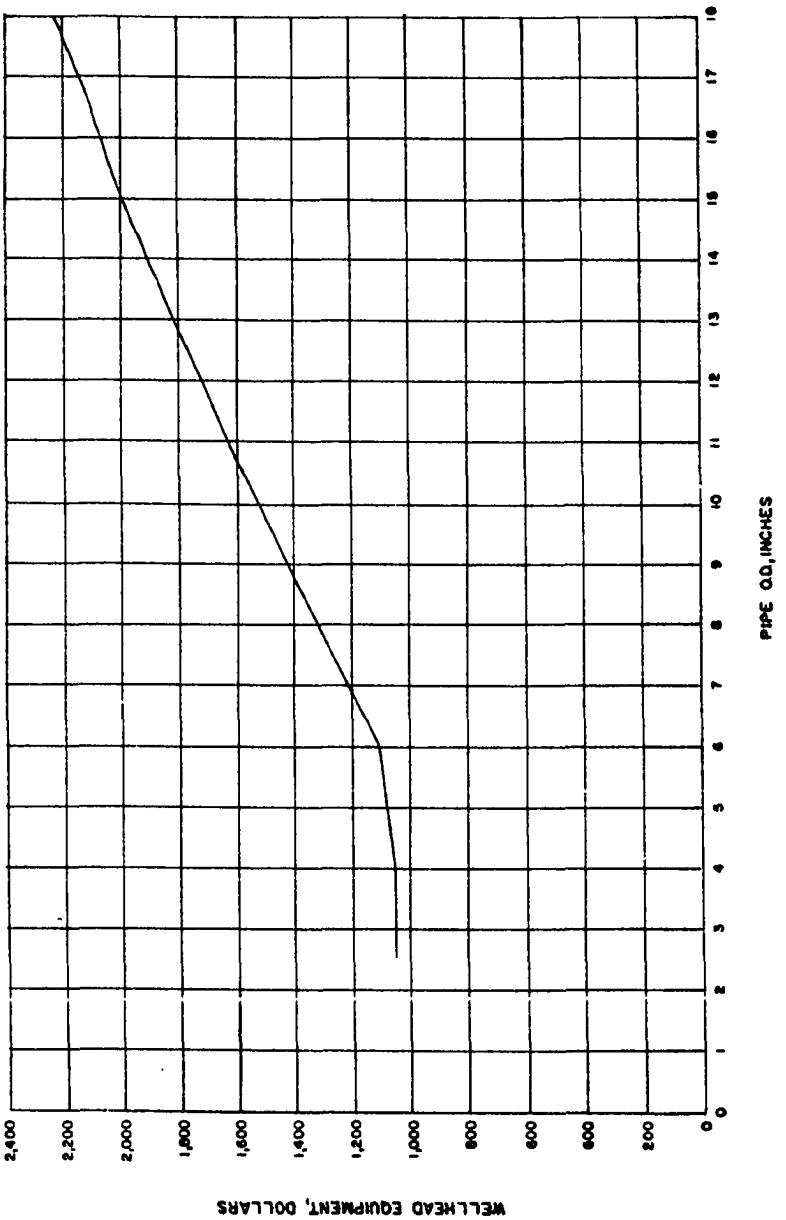
c. Enter value for cost of well-head equipment vs. O.D. (from Figure 23 or use better cost if available): _____$

d. Plastic lining:

(1) Enter value for cost of plastic lining pipe vs. pipe O.D. (from Figure 14 or use better cost if available): _____$/ft

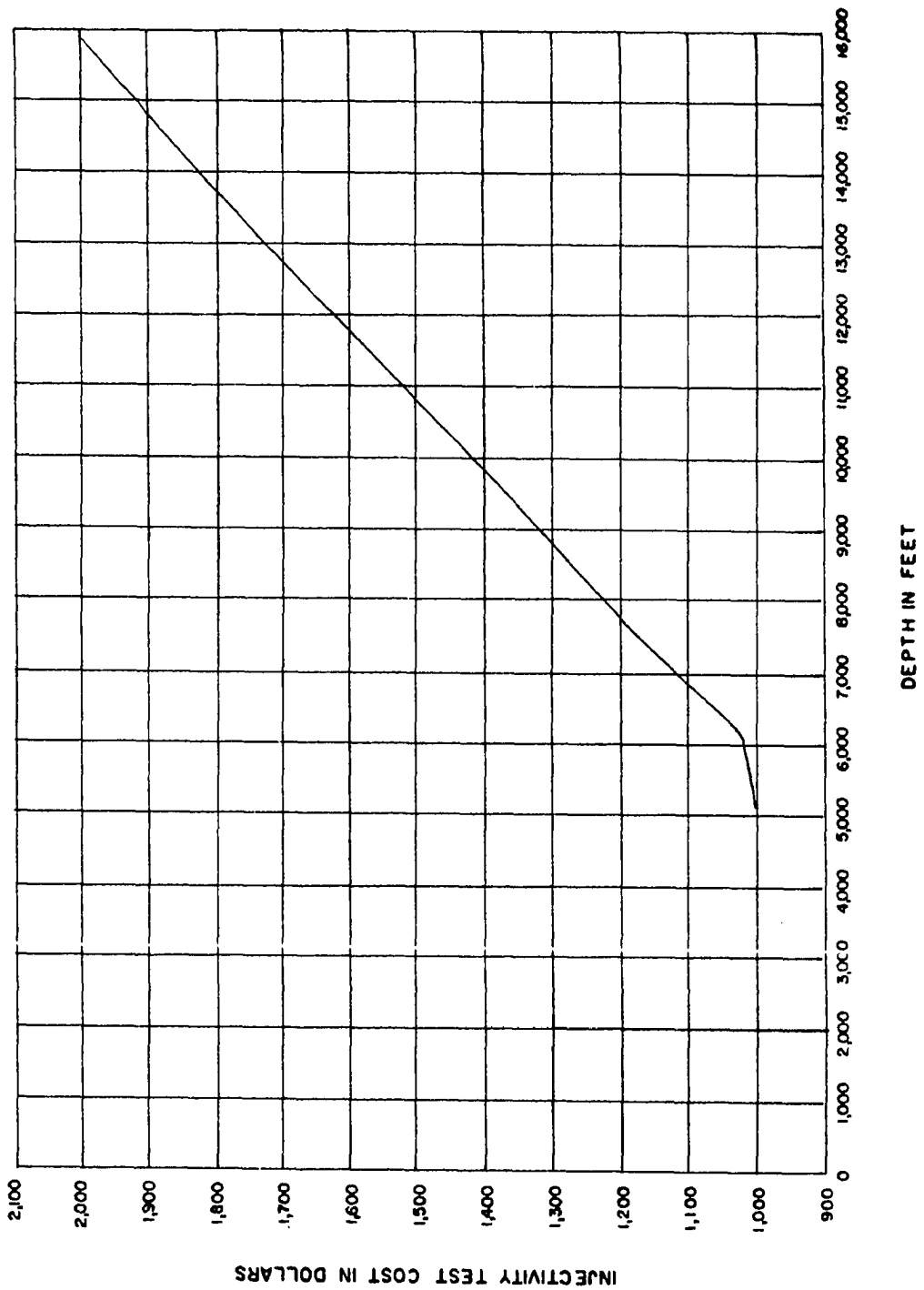
(2) Cost = ($/ft)(L-h) or ($/ft)(L) if sandstone, i.e., for sandstone lithology = 0 _____$

e. Enter value for injectivity test cost from Figure 24: _____$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 23. Cost of Wellhead Equipment in Dollars Versus Tubing Outside Diameter in Inches(92).



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 24. Injectivity Test Cost in Dollars Versus Depth of Well in Feet(92).

f. Total well cost (T_{wu}):

$T_{wu} = a + b + c + d + e$ _____$/well

g. Total well cost = (T_{wcl}):

T_{wcl} = (No. wells)(cost $/well) _____$

2. Distribution Pipe Cost:

a. For each pipe listed in item 6, "Distribution Piping - Cement-Lined," enter $/ft:

Type	Wt.	lb/ft	Feet	$/ft (lined or unlined)	
_____	_____	_____	_____	_____	_____$
_____	_____	_____	_____	_____	_____$
_____	_____	_____	_____	_____	_____$

Note: May be more or fewer than 3 distribution pipes; one pipe per well.

b. Total feet = _____. Total Distribution Cost (T_{DPC}): _____$

c. Installation and construction cost:

(1) Construction cost (T_{ICC}):

(Assume $.60 per foot or use better value.)

T_{ICC} = ($.60/ft)(total feet) _____$

(2) Right-of-way (ROW):

(Assume $109 per acre with 30' right-of-way or better value).

ROW = ($.075)(total feet) _____$

(3) Total cost of installation and construction (T_{IC}):

$$T_{IC} = T_{ICC} + ROW \qquad _____\$$$

Other Equipment (See Figures 15 and 25)

1. Pump station cost (T_{WPS}):
   (Enter value from Figure 15 with BHP approximation.) _____$
2. Storage cost (T_{SC}):
   (With storage volume = 1/3 daily flow = $\frac{X_{Bi}}{3}$, enter from Figure 25.) _____$
3. Treatment plant. This option is explored separately due to its potential application with any of the three types of disposal mechanisms.

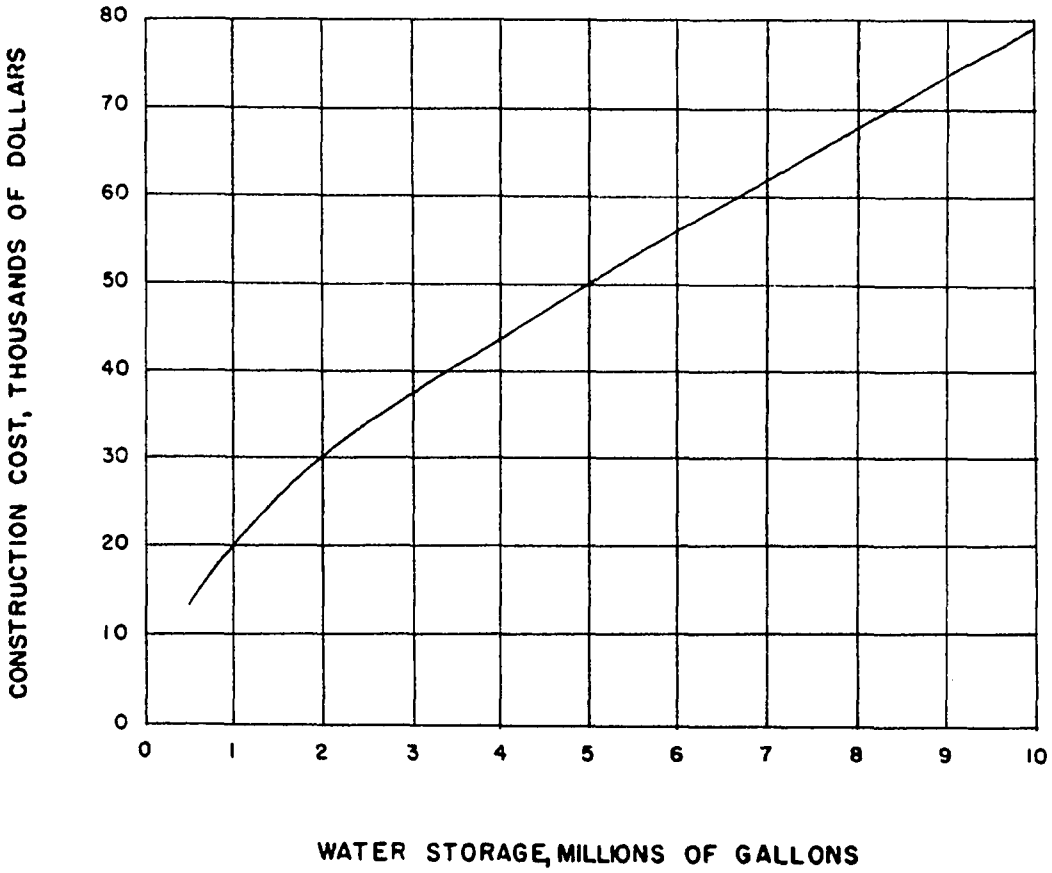
Injection System Capital and Annual Cost

1. Well Field:
   a. Capital costs:
      (1) Total well cost (T_{WC}):

$$T_{WC} = T_{WC1} + T_{DPC} + T_{IC} + T_{WPS} + T_{SC} \qquad _____\$$$

      (2) Site cost (S.C.):

$$S.C. = \frac{.25 \text{ acre}}{\text{well}} \text{ (no. wells)(\$/acre)} \qquad _____\$$$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 25. Cost of Water Storage Facilities in Thousands of Dollars Versus Water Storage in Millions of Gallons(93).

(3) Contingencies = (.10)(T_{WC}+S.C.):
(Assume 10% of well cost and site cost.) _____$

(4) Engineering = (.10)(T_{WC}+S.C. contingencies):
(Assume 10% of well cost, site cost, and contingencies.) _____$

(5) Interest on construction money (i_c):
i_c = .01625 ((3) + (4)) _____$
(Assume 1.625% of cumulative capital costs.) _____$

(6) Total capital cost (T_{CC}):
T_{CC} = (T_{WC} + S.C. + Conting. + Engineering + i_c) _____$

b. Annual expenditures:

(1) Operation and amintenance (OM), (enter value from "Estimated Operation and Maintenance" from Figure 16): _____$/year

(2) Supplies and materials = (.0025) (total capital cost):
(Assume .25% of total capital costs.) _____$/year

(3) Annual workovers = (no. wells) ($1/ft)(L): _____$/year

(4) Payroll overhead = (.15%)(OM):

(Assume 15% of operations and maintenance.) _____$/year

(5) General and administrative:

(Assume 30% of operation and maintenance and payroll.) _____$/year

(6) Amortization of capital cost (A):

$A = (\text{total capital cost}) \left[\frac{i(1+i)^Y}{(1+i)^Y-1}\right]$ _____$/year

(7) Subtotal, annual expenditures (ST_{AE}):

$ST_{AE} = ((1) + (2) + (3) + (4) + (5) + (6))$ _____$

(8) Interest on working capital (i_{wc}):

(Assume .7% of other annual costs.)

$i_{wc} = (.007)(\text{Subtotal})$ _____$

(9) Total = $T_{AWC} = (T_{SA}+i_{wc})$ _____$

2. Distribution Pipeline Costs:

a. Capital costs:

(1) Construction costs (T_{IC}):

(See 2.c.(3), under "Injection Well Field Cost Estimates.") _____$

(2) Contingencies = (.10)(total construction cost)

(Assume 10% of total construction cost.) _____$

(3) Engineering = 10% (Contingencies + total construction cost)

(Assume 10% of total contingencies and construction cost.) _____$

(4) Interest on construction money (i_c)

i_c = (.01625)(construction cost, contingencies, and engineering)

(Assume 1.625% of cumulative capital costs.) _____$

(5) Total distribution pipeline capital cost = T_{IC} + Contingency + Engineering + i_c _____$

b. Annual expenditures ($/yr): _____$

(1) Operation, maintenance, and supplies (OM&S):

OM&S = (.0025)(total dist. pipeline capital cost) _____

(Assume .25% of total distribution capital cost.) _____$/year

(2) Amortization of capital cost (A):

$$A = (\text{capital cost dis. pipes}) \left[\frac{i(1+i)^Y}{(1+i)^Y - 1} \right]$$

_____$/year

(3) Interest on working capital (i_{wc}):

i_{wc} = (.007)(OM&S + A)

(Assume .7% of other annual costs.) _____$/year

(4) Total distribution pipeline annual expenditure (T_{DPE}):

$T_{DPE} = OM\&S + A + i_{wc}$ _____$/year

3. Pump Station and Storage:

a. Capital cost:

(1) Pump station cost (Figure 15): _____$

(2) Storage cost (Figure 25): _____$

(3) Total facility cost ((1) + (2)): _____$

(4) Site cost = (no. acres)$[\frac{(\$)}{acre}]$: _____$

(5) Contingencies = .10 ((3) + (5))

(Assume 10% of facility and site cost.) _____$

(6) Engineering = .10 ((3) + (5) + (6)):

(Assume 10% of facility and site cost and contingencies.) _____$

(7) Subtotal = ((3) + (5) + (6) + (7)): _____$

(8) Interest on construction money (i_c):

$i_c = (.01625)(Subtotal)$

(Assume 1.625% of cumulative capital cost.) _____$

(9) Total capital cost (CC_i):

$CC_i = T_{ST} + i_{wc}$ _____$

b. Annual Expenditures:

(1) Power cost (P_C):

$P_C = (KWH)(8760)(ECU)$ _____$/year

(See Injection and Power Requirements, 4_1KWH)

(2) Enter value from "Operation and Maintenance" from Figure 16 _____$/year

(3) Supplies and materials (C_{SM}):

$C_{SM} = (.0025)(T_{CC})$

(Assume .25% of total capital cost.) _____$/year

(4) Payroll extras = (.15)(OM):

(Assume 15% of Operation and Maintenance cost.) _____$/year

(5) General and administrative (GA):

GA = (.30)(OM + payroll)

(Assume 30% of Operation and Maintenance, and Payroll costs.) _____$/year

(6) Amortization of capital cost (A):

$$A = (\text{capital cost}) \left[\frac{i(1+i)^Y}{(1+i)^Y - 1} \right]$$ _____$/year

(7) Subtotal = (1) + (2) + (3) + (4) + (5) + (6):

_____$/year

(8) Interest on working capital (i_{wc}):

$i_{wc} = (.007)(\text{Subtotal})$

(Assume .7% of all annual expenditures.) _____$/year

(9) Total annual expenditure for injection well field (TAE_i):

$TAE_i = (\text{Subtotal} + i_{wc})$ _____$/year

Injection Cost Summary

1. Total unit cost of injection well field per barrel of brine (TUC_{Bi}):

$$TUC_{Bi} = \frac{TAE_i \ (42)}{(X_B)(365.)} \quad \text{_____\$/brl brine}$$

2. Total unit cost of injection well field per barrel of oil (TUC_{Oi}):

$$TUC_{Oi} = \frac{TAE_i \ (42)}{(X_o)(365.)} \quad \text{_____\$/brl oil}$$

Total Injection System Cost (Injection Well + Pipeline + Pumping

1. Total capital cost (TCC_{is}):

$$TCC_{is} = CC_i + CC_p + CC_{ps} \quad \text{_____\$}$$

2. Total annual cost (TAE_{is}):

$$TAE_{is} = TAE_i + TAE_p + TAE_{ps} \quad \text{_____\$/year}$$

3. Total unit cost for injection system per barrel of brine injected (TUC_{Bis}):

$$TUC_{Bis} = TUC_{Bi} + TUC_{BPPS} \quad \text{_____\$/brl brine}$$

4. Total unit cost for injection system per barrel of oil produced (TUC_{Ois}):

$$TUC_{Ois} = TUC_{Oi} + TUC_{OPPS} \quad \text{_____\$/brl oil}$$

Water Treatment for Brine Disposal

Generally, there are several degrees and types of brine treatment. The treatment process selected depends on the characteristics of the brine to

be treated and the degree of treatment required by the intended disposal method or to meet the intended beneficial use of the water. This topic was described more thoroughly in the sections on pollution and water treatment; therefore, it will not be developed here.

This discussion of treatment is oriented to brine treatment prior to disposal (although treatment may be necessary prior to other methods of disposal). The treatment process (if it is necessary) can be inserted almost anywhere in the supply and distribution system connecting the production well and disposal device but is usually placed just prior to the disposal system. This way the treated water or brine has a minimum chance of being altered prior to disposal.

Two general descriptions of the design configuration-cost analysis approach to treatment will be given. The first involves the use of a single, overall relationship developed by Koenig (92) to describe pre-injection treatment. This relationship is displayed graphically as capital and operating costs associated with pre-injection treatment. (This analytical procedure is also followed by the conputer program described in the following section and Appendix E.)

The second method is to identify undesirable characteristics and present appropriate relationships to handle each case (96). It should be emphasized that the intent of both of these analyses is not to present or identify exact costs but rational arrangements associated with either

approach to treatment. Also, since this discussion is oriented toward disposal or preparation prior to disposal, a higher order beneficial use could conceivably introduce processes and costs not considered in this analysis.

Table 18 gives treatment operations.

Table 18. Treatment Operations (97)

Operation/Equipment	Objective
1. Baffles.	1. Remove oil particles.
2. Skimming.	2. Remove floating oil
3. Aeration.	3. Oxidation of souluble ferrous compounds to insoluble ferric compounds and soluble carbonate compounds to insoluble carbonate compounds.
4. Chlorination.	4. Aid in the further oxidation of iron, and control algae and bacterial growths.
5. Chemical coagulation and sedimentation (hydrated lime and alum).	5. Removal of the compounds which would form scales on the sand face; e.g., iron compounds, calcium compounds, and small amounts of hydrocarbon compounds.
6. Filtration (pressure, coal, and sand).	6. Removal of small particles from sedimentation operation.

On the level of treatment mechanisms, the aforementioned operations are carried out by specific treatment plant components.

Table 19 lists undesirable waste characteristics and removal operations.

Table 19. Undesirable Waste Characteristics and Removal Operations (97)

Undersirable Characteristics	Treatment Operations
1. Suspended Material:	
a. Oils and other floating material.	A.P.I. Separator Skimming Floatation
b. Solids, colloids, etc.	Chemical coagulation Sedimentation Centrifugation Gravity Sand Filtration Pressure Sand Filtration Diatomite Filtration
c. Biological growths (e.g. slime forming algae and bacteria)	Chlorination Filtration
2. Dissolved Substances:	
a. Gases	Aeration Purging Vacuum Degasifer
b. Undesirable ions	pH Adjustment Neutralization Precipitation, Chemical Coagulation Ion Exchange Membrane Process
3. Corrosiveness:	Removal of Gases pH Control

Water Treatment Analysis

The following information is required before beginning the analysis.

1. X_o = Quantity of oil produced with brine in gallons per day. _____gpd

2. X_B = Quantity of brine to be treated in gallons per day. _____gpd

3. MX_B = Quantity of brine to be treated in millions of gallons per day.

$$MX_B = \frac{X_B}{1{,}000{,}000}$$ _____mgpd

4. i = Discount rate or cost of capital. _____decimal fraction

5. Y = Project life. _____years

Design Analysis

A typical brine disposal system is shown in Figure 26. Components and configuration are reasonable; however, the less the amount of brine to be treated, the smaller the treatment plant. This analysis assumes a minimum of 1,000 gallons of brine to be treated per day, 365 days per year.

1. Capital cost:

   a. Capital cost may be taken directly from Figure 27: _____$

   b. Capital cost may instead be assumed to be composed of principle component costs (96) (enter zero if component not used):

      (1) Primary treatment (sedimentation) cost (C_P):

      $C_P = (.345)(MX_B)^{.708}\ (10547.)$ _____$

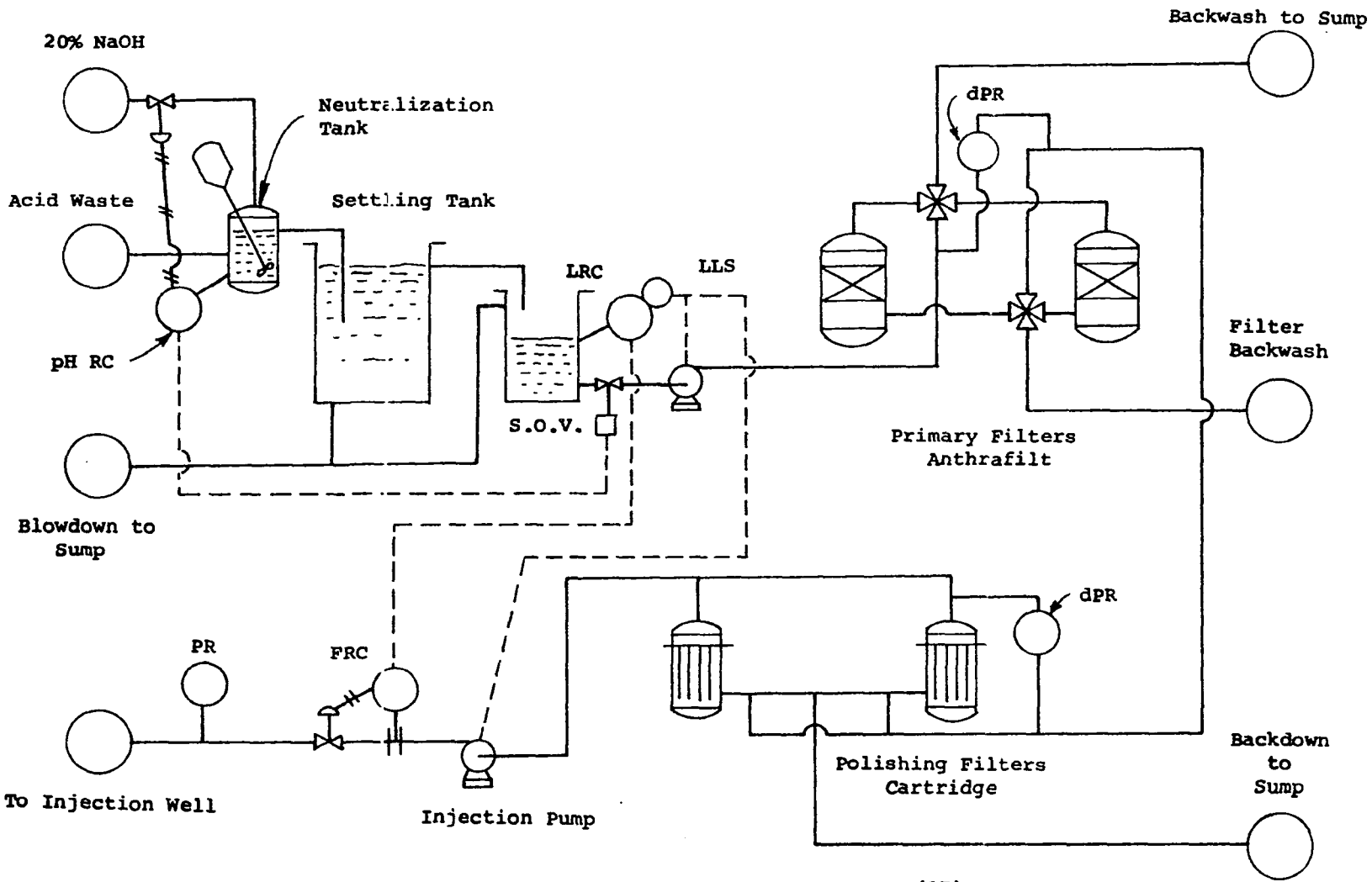
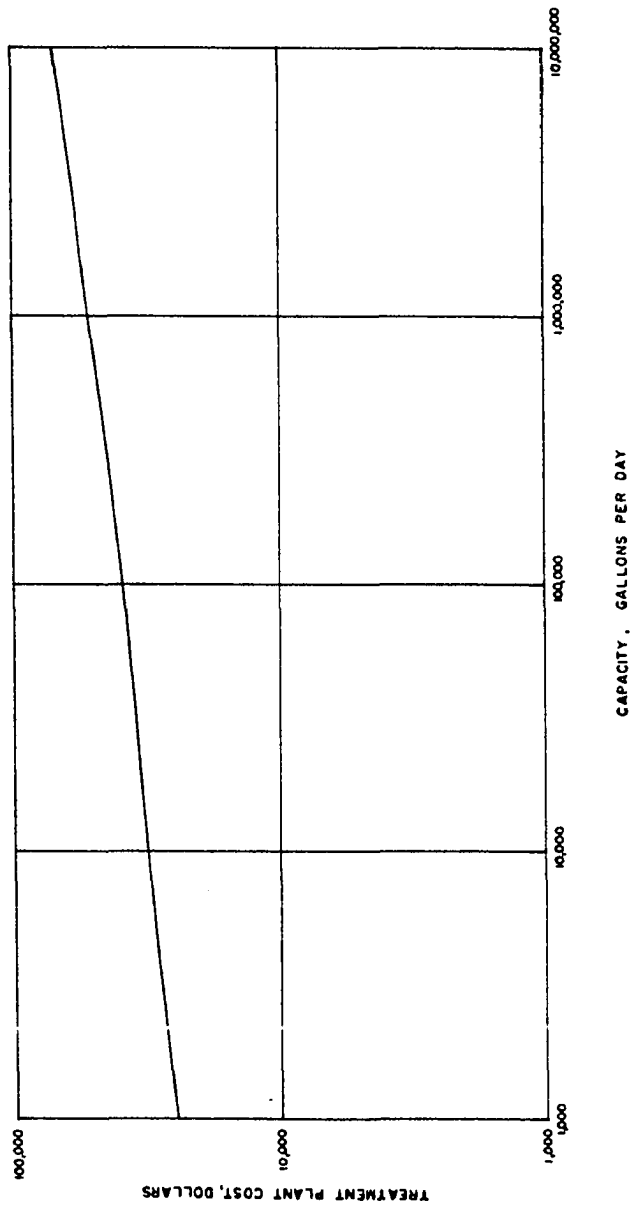
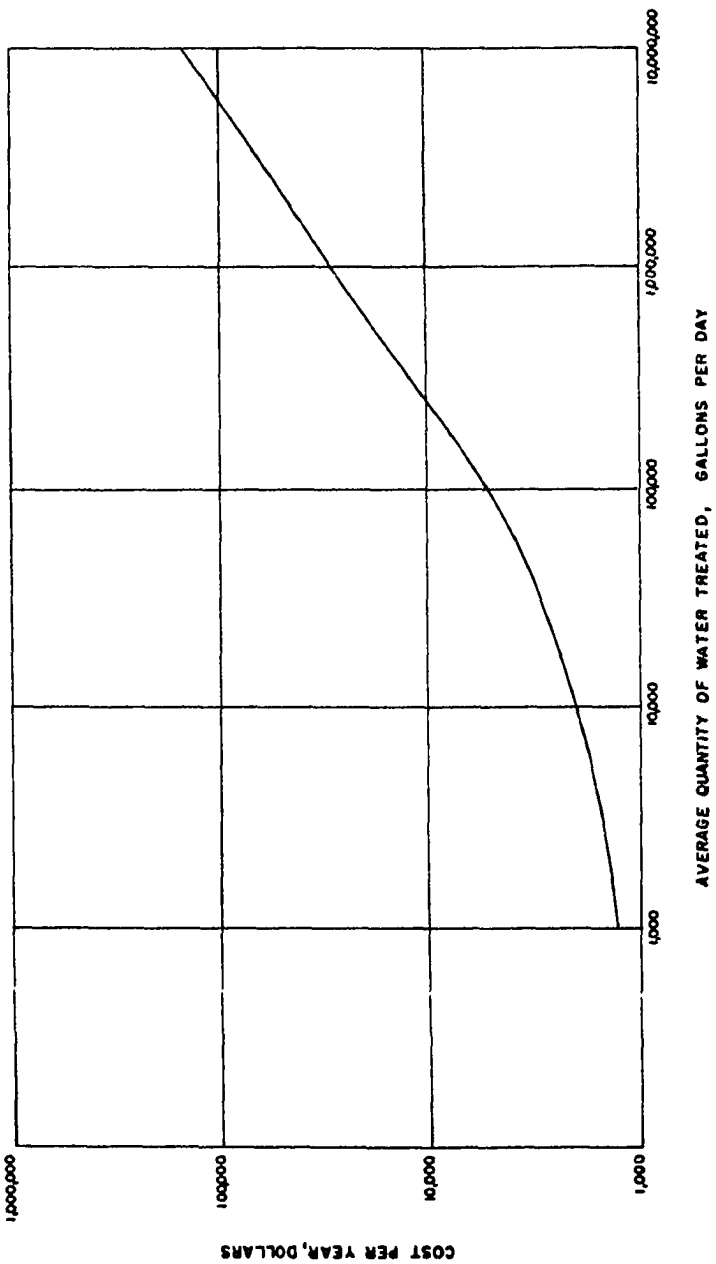


Figure 26. Pre-Injection Waste Treatment Scheme(97).



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 27. Cost of Treatment Plant in Dollars Versus Plant Capacity in Gallons per Day(92).



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 28. Annual Cost of Operation of Injection Water Treatment Plant in Dollars Versus Quantity of Water Treated in Gallons per Day(92).

(2) Secondary treatment (aeration)

Cost (C_S):

$C_S = (.531)(MX_B)^{.785}(10547.) - C_P$ _____$

c. Subtotal treatment system construction

Cost (enter either a or applicable of

(1), (2) (C_{TS}): _____$

d. Contingencies = $(.10)(C_{TS})$:

(Assume 10% of construction cost.) _____$

e. Engineering = (.10)(contingencies +

C_{TS})

(Assume 10% of construction cost and

contingencies.) _____$

f. Interest on construction money (i_c):

$i_c = (.01625)(C_{TS}$ + contingencies +

engineering)

(Assume 1.625% of cumulative capital

costs.) _____$

g. Total capital cost (CC_{TS}):

$CC_{TS} = (C_{TS}$ + contingencies + engineer-

ing + 1). _____$

2. Annual Cost:

a. Annual expense may be taken directly from

Figure 28: _____$/year

b. Annual cost may instead be assumed to be composed of appropriate principle component costs (96):

(1) Annualized capital cost for appropriate components:

$$A_{TS} = CC_{TS} \left[\frac{i(1+i)^Y}{(1+i)^Y-1}\right]$$ _____$/year

(2) Annual Operations and Maintenance for appropriate component (enter zero if component not used).

(a) Primary treatment (sedimentation) cost operation and maintenance (OM_P):

$$OM_P = (4.561)(10^{-2})(MX_B)^{-.205}(.565X_B)$$

_____$/year

(b) Secondary treatment (aeration) cost operation and maintenance (OM_S)

$$OM_S = (8.679)(10^{-2})(MX_B)^{-.2395}(.565X_B) - (OM_P)$$

_____$/year

(3) Operation and maintenance cost (OM_{TS}):

$$OM_{TS} = OM_P + OM_S$$ _____$/year

(4) Subtotal annual expenditures or sum of component annual costs:

(a) Operation and maintenance (OM_{TS}): _____$/year

(b) Annual amortized expenditure (A_{TS}): _____$/year

(5) Interest on construction (assume .7%) (i_c):

$$i_c = (.007)(OM_{TS} + A_{TS})$$ _____$/year

(6) Total annual expenditure (TAE_{TS}):

$$TAE_{TS} = i_c + OM_{TS} + A_{TS} \qquad \text{_____ \$/year}$$

(7) Total unit cost of treatment plant per barrel of brine treated (TUC_{BTP}):

$$TUC_{BTP} = \frac{TAE_{TS\ (42)}}{(X_B)(365.)} \qquad \text{_____ \$/brl brine treatment}$$

(8) Total unit cost of treatment plant per barrel of oil produced (TUC_{OTP}):

$$TUC_{OTP} = \frac{TAE_{TS\ (42)}}{(X_o)(365.)} \qquad \text{_____ \$/brl oil}$$

Selection of Best Alternative

If more than one disposal method is considered (assuming no treatment), then:

1. Compare TUC_{Ois} with TUC_{OES} with TUC_{OPPS}.
2. Select the least expensive allowable alternative on the basis of lowest annual cost.
3. These TUC values may be compared directly with oil price at the well head for use in analyzing the impact of disposal on production, as well as total production-disposal expenses.

If treatment is necessary, then:

1. Obtain the value of TUC_{OTP} which is composed of factors most nearly approximating each system's treatment needs.
2. Add appropriate TUC_{OTP} to applicable disposal system.

3. Compared TUC values after treatment costs have been added.
4. Select the allowable disposal alternative based on lowest annual costs.

Definition of Terms

H_f = Head loss due to friction (feet)

F^1 = Length of pipeline (miles)

F = Length of pipeline (feet = $5280F^1$)

L = Total depth of well (feet)

X_B = Quantity of disposed brine (gallons per day)

X_o = Quantity of produced oil (gallons per day)

Y = Project life (years)

i = Discount rate; cost of capital (decimal fraction)

EL = Relative elevation of discharge point (feet)

ROW = Right-of-way cost (%/acre)

ECU = Electricity cost ($/KWH)

H_p = Required pumphead (feet)

TAE_p = Total annual pipeline expenditure ($/year)

TAE_{ps} = Total annual pump station expenditure ($/year)

TUC_{opps} = Total unit cost of pipeline and pumping per barrel of oil produced ($/brl oil)

TUC_{BPPS} = Total unit of pipeline and pumping per barrel of brine handled ($/brl brine)

TAE_E = Total annual evaporation pond expenditure ($/year)

TUC_{OE} = Total unit cost of evaporation pond per barrel of oil produced ($/brl oil)

TUC_{BE} = Total unit cost of evaporation pond per barrel of brine produced with the oil ($/brl brine)

TAE_i = Total annual injection well field expenditure ($/year)

TUC_{Bi} = Total unit cost of injection well field per barrel of brine injected ($/brl brine)

TCU_{Oi} = Total unit cost of injection well field per barrel of oil produced ($/brl oil)

TAE_{TS} = Total annual cost of brine treatment plant _____ $/year

TUC_{BTP} = Total unit cost per barrel of brine treated for treatment plant

$$TUC_{BTP} = \frac{TAE_{TS}}{X_B\ (365)\ (42)} \qquad \text{_____ \$/brl brine}$$

TUC_{BTP} = Total unit cost per barrel of oil produced for treatment plant

$$TUC_{OTP} = \frac{TAE_{TS}}{X_o\ (365)\ (42)} \qquad \text{_____ \$/brl oil}$$

SECTION IX

COMPUTER PROGRAM (96,97)

The computer program in Appendix E follows the previously given hand calculation disposal system analysis very closely, but a few major factors differ. The hand calculation scheme has sufficient flexibility that: it may be used for new or converted injection systems; any piping may be used with any suitable pump merely by substituting design and cost values for the equipment (including '0' if the equipment is not used); and up-to-date prices can be used.

The computer only takes specific information (i.e., instead of up-to-date pipe costs, read in the RRC code (Region Rating Code, Table 20) of the state in which the drilling will be done and the computer will assign the costs from tables already in the program for appropriate 9" diameter J-55 or N-80 pipe). Also, some of the costs must be updated by referring to the Engineering News Record Building Cost Index (ENRBCI in program is 570 for 1962), and the updated cost must be read into the computer. The program only calculates the cost of an all-new system.

Input

The operator has the option of selecting any combination of disposal

Table 20. RRC Zones (98).

Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
Louisiana	Florida	Wyoming	Pennsylvania	Utah	Montana
Mississippi	Arizona	West Texas	New York	Nevada	Michigan
Southwest Texas	New Mexico	Panhandle Texas	West Virginia		Oklahoma
Gulf Texas	California	Colorado	Ohio		Arkansas
North Central Texas	South Dakota		Virginia		Illinois
North Dakota			Nebraska		Kentucky
Kansas			Indiana		
			East Texas		
			Alabama		

configuration he wants using the first input card. This program card calls the desired disposal system. If more than one disposal system is desired, the operator simply enters additional program call cards in the order he wishes to look at the prospective disposal system(s). Following the first program call card, the data for the specific disposal system is put into the computer.

Program Call Card

The program call card contains combinations of the numbers 1, 2, and 3 followed by a decimal point. The number 1. in any two columns of columns 1-10 calls the injection program. If the number 2. is entered in any two columns of columns 11-20, the evaporation program is called. The number 3. in any two columns of columns 21-30 calls the conveyance or direct discharge model.

Once the program call card starts a particular disposal system, the computer will calculate as many different configurations as desired; however, the computer operator must enter all the data necessary for each different configuration.

Data Cards

The specific data array of each program follows, but a brief introductory explanation is necessary. For any disposal program to work,

all the data required by the program must be inputted. Even if only a slight change is made in a variable value of a disposal method, all the data necessary for the new configuration must be printed on a data card because the computer saves no data from one system to the next. The last number in the last data card of each different type of disposal system (injection and evaporation are different types of disposal systems; $injection_1$ and $injection_2$ are different configurations of the same disposal system) must be the number 1. in the ten data columns following those columns containing disposal system data.

Data Deck

1. Program call card with a 1. in columns 1-10, a 2. in columns 11-20, and/or a 3. in columns 21-30.
2. Injection data requires two data cards per injection configuration in addition to and following the program call card, for a total of at least three cards. A "1." must be placed anywhere in the reserved ten columns after the value of the last variable, EL, in the final injection system configuration data card. (Note, F 10.0)
3. Evaporation requires three data cards per evaporation configuration in addition to and following the program call card for a total of at least four cards. A "1." must be placed after the value of the last variable, BCI, in the final evaporation system configuration data card. (Note, F 10.0)
4. Conveyance also requires three data cards per configuration

in addition to and following the program call card for a total of at least four cards. A "1." must be placed after the value of the last variable, Y, in the final conveyance system configuration. (Note, F 10.0)

Variables

1. Injection (97):

Variable	Format	Description
a. JC	13	Job code; number configurations.
b. PLACE (I)	10A1	Location name.
c. RRC	A2	Regional Rating Code; state number.
d. XO	F5.3	Total daily volume to be injected, Kgd (thousands of gallons per day).
e. RKW	F3.3	Cost of electrical power, $/KWH.
f. CPA	F4.0	Cost of land for pump station, injection well, and connecting distribution pipe, $/acre.
g. Y	I2	Estimated project life, years.
h. II	F4.3	Interest or discount rate, decimal fraction.
i. ENR	F3.0	Current Year Engineering News Record Building Cost Index, necessary to update cost values already in computer (ENRBCI = 570) 1962
j. LI	I1	Lithology - type of completion 0 (zero) indicates closed hole required; 1 indicates open hole.

Variable	Format	Description
k. L	F5.0	Total depth of well, feet.
l. H	F3.0	Effective height of injection zone, feet.
m. PHI	F2.2	Formation porosity, decimal fraction.
n. PK	F4.3	Formation permeability, darcies.
o. PR	F4.0	Reservoir pressure, psi.
p. D	F3.2	Inside diameter of injection conduit, inches.
q. COR1	F4.1.	Drilling correction cost term (allows for hole sizes other than standard 9 inches).
r. VCPIPE	F3.2	Fluid viscosity of brine, centipoise.
s. VCFORM	F3.2	Fluid viscosity of brine, centipoise.
t. SPGR	F2.1	Specific gravity of brine.
u. PCHTF	F3.2	Maximum casing head pressure test factor, psi/ft.
v. XP	F5.0	Oil flow, Kgd.
w. DPM	F4.0	Distance from collection point to well, miles.
x. EL	F4.0	Elevation of well below (+) or above (-) brine collection point, feet.
y. X LAST	F10.0	Write 1. at end of last configuration data card.

2. Evaporation (96)

Variable	Format	Description
a. XO	F10.3	Brine flow, Kgd.

Variable	Format	Description
b. XW	F10.3	Oil flow, Kgd.
c. CE	F10.3	Brine concentration, ppm.
d. PREC	F10.3	Precipitation, inches/year.
e. EO	F10.3	Evaporation rate (gross), inches/year.
f. FF	F10.3	Distance from collection point to pond, miles.
g. EL	F10.3	Elevation of pond below (+) or above (-) brine collection point, feet.
h. ECU	F10.3	Power cost, $/KWH.
i. CLU	F10.3	Land cost, $/acre.
j. I	F10.3	Capital discount rate or interest, decimal fraction.
k. Y	F10.3	Project life, years.
1. BCI	F10.3	Current Year Engineering News Record Building Cost Index.
m. X LAST	F10.0	Write 1. at end of last configuration data set.

3. Conveyance (Direct Discharge) (96)

Variable	Format	Description
a. XO	F10.2	Brine flow, Kgd.
b. XW	F10.2	Oil product flow, Kgd.
c. FF	F10.3	Distance from brine collection point to discharge, miles.
d. EL	F10.2	Elevation of discharge below (+) or above (-) collection point, feet.
e. ECU	F10.2	Power cost $/KWH.

Variable	Format	Description
f. ZI	F10.2	Capital discount rate or interest, decimal fraction.
g. BCI	F10.2	Current Year Engineering News Record Building Cost Index.
h. Y	F10.4	Project life, years.
i. X LAST	F10.0	Write 1. at end of last configuration data set.

Program Quirks and Limitations

1. Injection. Disregard Product Petrol Concentration, ppm, in printout.
2. Evaporation. Printout of capital investment for evaporation pond only, not entire system.
3. Computer program relationships only good for daily brine flow greater than 1,000 barrels per day.
4. Treatment capital and operating costs taken from Figures 27 and 28.

Regional Rating Code (RRC) Zones

The Regional Rating Code divides the continental United States (excluding Alaska and Hawaii) into six zones by average drilling cost per zone as reported in Joint Association Survey of Industrial Drilling Costs (Section 1), 1962. An adjustment has been made for states having predominently shallow/cheaper wells. RRC zones are given in Table 20.

Of note is the variable, COR 1 F4. 1, in the injection program. Certainly drilling and development expenses in either a production or development well are highly dependent on the diameter of the well bore. While hand calculations allow individual size allocations with regard to well diameter, the computer does not, directly. Rather, an expression relating cost with diameter and depth developed by Koenig and others is used to express well diameter and drilling costs in terms of a standard well; in effect, a common denominator. A statistical analysis of oilwell diameter performed by Koenig (92) revealed that the most common weighted production hole diameter (WPHD) was 9 inches. This computer program uses the previously mentioned standard types of pipes with diameters of 9 inches. Therefore, the COR 1 value must be calculated for each drilling situation to adjust for actual WPHD diameters. If a 9-inch diameter is used, the value entered will not be an adjusted value.

To arrive at the appropriate drilling cost adjustment for well diameter, the first step is to calculate the weighted production hole diameter, WPHD (because often the surface casing is larger in diameter than the production or bottom hole diameter) (97).

$$WPHD = \frac{N(SHD) + (10 - N)(BHD)}{10}$$

Where WPHD = Weighted production hole diameter (inches).

$N = \frac{L^1}{L} \times 10$ = Fraction of total depth which surface casing extends.

L = Total depth of the well (feet).

L^1 = Depth to which surface casing is set (feet).

BHD = Bottom hole diameter (inches).

SHD = Surface hole diameter (inches).

Using the value obtained the next step is to read, from Table 21 the Koenig Index corresponding to the weighted production hole diameter (WPHD):

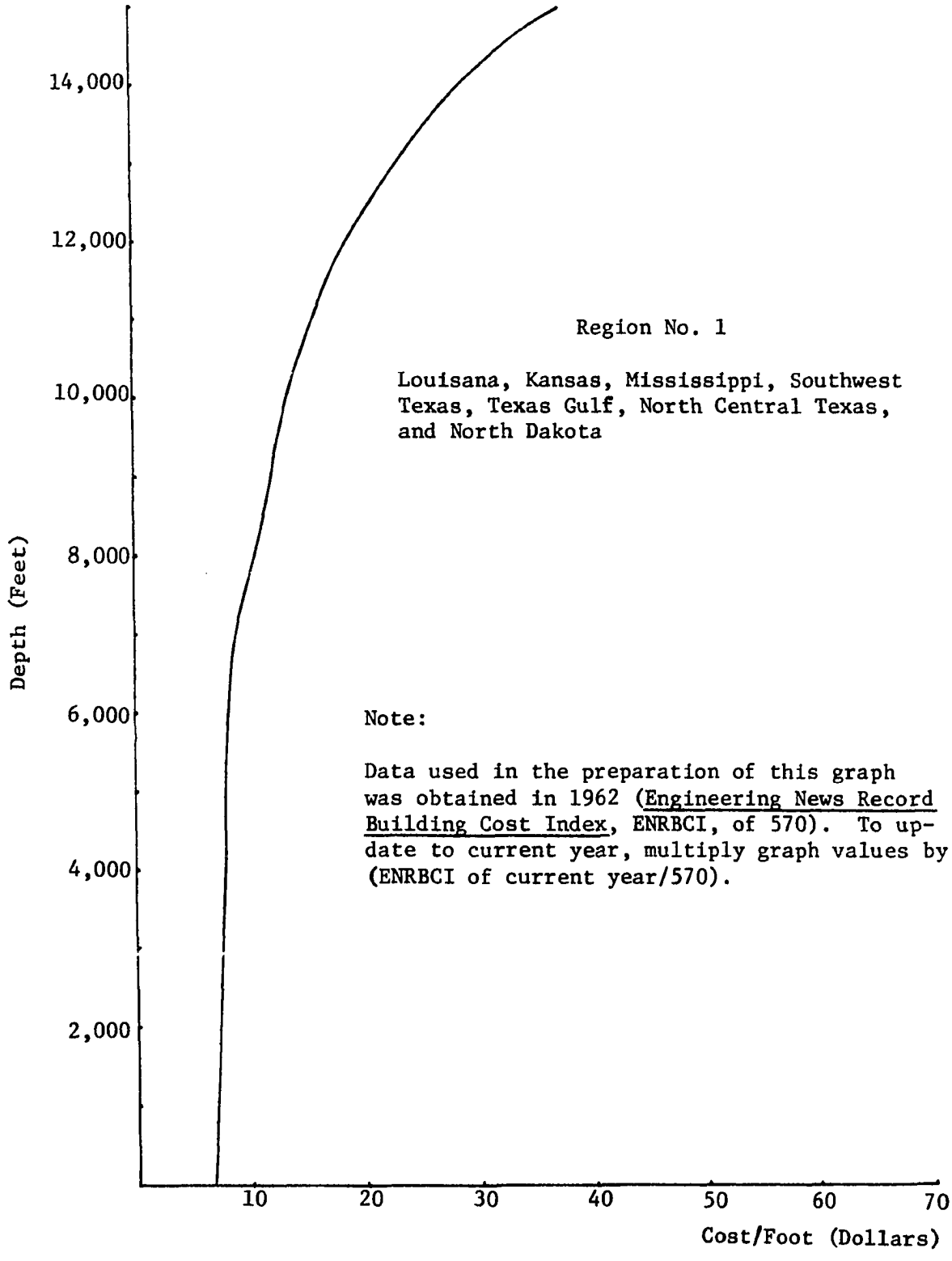
Table 21. Well Cost Variation with Hole Diameter (92, 97).

Bit Size (Inches)	Koenig Index (ft)
6 3/4	88.5
7 3/8	91.5
7 5/8	93.1
7 3/4	93.9
7 7/8	94.5
8 1/2	98.5
8 5/8	98.8
8 3/4	99.3
9	100
9 5/8	112.3
9 7/8	117.5
10 5/8	131
11	143
12	172
12 1/4	180
12 3/4	226
15	250
17 1/2	292

From Table 20, obtain the Regional Rating Code number of the well. Look up the cost ($/foot) of drilling at the depth desired in the appropriate RRC Graph (Figures 29 through 34), and multiply this value by the well depth. This value is the drilling cost of a 9-inch diameter well (D_9) and should be expressed in thousands of dollars (K dollars).

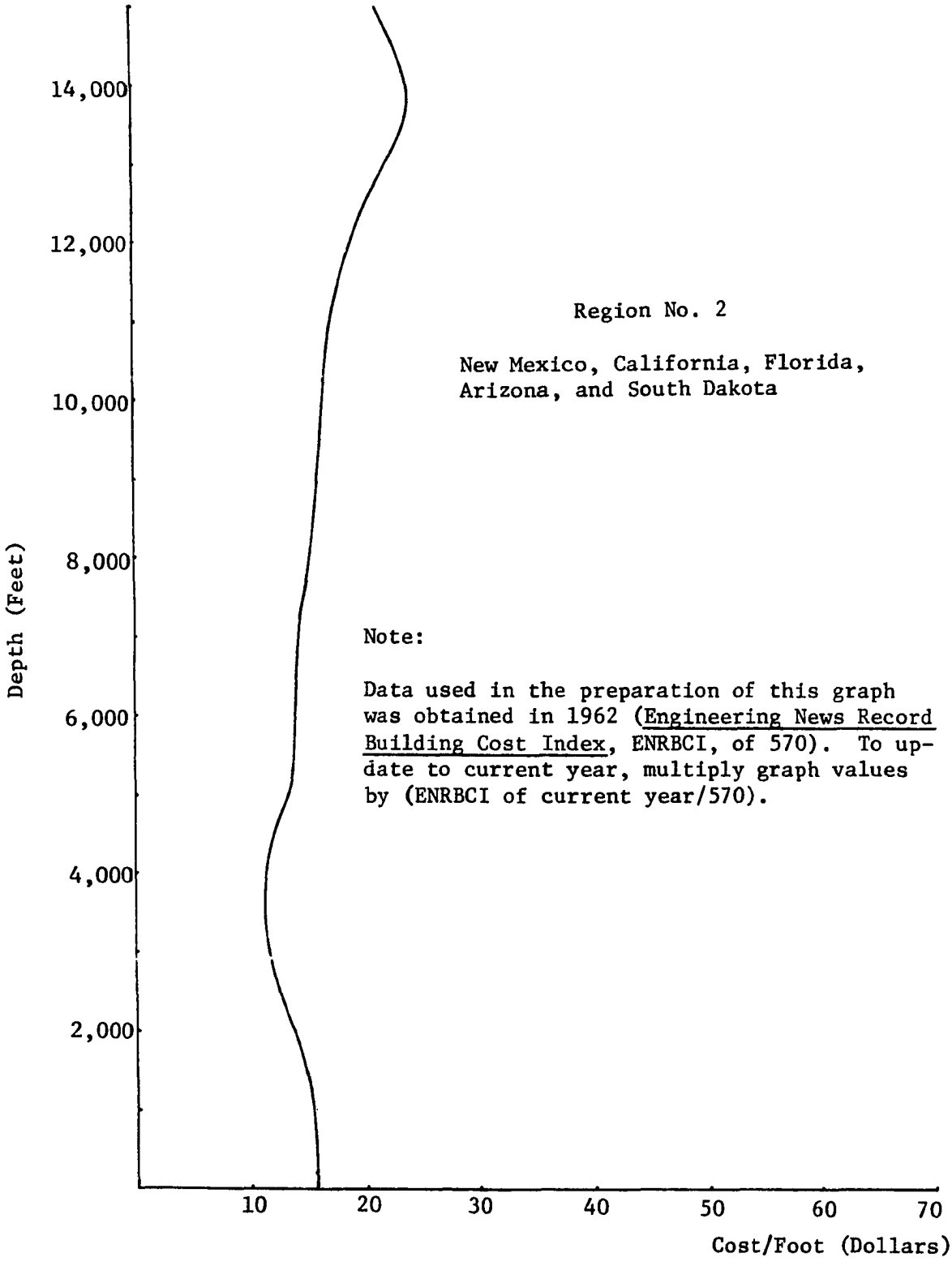
To calculate the COR 1 value (in K dollars), use the formula:

$$\text{Drilling Cost}_{(\text{COR 1})} = \left(\text{Drill Cost}_9 \times \frac{\text{Koenig Index}}{100}\right)$$



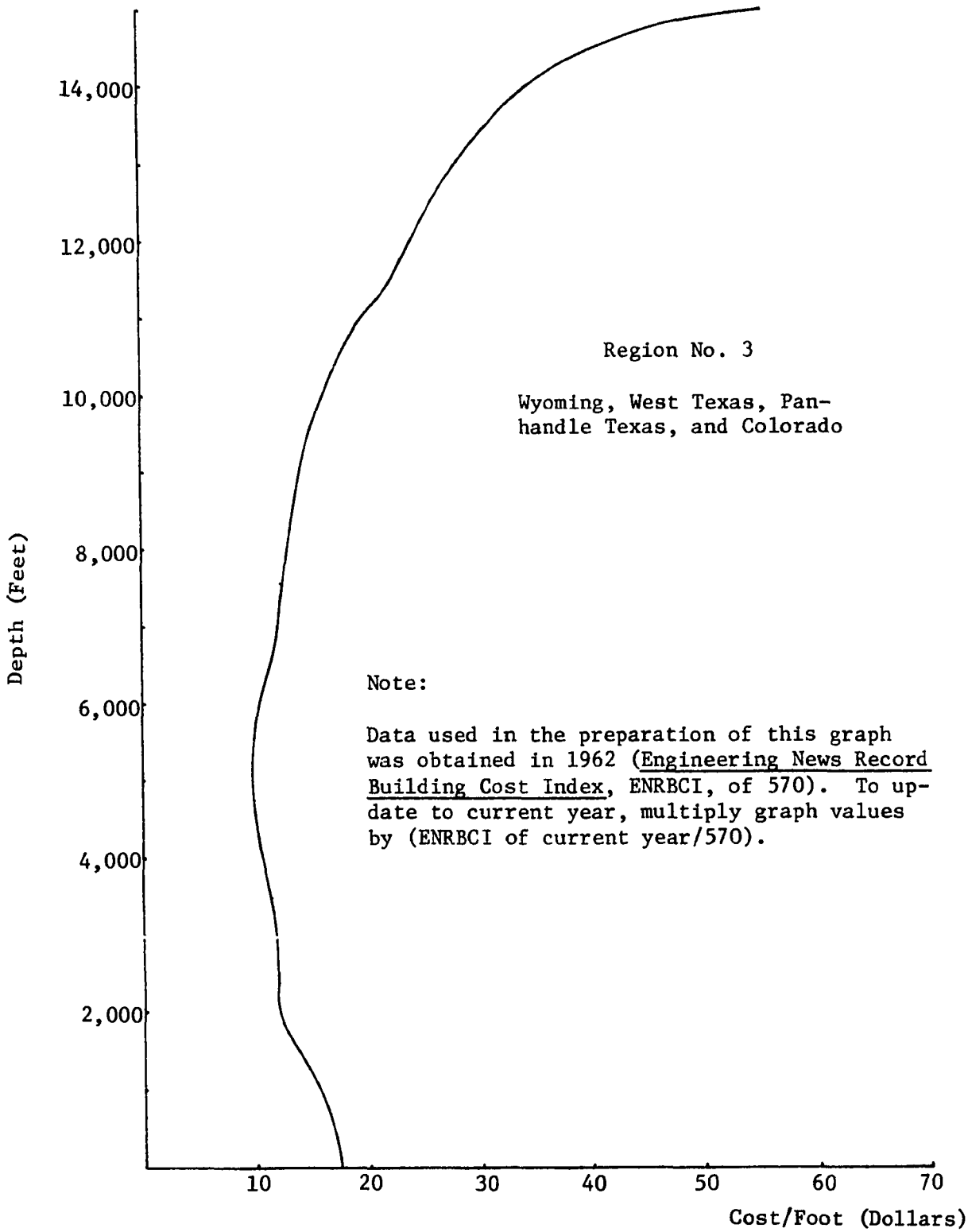
Depth vs Cost/Foot

Figure 29. Region Rating Code 1 (98).



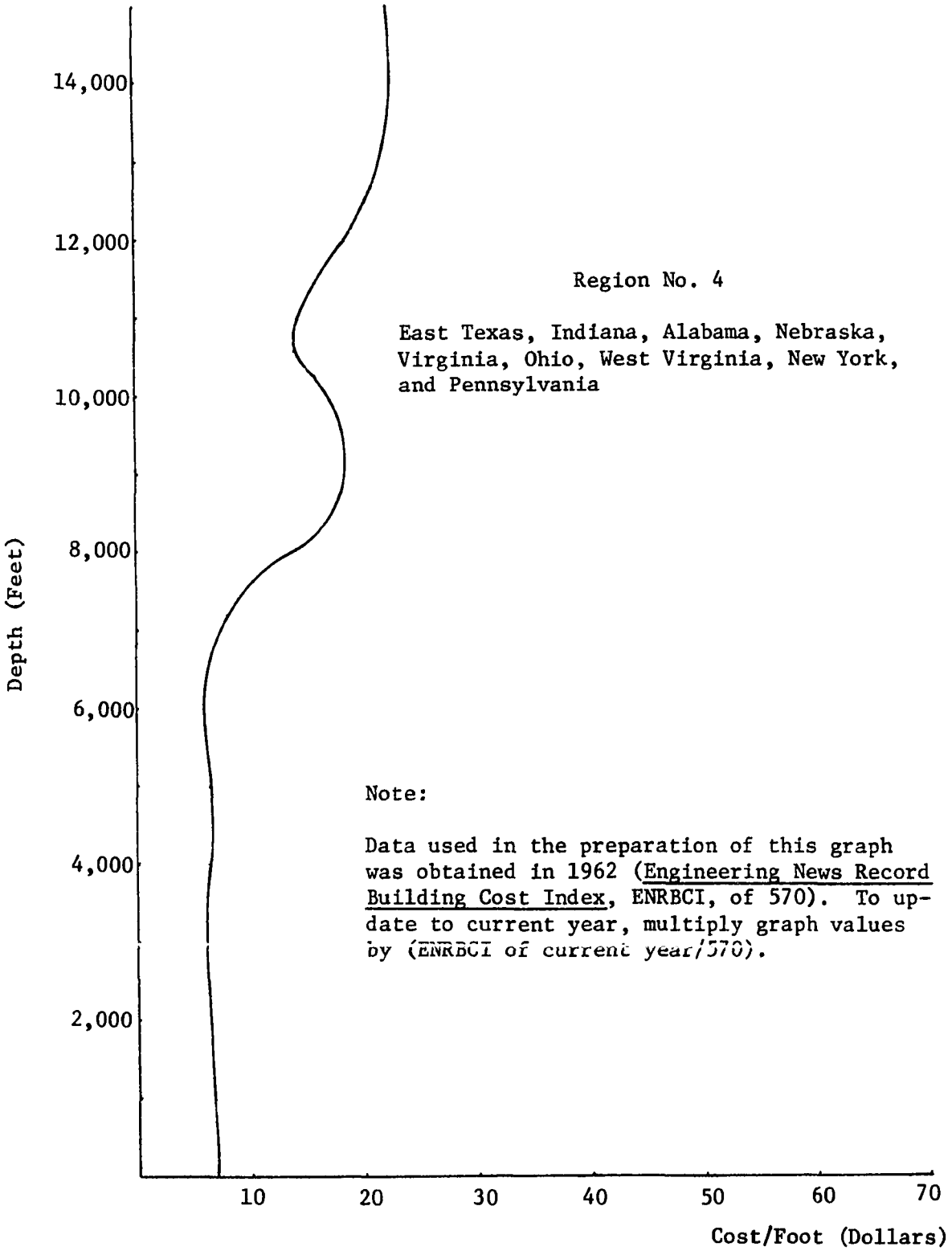
Depth vs Cost/Foot

Figure 30. Region Rating Code 2 (98).



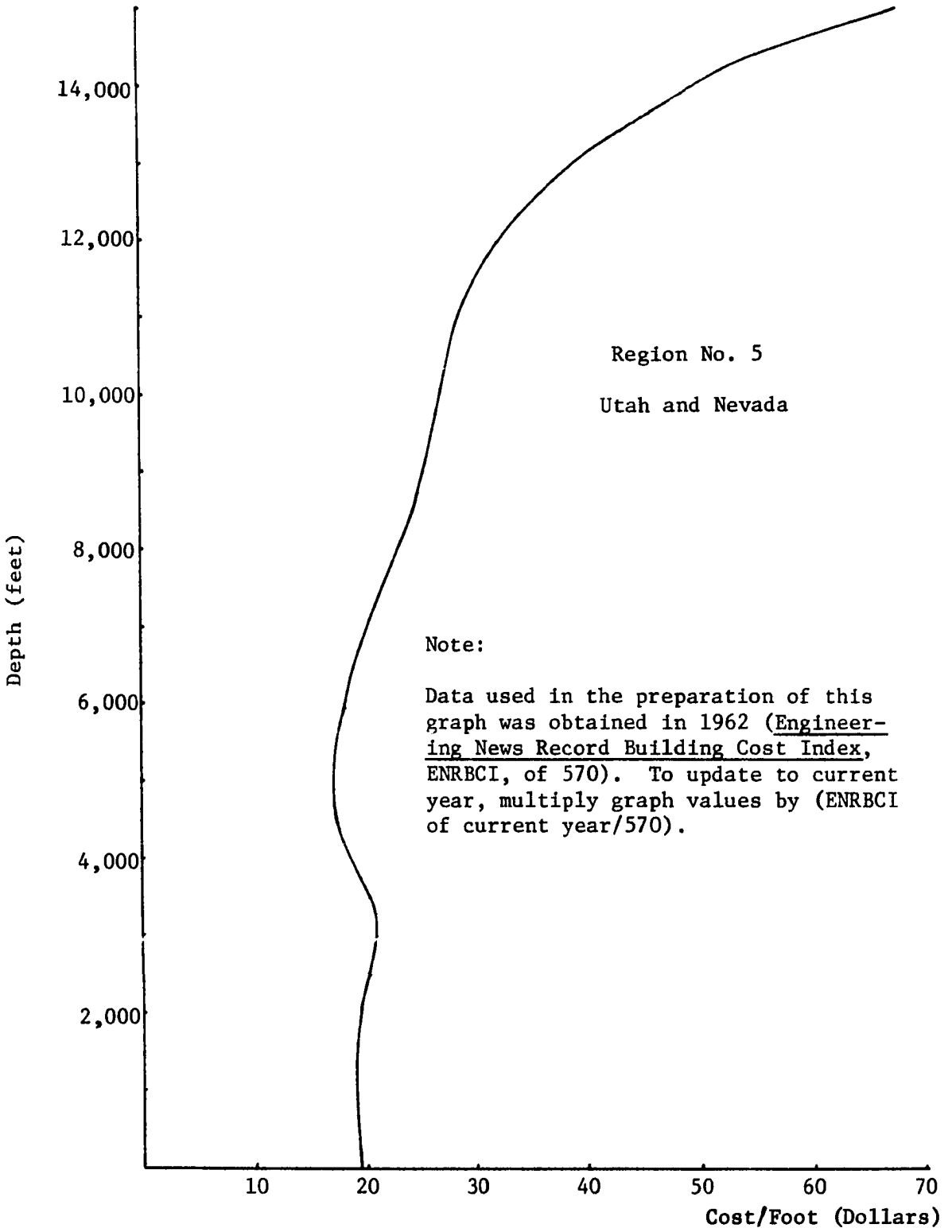
Depth vs Cost/Foot

Figure 31. Region Rating Code 3 (98).



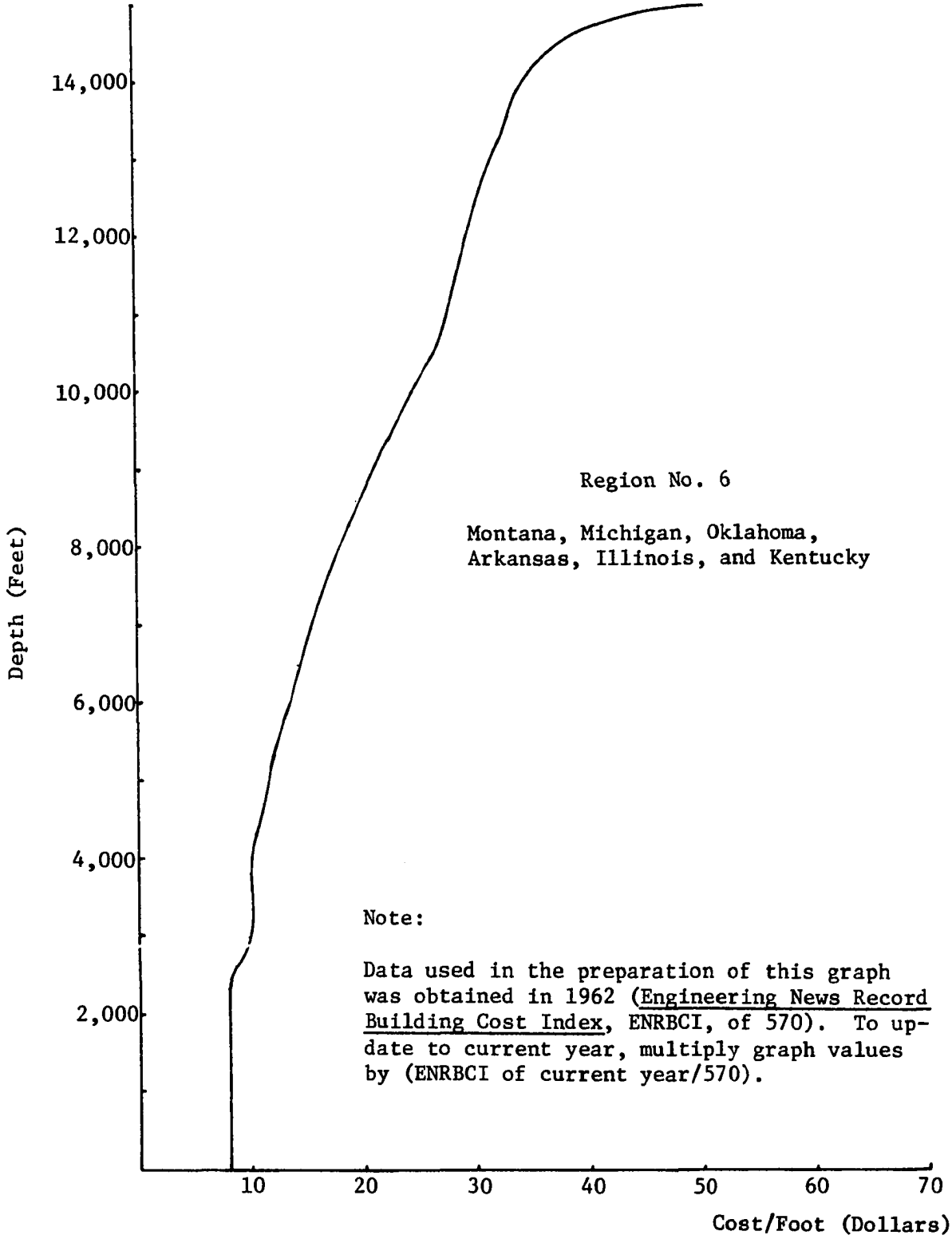
Depth vs Cost/Foot

Figure 32. Region Rating Code 4 (98).



Depth vs Cost/Foot

Figure 33. Region Rating Code 5 (98).



Depth vs Cost/Foot

Figure 34. Region Rating Code 6 (98).

The value thus obtained is the well drilling cost adjusted for diameter and expressed in thousands of dollars (K dollars).

SECTION X

CONCLUSIONS AND RECOMMENDATIONS

In the introductory section of this dissertation were presented the rather critical aspects of the present energy situation in the United States.

First, the expanding energy needs of an affluent and increasing population;

Second, a heavy reliance of many states on the petroleum industry for tax and employment revenues-an undeniable political influence;

Third, the pollutional complications introduced by high-sulfur coal, oil's only serious competitor as a fuel supply;

And lastly, the competitive nature of reliance on foreign oil imports.

It is highly unlikely that the level of energy consumption will be significantly diminished in the foreseeable future. Rather the burden of supplying these huge energy requirements will probably fall on domestic oil production until the economic strains make other sources available-quite possibly by both erroding pollutional standards to a compatable balance with energy supply and demand, and elevating energy costs to the feasibility levels of alternate "fuels." Thus in the continued exploitation of domestic reserves, it is not unlikely that the feasible oil to brine ratio could significantly diminish resulting in larger amounts of brine production with oil production, and consequently, a larger brine disposal problem. In a recent nationwide

poll of oil producers, respondents indicated that an average of ten barrels of brine were produced per barrel of oil (average of three dollars per barrel at the well head), and cost three cents per barrel of brine-or a cost of ten percent of the value of the produced oil for disposal. Furthermore, the small producer is at least as likely to experience the combined situation of increased quantities of brine, higher disposal costs, and stricter anti-pollution enforcement with neither the staff nor the scale of operations to effectively solve the problem of the major producer. Certain terminology has also been indicated to be a significant barrier to recognizing the problem.

Therefore the oil producer having read this text should be able to understand pollution, in general, and brine pollution in particular.

The pollutional dangers of an oil field brine depend primarily on the nature and amounts of its constituents in conjunction with the beneficial uses of the receiving body of water. If the brine must be disposed of, it must be in a legal manner. Utilizing the Appendix information along with the disposal cost computation foremat, the least expensive legal means of disposal can be developed, and the feasibility of production can be determined. If the unit value of oil does not exceed the unit cost (per barrel of oil) of disposal over the projected life of the production well, the operation is not feasible, and the well should be considered for methods of higher productive yield or abandoned.

Recommendations

No discussion of oilfield brine disposal is complete without mentioning two areas that potentially not only increase the efficiency of production disposal (as far as lowering brine disposal costs) but also could result in an additional source of income. The first area is secondary recovery (99). The second type of beneficial use is mineral recovery in which there is sufficient value attached to the minerals in the brine so that these minerals can be "mined" (101,102).

Secondary Recovery

State oil production regulating agencies specify procedures for unitizing a reservoir. Usually, the consent of a majority is equal to or greater than the percent specified by state law. After or concurrent with the landowners consent, a formula for dividing oil production revenues is devised and approved by the members of the unit. The next step is to decide how the unit will be run and who will run it. Normal practice is for the largest operator in the field to direct the production and secondary recovery operations of the entire reservoir.

It is not the intent of this publication to discuss waterflooding however, a summary of the advantages and disadvantages of this method of operation might prove useful to prospective unit participants (103). Table 22 gives that summary.

Table 22. Waterflooding
Advantages and Disadvantages.

Advantages	Disadvantages
1. Permits efficient, controlled production of a reservoir for maximum yield at minimum cost.	1. Pool may be too small to justify secondary recovery.
2. Handles large volumes of fluid yielding economies of scale, byproduct recovery.	2. Pool may have so many landowners that arbitration may be impossible.
3. Eases the burden of disposal.	3. Reservoir characteristics might prevent secondary recovery.
4. Small landowner can participate without drilling.	4. Minor operators may encounter idle drilling crews.
5. Conserves reservoir energy through higher yeilds; i.e. more complete production and increased productive life.	5. Major operators' interest may be too small to justify his participation.

Mineral Recovery

It should be recognized that at the present there are several major multimillion-dollar-per-year operations that mine surface deposits or solid deposits of salt (109,110). In addition, there are numerous operations which withdraw brine groundwater and extract salts and minerals (101,102,111,112,113). However, a key factor to analysis, the fluid volume that must be handled to make production feasible, must be examined thoroughly.

Relatively recently, there have been several publications advocating the potential of mineral byproduct recovery from oilfield brines.

A valid basis for this interest is that it is estimated approximately 8×10^9 barrels of brine are produced each year with the oil produced in the United States. These brines contain more than 1.3×10^8 tons of minerals and salts (32 pounds per barrel). An earlier table has listed concentrations of dissolved salts. Another article developed the point that based on sheer quantity, the mineral content of oilfield brine disposed of each year is worth more than $3 billion (114). As a rough estimate, the Tables 25 and 26 (115) indicate the dependence of the market value of specific recoverable chemicals on quantity of fluid handled and depth of reservoir.

Table 25. Dollar Value of Dissolved Chemicals a Brine Should Contain Per 1 Million Pounds (2,840 brls) of Brine Produced from a Given Depth.

Value ($/million lb of brine)	Depth of Well (ft)
210	2,500
440	7,000
650	10,000

When Table 25 is used with the Table 26, it becomes apparent that considerable profits can result if it is possible to process a concentrated brine either at the surface of the ground after separation from the oil or after raising the brine from a fairly shallow depth.

Table 26. Amount of Element per 1 Million Pounds of Brine Necessary to Produce Corresponding Chemical Product Worth $250.

Element	Concentration (ppm)	Product
Sodium	50,000	Sodium chloride
Lithium	170	Lithium chloride
Strontium	4,000	Strontium chloride
Boron	1,400	Sodium borate
Bromide	1,700	Bromine
Iodine	250	Iodine

These two tables should be used together; i.e., 1 million pounds (2,840 barrels) of brine containing 50,000 ppm sodium and 1,700 ppm bromine produced from a depth of 7,000 feet would be worth $250 + $250 - $440 = $60 (assuming Table 25 gives cost of mining).

Perhaps one reason for the seeming general lack of activity can be explained by some of the operating figures of some companies currently mining bromine in the Smackover region of Arkansas. These Figures are given in Table 27.

Table 27. Brine Quantities

Company	Volume (Brls/month)	Concentration Bromine (ppm)	Depth (ft)
1.	2,055,818	4,800	8,300
2.	175,797	4,000	7,600
3.	355,895	5,000	7,600
4.	4,823,242	4,500	8,400
5.	2,038,923	4,500	7,700
6.	2,691,120	4,500	7,400

Company no. 6 processes approximately 3.16 million pounds of brine a day. Assuming it is worth (2.65) ($250) = $663 per million pounds of brine, then the company could have a gross revenue from this activity of $2,090 - (3.16) (450) = $668 per day.

The reluctance of most small operators to get into mineral byproduct operations seems mainly due to the following reasons:

1. There is a relatively high initial and operational cost of equipment, especially in remote areas.
2. Proration and well spacing requirements make accumulation of high brine volumes expensive.
3. Occasional oil in the brine fouls separating mechanisms, especially if chelation (a relatively recent ion-exchange-type process) is used (86).
4. Equipment is fairly complicated to operate.
5. Market for minerals is variable.

In cooperative groupings however, the individual small operator acquires the resource potential of a large operator (from the reservoir operations point of view), and such operations as mineral byproduct recovery enter his realm as a potential source of additional profit.

Further Research

The development of this dissertation uncovered several areas of additional research needs specifically relating to oilfield brine disposal:

1. Economic incentive programs are necessary to induce oil producers to dispose of their brines. Several states have these types of programs; however their compensatory value is often questionable.
2. Legal procedures are needed to more effectively establish and police secondary recovery projects expecially in specifying an equitable distribution of income.
3. Mechanisms are necessary for the rapid determination of the cause of pollution from specific production sites both above and below ground especially the latter.
4. Further work needs to be done in the area of feasible byproduct recovery procedures on a small scale basis.
5. Additional efforts should be made to more specifically determine the economics of small scale production and alternative, low-cost disposal mechanisms which can be effectively used in this type of operation.

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APPENDIX A

SUMMARY OF STATE OIL REGULATING AGENCIES

ALABAMA

1. Regulating Agency:

   State Oil & Gas Board of Alabama
   P.O. Drawer 0
   Walter Bryan Jones Hall
   University, Alabama 35486

2. Publication of Regulations:

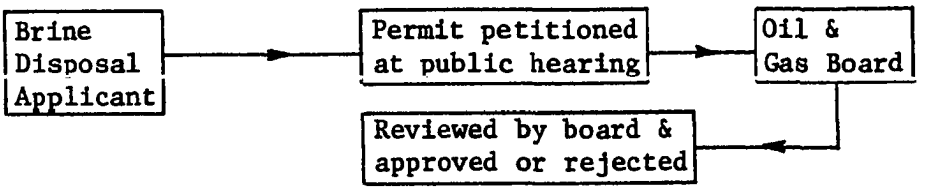
   Oil & Gas Laws of Alabama with Oil & Gas Board Forms and Definitions of Oil and Gas Terms

   Geological Survey of Alabama
   Reprint Series 20
   (1967)

3. Coordinating Agency:

   Alabama Water Improvement Commission
   Montgomery, Alabama

4. Application Flow Chart:



5. Allowable Methods of Disposal:

   Injection.

   Pits, lined.

   Pits, unlined (depending on soil).

6. Permit Costs

None.

ALASKA

1. Regulating Agency:

Department of Natural Resources
Oil and Gas Conservation Committee
3001 Porcupine Drive
Anchorage, Alaska 99504

2. Publication of Regulations:

Oil and Gas Conservation Regulations and Statutes
(1969)

3. Coordinating Agencies:

Department of Health and Welfare
Pouch H
Juneau, Alaska 99801

Environmental Protection Agency
Alaska Operations Office
Room 8, Federal Building
605 Fourth Avenue
Anchorage, Alaska 99501

No brine disposal permits to date.

No regulations on brine disposal.

ARIZONA

1. Regulating Agency:

   Oil & Gas Conservation Commission
   State of Arizona
   4515 North 7th Avenue
   Phoenix, Arizona 85013

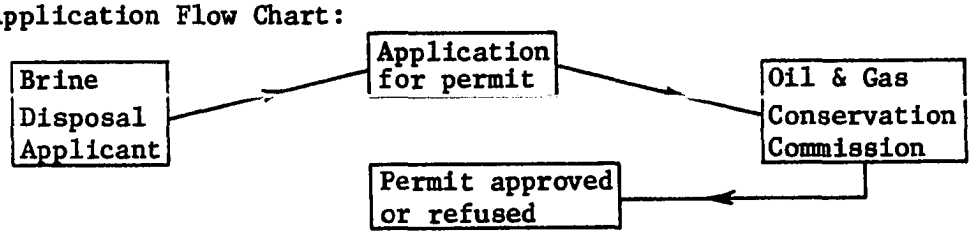
2. Publication of Regulations:

   Rules and Regulations,
   The Oil and Gas Conservation Commission
   of the State of Arizona
   (1965)

3. Coordinating Agency:

   Department of Health
   Fifth Floor
   Goodrich Building
   14 North Central Avenue
   Phoenix, Arizona 85004

4. Application Flow Chart:



5. Allowable Methods of Disposal:

   Injection.

   Pits, lined.

   Pits, unlined (where approved depending on soil).

ARIZONA (Cont)

6. Permit Costs:

   Injection: $25.00 (plus $5,000 plugging bond).

   Pits: No permit required.

ARKANSAS

1. Regulating Agency:

   State of Arkansas Oil & Gas Commission
   Oil & Gas Building
   El Dorado, Arkansas

2. Publication of Regulations:

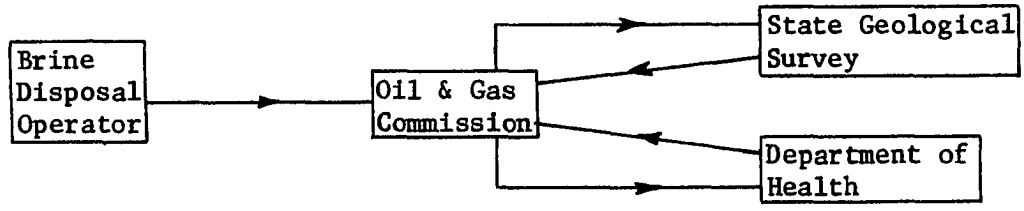
   General Rules & Regulations Relating to Oil & Gas
   Order No. 2-39
   (revised February 1956)

3. Coordinating Agencies:

   State Geological Survey
   State Capitol Building
   (Director, Norman F. Williams)

   State Department of Health
   4815 W. Markham Street
   Little Rock, Arkansas 72201

4. Application Flow Chart:



Note: The commission, in passing on applications for the use of non-producing formations for disposal formations, will be advised by the technical recommendations of the State Geological Survey and the State Board of Health in determining whether such formations may be safely and legally used.

5. Allowed Disposal Methods:

Injection.

Ponds, lined.

Ponds, unlined.

6. Disposal Permit Costs:

Injection: None.

Ponds: None.

CALIFORNIA

1. Regulating Agency:

Department of Conservation
Division of Oil & Gas
1416 Ninth Street
Sacramento, California 95814

CALIFORNIA (Cont)

2. Publication of Regulations:

California Laws for Conservation of Petroleum and Gas (1968)

3. Coordinating Agency:

California State Water Resources Control Board
Room 1140, 1416 Ninth Street
Sacramento, California 95814

4. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

Discharge into ocean.

5. Permit Costs:

None listed in regulations.

COLORADO

1. Regulating Agency:

Oil & Gas Conservation Commission
Room 237, Columbine Building
1845 Sherman Street
Denver, Colorado 80203

2. Publications of Regulations:

Rules & Regulations, Rules of Practice and Procedure and Oil and Gas Conservation Act (1970)

3. Coordinating Agencies:

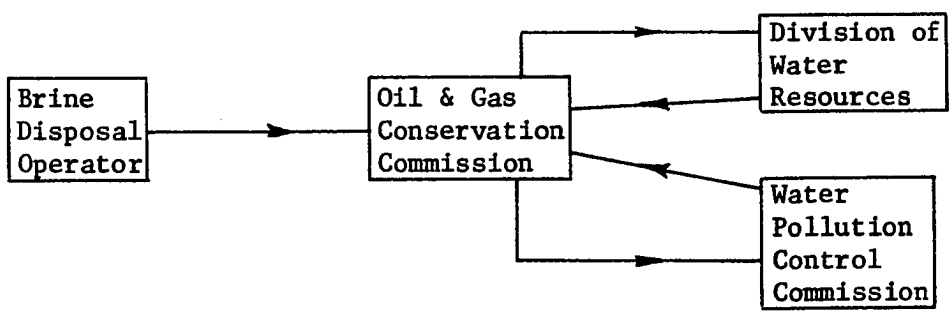
Division of Game,
Fish & Parks
6060 Broadway
Denver, Colorado 80221

Water Pollution Control Commission
4210 E. 11th Avenue
Denver, Colorado 80220

Division of Water Resources
1845 Sherman Street
Denver, Colorado 80203

Geological Survey
1845 Sherman Street
Denver, Colorado 80203

4. Application Flow Chart:



Note: Copies of the application are given to the Division of Water Resources and the Water Pollution Control Commission for comments. If they have no objection and there is no objection from land owners near the well site, then the application is approved.
No permit needed for pits.

5. Allow Disposal Methods:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $75 (plus $5,000 plugging bond per well or $15,000 blanket bond).

Pits: None.

CONNECTICUT

No regulating agency (no production).

DELAWARE

No regulating agency (no production).

FLORIDA

1. Regulating Agency:

   Department of Natural Resources
   Bureau of Geology
   Oil & Gas Administration
   P.O. Drawer 631
   Tallahassee, Florida 32302

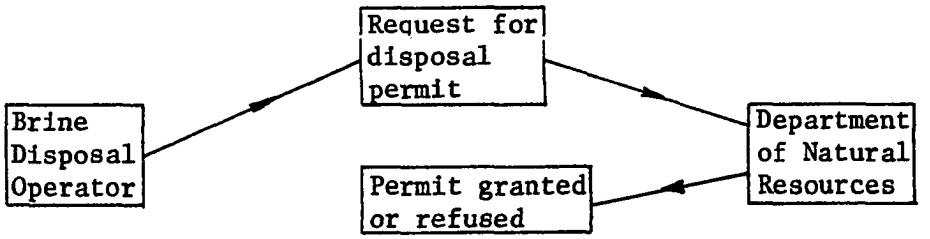
2. Publication of Regulations:

   General Rules and Regulations Governing the Conservation of Oil and Gas in Florida
   (1962)

3. Coordinating Agency:

   Department of Air and Water Pollution Control
   P.O. Drawer 631
   Tallahassee, Florida 32302

4. Application Flow Chart:



Note: All applications for permits for disposal of brine are made through the Oil and Gas Administrator and acted on by the Executive Board of the Department of Natural Resources, which is the Cabinet and the Governor. After a public hearing, rules for use of the injection well are devised and an order from the department is issued.

FLORIDA (Cont)

5. Allowable Methods of Disposal:

   Injection only.

6. Permit Costs:

   None.

IDAHO

No regulating agency (no production).

ILLINOIS

1. Regulating Agency:

   Department of Mines & Minerals
   Division of Oil & Gas
   400 South Spring Street, Room 112
   Springfield, Illinois

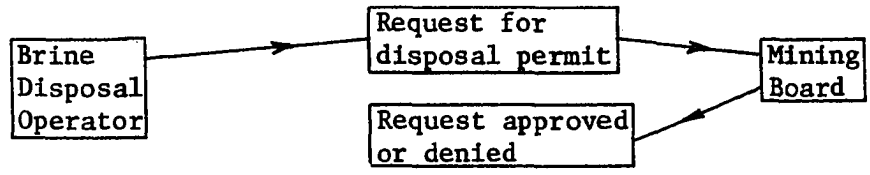
2. Publication of Regulations:

   An Act in Relation to Oil, Gas Coal & Other Surface & Underground Resources and Rules and Regulations
   (1969)

3. Coordination Agency:

Department of Mines & Minerals
Mining Board
400 South Spring Street, Room 112
Springfield, Illinois

4. Application Flow Chart:



Note: Application either accepted or refused by Mining Board within 10 days after receipt. Application must be resubmitted each year. Sites subject to inspection by Mining Board.

5. Allowed Disposal Methods:

Injection, drilled or converted well.

Ponds, lined or unlined (depending on soil characteristics).

6. Disposal Permit Costs:

Injection: $40/year (plus $1,000 plugging bond per well or $2,500 blanket bond).

Ponds: None, but permit must be resubmitted each year.

INDIANA

1. Regulating Agency:

Department of Natural Resources
Division of Oil & Gas
606 State Office Building
Indianapolis, Indiana 46204

2. Publication of Regulations:

Indiana Division of Oil & Gas
Department of Natural Resources
Rules and Regulations
(1964)

3. Coordination Agencies:

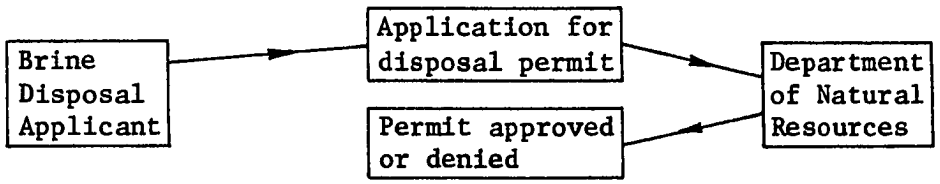
Indiana State Board of Health
Stream Pollution Control Board
1330 W. Michigan Street
Indianapolis, Indiana

Indiana State Board of Health
Water Pollution Control
1330 W. Michigan Street
Indianapolis, Indiana

Indiana State Board of Health
Industrial Waste Disposal Section
1330 W. Michingan Street
Indianapolis, Indiana

Indiana Geological Survey
611 North Walnut Grove Avenue
Bloomington, Indiana 47401

4. Application Flow Chart:



Note: All applications for brine disposal permits are submitted to the Department of Natural Resources for processing. If there is any particular question in regard to a disposal application, one or more agencies may be contacted. If there are no questions the permit is processed and issued under the Statutes and Regulations. Any applications for salt water evaporation pits are also submitted to this office and each pit is then checked in the field for size, type of construction, etc. If the pit meets all requirements, a permit is issued for one year only. The operator must re-apply for a permit each year, and the pit is checked on each application.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $25 for new well, none for converted well.

Pits: None.

IOWA

No production.

1. Regulating Agency:

Iowa Natural Resources Council
Grimes State Office Building
Des Moines, Iowa 50319

2. Publication of Regulations:

Iowa Natural Resources Council
Code Chapter 84
Relating to Oil & Gas Wells
(1966)

KANSAS

1. Regulating Agency:

State Corporation Commission
State Office Building
Topeka, Kansas 66612

2. Publication of Regulations:

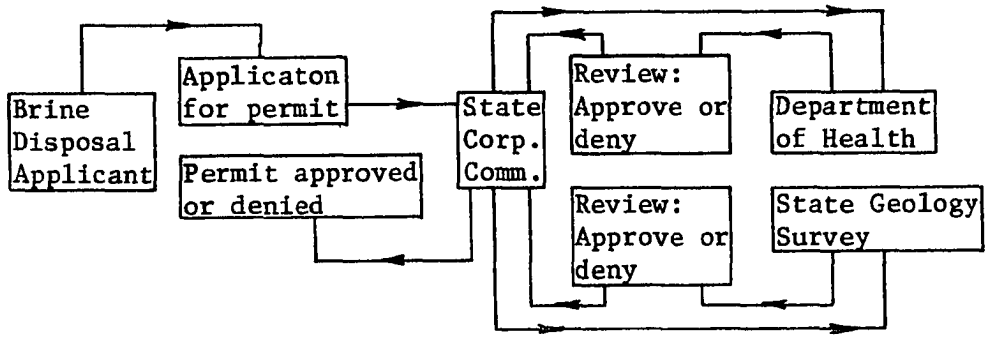
General Rules and Regulations for the Conservation of Crude Oils and Natural Gas
(1966)

3. Coordination Agencies:

Kansas State Department of Health
State Office Building
Topeka, Kansas 66612

State Geological Survey
University of Kansas
Lawrence, Kansas 66044

4. Application Flow Chart:



5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $15.00 where one lease is involved, $5.00 for each additional lease.

Pits: None.

KENTUCKY

1. Regulating Agency:

Department of Mines and Minerals
P.O. Box 680
120 Graham Avenue
Lexington, Kentucky 40501

2. Publication of Regulations:

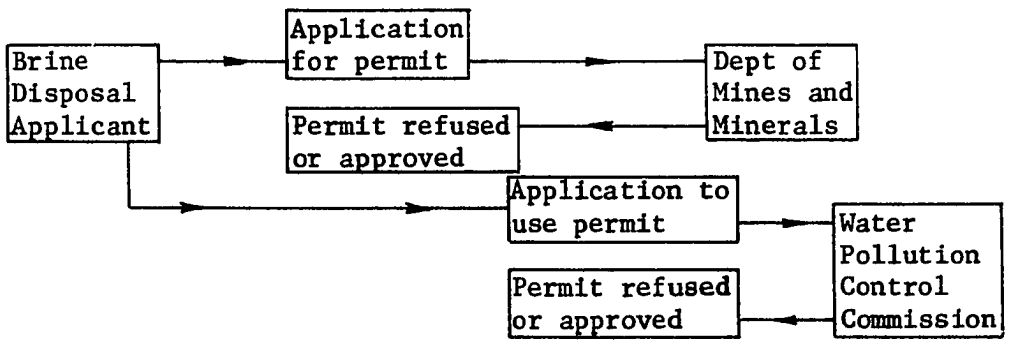
Rules and Regulations Affecting the Oil and Gas Industry in Kentucky
(1967)

3. Coordinating Agencies:

Water Pollution Control Commission
275 East Main Street
Frankfort, Kentucky 40601

Department of Fish and Wildlife
State Office Building Annex
Frankfort, Kentucky 40601

4. Application Flow Chart:



Note: Drilling is controlled by Department of Mines and Minerals, and use of wells is controlled by Water Pollution Control Commission.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $10(plus $10,000 plugging bond).

Pits: None.

LOUISIANA

1. Regulating Agency:

   Department of Conservation
   Louisiana Geological Survey
   Geology Building
   Box G
   University Station
   Baton Rouge, Louisiana 70903

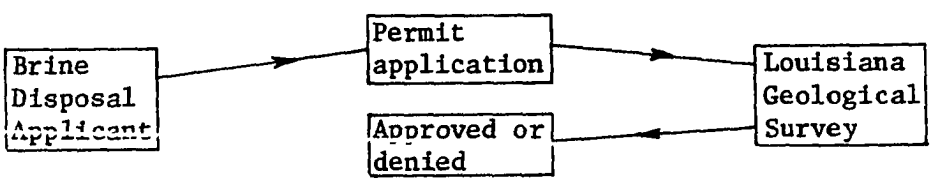
2. Publication of Regulations:

   Salt Water & Waste Disposal Wells
   State Regulations & Geological Problems
   (Revised, 1968)

3. Coordination Agency:

   None.

4. Application Flow Chart:



5. Allowable Methods of Disposal:

   Injection.

   Pits, lined.

   Pits, unlined.

   In tide-affected waters (waters unfit for human comsumption or agricultural purposes).

LOUISIANA (Cont)

6. Permit Costs:

No costs given.

MAINE

No production.

1. Regulating Agency:

Maine Mining Bureau
State House
Augusta, Maine 04330

2. Publication of Regulations:

Maine Mining Law for
State-Owned Lands
(1969)

MARYLAND

Natural Gas Production.

1. Regulating Agency:

Maryland Geological Survey
214 Latrobe Hall
John Hopkins University
Baltimore, Maryland 21218

2. Publication of Regulations:

Rules & Regulations Governing
Oil & Gas Wells
(1964)

3. Coordinating Agency:

Department of Water Resources
State Office Building
Annapolis, Maryland 21401

Note: Above agency is responsible for regulating the quality of surface and ground water in Maryland.

4. Allowable Method of Disposal:

No rules or regulations for brine disposal in publication of regulations.

MASSACHUSETTS

No regulating agency (no production).

MICHIGAN

1. Regulating Agency:

Oil and Gas Section (Regulatory Control Unit)
Michigan Geological Survey Division
Department of Natural Resources
Stevens T. Mason Building
Lansing, Michigan 48900

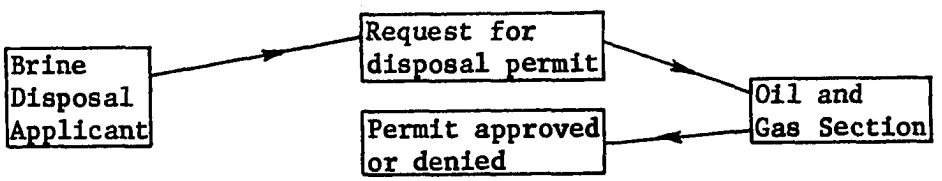
2. Publication of Regulations:

General Regulations Governing Oil & Gas Operations in the State of Michigan (1963)

3. Coordination Agency:

None.

4. Application Flow Chart:



5. Allowable Methods of Disposal:

Injection only.

6. Permit Costs:

Injection: $25.00 (plus $6,000 plugging bond per well or $15,000 blanket bond).

MINNESOTA

No regulating agency (no production).

MISSISSIPPI

1. Regulating Agency:

State Oil & Gas Board
1207 Woolfork State Office Building
P.O. Box 1332
Jackson, Mississippi

2. Publication of Regulations:

State Oil & Gas Board
State of Mississippi
Statutes Rules of
Procedure Statewide
Rules and Regulations
(1970)

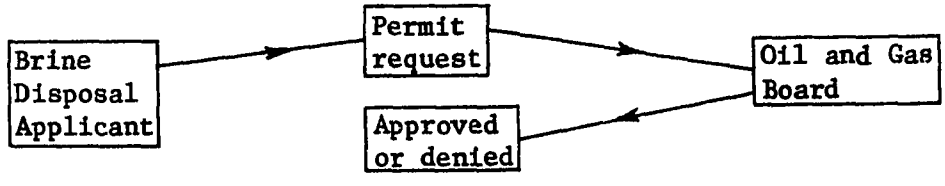
3. Coordination Agencies:

Mississippi Air & Water Pollution
Control Commission
Robert E. Lee Office Building
Jackson, Mississippi 39201

Mississippi Board of Water Commissioners
416 N. State Street
Jackson, Mississippi 39201

Note: Agencies consulted in cases involving pollution or probable pollution.

4. Application Flow Chart:



5. Allowable Methods of Disposal:

Injection.

Pit, unlined (in impervious soil).

Pit, lined (in porous soil).

Into receiving bodies of water when not prohibited by State Fish and Game Commission or other regulatory bodies.

6. Permit Costs:

Injection: $50 for new wells, $25 for converted wells.

Earthen pits: None.

Discharge into receiving body of water: None.

MISSOURI

1. Regulating Agency:

Missouri State Oil and Gas Council
P.O. Box 250
Rolla, Missouri

2. Publication of Regulations:

State of Missouri Rules and Regulations Governing Practice and Procedure Before the State Oil & Gas Council Under the Provisions of Senate Bill No. 13
Second Extra Session, 73rd General Assembly
(1970)

3. Coordinating Agency:

Missouri State Oil and Gas Council
P.O. Box 250
Rolla, Missouri

Note: The State Oil & Gas Council is composed of one staff member from each of the following State agencies with the State Geologist as active administrator.

1. Division of Geological Survey and Water Resources.
2. Division of Commerce and Indsutrial Development.
3. Missouri Public Service Commission.
4. Water Pollution Board.
5. University of Missouri (a professor of petroleum engineering).

4. Allowable Methods of Disposal:

Injection.

Note: Pertinent data concerning details of the proposed operation shall be submitted by letter to the State Geologist for approval.

5. Permit Costs:

Injection: $25.00

MONTANA

1. Regulating Agency:

Oil & Gas Conservation Commission
325 Fuller Avenue
Box 217
Helena, Montana 59601

2. Publication of Regulations:

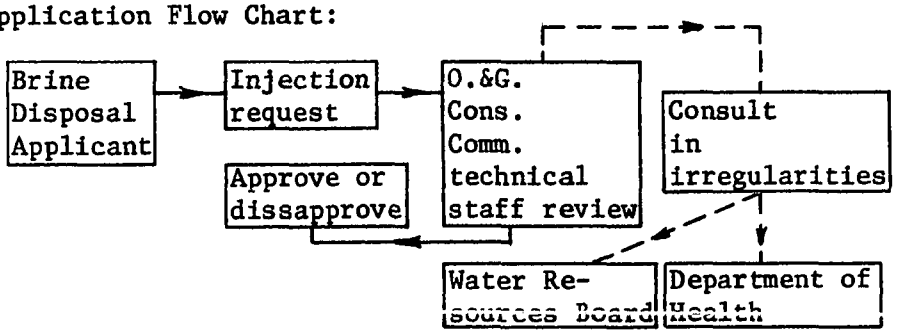
General Rules & Regulations and
Rules of Practice & Procedure
Relating to Oil & Gas
(1954)

3. Coordinating Agencies:

State Department of Health
Cogswell Building
Helena, Montana 59601

Water Resources Board
Mitchell Building
Helena, Montana 59601

4. Application Flow Chart:



Note: The State Department of Health and the Water Resources Board report and consult on water pollution.

5. Allowed Disposal Methods:

Injection. (encouraged)

Pits, lined.

Pits, unlined.

MONTANA (Cont)

6. Permit Costs:

Injection: Depth	Cost
0' - 3,500'	$ 25.00
3,501' - 7,000'	$ 75.00
7,000' - below	$150.00

(plus $5,000 to $20,000 bond. See page 12 of Regulations.)

Pits. No permits required.

NEW HAMPSHIRE

No regulating agency (no production).

NEW JERSEY

No regulating agency (no production).

NEW MEXICO

1. Regulating Agency:

New Mexico Oil Conservation Commission
P.O. Box 2088
Santa Fe, New Mexico 87501

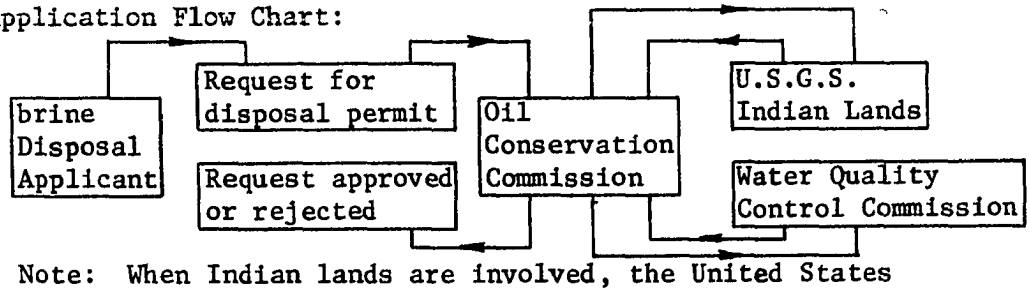
2. Published Regulations:

State of New Mexico Oil Conservation Commission
Rules & Regulations
(1968)

3. Coordinating Agency:

New Mexico Water Quality Control Commission
P.O. Box 2088
Santa Fe, New Mexico 87501

4. Application Flow Chart:



Note: When Indian lands are involved, the United States Geological Survey is consulted. Normally, the Water Quality Control Commission acts as consultant to the Oil Conservation Commission. The Water Quality Control Commission is made up of the heads of the Oil Conservation Commission, Department of Health and Social Services, Department of Game and Fish, Department of Agriculture, and one citizen at large.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $10,000 plugging bond and $10,000 performance bond on treatment plants).

Pits: None.

NEW YORK

1. Regulating Agency:

   Division of Mineral Resources
   Department of Environmental Conservation
   Albany, New York 12201

2. Publication of Regulations:

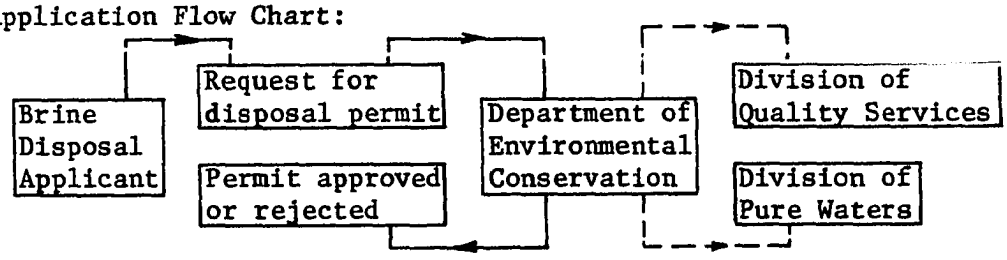
   State of New York, Division of Mineral Resources
   Environmental Conservation Department
   Bureau of Oil and Gas Rules and Regulations
   (1966)

3. Coordinating Agencies:

   Division of Quality Services
   Department of Environmental Conservation
   Albany, New York 12201

   Division of Pure Waters
   Department of Environmental Conservation
   Albany, New York 12201

4. Application Flow Chart:



   Note: The Divisions of Quality Services and Pure Waters consult only in cases where irregularities exist.

5. Allowable Methods of Disposal:

   Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $2,000 plugging bond for new wells and $1,000 plugging bond for old wells).

NEVADA

1. Regulating Agency:

Nevada Oil & Gas Conservation Commission
c/o Nevada Bureau of Mines
University of Nevada
Reno, Nevada 89507

2. Publication of Regulations:

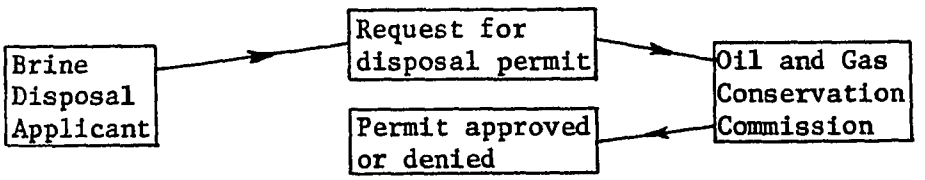
Oil & Gas Conservation Law and
General Rules & Regulations
(1954)

3. Coordinating Agency:

None.

Note: Only 13 wells and three operators in state.

4. Application Flow Chart:



5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $2,500 plugging bond).

Pits: None.

NEBRASKA

1. Regulating Agency:

Nebraska Oil & Gas Conservation Commission
Box 399
Sidney, Nebraska

2. Publication of Regulations:

Rules & Regulations of the Nebraska Oil & Gas Conservation Commission
(1969)

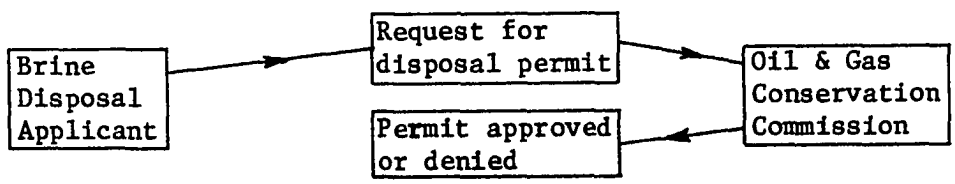
NEBRASKA (Cont)

3. Coordination Agencies:

Department of Health
State Capitol Building
Lincoln, Nebraska

Nebraska Geological Survey
Nebraska Hall
Lincoln, Nebraska

4. Application Flow Chart:



5. Allowable Disposal Methods:

Injection only.

6. Permit Costs:

Injection. None (but $2,500 plugging bond).

NORTH CAROLINA

No regulating agency (no production).

NORTH DAKOTA

1. Regulating Agency:

   North Dakota Industrial Commission
   University Station
   Grand Forks, North Dakota 58201

2. Publication of Regulations:

   General Rules and Regulations for the Conservation of Crude Oil and Natural Gas (1969)

3. Coordinating Agency:

   None.

4. Allowable Methods of Disposal:

   Injection.

   Pits, lined (in permeable soil).

   Pits, unlined (in impermeable soil).

5. Permit Costs:

   Permits must be obtained for both pits and injection wells, but no prices given.

OHIO

1. Regulating Agency:

   Department of Natural Resources

Division of Oil & Gas
1500 Dublin Road
Columbus, Ohio 43215

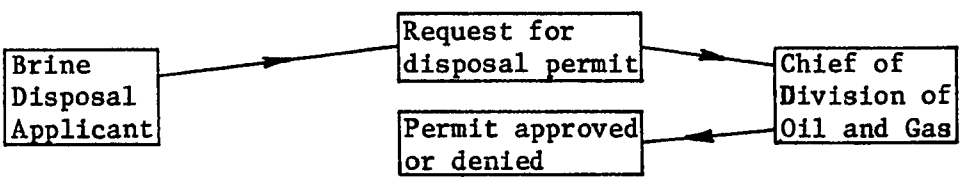
2. Publication of Regulations:

Ohio Oil & Gas Law
Revised Code Chapter 1509
with Rules & Regulations
(1970)

3. Coordinating Agency:

None.

4. Application Flow Chart:



Note: The Chief of the Division of Oil and Gas either accepts or rejects the application for disposal permit.

5. Allowable Disposal Methods:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None.

Pits: None.

OKLAHOMA

1. Regulating Agency:

Oil Corporation Commission
Jim Thorpe Building
Oklahoma City, Oklahoma 73105

2. Publication of Regulations:

Regulations of the Oklahoma Corporation Commission
Conservation Division
(1969)

3. Coordination Agency:

Department of Pollution Control
Jim Thorpe Building
Oklahoma City, Oklahoma 73105

Note: Copies of all applications for subsurface disposal are sent to the other member agencies of the Department of Pollution Control for their review and comments.

4. Allowable Methods of Disposal:

Injection only.

5. Permit Costs:

None.

OREGON

No production in 1971.

1. Regulating Agency:

Department of Geology & Mineral Resources
1069 State Office Building
Portland, Oregon 97201

2. Publication of Regulations:

Rules & Regulations for the Conservation of Oil & Natural Gas and Laws relating to Development of Oil & Gas Minerals
(1962)

3. Coordinating Agency:

Department of Environmental Quality
720 State Office Building
Portland, Oregon 97201

4. Allowed Disposal Methods:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

OREGON (Cont)

5. Cost of Permits:

No production. No permits issued as of February 1971.

PENNSYLVANIA

1. Regulating Agency:

Department of Mines & Minerals Industries
Oil & Gas Division
Towne House Apartments
660 Boas Street
Harrisburg, Pennsylvania

2. Publication of Regulations:

Commonwealth of Pennsylvania
Compilation of Oil and Gas Laws
Administered by the Department of Mines
and Mineral Industries, Oil and Gas Division
(1969)

3. Coordination Agency:

Sanitary Water Board
Department of Health
Towne House Apartments
660 Boas Street
Harrisburg, Pennsylvania

Note: The Oil and Gas Division coordinated with the Sanitary Water Board in the adoption of rules for the prevention of stream pollution.

PENNSYLVANIA (Cont)

4. Allowable Methods of Disposal:

"For all producing wells, adequate provision shall be made to receive all salt water, oil and basic sediment (B.S.) in tub tanks or suitable containers from which all such wastes, tank bottoms, and other petroleum residues shall be discharged into one or more dumps of adequate size, or into equivalent settling devices, equipped with baffles, siphons, or other suitable means to prevent all oil and residues from reaching the water of the Commonwealth." (Quoted from Regulations.)

5. Permit Costs:

Treatment Plant Permit: $25.00

RHODE ISLAND

No regulating agency (no production).

SOUTH CAROLINA

No regulating agency (no production).

SOUTH DAKOTA

1. Regulating Agency:

Oil & Gas Board
State Capitol
Pierre, South Dakota 57501

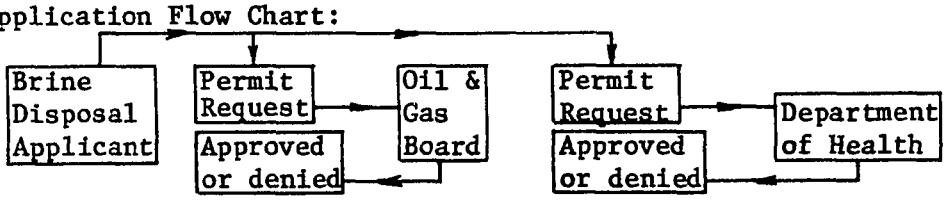
2. Publication of Regulations:

Out of print.

3. Coordinating Agency:

Department of Health
State Capitol
Pierre, South Dakota 57501

4. Application Flow Chart:



Note: An oil well operator, in addition to complying with the regulations of Oil & Gas Board, must also apply for a permit for the discharge of waste from the South Dakota Committee on Water Pollution (Department of Health).

5. Allowable Methods for Disposal:

Present policy is to dispose of brine by evaporation in a properly sealed holding pond. No injection of brine as of March 18, 1971.

6. Costs of Permits: None given.

TENNESSEE

1. Regulating Agency:

State Oil & Gas Board
G-5 State Office Building
Nashville, Tennessee 37219

TENNESSEE (Cont)

2. Publication of Regulations:

   Rules & Regulations Pertaining to Oil & Gas Exploration Adopted by the State Oil & Gas Board

3. Coordinating Agency:

   Department of Health
   Division of Stream Pollution
   G-5 State Office Building
   Nashville, Tennessee 37219

   Note: According to the State Oil and Gas Board, there has been no brine for disposal to date.

TEXAS

1. Regulating Agency:

   The Railroad Commission of Texas
   Oil and Gas Division
   Ernest O. Thompson Building
   Capitol Station, P.O. Drawer 12967
   Austin, Texas 78711

2. Publication of Regulations:

   The Railroad Commission of Texas
   General Conservation Rules & Regulations of state wide application, State of Texas
   (1971)

3. Coordinating Agencies:

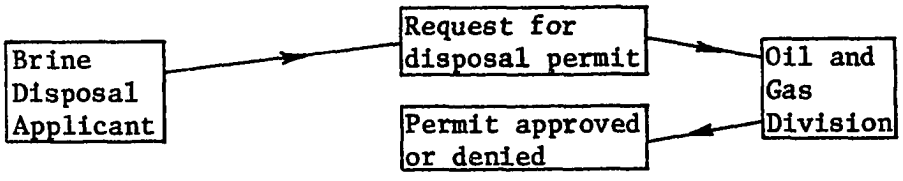
Texas Water Quality Board
1108 Lavaca Street
Austin, Texas 78701

Texas Water Development Board
P.O. Box 12386
Austin, Texas 78711

Texas Parks and Wildlife Department
John H. Reagan Building
Austin, Texas 78701

State Health Department
1100 W. 49th Street
Austin, Texas 78756

4. Application Flow Chart:



Note: All brine disposal permit applications are processed through the Oil and Gas Division. A majority of the requests are acted on administratively; however, if the request is for an exception to a Statewide Rule, it may be set for public hearing.

5. Allowable Methods of Disposal:

Injection.

No pits.

Discharge into waters off shore and adjacent estuarine zones.

TEXAS (Cont)

6. Permit Costs:

Permits required but no cost given.

UTAH

1. Regulating Agency:

Division of Oil & Gas Conservation
Department of Natural Resources
1588 West North Temple
Salt Lake City, Utah 84116

2. Publication of Regulations:

The Oil and Gas Conservation Act and
The General Rules and Regulations and
Rules of Practice and Procedure
(1969)

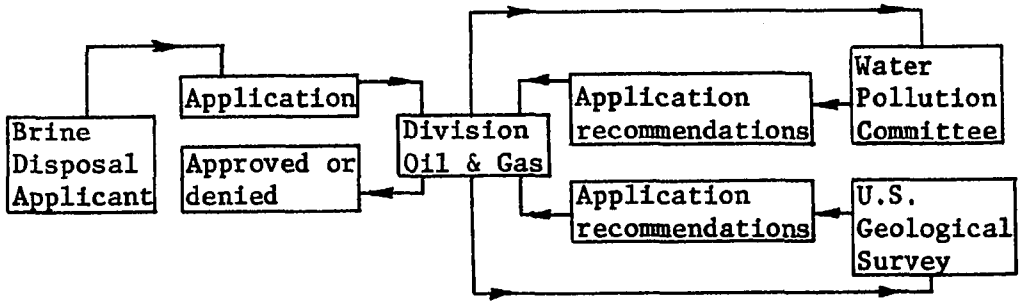
3. Coordinating Agencies:

Utah Water Pollution Committee
Calvin K. Sudweeks, Executive Secretary
44 Medical Drive
Salt Lake City, Utah 84113

U.S. Geological Survey
1588 West North Temple
Salt Lake City, Utah 84116

4. Application Flow Chart:

UTAH (Cont)



Note: Disposal applications submitted and approved or denied by Division of Oil and Gas Conservation with consideration given to recommendations given by Utah Water Pollution Committee and the U.S. Geological Survey.

5. Allowable Methods of Disposal:

Injection.

Pits, lined (in porous soil).

Pits, unlined (in tight soil).

6. Permit Costs:

None.

VERMONT

No regulating agency (no production).

VIRGINIA

1. Regulating Agency:

Department of Labor and Industry
Division of Mines and Quarries
Big Stone Gap, Virginia 24219

2. Publication of Regulations:

Mining Laws of Virginia (Including Oil and Gas)
Issued by The Department of Labor and Industry
(1970)

3. Coordinating Agency:

State Water Control Board
P.O. Box 11143
Richmond, Virginia 23230

There are no rules or regulations covering the disposal of brine.

WASHINGTON

No production

1. Regulating Agency:

State Oil & Gas Conservation Committee
Division of Mines & Geology
General Administration Building
Olympia, Washington 98501

Note: The Supervisor of the Division of Mines and Geology of the Department of Natural Resources is also Supervisor for the State Oil and Gas Conservation Committee.

WASHINGTON (Cont)

2. Publication of Regulations:

Department of Natural Resources
Oil and Gas Rules and Regulations
(1957)

No provisions for brine disposal.

WEST VIRGINIA

1. Regulating Agency:

Department of Mines
Oil and Gas Division
P.O. Box 206
Grantsville, West Virginia

2. Publication of Regulations:

Oil and Gas Division of the
Department of Mines
(1969)

3. Coordinating Agency:

Department of Natural Resources
Charleston, West Virginia

4. Allowable Methods of Disposal:

Injection.

WEST VIRGINIA (Cont)

5. Permit Costs:

Injection: $100.00.

WISCONSIN

No regulating agency (no production).

WYOMING

1. Regulating Agency:

Oil and Gas Conservation Commission
State Oil and Gas Supervisor
E.S.C. Building
P.O. Box 2640
Casper, Wyoming 82601

2. Publication of Regulations:

Rules and Regulations of Wyoming Oil and Gas Conservation Commission including Rules of Practice and Procedure (1969)

3. Coordinating Agencies:

Wyoming Department of Health and Social Services
Division of Health and Medical Services
Cheyenne, Wyoming 82001

Wyoming Game and Fish Commission
Cheyenne, Wyoming

Note: The Wyoming Department of Health and Social Services is concerned with the quality of water in lakes and streams. The Wyoming Game and Fish Commission is also concerned with water quality in lakes and streams and becomes involved in pollution problems when the quality of these waters is threatened.

4. Allowable Methods of Disposal:

   Injection.

   Pits.

5. Permit Costs:

   Injection: $25.

   Pits: $25.

APPENDIX B

SUMMARY OF
STATE WATER CONTROL AGENCIES,
POWERS AND PENALTIES (117)

ALABAMA

1. Agency:

   Alabama Water Improvement Commission
   State Office Building
   Montgomery, Alabama 36104

2. Agency Powers:

   a. Develop programs for treatment and disposal of industrial wastes and sewage.

   b. Establish water quality standards.

   c. Receive and examine plans.

   d. Determine permit compliance.

   e. Issue Orders.

3. Penalties:

   $100 to $10,000; also damages for loss or destruction of wild life, aquatic, fish, or marine life.

ALASKA

1. Agency:

   Department of Health and Welfare
   Division of Environmental Health
   Pouch H
   Juneau, Alaska 99801

2. Agency Powers:

Jurisdiction to:

a. Abate and prevent pollution.

b. Adopt standards.

c. Issue, modify, or revoke pollution control permits.

3. Penalties:

Up to $25,000 fine and/or up to one year in prison. Also liable up to $100,000 in civil action. Fines for oil discharges from vessels up to $14 million.

ARIZONA

1. Agency:

State Department of Health Division of Water Pollution Control
Hayden Plaza West
4019 No. 33rd Ave.
Phoenix, Arizona 85917

2. Agency Powers:

a. Issue, modify, or revoke orders prohibiting or abating waste discharge into state waters.

b. Require submission of disposal plans and specifications prior to construction.

c. Issue, modify, or revoke orders requiring construction or modification of disposal systems.

d. Adopt remedial measures to abate, prevent, or control pollution.

ARIZONA (Cont)

3. Penalties:

Injuction, conviction of misdemeanor.

ARKANSAS

1. Agency

Arkansas Pollution Control Commission
1100 Harrington Avenue
Little Rock, Arkansas 72202

2. Agency Powers:

a. Administer and enforce laws.

b. Conduct research, investigations, surveys, and studies.

c. Establish or alter water quality standards.

d. Require submission of plans and specifications.

e. Issue or revoke orders and permits.

f. Adopt rules and regulations.

3. Penalties:

Misdemeanor. Each day a separate offense.

CALIFORNIA

1. Agency

State Water Resources Control Board
Division of Water Quality, Rooms 1140-1416
9th Street
Sacramento, California 95814

2. Agency Powers:

   a. Adopt water pollution and water quality control plans.

   b. Regulate a new water appropriations to carry out plans.

   c. Review actions of regional boards.

   d. Accept grants.

   e. Conduct research.

   f. Make loans.

3. Penalties:

   Misdemeanor and/or injunctive relief.

COLORADO

1. Agency

   Colorado Department of Health
   Water Pollution Control Commission
   4210 E. 11th Ave.
   Denver, Colorado 80220

2. Agency Powers:

   a. Supervise administration and enforcement of Act.

b. Adopt, modify, and repeal rules and orders.

c. Accept and administer loans and grants.

d. Certify costs and expenditures for pollution control equipment and construction.

e. Hold hearings.

3. Penalties:

$50 to $2,500 per day.

CONNECTICUT

1. Agency:

Water Resources Commission
Room 225
State Office Building
Hartford, Connecticut 06115

2. Agency Powers:

a. Advise, consult, and cooperate with state and federal agencies and industry.

b. Submit prevention and control plans.

c. Conduct studies, investigations, research, and demonstrations.

d. Collect and disseminate information.

e. Issue, revoke or modify orders or permits.

f. Hold hearings.

g. Require submission of plans and specifications.

h. Require proper operation and maintenance of disposal systems.

3. Penalties:

$1,000. Each day a separate offense.

DELAWARE

1. Agency:

State of Delaware
Division of Environmental Control
Department of Natural Resources and Environmental Control
P.O. Box 916
Dover, Delaware 19901

2. Agency Powers:

a. Conduct experiments, investigations, research, and studies.

b. Issue general and special orders.

c. Adopt rules and regulations.

d. Make inspections.

e. Enter into agreements.

3. Penalties:

$500 per day of violation. Court stoppage orders.

FLORIDA

1. Agency

   Department of Air and Water Pollution Control
   Suite 300
   Tallahassee Bank Building
   315 S. Calhoun Street
   Tallahassee, Florida 32301

2. Agency Powers:

   a. Hire necessary personnel.

   b. Accept state monies.

   c. Adopt, modify, and repeal rules and regulations.

   d. Hold hearings.

   e. Establish water standards.

   f. Conduct field studies.

   g. Establish permit system.

   h. Issue orders.

   i. Require construction notice.

   j. Collect and disseminate information.

3. Penalties:

   $1,000. Each day a separate offense. Injunctive relief.

GEORGIA

1. Agency:

Georgia Water Quality Control Board
47 Trinity Avenue, S.W.
Atlanta, Georgia 39334

2. Agency Powers:

   a. Establish standards.

   b. Require registration and report filing for operations producing pollution (board).

   c. Accept and administer loans and grants.

   d. Conduct studies, investigations, research, and demonstrations.

   e. Collect and disseminate information.

   f. Issue orders.

   g. Hold hearings.

   h. Require maintenance and operation of abatement systems (department).

3. Penalties:

   Misdemeanor. Each day a violation.

HAWAII

1. Agency:

   Environmental Health Division
   Department of Health
   P.O. Box 3378
   Honolulu, Hawaii 96801

HAWAII (Cont)

2. Agency Powers:

   a. Enforce water quality standards via a permit system.

   b. Surveillance and monitoring of coastal waters.

3. Penalties:

   $500 and/or one year in prison.

IDAHO

1. Agency:

   Environmental Improvement Division
   Idaho Department of Health
   Statehouse
   Boise, Idaho 83707

2. Agency Powers:

   a. Establish and enforce regulations.

   b. Establish effluent quality standards.

   c. Require inspection and approval of plans.

3. Penalties:

   $1,000 and/or one year in prison. Each day a separate offense.

ILLINOIS

1. Agency

   Environmental Protection Agency
   State of Illinois
   2200 Churchill Road
   Springfield, Illinois 62706

2. Agency Powers:

   a. Enforce state standards.

   b. Assist design engineers.

3. Penalties:

   Fine not to exceed $10,000 for a violation, and additional fine not to exceed $1,000 for each day violation continues.

INDIANA

1. Agency:

   Indiana Stream Pollution Control Board
   1330 W. Michigan Street
   Indianapolis, Indiana 46206

2. Agency Powers:

   a. Establish water quality standards.

   b. Make regulations.

   c. Conduct hearings.

   d. Issue orders.

INDIANA (Cont)

e. Enforce law.

3. Penalties:

Misdemeanor. $100 and 90 days in jail. Each day $100 extra.

IOWA

1. Agency:

State Department of Health
Lucas State Office Building
Des Moines, Iowa 50319

2. Agency Powers:

a. Adopt, modify, or repeal reasonable water quality standards.

b. Hold hearings.

c. Issue orders.

d. Direct Health Department to approve plans and specifications and issue permits.

3. Penalties:

Injunction, $100.

KANSAS

1. Agency:

   Environmental Health Services
   Kansas State Department of Health
   5th Floor State Office Building
   Topeka, Kansas 66612

2. Agency Powers:

   a. Revoke permits on 30 days notice.

   b. Adopt water quality standards and regulations.

   c. Unlimited emergency powers.

3. Penalties:

   $25 per day for failure to comply with regulations; $50 to $500 per day for failure to comply with order.

KENTUCKY

1. Agency:

   Legislative Research Commission
   Capitol Building
   Frankfort, Kentucky 40601

2. Agency Powers:

   a. Conduct studies, investigations, research, experiments, and demonstrations.

   b. Establish water quality standards.

   c. Hold hearings.

d. Issue orders.

e. Examine plans and specifications.

f. Inspect construction.

g. Issue, revoke, or modify permits.

h. Examine records.

3. Penalties:

$1,000; value of fish or wildlife killed.

LOUISIANA

1. Agency:

Louisiana Stream Control Commission
P.O. Drawer FC
University Station
Baton Rouge, Louisiana 70803

2. Agency Powers:

a. Set water quality standards.

b. Order or regulate waste discharges.

c. Prohibit discharge.

3. Penalties:

$1,000 and/or up to one year in prison.

MAINE

1. Agency:

   Environmental Improvement Commission
   State House
   Augusta, Maine 04330

2. Agency Powers:

   a. Recommend best use classifications.

   b. Issue permits.

   c. Approve plans.

   d. Enforce legislation.

3. Penalties:

   $25 to $1,000 fine each day of violation.

MARYLAND

1. Agency:

   Maryland State Department of Health and Mental Hygiene
   2305 N. Charles Street
   Baltimore, Maryland 21218

2. Agency Powers:

   a. Health Department controls sewage pollution as it affects health.

   b. Department of Water Resources has control of all other sources.

MARYLAND (Cont)

3. Penalties:

   $500. $50 each additional day.

MASSACHUSETTS

1. Agency:

   Water Resources Commission
   Commonwealth of Massachusetts
   Division of Water Pollution Control
   100 Cambridge Street
   Boston, Massachusetts 02202

2. Agency Powers:

   Division of Water Pollution Control has joint jurisdiction with Department of Public Health.

3. Penalties:

   $100 each day of violation.

MICHIGAN

1. Agency:

   Water Resources Commission
   Department of Natural Resources
   Stevens T. Mason Building
   Lansing, Michigan 48926

MICHIGAN (Cont)

2. Agency Powers:

   a. Issue orders and permits.

   b. Restrict new disposal.

   c. Enforce laws.

3. Penalties:

   $500 each day of violation.

MINNESOTA

1. Agency:

   Minnesota Pollution Control Agency
   717 Delaware Street, S.E.
   Minneapolis, Minnesota 55440

2. Agency Powers:

   a. Set water quality and effluent standards.

   b. Inspect plans.

   c. Issue permits.

   d. Enforce compliance.

   e. Issue orders.

   f. Assume municipality powers to construct disposal system and levy taxes.

MINNESOTA (Cont)

3. Penalties:

Injunction. $300 or 90 days in jail or both. Each day is a separate offense.

MISSISSIPPI

1. Agency:

Mississippi Air & Wate[redacted]l Commission
P.O. Box 827
Jackson, Mississipp[redacted]

2. Agency Powers:

a. Enforce rule[redacted]

b. Accept and ad[redacted]from the federal government.

c. Conduct studies, rese[redacted]tigations, and demonstrations.

3. Penalties:

Up to $3,000 and/or one year in prison. Each day a separate violation.

MISSOURI

1. Agency:

Missouri Water Pollution Board
P.O. Box 154
Jefferson City, Missouri 65101

MINNESOTA (Cont)

3. Penalties:

   Injunction. $300 or 90 days in jail or both. Each day is a separate offense.

MISSISSIPPI

1. Agency:

   Mississippi Air & Water Pollution Control Commission
   P.O. Box 827
   Jackson, Mississippi 39205

2. Agency Powers:

   a. Enforce rules and regulations.

   b. Accept and administer loans and grants from the federal government.

   c. Conduct studies, research, investigations, and demonstrations.

3. Penalties:

   Up to $3,000 and/or one year in prison. Each day a separate violation.

MISSOURI

1. Agency:

   Missouri Water Pollution Board
   P.O. Box 154
   Jefferson City, Missouri 65101

MISSOURI (Cont)

2. Agency Powers:

   a. Issue or restrict permits.

   b. Enforce law.

   c. Issue tax bills for construction.

   d. Seek injunctions.

3. Penalties:

   Injunction. $25 to $500 fine. Maximum of $100 per day for continuing violation.

MONTANA

1. Agency:

   Water Pollution Control Section
   Division of Environmental Sanitation
   State Department of Health
   Helena, Montana 59601

2. Agency Powers:

   a. Establish standards.

   b. Recommend research and demonstrations.

   c. Direct Board of Health to issue orders.

   d. Holding hearings.

   e. Cause surveys and investigations.

MONTANA (Cont)

3. Penalties:

   Fines up to $1,000 for each day of violation.

NEBRASKA

1. Agency:

   Nebraska Water Pollution Control Council
   Box 94757
   State House Station
   Lincoln, Nebraska 68509

2. Agency Powers:

   a. Supervise administration and enforcement of pollution control laws.

   b. Accept and administer loans and grants.

   c. Collect and disseminate information.

   d. Conduct studies, investigations, research, and demonstrations.

   e. Issue orders and permits.

   f. Hold hearings.

   g. Require submission of plans and inspect construction.

3. Penalties:

   $100 to $500 and $10 each additional day.

NEVADA

1. Agency:

   Department of Health, Welfare and Rehabilitation
   210 S. Fall Street
   Carson City, Nevada 89701

2. Agency Powers:

   a. Approve loans and grants to municipalities from Federal aid.

   b. Adopt and enforce reasonable rules and regulations.

3. Penalties:

   Gross misdemeanor

NEW HAMPSHIRE

1. Agency:

   Water Supply and Pollution Control Commission
   State of New Hampshire
   61 S. Spring Street
   Concord, New Hampshire 03301

2. Agency Powers:

   a. Conduct experiments, investigations, and research.

   b. Require filing of plans and specifications.

   c. Set standards of design and construction.

   d. Monitor pesticides in water.

e. Set up laboratories.

f. Investigate applications for Federal Aid.

3. Penalties:

$1,000 each day of violation

NEW JERSEY

1. Agency

Department of Environmental Protection
P.O. Box 1390
Trenton, New Jersey 08625

2. Agency Powers:

Department of Environmental Protection is responsible for abating all water pollution and maintaining water quality and has broad powers regarding sanitation and sewage disposal.

3. Penalties:

Injunctive relief and various penalties.

NEW MEXICO

1. Agency:

NEW MEXICO (Cont)

New Mexico Water Quality Control Commission
P.O. Box 2348
Sante Fe, New Mexico 87501

2. Agency Powers:

Adopt standards and regulations for pollution prevention.

3. Penalties:

Injunction and fine

NEW YORK

1. Agency:

New York State Department of Health
84 Holland Avenue
Albany, New York 12208

2. Agency Powers:

a. Hold hearings.

b. Issue orders.

c. Issue, extend, deny, revoke, or modify permits.

d. Conduct investigations.

3. Penalties:

Injunction. Fine of $100 to $500 per day of violation

NORTH CAROLINA

1. Agency:

   Water Pollution Control Division
   North Carolina Department of Water and Air Resources
   P.O. Box 9392
   Raleigh, North Carolina 27603

2. Agency Powers:

   a. Issue permits.

   b. Approve plans.

   c. Organize programs.

3. Penalties:

   $100 to $1,000. Each day a separate violation.

NORTH DAKOTA

1. Agency:

   Division of Water Supply and Pollution Control
   North Dakota State Department of Health
   Bismarch, North Dakota 58501

2. Agency Powers:

   a. Supervise enforcement of rules and regulations.

   b. Accept and administer loans and grants.

   c. Conduct demonstrations.

d. Collect and disseminate information.

e. Issue, modify, or revoke orders.

f. Hold hearings.

g. Require submission of plans and specifications.

h. Require proper maintenance and operation of disposal system.

3. Penalties:

Injunction, misdemeanor.

OHIO

1. Agency:

Ohio Water Pollution Control Board
P.O. Box 118
Columbus, Ohio 43216

2. Agency Powers:

a. Conduct research, education, and investigation.

b. Enforce programs.

c. Require construction or modification of sewage or waste disposal systems.

d. Suspend construction.

e. Obtain injunctions.

3. Penalties:

$500 and/or one year imprisonment.

OKLAHOMA

1. Agency:

Environmental Health Services
Oklahoma State Department of Health
3400 North Eastern
Oklahoma City, Oklahoma 73105

2. Agency Powers:

a. To prevent or abate water pollution.

b. Conduct studies investigation, research, and demonstrations.

c. Adopt rules and regulations.

d. Accept funds and grants.

e. Prescribe water criteria.

3. Penalties:

$500 and/or 90 days in jail. Each day a separate violation.

OREGON

1. Agency:

OREGON (Cont)

Oregon State Department of Environmental Quality
State Office Building
1400 S.W. Fifth Avenue
Portland, Oregon 97201

2. Agency Powers:

   a. Formulate rules and regulations.

   b. Conduct studies, investigations, and programs.

   c. Cooperate with other agencies.

   d. Issue orders and hold hearings.

   e. Employ personnel.

3. Penalties:

   Vary, civil or criminal.

PENNSYLVANIA

1. Agency:

   Bureau of Sanitary Engineering
   Pennsylvania Department of Environmental Resources
   P.O. Box 2351
   Harrisburg, Pennsylvania 17120

2. Agency Powers:

   a. Require discharge permits.

   b. Set treatment standards.

PENNSYLVANIA (Cont)

3. Penalties:

$100 to $5,000 plus imprisonment up to one year. Civil penalties: $10,000 plus $500 per day.

RHODE ISLAND

1. Agency:

Division of Water Supply and Pollution Control
Rhode Island Department of Health
335 State Office Building
Providence, Rhode Island 02903

2. Agency Powers:

a. Advice, consult, and co-operate with other agencies.

b. Accept and administer loans and grants.

c. Conduct studies, investigations, research, and demonstrations.

d. Collection and disseminate information.

e. Adopt, modify and repeal water classes and standards.

f. Hold hearings and issue orders.

g. Require submission of plans and inspect construction.

h. Consult advisory board.

i. Make, amend, and revoke pollution control rules and regulations.

j. Superior court empowered to enforce orders of division.

3. Penalties:

$500 fine and/or 30 days in prison.

SOUTH CAROLINA

1. Agency:

   South Carolina Pollution Control Authority
   J. Marion Sims Building
   Columbia, South Carolina 29201

2. Agency Powers:

   a. Require waste sources to meet standards.

   b. Act as state agent in Federal Government dealings with water pollution.

   c. Perform all necessary acts.

3. Penalties:

   $100 to $5,000 and/or one year in prison. Each day a separate violation.

SOUTH DAKOTA

1. Agency:

   South Dakota Committee on Water Pollution
   State Department of Health
   Pierre, South Dakota 57501

2. Agency Powers:

   a. Establish Class A and Class B water standards, which can be modified when necessary.

   b. Conduct investigations.

   c. Issue orders.

   d. Instigate hearings.

   e. Issue annual permits upon approval of applications.

3. Penalties:

   $100 and/or one year imprisonment.

TENNESSEE

1. Agency:

   Tennessee Stream Pollution Control Board
   612 Cordell Hull Building
   Nashville, Tennessee 37219

2. Agency Powers:

   a. Establish air quality standards, emission standards, permit system.

   b. Promulgate rules and regulations, hold hearings.

   c. Collect fees.

   d. Require information submission.

TENNESSEE (Cont)

3. Penalties:

   Misdemeanor, injunctive relief.

TEXAS

1. Agency:

   Texas Water Quality Board
   1108 Lavaca Street
   Austin, Texas 78701

2. Agency Powers:

   a. Establish water quality standards.

   b. Issue and amend permits.

   c. Limit or reduce septic tanks.

   d. Inspect and conduct investigations.

   e. Accept and administer funds.

   f. Enforce Water Quality Act.

   g. Make agreements with Federal agencies.

3. Penalties:

   Injunction. Up to $1,000 for each violation or day of violation.

UTAH

1. Agency:

   Utah Water Pollution Committee
   44 Medical Drive
   Salt Lake City, Utah 84113

2. Agency Powers:

   a. Hold hearings.

   b. Review and approve plans.

   c. Issue orders to correct pollution.

   d. Issue permits.

   e. Establish standards.

3. Penalties:

   Misdemeanor. Also can be enjoined.

VERMONT

1. Agency:

   Vermont Department of Water Resources
   State Office Building
   Montpelier, Vermont 05602

2. Agency Powers:

   a. Issue orders.

   b. Hold hearings.

c. Conduct studies, investigations, and demonstrations.

d. Supervise flood control, channel clearing, and river bank protection.

e. Adopt, modify, and enforce rules and regulations.

f. Issue permits.

g. Administer loans and grants.

h. Require filing of new construction plans.

3. Penalties:

$50 each day of violation; up to $1,000 total.

VIRGINIA

1. Agency:

State Water Control Board
P.O. Box 11143
Richmond, Virginia 23230

2. Agency Powers:

a. Establish water quality standards.

b. Maintain standards.

c. Issue orders

d. Compel compliance.

VIRGINIA (Cont)

3. Penalties:

Injunction. Up to $5,000 fine for each day.

WASHINGTON

1. Agency:

Washington Water Pollution Control Commission
P.O. Box 829
Olympia, Washington 98501

2. Agency Powers:

a. Approve reports, plans, and specifications for waste treatment facilities.

b. Issue waste discharge permits.

c. Administer state and federal construction grants.

d. Establish basin policy on waste collection, treatment, and discharge.

3. Penalties:

Criminal prosecution; $100 fine each day; recovery of damages incurred; oil discharge penalty, maximum $20,000 fine; full or partial closure of discharger.

WEST VIRGINIA

1. Agency:

Division of Water Resources
Department of Natural Resources
1201 Greenbriar Street
Charleston, West Virginia 25311

2. Agency Powers:

   a. Issue permits.

   b. Obtain compliance.

   c. Institute criminal proceedings.

3. Penalties:

   Violation, $100 to $1,000; willful violation, $1,000 to $10,000. Also up to 6 months prison.

WINCONSIN

1. Agency:

   Division of Environmental Protection
   Department of Natural Resources
   P.O. Box 450
   Madison, Wisconsin 53701

2. Agency Powers:

   a. Monitor surface water quality.

   b. Conduct stream surveys.

   c. Hold hearings.

   d. Issue orders.

e. Approve plans.

f. Disburse state and Federal aid.

g. Issue licenses and permits.

3. Penalties:

Up to $5,000 each day of violation.

WYOMING

1. Agency:

Division of Health and Medical Services
Wyoming Department of Health and Social Services
State Office Building
Cheyenne, Wyoming 82001

2. Agency Powers:

a. Suggest to, advise, and assist the council.

b. Conduct and supervise studies, investigations, and research.

c. Require consultations and approval of plans prior to construction of waste treatment facilities.

3. Penalties:

Up to $1,000.

APPENDIX C

LABORATORY TESTS

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UNIVERSITY MICROFILMS.

Filmed as received

without page(s) 320 .

UNIVERSITY MICROFILMS.

k = Average formation permeability (darcies).

h = Effective height of the formation face (ft).

ϕ = Average formation porosity as a decimal fraction; volume of voids divided by total volume.

P_r = Reservoir pressure (psi).

P_b = Bottom hole pressure; pressure at the bottom of the well (psi).

The following relationships should be developed to accompany these basic facts.

Pipe Diameter, d

d = Inside diameter of pipe in inches.

W = Fluid flow rate in thousands of pounds per hour (lb_m/hr)

ρ = Density of the fluid (lb_m/ft^3) Note: Koenig (92). Pure water may be used because fluid density is not a major factor in injection.

Assume: $\rho = 62.5\ lb_m/ft^3$

$$d = \frac{2.2W^{.45}}{(\rho)\ .31}$$

$$X_i = \text{Gallons per day} = W\left(\frac{lb_m}{hr}\right)\left(\frac{24\ hr}{day}\right)\left(\frac{1\ ft^3}{62.5\ lb_m}\right)\left(\frac{7.48\ gal}{ft^3}\right)$$

$$X_i = 2.87\ W^{.45}$$

$$W = \frac{X_i}{2.87}$$

$$d = (.6)\ \frac{(W)}{1000}^{.45}$$

$$d = \frac{2.2X_i^{.45}}{(3.6)(35.9)} = (1.7)(10^{-2})\ (X_i^{.45})$$

Fluid Velocity, V

A = Cross section area of pipe (ft^2)

Q = Volume flow rate (ft^3/sec)

$$Q\left(\frac{ft^3}{sec}\right) = A\ (ft^2)\ V\left(\frac{ft}{sec}\right)$$

$$Q\left(\frac{ft^3}{sec}\right) = X_i\left(\frac{gal}{day}\right)\left(\frac{1\ day}{86400\ sec}\right)\left(\frac{1\ ft^3}{7.48\ gal}\right)$$

$$\frac{X_i}{(86400)(7.48)}\left(\frac{ft^3}{sec}\right) = \pi r^2\ (ft^2)\ V\left(\frac{ft}{sec}\right)$$

$$V\left(\frac{ft}{sec}\right)\ \frac{X_i\ (ft^3)}{(86400)\ (7.48)(3.14)r^2(ft^2)(sec)}$$

$r = \frac{D}{2}$ = Radius of pipe

$$D = \frac{d}{12}$$

$$r = \frac{d}{24}$$

and $r^2 = \frac{d^2}{576}$

then $V = \frac{576}{(86400)(7.48)(3.14)}\ \frac{X_i}{d^2}$

and $V = (2.84)\ (10^{-4})\left(\frac{X_i}{d^2}\right)$

Injection

Fluid radius, r_e, at end of project life (Y).

r_e = Fluid radius (extent of injected fluid from well assuming homogeneous formation and fluid dispersion into formation in the shape of a cylinder of height, h, and radius, r_e).

Y = Project life (years).

X = Flow rate per well (gpd).

h = Formation height (ft).

ϕ = Formation porosity (decimal fraction).

Vol = Volume injected per year = $\frac{365}{7.48}(X_i)(Y) = 48.8(X_i)(Y)$

Vol_1 = Volume of void space in formation = $(\pi)(r_e^2)(h)(\phi) = Vol$

$$r_e^2 = \left[\frac{48.8}{\pi}\right]\frac{(X_i)(Y)}{(h)(\phi)}$$

$$r_e = \left[\frac{48800}{\pi}^{1/2}\right]\left[\frac{(X_i)(Y)}{(1000)(h)(\phi)}^{1/2}\right]$$

$$r_e = (124.6)\left[\frac{(X_i)(Y)}{(1000)(h)(\phi)}^{1/2}\right]$$

Reynold's Number (Figure 27)

$$N_{re} = \frac{VD}{\nu} = \frac{VD\rho}{\mu};\ D = \frac{d}{12}$$

Assume: $\rho = 62.5\left(\frac{lb_m}{ft^3}\right)$ and μ = 1 centipoise = $\frac{1\ lb_m}{1488(ft\text{-}sec)}$,

then $N_{re} = \frac{(1488)(62.5)}{12}(V)(d)$

and $N_{re} = (7.75)(10^3)(d)(V)$ or $2.201\left(\frac{X_i}{d}\right)$

f = Fluid friction factor = function of N_{re} obtained using Moody Diagram (see fluid mechanics text).

Friction Loss, P_f (psi)

H_f = Head loss due to friction = $\frac{2fLV^2}{g_c D}$;

but P_f = Pressure loss due to friction = $\frac{(H_f)\rho}{144}$ and $D = \frac{d}{12}$

so $P_f = \frac{2fLV^2}{g_c d}\ \frac{12\rho}{144}$.

Assuming: ρ = Pure water density (negligible effect on overall analysis) = 6.25, then

$$P_f\ (psi) = \frac{2(12)(62.5)}{(32.17)(144)}\ \frac{fLV^2}{d}$$

and $P_f = 32.36\ (10^{-2})(fLV^2/d)$.

Driving Pressure, P_d (psi)

X_i = Fluid flow rate through the formation (gpm).

K = Formation permeability (darcies).

A = Area of the formation face perpendicular to the direction of flow (ft^2).

μ = Fluid viscosity (centipoise).

I = Injection pressure gradient (ratio of the difference) in pressure between the bottom hole and reservoir pressure to the difference in distance between the fluid radius and well bore radius).

$$X_i = \frac{KIA}{\mu}$$

$$X_i = \frac{K}{\mu}\left[\frac{P_b - P_r}{r_e - r_w}\right] 2\pi rh$$

$$X_i = \frac{K}{\mu}\left[\frac{\Delta P}{\Delta r}\right] 2\pi rh$$

$$X_i = \left(\frac{\Delta r}{r}\right) = \left(\frac{2\pi hk}{\mu}\right)\Delta P$$

$$X_i \int_{r_w}^{r_e} \frac{dr}{r} = \frac{2\pi hk}{\mu} \int_{P_r}^{P_b} dp$$

$$X_i \, In\left(\frac{r_e}{r_w}\right) = P_d\left(\frac{2\pi hk}{\mu}\right)$$

$$P_d = \frac{X_i \mu In\left(\frac{r_e}{r_w}\right)}{2\pi hk}$$

$$K = 1 \text{ darcy} = \frac{1(cp)(cm^2)}{(sec)(atm)}$$

$$1 \ (cm^2) = .001076 \ ft^2$$

$$1 \text{ atm} = 14.7 \frac{\text{lb}_f}{\text{in}^2}$$

$$1 \text{ darcy} = (4.92)(10^{-8}) \frac{\text{lb}_m\text{-ft-in}^2}{\text{lb}_f\text{-sec}}$$

Substituting:

$$P_d = \left(X_i\right)\left(\frac{\text{gal}}{\text{day}}\right)\left(\mu\right)\left(\frac{\text{lb}_m}{1488 \text{ ft-sec}}\right) \frac{2.303 \log\left(\frac{r_e}{r_w}\right)(\text{lb}_f\text{-sec}^2)}{(2)(3.14)(\text{h})(\text{ft})(\text{K})(4.92)(10^{-8})(\text{lb}_m)(\text{ft})(\text{in}^2)}$$

$$= (7.75)(10^{-3})\left[\frac{X_i \mu \log}{hk}\left(\frac{r_e}{r_w}\right)\right].$$

Let μ= 1 centipoise,

$$\text{then } P_d = \frac{X_i \log\left(\frac{r_e}{r_w}\right)}{(128.9)(\text{K})(\text{h})}$$

Static Pressure (Constant), P_c (psi)

$$P_c \ (\text{lb}_f \ 1 \text{ in}^2) = \frac{\rho L g}{g_c} .$$

$$\text{Assume: } \rho = 62.5 \frac{\text{lb}_m}{\text{ft}^3} \text{ and } g = 32.17 \left(\frac{\text{ft}}{\text{sec}^2}\right)$$

$$P_c = \frac{(62.5 \text{ lb}_m)(\text{L})(\text{ft})(32.17)(\text{ft})(\text{lb}_f\text{-sec}^2)(1)(\text{ft}^2)}{(\text{ft}^3)(\text{sec}^2)(32.17)(\text{lb}_m\text{-ft})(144)(\text{in}^2)}$$

$$P_c = \frac{(62.5)(\text{L})}{144} \ \frac{(\text{lb}_f)}{\text{in}^2}$$

$$P_c = (0.434)(L)\ \frac{lb_f}{in^2}\ .$$

Wellhead Pressure, P_{ch}(psi)

P_{ch} = Wellhead pressure = pressure at the top of the well = $P_b + P_f - P_c$.

Note: P_{ch} may also be thought of as a change in the pressure head to be supplied by the pump. That is, both P_b and P_f must be overcome if the fluid is to flow in the pipe. Therefore, if $P_b + P_f - P_c$ is negative, no pressure must be supplied by pumping. If $P_b + P_f - P_c$ is positive, the combined resistence to flow of the reservoir exceed the pressure head of weight of the fluid column in the tube, and pumps must be supplied to drive water into the receiving formation.

$$P_{ch} = P_b + P_f - P_c,$$

but $P_b = P_d + P_r$;

therefore, $P_{ch} = P_d + P_r + P_f - P_c$.

Hydraulic Horesepower

P_p = Pump discharge pressure = Change in pressure head (P_{ch} in psi) + FL (in psi)(pipeline pressure loss due to fricition)

$\overline{FL}$ = (.0013) (length of supply pipeline in ft)

$$HHP = \text{Hydraulic Horesepower} = \frac{(P_p)(X_i)(144)}{(550)(7.48)(86400)}$$

$$HHP = \frac{(P_p)\ (X_i)}{(2.468)(106)} .$$

Brake Horsepower

$$BHP = \text{Brake Horsepower} = \frac{\text{Hydraulic Horsepower}}{\text{Pump Efficiency}}$$

Assume a pump efficiency of .85:

$$BHP = \frac{HHP}{.85} .$$

Kilowatts

$$KW = \text{Kilowatts} = \frac{(\text{Brake Horsepower})(.7457\ \text{kw/hp})}{\text{motor efficiency}} .$$

Assume a motor efficiency of .93:

$$KW = \frac{(BHP)(.7457)}{.93} \quad (BHP)\ (.802)$$

KW = (HHP) (.943).

Pump Capacity

$$GPM = X_i \frac{\text{gallons}}{\text{day}} \times \frac{1\ \text{day}}{1440\ (\text{minute})} .$$

$$GPM = \frac{X_i}{1440} .$$

Right-of-Way Cost

$$\$/ft = (\text{cost per acre})\left(\frac{\$}{\text{acre}}\right)\left(\frac{1 \text{ acre}}{43560 \text{ ft}^2}\right)(\text{Right-of-way width})(\text{ft}).$$

Assume: $109 per acre and 30 ft right-of-way width,

$$\text{then } \$\text{foot} = \frac{(109)(30)}{43560} = .075.$$

APPENDIX E

COMPUTER PROGRAM FOR DISPOSAL BY INJECTION, EVAPORATION, DIRECT DISCHARGE (PRICING FOR ALL-NEW EQUIPMENT)

```
FORTRAN IV G LEVEL  20                  MAIN              DATE = 71356          12/55/56              PAGE 0001

                C      MAIN PROGRAM FOR PRIME DISPOSAL
                C  1=INJECTION    2=EVAPORATION    3=CONVEYANCE
0001                   COMMON / C / EAR, CRF, XE, XF                                                  106C
0002                   COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(15,2), TT3B(13,2),                     07C
                      1     TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),                 08C
                      2     TT5J(20,2), TT5A(23,2), TT6(7,2), TT7(13,2), TT8(6,2),                    09C
                      3     TT9(19,2), TT10(12,2), TT11(8,2)                                          11C
0003                   READ 10,C1,C2,C3
0004                10 FORMAT(3F10.0)
0005                   IF(C1-EC-1.) GO TO 21
0006                   GO TO 25
0007                21 CALL INJECT
0008                25 IF(C2-EC-2.) GO TO 31
0009                   GO TO 27
0010                31 CALL EVAP
0011                27 IF(C3-EC-3.) GO TO 41
0012                   GO TO 50
0013                41 CALL CONVEY
0014                50 STOP
0015                   END
```

```
                      1(1, L, M, PHI, PK,PR, D, CCR1, VCPIPE, VCFORM, SPGR, FCHTF,      3011
                     2XN,CPM,EL,XLAST
                C     FORMAT FOR READ                                                   3025
 004P             100 FORMAT (13, 1CA1, A2, F5.C, F3.3, F4.0, I2,F4.3,F3.0, I1, F5.C,  3030
                     1F1.0, F2.2, F4.3, F4.C, F3.2, F4.1,F3.2, F3.2, F2.1, F3.2/
                     2F5.C,2F4.C,F1C.0)
                C     CONVERT INPUTS TO PROPER MAGNITUDE                                3040
 0048                 XC = XC * 1CCC.                                                   3041
 0049                 XF=XF*1CCC.
 004A                 CCR1 = CCR1 * 1CCC.
 004B                 FL = 25.
                C     SET UP DUMMY FORMATION NAME
 004C                 DATA FNAME/6H*TEST*/
                C     SET INITIAL N EQUAL TO 1
 004D                 N = 1
                C     CALCULATE WELLHEAD EQUIPMENT COST
 004E                 IF (D  .GT. 4.0) GO TO 201
 004F               200 WHC = 1C5C.
 0050                   GO TO 210
 0051               201 IF (D .GT. 6.0) GO TO 202
 0052               202 WHC = 1C5C. + 3C. * (D - 4.0)
 0053                   GO TO 210
 0054               203 WHC = 1110. + 101.6 * (D-6.0)
 0055               210 CONTINUE
                C     CALCULATE PLASTIC LINING COSTS
 0056                 RADL = .1572 * D
                C     CALCULATE PRODUCTION HOLE DIAMETER                                30
 0057                 RW = 7.0 + 1.5 * (D-1.0)
                C     CONVERT INTEREST RATE FROM PERCENT                                3075
 0058               2 II = II * .01                                                     3080
                C     CALCULATE CAPITAL RECOVERY FACTOR                                 3085
 0059                 CRF = (II*(1. + II)**Y)/((1. + II)**Y - 1.)                       3090
                C     CALCULATE DENSITY                                                 3095
 005A                 RHO = 62.43 * SPGR                                                3100
                C     CONVERT RW FROM DIA TO RADIUS  AND INCHES TO FEET                 3095
 005B                 RW = RW / 24.                                                     3110
                C     CALCULATE STATIC HEADS                                            3115
 005C                 PC = L * RHO / 144.                                               3120
                C     N = NUMBER OF WELLS IN THE INJECTION FIELD                        3070
 005D                 IF(N .EQ. 0) GO TO 3
 005E                 GO TO 33
                C     FIND NUMBER OF WELLS                                              3100
 005F               3 N = N + 1                                                         3130
                C     CALCULATE FLOW RATE FOR EACH WELL                                 3135
 0060              33 XI = XC/N                                                         3140
                C     CALCULATE FLUID VELOCITY IN INJECTION CONDUIT                     3145
 0061                 V = .000284 * XI / (D**2)                                         3150
                C     CALCULATE REYNOLDS NUMBER                                         3155
 0062                 RNRE = ( 124. * RHO * D * V ) / VCPIPE                            3160
                C     LOOK-UP FANNING FRICTION FACTOR                                   3165
 0063                 CALL TLKUP1(1, 1, 1C, RNRE, F, 1, 1)                              3170
                C     CALCULATE FRICTION LOSS                                           3209
 0064                 PF = ( RHO / 193.02 ) * F * L * ( V**2 ) / D                      3210
```

```
0001            SUBROUTINE INJECT
0002            DOUBLE PRECISION SABCV,SBELO,FNAME,TEMP
0003            REAL I,II,L,KW,KW2,LOGF
0004            INTEGER Y
0005            COMMON / C / ENR, CRF, XC, XP                                   1060
0006            COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(19,2), TT3B(13,2),      070
               1    TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),    080
               2    TT5J(20,2), TT5N(23,2), TT6(7,2), TT7(13,2), TT8(6,2),       090
               3    TT9(18,2), TT10(12,2), TT11(8,2)                             110
0007            DIMENSION PLACE(40), MARK(40), FNAME(6), TEST(20)               1110
0008            DATA BLANK/' '/,SABCV/'ABOVE BR'/,SBELO/'BELOW BR'/
0009            DATA TEST/' 1',' 1 ',' 2',' 2 ',' 3',' 3 ',' 4',' 4 ',' 5',' 5 ',' 6',
               1' 6 '/
0010            LOGF(X)=ALOG(X)
0011            SQRTF(X)=SQRT(X)
0012            ABSF(X)=ABS(X)
          C     PRINT PERMANENT DATA TABLES                                     2005
0013            PRINT 301, (TT1(I,1), TT1(I,2), I=1,10)                         2010
0014            PRINT 302, (TT2(I,1), TT2(I,2), I=1,11)                         2020
0015            PRINT 303, (TT3A(I,1), TT3A(I,2),I=1,19)                        2030
0016            PRINT 304, (TT3B(I,1), TT3B(I,2), I=1,13)                       2040
0017            PRINT 306, (TT3C(I,1), TT3C(I,2), I=1,13)                       2050
0018            PRINT 307, (TT3D(I,1), TT3D(I,2), I=1,14)                       2060
0019            PRINT 308, (TT3E(I,1), TT3E(I,2), I=1,11)                       2070
0020            PRINT 309, (TT3F(I,1), TT3F(I,2), I=1,15)                       2080
0021            PRINT 310, (TT4(I,1), TT4(I,2), I=1,4)                          2090
0022            PRINT 311, (TT5J(I,1), TT5J(I,2), I=1,20)                       2100
0023            PRINT 305, (TT5N(I,1), TT5N(I,2), I=1,23)                       2110
0024            PRINT 312, (TT6(I,1), TT6(I,2), I=1,7)                          2120
0025            PRINT 312, (TT7(I,1), TT7(I,2), I=1,13)                         2130
0026            PRINT 314, (TT8(I,1), TT8(I,2), I=1,6)                          2140
0027            PRINT 315, (TT9(I,1), TT9(I,2), I=1,18)                         2150
0028            PRINT 316, (TT10(I,1), TT10(I,2), I=1,12)                       2160
0029            PRINT 317, (TT11(I,1), TT11(I,2), I=1,8)                        2162
0030          301 FORMAT (1H1, 3HTT1,//(2F20.4))                                2210
0031          302 FORMAT (1H1, 3HTT2,//(2F20.4))                                2220
0032          303 FORMAT (1H1, 4HTT3A,// (2F20.4))                              2230
0033          304 FORMAT (1H1, 4HTT3B, // (2F20.4))                             2240
0034          306 FORMAT (1H1, 4HTT3C,// (2F20.4))                              2250
0035          307 FORMAT (1H1, 4HTT3D, // (2F20.4))                             2260
0036          308 FORMAT (1H1, 4HTT3E, // (2F20.4))                             2270
0037          309 FORMAT (1H1, 4HTT3F, // (2F20.4))                             2280
0038          310 FORMAT (1H1, 4HTT4 , // (2F20.4))                             2290
0039          311 FORMAT (1H1, 4HTT5J, // (2F20.4))                             2300
0040          305 FORMAT (1H1, 4HTT5N, // (2F20.4))                             2310
0041          312 FORMAT (1H1, 4HTT6 , // (2F20.4))                             2320
0042          313 FORMAT (1H1, 4HTT7 , // (2F20.4))                             2330
0043          314 FORMAT (1H1, 4HTT8 , // (2F20.4))                             2340
0044          315 FORMAT (1H1, 4HTT9 , // (2F20.4))                             2350
0045          316 FORMAT (1H1, 4HTT10, // (2F20.4))                             2360
0046          317 FORMAT(1H1, 4HTT11, // (2F20.4))                              2362
          C     READ DATA INPUT CARDS                                           2005
0047            1 READ 100, JC, (PLACE(I), I = 1,10), BRC, XC, RKW, CPA, Y, II, ENR,2010
```

```
C     CALCULATE DISTANCE TO CUTTERHOST FLOOD FRONT                      3215
0078        RF = 124.6  * SQRT(XI * Y /(1000. * P * PHI))                3220
C     CALCULATE DRIVING PRESSURE WITH DARCY EQUATION                    3225
0079        DELP =(XI * .434294482 * LOG(RE/RW))/(128.9*PK*H) * VOFORM    3230
C     CALCULATE WELL SPACING                                            3235
0080        RF = 2.*RF                                                    3240
C     COMPUTE CASINGHEAD PRESSURE FROM OTHER PRESSURE TERMS             3245
0081        PCH = DELP + PR - PC * RF                                     3250
C     SET UP DUMMY VARIABLE TO DISTANCE TO FLOODFRONTS                  3250
0082        CCC = RF/2.                                                   3251
0083        PRINT 1111, ER, PK, XI, A, V, XNRE, E, RF,CCC, DELP, PC, PCH  3252
0084   1111 FORMAT(1H,/////,25H  PRESSURE TEST PRINT-OUT,/ , 6H P R =, F6.0,/ 3252
     1  5H PK =, F7.3,/,5H XI =, F8.0,/, 4H A =, I5,/, 4H V =, F20.5,/, 3254
     2  7H XNRE =, F20.5,/, 4H E = , F20.5,/, 5H RF =, F20.5,/           3255
     3 22H RF(BEFORE DOUBLING) =,  F6.0,/, 7H DELP =, F20.5,/ , 6H PC  =3256
     4  ,F20.5,//,6H PCH =, F20.5)                                       3257
C     TEST  A                                                           3256
0085        IF(A .GT. 25) GO TO 77
0086        GO TO 76
0087     77 SWN = 1                                                      3258
0088        GO TO 93                                                     3259
0089     76 SWN = 0                                                      3260
C     TEST COMPUTED PCH AGAINST MAX. ALLOWABLE PCH                      3260
008A        IF(PCH  - PCHTF * L ) 93, 4, 3                               3265
008B     93 IF(PCH-0.0)92, 91, 91                                        3262
008C     92 LUP= 1                                                       3264
008D        PCH= 0.0                                                     3266
008E        GO TO 4                                                      3267
008F     91 LUP = 0                                                      3268
C     A IS NOW THE MAXIMUM NUMBER OF WELLS NEEDED                       3270
C     RF IS THE MINIMUM DISTANCE BETWEEN ANY 2 WELLS                    3280
0090      4 CONTINUE                                                    3290
C     USE SUBR X  WFC TO DESIGN WELLFIELD                               3295
0091        CALL WFC(N,XC,RF,PCH,SCAF,COLC,CCDS,CRWDS,XLL, RFC )        3300
C     CALCULATE FRICTION LOSSES IN DISTRIBUTION SYSTEM PIPING           3305
0092        FL = .0013 * XLL                                            3310
C     COMPUTE TOTAL INJECTION PUMP HEAD                                 3215
0093        PI = PCH + FL                                               3320
0094        IF(LUP -1) 99, 85, 85                                       3322
0095     85 BHP = 1.1                                                   3324
0096        GO TO 88                                                    3326
C     CALCULATE REQD BRAKE HORSEPOWER FOR INJECTION PUMPS               3329
0097     99 BHP = (XC * PI/2468CCC.)/.85                                3330
C     COMPUTE ENERGY REQUIREMENTS FOR INJECTION PUMPS                   3335
0098     88 KW = BHP * .746 / .93                                       3340
C     CONVERT  HP  TO FEET OF HEAD                                      3345
0099        PI = PI / ( RHO / 144. )                                    3350
C     CONVERT FLOW RATE FROM GPD TO GPM                                 3355
009A        GPM = XC/1440.                                              3360
C     CALCULATE DIAMETER OF SUPPLY LINE                                 3365
009B        DCO = .00951 * ( XC**.45 ) * ( RHO**.14 )                   3370
C     COMPUTE HEAD LOSS IN SUPPLY LINE                                  4005
009C        HF = .003 * GPM * 528C.                                     4010
```

```
                C     DETERMINE TOTAL HEAD REQUIRED                                    4019
0109                  DEL = EL - EF                                                    4020
                C     CALCULATE SUPPLY HEAD REQD                                       4029
0110                  PMIN = ABSF ( DELH ) * RHO / 144.                                4030
                C     SET PHP  AND  KW  EQUAL TO ZERO                                  4034
0111                  PHP2=0.
0112                  KW2=0.
0113                  IF(DELH - 0.) 5, 6, 6                                            4040
                C     COMPUTE RHP REQUIREMENTS FOR SUPPLY PUMPS                        4049
0114                5 PHP2 = (XC * PMIN/2460000.)/.85                                  4050
                C     COMPUTE POWER REQUIREMENTS                                       4059
0115                  KW2 = PHP2 * .746 / .92                                          4060
                C     CALCULATE CAPACITY OF STORAGE FACILITIES                         4139
0116                6 SCXC = XC/ 3.                                                    4140
0117                  IF(N - 1) 86, 87, 86                                             4210
0118               87 RF = 0.0                                                         4220
0119               86 TEMP = SRELF                                                     4230
0120                  IF(EL - 0.) 85, 84, 84                                           4240
0121               85 TEMP = SABOV                                                     4250
                C     CENTER TITLE ON OUTPUT PAGE                                      4259
0122               84 KL = 0                                                          4260
0123                  DO 83 IL=1,35                                                    4270
0124               83 WORK(IL) = BLANK                                                 4280
0125                  DO 81 IL = 1, 35                                                 4290
0126                  JL = 40 - IL                                                     4300
0127                  IF(PLACE(JL) .EQ. BLANK) GO TO 82
0128                  GO TO 80
0129               82 KL = KL + 1                                                     4320
0130               81 CONTINUE                                                        4330
0131                  GO TO 78                                                         4340
0132               80 KL = KL/2                                                       4350
0133                  DO 79 ILL = 1, JL                                                4360
0134               79 WORK(KL + ILL) = PLACE(ILL)                                      4370
                C     PRINT 2ND PAGE TITLES                                            4404
0135               78 PRINT 102, (WORK(I), I=1,10),                                    4405
                     1           RRC, N, RF, XC, IFC, PCH, XP, FI, IPC, GPM, BHP, Y, KW 4410
0136                  F=0.
0137                  GPM1=0.
0138                  DEL = ABSF(EL)                                                   4413
0139                  IF(DELH) 10, 11, 11                                              4415
0140               10 F=(-1.)*DELH
0141                  GPM1=GPM
                C     PRINT 2ND PAGEDATA                                               4419
                C     SET UP TEMP PRINTING VARIABLES                                   4419
0142               11 PRINT 103, IT, RKW, F, CPA,GPM1, ENR, XC, SCXC, GPM, TEMP, DEL,  4420
                     1     (PNAME(I), I=1,6)                                          4430
0143                  IF(LT - 0) 13, 12, 13                                            4440
0144               12 PRINT 104                                                        4450
0145                  GO TO 14                                                         4460
0146               13 PRINT 105                                                        4470
0147               14 PHIO = PH * 24.                                                  4480
0148                  PRINT 106, L, PHI, PM, M, PR, D, PHIE, SPGR, VCPIPE, VCPCRM, PCHTF4490
                C                                                                      5070
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C       RECTA COST COMPUTATIONS                                                          5080
C                                                                                        5090
C       SELECT PROPER  RRC  DISTRICT                                                     5095
0145          74  DO 15 I=1,12
0150              IF(RRC .EQ. IEST(I)) GO TO 16
0151          15  CONTINUE                                                             5120
0152              PRINT 131, RRC                                                       5130
0153              GO TO 55                                                             5150
C       RRC = --1--  --2--  --3--  --4--  --5--  --6--
0154          16  GO TO (21,21, 22,22, 18,18, 19,19, 20,20, 17,17),I
C       LOOK-UP DRILLING COST                                                        5165
0155          17  CALL TLKL(TT3A, 3, 15, L, F, C, 0)                                  5170
0156              GO TO 23                                                             5210
0157          18  CALL TLKL(TT3B, 3, 13, L, F, C, 0)                                  5220
0158              GO TO 23                                                             5230
0159          19  CALL TLKL(TT3C, 3, 13, L, F, C, 0)                                  5240
0160              GO TO 23                                                             5250
0161          20  CALL TLKL(TT3D, 3, 14, L, F, C, 0)                                  5260
0162              GO TO 23                                                             5270
0163          21  CALL TLKL(TT3E, 3, 11, L, F, C, 0)                                  5280
0164              GO TO 23                                                             5290
0165          22  CALL TLKL(TT3F, 3, 15, L, F, C, 0)                                  5300
0166          23  F = L * F                                                            5310
C       COMPUTE PLASTIC LINING COST                                                  5311
0167              IF(LI)800,801,800
0168         800  PLC = PAPL * (L-LI*H)
0169              GO TO 802
0170         801  PLC = PAPL * (L-LI*H) +10. * F
0171         802  CONTINUE
C       LI IS 0 FOR A SANDSTONE FORMATION, THEREFORE F IS NOT USED IN                5330
0172              CALL TLKL(TT4, 4, 4, L, FF, C, 0)                                    5350
C       CALCULATE COST OF EACH WELL                                                  5355
0173              TWC = F + WHC + PLC + FF + CCR1                                      5360
0174         1001 CONTINUE
C       COMPUTE COST OF ALL WELLS                                                    5365
0175              TWC = N * TWC                                                        5370
0176              CALL TLKL(TT11, 11, F, CCC, F, C, 0)                                 6030
C       COMPUTE SUPPLY LINE COAST COST                                               6045
0177          26  CCSS = .6 * DPM * 528C.                                             6050
C       CALCULATE SUPPLY LINE R-C-W COST                                             6055
0178              CRLSS = .075 * DPM * 528C.                                           6060
C       CALCULATE COST OF SUPPLY PIPE                                                6075
0179              SSAC = F * DPM * 528C.                                               6080
C       AC LINING REQD FOR SUPPLY PIPE                                               6085
0180              CSLC = 0.0                                                           6050
C       LOOK-UP PUMP  F. P. SIZES                                                    6075
0181              CALL TLKL(TT7, 7, 13, PHP, F, 1, 1)                                  6100
0182              CPUMP = PHP * F                                                      6110
0183              CPUMP2 = 0.0                                                         6115
0184              IF(PHP1)  27, 28, 28                                                 6120
0185          27  CALL TLKL(TT7, 7, 13, PHP2, F, 1, 1)                                6130
0186              CPUMP2 = PHP2 * F                                                    6140
C       SET UP TEMP VARIABLE FOR STORAGE CAPACITY                                    6149
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```
0187          28 F = X**3.                                                    6150
              C     LOOK-UP STORAGE COSTS                                     6159
0188          C     CALL TLKL(TTR, A, 6, F, STRC, 0, 0)                       6160
              C     CALCULATE TREATMENT PLANT CAPITAL COSTS                   6169
0189          C     TPLC = 10.**(4.062 + .C4F6 * LOGF(XC))                    6170
              C     LOOK-UP WELL FIELD  C+M                                   6209
0190          C     CALL TLKL(TTS, S, 10, XC, F, C, C)                        6210
              C     SET UP ENR CONVERSION FACTOR                              6241
0191          C     CENR = ENR/57C.                                           6215
              C     ROUND OFF ALL $-ITEMS TO NEAREST DOLLAR                   6219
0192          C     AX=TWC*CENR+.5
0193          C     TWC=AX
0194          C     AX=SSBC*CENR+.5
0195          C     SSAC=AX
0196          C     AX=CSLC*CENR+.5
0197          C     CSLC=AX
0198          C     AX=SDBC*CENR+.5
0199          C     SDAC=AX
0200          C     AX=CDLC*CENR+.5
0201          C     CDLC=AX
0202          C     AX=TPLC*CENR+.5
0203          C     TPLC=AX
0204          C     AX=CPUMP*CENR+.5
0205          C     CPUMP=AX
0206          C     AX=CPUMP2*CENR+.5
0207          C     CPUMP2=AX
0208          C     AX=STRC*ENR/SEC.+.5
0209          C     STRC=AX
0210          C     AX=.2**A*CPA+.5
0211          C     WPSC=AX
0212          C     AX=5.*CPA+.5
0213          C     PSSC=AX
0214          C     SLTLC=SSAC+CSLC
0215          C     DSTLC=SDAC+CDLC
0216          C     SLCRC=CCSS*CRWSS
0217          C     PSCRC=CCPS*CRWDS
0218          C     AX=F+.5
0219          C     WFCM=AX
0220          C     AX=.CC2555*XC+.5
0221          C     WFSM=AX
0222          C     WFWCM=A*L
0223          C     AX=.15*F+.5
0224          C     WFPC=AX
0225          C     AX=.345*F+.5
0226          C     WFGA=AX
0227          C     PSCM=WFCM
0228          C     AX=.15*F+.5
0229          C     PSPC=AX
0230          C     AX=.345*F+.5
0231          C     PSGA=AX
0232          C     AX=8760.*PKW*KW2+.5
0233          C     SLPC=AX
0234          C     AX=8760.*RKW*KW+.5
```

```
0235            PSPC=AX
0236            F = F * 1.495                                                   6346
                C   CALCULATE AND PRINT REMAINDER OF COST ITEMS                 6359
                C   COST WELLHEAD COMPONENTS                                   6369
0237            CALL MCREV(TWC, WFSC, WFSM + WFWCV + F, C., WC, WE, WICM,       635C
               1            WSLM, WEAM, WFIWC, WSLMAE, WFC, WFC)                6360
                C   COST SUPPLY LINE COMPONENTS                                6365
0238            CALL MCREV(SLTLC + CPUMP2, SLCRC, SLFC, .0025, SC, SE, SICM,    637C
               1            SSLM, SLAM, SLIWC, SSLMAE, SFC, SFC)                63P0
                C   COMPUTE SUPPLY LINE  C+M                                   6385
0239            AX=.0025*SSLM+.5
0240            SLCM=AX
                C   COST DISTRIBUTION SYSTEM COMPONENTS                         64C5
0241            CALL MCREV(DSTLC, DSCRC, 0., .0025, DC, DE, DICM,               641C
               1            DSLM, DSAM, DSIWC, DSLMAE, DEC, DFC)                6420
                C   COMPUTE DISTRIBUTION SYSTEM  C+M                           6425
0242            AX=.0025*DSLM+.5
0243            DSDM=AX
                C   LOCK-UP TREATMENT PLANT  C+M                              6435
0244            CALL TLKUP(TTIC, IC, 12, XC, TPCM, 1, 1)                        644C
                C   ROUND OFF TREATMENT PLANT  C+M                             6444
0245            AX=TPCM+.5
0246            TPDM=AX
                C   COST TREATMENT PLANTPLANT                                  6449
0247            CALL MCREV(TPLC, 0., TPCM, 0.,  TC, TPE, TPICM,                 645C
               1            TSLM, TPAM, TPIWC, TSLMAE, TEC, TFC)                646C
                C   COST PUMPING INSTALLATIONS                                 6465
0248            CALL MCREV(CPUMP, STRC + PSSC, PSPC + F, .0025, PC, PE, PICM,   647C
               1            PSLM, PSAM, PSIWC, PSLMAE, PEC, PFC)                648C
                C   COMPUTE PUMP STATION  C+M                                  6485
0249            AX=.0025*PSLM+.5
0250            PSSM=AX
                C   CALCULATE TOTAL CAPITAL COSTS                              6495
0251            T=1.
0252            TSI = WSLM + SSLM + DSLM + TSLM + PSLM                          6510
                C   REDEFINE CAP COST IN MILLIONS                              6511
0253            XTCC = ( WSLM + SSLM + DSLM + TSLM + PSUM ) / 1000000.          6512
0254            PRINT 107, (PLACE(I), I=1,10), (PNAME(J), J=1,6), XO, IEC, XP,  6520
               1            IFC, A                                              653C
0255            PRINT 108, WSLM, SSLM, DSLM, TSLM, PSLM, TSI                    6540
0256            PRINT 109, TWC, T, T, T, T, TWC                                 655C
0257            TSI = WFSC + PSSC                                               656C
0258            PRINT 110, WFSC, T, T, T, PSSC, TSI                             657C
0259            TSI = SLTLC + DSTLC                                             661C
0260            PRINT 111, T, SLTLC, DSTLC, T, T, TSI                           662C
0261            TSI = SLCRC + DSCRC                                             663C
0262            PRINT 112, T, SLCRC, DSCRC, T, T, TSI                           664C
0263            PRINT 113, T, T, T, TPLC, T, TPLC                               665C
0264            TSI = CPUMP2 + CPUMP                                            6660
0265            PRINT 114, T, CPUMP2, T, T, CPUMP, TSI                          667C
0266            PRINT 115, T, T, T, T, STRC, STRC                               668C
0267            TSI = WC + SC + DC +  TC + PC                                   669C
0268            PRINT 116, WC, SC, DC,  TC, PC, TSI                             670C
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0269            TS1 = WE + SE + CE + TPE + PE                                   6710
0270            PRINT 117, WE, SE, CE, TPE, PE, TS1                             6720
0271            TS1 = WICM + SICM + CICM + TPICM + PICM                         6730
0272            PRINT 118, WICM, SICM, CICM,TPICM, PICM, TS1                    6740
0273            TS1 = WSUMAE + SSUMAE + CSUMAF + TSUMAE + PSUMAE                6750
0274            PRINT 119, WSUMAF,  SSUMAE, CSUMAE, TSUMAE, PSUMAE, TS1         6760
0275            TS1 = WFCM + SLCM + CSCM + TPCM + PSCM                          6770
0276            PRINT 120, WFCM, SLCM, DSCM, TPCM, PSCM, TS1                    8810
0277            TS1 = WFSM + PSSM                                               8820
0278            PRINT 121, WFSM, T, T, T, PSSM, TS1                             8830
0279            PRINT 122, WFWCV, T, T, T, T, WFWCV                             8840
0280            TS1 = WFPC + PSPC                                               8844
0281            PRINT 123, WFPC, T, T, T, PSPC, TS1                             8846
0282            TS1 = WFGA + PSGA                                               8850
0283            PRINT 124, WFGA, T, T, T, PSGA, TS1                             8860
0284            TS1 = WFAM + SLAM + CSAM + TPAM + PSAM                          8870
0285            PRINT 125, WFAM, SLAM, CSAM, TPAM, PSAM, TS1                    8880
0286            TS1 = WFIWC + SLIWC + CSIWC + TPIWC + PSIWC                     8890
0287            PRINT 126, WFIWC, SLIWC, DSIWC, TPIWC, PSIWC, TS1               8900
0288            TS1 = SLPC + PSPC                                               8910
0289            PRINT 127, T, SLPC, T, T, PSPC, TS1                             8920
0290            TCE = WEC + SEC + TEC + PEC                                     8930
0291            PRINT 128, WEC, SEC, CEC, TEC, PEC, TCE                         8940
0292            TS1 = WPC + SPC + CPC + TPC + PPC                               8950
0293            PRINT 129, WPC, SPC, CPC, TPC, PPC, TS1                         8960
      C         REDEFINE XC IN MILLIONS                                         8966
0294            XCO = XO / 1000000.                                             8966
0295         72 SWN = 0                                                         8967
0296            IF(XLAST.EQ.1.) GO TO 987
0297            GO TO 1
      C   PLOT STOP
0298         99 CONTINUE
      C                                                                         7600
      C                                                                         7520
      C     OUTPUT FORMATS                                                      7510
      C                                                                         7090
      C                                                                         7100
0299        743 FORMAT(1H4,I3,10A1,  F8.0,F5.0, 2PF3.0, 3PF4.0, 0PF4.0, I2, 4PF8.0,7104
         1    , 2X)                                                           7105
      C                                                                         7720
      C                                                                         7795
0300        102 FORMAT(1H1,40X,10A1,//,29X,5HINPUT,53X,6HOUTPUT,///,2X,14HR R C I7110
         1STRICT,29X,A2,23X,15HNUMBER OF WELLS,25X,I3,//,67X, 7HSPACING,28X,7120
         2F8.0,6H FEET,/,17H  EFFLUENT VOLUME,22X,F8.0,4H CFD,16X,19HINJECTI7130
         2ON CONCENTRATION,
         3                 16X,I7,4H PPM,16X,20HTUBING HEAD PRESSURE,15X,F8.0,7140
         44H PSI,//,22H  PRODUCT PETRO VOLUME,17X,F8.0,4H CPD,16X,19HINJECTI7150
         5ON PUMP HEAD,16X,F8.0,5H FEET,//,29H  PRODUCT PETRO CONCENTRATION,7160
         612X,I6,4H PPM,16X,23HINJECTION PUMP CAPACITY,12X,F8.0,4H GPM,//,  7170
         767X,25HINJECTION PUMP BRAKE HORSE POWER   ,F8.0,4H BHP,/,14H  PROJ7180
         8ECT LIFE,31X, I2 ,6H YEARS,//,67X,20HINJECTION PUMP MOTOR,15X,F8.0,7190
         83H KW)                                                            7200
0301        103 FORMAT(23H  CAPITAL DISCOUNTED AT,20X,2PF4.2, 9H PERCENT ,//,   7210
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     1  12H  POWER RATE,                                                    7215
     2   29X,OPF6.4,6H $/KWH,14X,16HSUPPLY PUMP HEAD,19X,F6.0,5H FEET,//722C
    311H  LAND COST,32X,F4.0,7H $/ACRE,13X,20HSUPPLY PUMP CAPACITY,15X,723C
    3 F8.0,                                                                7235
    44H GPM,///,25H  ERR PUBLICINC COST INDEX,18X,F4.0,/,67X,24HTREATMENT724C
    5 PLANT CAPACITY,11X,F8.0,4H GPD,//,13H  WELL FIELD ,54X,16HSTORAGE725C
    6 CAPACITY,19X,F8.0,5H GAL.,//,6X,26HDISTANCE FROM BR.CCL POINT,12X7260
    7,F3.0,6H MILES,//,6X,20HELEVATION OF INJECTION STATION,/,11X,AF,  727C
    8ICH.CCL POINT,13X,F5.0,5H FEET,///,16H  FORMATION NAME,32X,5A8,A2)72P0
0302      104 FORMAT(1HO,10H LITHOLOGY,37X, 9HSANDSTONE)                   8010
0303      105 FORMAT(1HC,10H LITHOLOGY)                                    8020
0304      106 FORMAT(1HC,12H TOTAL DEPTH,28X,F6.0,5H FEET,//,10H  POROSITY,34X, 803C
    1 2PF3.0,9H PERCENT ,                                                  8035
    2  //,14H  PERMEABILITY,28X,0PF5.3,8H DARCIES,//,18H  EFFECTIVE THICKC4C
    3CHT,25X,F4.0,5H FEET,///,20H  RESERVOIR PRESSURE,22X,F5.0,4H PSI,//805C
    4/,14H  TUBING I. D.,27X,F6.3,7H INCHES,//,23H  PRODUCTION HOLE I. 8C6C
    5D.,18X,F6.3,7H INCHES,//,18H  SPECIFIC GRAVITY,24X,F5.3,//,       8070
    6 25H  EFFLUENT VISCOSITY IN--,/, 21H      INJECTION TUBING,20X,    8080
    7 F4.3, 3H CP,/, 14H      FORMATION, 27X, F6.3, 3H CP,//,          8083
    8 20H  MAXIMUM PRESSURE TEST FACTOR, 12X, F5.3, 7H PSI/FT )        80P7
0305      107 FORMAT(1H1,6X,9HLOCATION ,10A1,33X,9HR.R.CODE ,5A8,A2,/,7X,17H EFF8C9C
    1LUENT VOLUME ,F8.0,4H GPD,24X,27HEFFLUENT CONCENTRATION      ,I7, 81CC
    2 4H PPM,/,7X,16HPRODUCT VOLUME  ,F8.0,4H GPD,24X,28HPRODUCT PETRC 8110
    3CONCENTRATION ,I6,4H PPM,/,37X,17HNUMBER OF WELLS  ,I3,//,28X,4HWEE12C
    411,8X,48HSUPPLY    DISTRIBUTION  TREATMENT   PUMP STATION,/,28X,9H8130
    5FIELD,8X,4HLINE,8X,44HSYSTEM       PLANT     AND  STORAGE    TOTAL8140
    6)                                                                     815C
0306      108 FORMAT(1HC,23HCAPITAL COST, $       ,6(F11.0,2X))           8160
0307      109 FORMAT(1HO,22H  WELL COST           ,6(F11.0,2X), 9H  DOLLARS)  8170
0308      110 FORMAT(1HO,22H  SITE COST           ,6(F11.0,2X), 9H  DOLLARS)  8210
0309      111 FORMAT(1HO,22H  PIPE AND CEMENT      ,/,                       8220
     1       1H ,22H  LINING COST           ,6(F11.0,2X), 9H  DOLLARS)  8230
0310      112 FORMAT(1HC,22H  CONSTRUCTION AND     ,/,                       8240
     1       1H ,22H  RIGHT-OF-WAY COST     ,6(F11.0,2X), 9H  DOLLARS)  8250
0311      113 FORMAT(1HO,22H  PLANT COST          ,6(F11.0,2X), 9H  DOLLARS)  826C
0312      114 FORMAT(1HC,22H  PUMP STATION COST   ,6(F11.0,2X), 9H  DOLLARS)  827C
0313      115 FORMAT(1HO,22H  STORAGE COST        ,6(F11.0,2X), 9H  DOLLARS)  8280
0314      116 FORMAT(1HO,22H  CONTINGENCIES       ,6(F11.0,2X), 9H  DOLLARS)  8290
0315      117 FORMAT(1HO,22H  ENGINEERING         ,6(F11.0,2X), 9H  DOLLARS)  8295
0316      118 FORMAT(1HO,22H  INTEREST ON         ,/,                       83CC
     1       1H ,22H  CONSTRUCTION MONEY    ,6(F11.0,2X), 9H  DOLLARS,/) 831C
0317      119 FORMAT(23HOANNUAL EXPENDITURE, $ ,6(F11.0,2X),14H  DOLLARS/YEAR)  832C
0318      120 FORMAT(23HC  O + M               ,6(F11.0,2X),14H  DOLLARS/YEAR)  833C
0319      121 FORMAT(23HC  SUPPLIES + MATERIAL ,6(F11.0,2X),14H  DOLLARS/YEAR)  834C
0320      122 FORMAT(23HC  WORKOVERS           ,6(F11.0,2X),14H  DOLLARS/YEAR)  835C
0321      123 FORMAT(23HC  PAYROLL OVERHEAD    ,6(F11.0,2X),14H  DOLLARS/YEAR)  836C
0322      124 FORMAT(23HC  G + A               ,6(F11.0,2X),14H  DOLLARS/YEAR)  837C
0323      125 FORMAT(23HO  AMORTIZATION        ,6(F11.0,2X),14H  DOLLARS/YEAR)  8410
0324      126 FORMAT(23HO  INTEREST ON         ,/,                           842C
     1       23H  WORKING CAPITAL      ,6(F11.0,2X),14H  DOLLARS/YEAR)  843C
0325      127 FORMAT(23HO  POWER COST          ,6(F11.0,2X),14H  DOLLARS/YEAR,/)844C
0326      128 FORMAT(23HC  ANNUAL COST PER 1000,/,23H   GAL. EFFLUENT, $     :  845C
     1       6(F11.4,2X),15H  DOLLARS/1000 GAL.)                           846C
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 0327          125 FORMAT(22HO  ANNUAL COST PER 1000,/,23H   GAL. PRODUCT, $      ,    8470
                   1       6(F11.4,2X),15H  DOLLARS/1000 GAL.)                          8480
 0328          131 FORMAT(1H1,14H PRC DISTRICT,, A2,11H IS LARACHA)                      8500
 0329              STOP  RETURN
 0330                    END
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FORTRAN IV G LEVEL 20                WFC                DATE = 71356          12/55/56          PAGE 0001

0001                SUBROUTINE WFC (N, XC, RE, PCH, PC, PLC, CC, RWC, XLL, RHO )        1010
                C   THIS SUBR DESIGNS THE DISTRIBUTION SYSTEM FOR THE WELLFIELD        1020
0002                IF (N-1) 1, 1, 50                                                    1030
0003              1 PC=0.
0004                PLC=0.
0005                CC=0.
0006                RWC=0.
0007                XLL=0.
0008                RETURN                                                             1050
0009             50 QQ1= .00551 * ( XC / N )**.45 * RHO**.14 + .5                      1060
0010                IF (N-5) 51, 51, 52                                                1070
0011             51 CALL GETCST (QQ1, PCH, CPF1,CLPF1,KSW)                            1080
0012                C2=0.
0013                C3=0.
0014                C4 =C.
0015                C5=0.
0016                C6=C.
0017                IF (N-3) 2, 3, 511                                                 1100
0018              3 CC= 0.58                                                           1110
0019                C1= 1.73                                                           1120
0020                GO TO 99                                                           1130
0021              2 CC= 0.5                                                            1140
0022                C1= 1.0                                                            1150
0023                GO TO 99                                                           1160
0024            511 IF (N-5) 4, 5, 5                                                   1170
0025              4 CC= 0.71                                                           1180
0026                C1= 2.828                                                          1190
0027                GO TO 99                                                           1200
0028              5 CC= 1.0                                                            2010
0029                C1= 4.0                                                            2020
0030                GO TO 99                                                           2030
0031             52 QQ2= .00551 * ( 2. * XC / N )**.45 * RHO**.14 + .5                 2040
0032                IF (N-9) 53, 53, 54                                                2050
0033             53 CC= 2.0                                                           2060
0034                C1= 4.0                                                            2070
0035                C3=0.
0036                C4=0.
0037                C5=0.
0038                C6=0.
0039                CALL GETCST (QQ2, PCH, CPF2, CLPF2, KSW)                           2090
0040                CALL GETCS2 (QQ1, KSW, CPF1, CLPF1)                                2100
0041                IF (N-8) 531, 8, 9                                                 2110
0042              8 C2= 3.0                                                            2120
0043                GO TO 99                                                           2130
0044              9 C2= 4.0                                                            2140
0045                GO TO 99                                                           2150
0046            531 IF (N-6) 6, 6, 7                                                   2160
0047              6 C2= 1.0                                                            2170
0048                GO TO 99                                                           2180
0049              7 C2=2.0
0050                GO TO 99                                                           2200
0051             54 QQ3= .00551 * ( 3. * XC / N )**.45 * RHO**.14 + .5                 3010
0052                IF (N-13) 55, 55, 56                                               3020
```

```
0053          55 CC= 2.0                                                    3030
0054             C4=0.
0055             C5=0.
0056             C6=0.
0057             CALL GETCST (DD3, PCH, CPF3, CLPF3, KSW)                   3050
0058             CALL GETCS2 (DD2, KSW, CPF2, CLPF2)                        3060
0059             CALL GETCS2 (DD1, KSW, CPF1, CLPF1)                        3070
0060             IF (N-12) 551, 12, 13                                      3080
0061          12 C1= 7.0                                                    3090
0062             C2= 1.0                                                    3100
0063             C3= 3.0                                                    3110
0064             GO TO 99                                                   3120
0065          13 C1= 8.0                                                    3130
0066             C2= 0.0                                                    3140
0067             C3= 4.0                                                    3150
0068             GO TO 99                                                   3160
0069         *551 IF (N-11) 10, 11, 11                                      4010
0070          11 C1= 6.0                                                    4020
0071             C2= 2.0                                                    4030
0072             C3= 2.0                                                    4040
0073             GO TO 99                                                   4050
0074          10 C1= 5.0                                                    4060
0075             C2= 3.0                                                    4070
0076             C3= 1.0                                                    4080
0077             GO TO 99                                                   4090
0078          56 DD4= .00551 * ( 4. * XC / A )**.45 * RHO**.14 + .5         4100
0079             CC= 3.0                                                    4110
0080             IF (N-17) 57, 57, 58                                       4120
0081          57 C1= 5.0                                                    4130
0082             C5=0.
0083             C6=0.
0084             CALL GETCST (DD4, PCH, CPF4, CLPF4, KSW)                   4150
0085             CALL GETCS2 (DD3, KSW, CPF3, CLPF3)                        4160
0086             CALL GETCS2 (DD2, KSW, CPF2, CLPF2)                        4170
0087             CALL GETCS2 (DD1, KSW, CPF1, CLPF1)                        4180
0088             IF (N-16) 571, 16, 17                                      5010
0089          16 C2= 3.0                                                    5020
0090             C3= 1.0                                                    5030
0091             C4= 3.0                                                    5040
0092             GO TO 99                                                   5050
0093          17 C2= 4.0                                                    5060
0094             C3= 0.0                                                    5070
0095             C4= 4.0                                                    5080
0096             GO TO 99                                                   5090
0097         *571 IF (N-15) 14, 15, 15                                      5100
0098          15 C2=2.
0099             C3=2.
0100             C4=2.
0101             GO TO 99                                                   5120
0102          14 C2=1.
0103             C4=1.
0104             C3= 3.0                                                    5140
0105             GO TO 99                                                   5150
```

```
0106          58 CD5= .C0551 * ( 5. * XC / A )**.45 * RHC**.14 + .5                  5160
0107             IF (N-21) 55, 55, 60                                                5170
0108          55 C1= 8.0                                                             6C1C
0109             C6= C.C                                                             602C
0110             CALL CETCST (CD5, PCH, CPF5, CLPF5, KSW)                            6030
0111             CALL CETCS2 (CD4, KSW, CPF4, CLPF4)                                 6C4C
0112             CALL CETCS2 (CD3, KSW, CPF3, CLPF3)                                 605C
0113             CALL CETCS2 (CD2, KSW, CPF2, CLPF2)                                 6060
0114             CALL CETCS2 (CD1, KSW, CPF1, CLPF1)                                 607C
0115             IF (N-20) 551, 20, 21                                               6080
0116          20 C2= 7.C                                                             6090
0117             C3= C.C                                                             61CC
0118             C4= 1.C                                                             611C
0119             C5= 3.0                                                             612C
0120             GC TC 99                                                            613C
0121          21 C2= 8.C                                                             614C
0122             C3=0.
0123             C4=C.
0124             C5= 4.C                                                             616C
0125             GC TC 99                                                            617C
0126         551 IF (N-18) 18, 19, 19                                                7C1C
0127          18 C2= 5.C                                                             7C2C
0128             C2= C.0                                                             7C3C
0129             C4= 3.C                                                             7C4C
0130             C5= 1.C                                                             7C5C
0131             GC TC 99                                                            7C6C
0132          19 C2= 6.C                                                             7C7C
0133             C3= C.C                                                             708C
0134             C4=2.
0135             C5=2.
0136             GC TC 99                                                            71CC
0137          60 CD6= .C0551 * ( 6. * XC / A )**.45 * RHC**.14 + .5                  711C
0138             CALL CETCST (CD6, PCH, CPF6, CLPF6, KSW)                            7120
0139             CALL CETCS2 (CD5, KSW, CPF5, CLPF5)                                 713C
0140             CALL CETCS2 (CD4, KSW, CPF4, CLPF4)                                 714C
0141             CALL CETCS2 (CD3, KSW, CPF3, CLPF3)                                 7150
0142             CALL CETCS2 (CD2, KSW, CPF2, CLPF2)                                 716C
0143             CALL CETCS2 (CD1, KSW, CPF1, CLPF1)                                 717C
0144             IF(N-24) 601, 24, 25                                                8010
0145          24 C1= 11.0                                                            8C2C
0146             C2= 6.C                                                             8030
0147             C3= 2.0                                                             804C
0148             C4= C.C                                                             805C
0149             C5= 1.C                                                             806C
0150             C6= 3.0                                                             807C
0151             GC TC 99                                                            808C
0152          25 C1= 12.0                                                            809C
0153             C2=4.
0154             C3=4.
0155             C6=4.
0156             C4=C.
0157             C5=C.
0158             IF (N-25) 55, 55, 26                                                8120
```

```
0159          26 PRINT 27, N                                                  8130
016C             GC TC 99                                                     814C
0161          27 FCRMAT (1H1, 14HA IS EGLAL TC , I2)                          8150
0162         601 IF (N-23) 22, 23, 23                                         8160
0163          22 C1= 9.C                                                     SC1C
0164             C2= 7.C                                                     9020
0165             C3=1.
0166             C6=1.
0167             C4= C.0                                                     9040
0168             C5= 2.0                                                     SC5C
0169             GC TC 99                                                    S06C
017C          23 C1= 1C.0                                                    S07C
0171             C2= 6.0                                                     SC8C
0172             C3=2.
0173             C5=2.
0174             C6=2.
0175             C4= C.C                                                     91CC
0176          99 PC=RE*(C1*CPF1 + C2*CPF2 + C3*CPF3 + C4*CPF4 + C5*CPF5 + C6*CPF6) 911C
0177             PLC= RE* (C1*CLPF1 + C2*CLPF2 + C3*CLPF3 + C4*CLPF4 + C5*CLPF5 +  S12C
                1C6*CLPF6)                                                   S13C
017R             CC = 0.6*RE*(C1 + C2 + C3 + C4 + C5 + C6)                   S14C
0179             RLC= C.0754RE* (C1  + C2 + C3 + C4 + C5 + C6)               S15C
018C             XLL = CC*RF                                                 S16C
0181             RETURN                                                      S17C
01R2             END
```

```
FORTRAN IV G LEVEL  20                GETCS2          DATE = 71356        12/55/56          PAGE 0001

0001                  SUBROUTINE GETCS2 (CC, KSH, CPF, CLPF)                                  1C10
                C     THIS SUBR CALCULATES THE COST OF PIPE                                   1CC9
0002                  COMMON/ TABLE/ TT1(1C,2), TT2(11,2),TT3A(19,2), TT3B(13,2),              07C
                     1    TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),          080
                     2    TT5J(2C,2), TT5A(22,2), TT6(7,2), TT7(13,2), TT8(6,2),             C9C
                     3    TT9(18,2), TT1C(12,2), TT11(6,2)                                   110
0003                  IF (KSH - 1) 2C, 1C, 1C                                                 1C2C
0004               2C CALL TLKL(TT5J, 51, 2C, CC, CPF, 0, 0)                                  1C3C
0005                  GO TO 30                                                                1040
0006               1C CALL TLKL(TT5A, 52, 22, CC, CPF, 0, 0)                                  1C5C
0007               3C CC = CC + C.5                                                           106C
0008                  CALL TLKL(TT6, 6, 7, CC, CLPF, 0, 0)                                    107C
0009                  RETURN                                                                  1C8C
0010                  END                                                                     109C
```

```
FORTRAN IV G LEVEL  20                  GETCST          DATE = 71356        12/55/56          PAGE CCC1

0001                  SUBROUTINE GETCST (DC, PCH, CPF, CLPF, KSW)                          1010
                C     THIS SUBR COMPUTES THE RECC WEIGHT OF PIPE                           1C21
0002                  COMMON/ TABLE/ TT1(1C,2), TT2(11,2),TT3A(19,2), TT3B(13,2),           07C
                     1    TT3C(12,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),       080
                     2    TT5A(2C,2), TT5A(23,2), TT6(7,2), TT7(13,2), TT8(6,2),          090
                     3    TT9(18,2), TT1C(12,2), TT11(E,2)                                110
0003                  CALL TLKL(TT2, 2,11, DC, YPRES, C, C)                               1C3C
0004                  IF (YPRES-PCH) 1C, 2C, 2C                                           1C4C
0005                20 KSW= C                                                             1C5C
0006                  CALL TLKL(TT5J, 51, 2C, DC, CPF, C, C)                              1C6C
0007                  GC TC 3C                                                            107C
0008                1C KSW= 1                                                             1C8C
0009                  CALL TLKL(TT5A, 52, 22, DC, CPF, C, C)                              1C9C
0010                3C DC = DC + C.5                                                      11CC
0011                  CALL TLKL(TTA, 6, 7, DC, CLPF, C, C)                                1110
0012                  RETURN                                                              112C
0013                  END                                                                 1130
```

```
0001            SUBROUTINE TLKU(TABLE,NC,K,VAL,OUT,LIN,LOUT)                    1010
                C     THIS SUBR PERFORMS THE TABLE LOOK-UPS-                    1020
0002            DIMENSION TABLE(K,2)                                            1030
0003            VAR = VAL                                                       1040
0004            IF(LIN) 10,11,10
0005           10 VAR=.4342944819*ALOG(AMAX1(1.,VAR))
0006           11 DO 4 N=1,K                                                    1050
0007              IF (VAR - TABLE(N,1)) 3, 2, 4                                 1060
0008            2 OUT=TABLE(N,2)                                                1070
0009              GO TO 99                                                      1080
0010            3 IF (N-1) 5, 5, 6                                              1090
0011            6 OUT= TABLE(N-1,2) + ((TABLE(N,2)- TABLE(N-1,2))*(VAR- TABLE(N-1,1))1100
                 1)/(TABLE(N,1)- TABLE(N-1,1)))                                 1110
0012              GO TO 99                                                      1120
0013            4 CONTINUE                                                      1130
0014              OUT= TABLE(K,2)                                               1140
0015              GO TO 7                                                       1150
0016            5 OUT= TABLE(1,2)                                               1160
0017            7 PRINT 100, VAR, NC                                            1170
0018           99 IF(LOUT)12,13,12
0019           12 KK=OUT
0020              OUT1=KK
0021              OUT2=ABS(OUT-OUT1)
0022              OUT = (10.**OUT1) * (10.**OUT2)                               1176
0023           13 RETURN                                                        1177
0024          100 FORMAT (1H1, 1CHARGUMENT  , F11.4, 29H  OUTSIDE BOUNDRIES OF TABLE1080
                 1 , I2)                                                        1085
0025              END                                                           1090
```

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FORTRAN IV G LEVEL  20                  MCKEY                   DATE = 71356          12/55/56          PAGE 0001

0001                  SUBROUTINE MCKEY( A, B, G, X, C, D, E, F, I, J, K, L, M)                          1010
                C     THIS SUBR MODIFIES COST ITEMS TO ALLOW FOR INTEREST, E+C,ETC.                     1020
0002                  REAL K,L,M,I,J
0003                  COMMON/C/ ENR, CRF, XC, XP                                                        1025
0004                  A=A+.5
0005                  B=A
0006                  A=.1*(A+B)+.5
0007                  C=A
0008                  A=.1*(A+B+C)+.5
0009                  D=A
0010                  A=.01625*(A+B+C+D)+.5
0011                  E=A
0012                  F = A + B + C + D + E                                                             1070
0013                  A=G+.5
0014                  G=A
0015                  A=X*F+.5
0016                  F=A
0017                  A=F*CRF+.5
0018                  I=A
0019                  A=.007*(G+F+I)+.5
0020                  J=A
0021                  K = G + F + I + J                                                                 1110
0022                  A =(K / (XC * .365)) * 10000. + .5                                                1120
0023                  L = A/10000.                                                                      1130
0024                  A =(K / (XP * .365)) * 10000. + .5                                                1140
0025                  M = A/10000.                                                                      1150
0026                  RETURN                                                                            1160
0027                  END
```

```
0001            BLOCK DATA                                                      C7C
0002            COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(19,2), TT3B(13,2),     080
               1    TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),   C9C
               2    TT5J(20,2), TT5N(23,2), TT6(7,2), TT7(13,2), TT8(6,2),      11C
               3    TT9(19,2), TT1C(12,2), TT11(8,2)                            1234
          C     LIST PERMANENT DATA TABLES                                      1135
          C     TABLE I   REYNOLDS NO. VS FRICTION FACTOR
0003            DATA TT1/ 3.301,3.699,4.0,4.699,5.0,5.699,6.0,6.301,6.699,7.0,  114C0080
               1  -2.152,-2.053,-3.982,-3.819,-3.748,-3.643,-3.602,-3.568,-3.505, 115C00EC
               2  -3.431/
          C     TABLE II   INSIDE PIPE DIAMETER VS APPROXIMATE YIELD PRESSURE -J551165
0004            DATA TT2 / 3.,3.5,4.,5.,6.,8.,10.,12.,16.,18.,20.,              117CCCEC
               1    3150.,2775.,2550.,2295.,2100.,1860.,1650.,1470.,1200.,1080.,  1175008C
               2    975./
          C     TABLE IIIA  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 6
0005            DATA TT3A/ 800.,1100.,1750.,2300.,3000.,3800.,4300.,4700.,5300.,  119C008C
               1  6000.,                                                        1195008C
               1  6500.,7000.,7800.,8600.,9400.,10000.,10500.,14600.,15000., 8.,  12CCCCEC
               2 8.,8.,8.1,8.9,10.,10.5,11.1,12.,13.5,14.4,15.5,17.4,19.5,
               3  22.2,24.7,26.5,38.8,50.7/
          C     TABLE IIIB  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 3
0006            DATA TT3B/ 700.,1850.,2400.,2950.,3500.,4150.,4750.,5550.,6350.,  12300080
               1  7550.,11800.,14000.,15000.,16.4,12.4,12.0,11.8,11.4,10.5,10.,
               2  10.,11.,12.3,23.4,34.5,55.4/
          C     TABLE IIIC  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 4
0007            DATA TT3C/ 700.,1700.,4000.,5000.,6000.,7200.,8000.,9000.,10000., 126CCCEC
               1  10800.,11000.,12000.,15000.,6.7,6.2,6.3,6.4,6.5,8.,13.6,18.3,
               2  17.,14.8,14.4,18.5,22.2/
          C     TABLE IIIC  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 5
0008            DATA TT3D/ 700.,1200.,1600.,2100.,2600.,3000.,3500.,4500.,5950.,  125000BC
               1  7400.,8750.,10000.,13800.,15000.,19.2,19.2,19.1,19.6,20.4,21.,
               2  20.4,17.7,18.3,21.2,24.9,26.9,47.5,68./
          C     TABLE IIIE  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 1
0009            DATA TT3E/ 800.,1800.,3200.,4250.,5200.,6500.,7500.,8550.,10000., 132CCCEC
               1  13700.,15000.,6.8,6.5,7.4,7.7,8.,8.4,9.2,11.4,13.3,26.5,37.2/
          C     TABLE IIIF  DEPTH VS DRILLING COST PER FOOT FOR BBC DIST. 2
0010            DATA TT3F/ 200.,600.,1000.,1500.,2000.,3000.,5000.,7000.,7700.,   1332CCEC
               1  8500.,9000.,9500.,12500.,13500.,15000.,15.6,15.5,15.3,14.7,
               2  13.8,11.6,12.3,14.3,15.,15.6,16.,16.3,20.,23.6,21.2/
          C     TABLE IV  DEPTH VS INJECTIVITY COST                             1335CCEC
0011            DATA TT4/0.,5000.,6000.,16000.,1000.,1000.,1020.,2020./
          C     TABLE VJ  INSIDE DIAMETER VS COST PER FOOT  J-55                1345008C
0012            DATA TT5J/ 0.,0.5,1.,1.5,2.,2.5,3.,3.6,4.9,6.1,7.1,8.0,9.8,11.5,  135CCCEC
               1    13.2,15.6,17.,18.,19.,20.,                                  136C00EC
               2          0.,.2,.4,.56,.75,.9,1.05,1.26,1.8,2.3,2.85,3.35,4.4,  137CCCEC
               3    5.45,6.48,8.05,8.56,9.53,10.67,11.5/
          C     TABLE VA  INSIDE DIAMETER VS COST PER FOOT  N-80                 140500BC
0013            DATA TT5N/ 0.,0.5,1.,1.5,2.,2.5,3.,3.6,4.9,5.7,6.2,7.,7.7,8.4,9.7,141CCCEC
               1    10.5,12.1,13.3,14.4,17.,18.,19.,20.,                        141500EC
               2          0.,.35,.62,.84,1.02,1.23,1.45,1.7,2.35,2.84,3.16,3.72, 142000BC
               3    4.33,4.88,6.,7.13,8.25,9.38,10.51,13.1,14.25,15.3,16.3/
          C     TABLE VI OUTSIDE DIAMETER VS CEMENT LINING COST PER FOOT        143500EC
0014            DATA TT6/ 0.,8.7,12.6,13.,18.,19.,20.,                          144CCCEC
```

```
     1          0.,1.6,2.5,2.6,3.6,3.8,4.0/
      C   TABLE VII  BRAKE HORSEPOWER VS COST OF PUMP & MOTOR PER HP
0015       DATA TT7/ 0.,1.,1.301,1.699,2.,2.301,2.477,2.845,3.,3.301,3.477,
     1          3.699,4.,
     2     3.114,2.38,2.176,1.954,1.813,1.699,1.672,1.623,1.515,1.301,
     3          1.176,1.,0.778/
      C   TABLE VIII RAW WATER STORAGE VS CONSTRUCTION COST
0016       DATA TT8/0.,50000.,100000.,200000.,500000.,1000000.,13000.,
     1    13000.,20000.,30000.,50000.,80000./
      C   TABLE IX  FLOW RATE VS OPERATION & MAINTENANCE COST
0017       DATA TT9/3800.,10000.,20000.,30000.,60000.,1000000.,
     1500000.,2500000.,3500000.,4500000.,5000000.,6000000.,8000000.,
     2  10000000.,20000000.,30000000.,40000000.,50000000.,
     3  1000.,1825.,2715.,3560.,5475.,7200.,9310.,12590.,15970.,18260.,
     4  21900.,25750.,33300.,40150.,65700.,87600.,110000.,127750./
      C   TABLE X  LOG FLOW VS LOG OPERATION COST
0018       DATA TT10/ 3.,3.301,3.602,4.,4.301,4.602,4.699,4.845,5.,6.301,7.,
     1    8.,
     2          3.1,3.13,3.164,3.286,3.38,3.518,3.544,3.613,3.711,4.67,
     3    5.164,5.504/
      C   TABLE XI    PIPE DIA., 300 PSI INCHES, VS. COST, $/FOOT
0019       DATA TT11/ 0.,10.,12.,14.,22.,36.,39.,60.,
     1          0.,4.45,5.66,7.42,20.91,23.70,26.18,52.07/
0020       END
```

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FORTRAN IV G LEVEL 20                EVAP              DATE = 71356        12/55/56            PAGE 0001

0001                SUBROUTINE EVAP
                    C
                    C  ***************************************************************************
                    C  *                                                                         *
                    C  *                                 MAINE                                   *
                    C  *          BRINE DISPOSAL BY EVAPORATION MAIN PROGRAM                     *
                    C  *                                                                         *
                    C  ***************************************************************************
                    C
0002                    IMPLICIT REAL*8(A-H,O-Z)
0003                    REAL*8 KW
0004                    DIMENSION ANAME(10)
                    C
                    C       XC      BRINE FLOW
                    C       XW      PRODUCT FLOW CAPACITY
                    C       CE      BRINE CONCENTRATION
                    C       PREC    PRECIPITATION
                    C       EC      EVAPORATION RATE
                    C       FF      DISTANCE FROM PLANT TO SOURCE
                    C       EL      ELEVATION OF SOURCE
                    C       ECU     POWER COST
                    C       CLU     LAND COST
                    C       ZI      CAPITAL DISCOUNT RATE
                    C       Y       PROJECT LIFE
                    C       BCI     BUILDING COST INDEX
0005                    AMORT(X,Z)=(X*(1.+X)**Z)/((1.+X)**Z-1.)
0006                900 READ 51, (ANAME(J),J=1,10),XC,XW,CE,PREC,EC,FF,EL,ECU,CLU,ZI,Y,BCI
                       1,XLAST
0007                 51 FORMAT(10A8/8F10.3/4F10.3,F10.0)
0008                    XW=XW*1.0E
0009                    XC=XC*1.0E
0010                    ZI=ZI/100.
0011                    IPRNT=6
0012                    LIST=6
0013                    CENT=0.
0014                    TICST=0.
0015                    RWY=0.
0016                    AFF=0.
0017                    XIC=0.
0018                    SUM1=0.00
0019                    SUM2=0.00
0020                    SUM3=0.00
0021                    SUM4=0.00
0022                    EC=0.00
                    C       PRELIM CALCS FOR DIKE COSTS
0023                    EA=EC-PREC
0024                    IF(EA.GT.0.00) GO TO 8000
0025                     WRITE(6,6)
0026                6   FORMAT('0 *** ERROR -- ZERO NET PRECIPITATION')
0027                    GO TO 100
0028                8000 XCD=XC/1000.
0029                    AF=1.44*XCD/EA
0030                    RA=4.24*((1CF-5CCCC.)/5CCCC.)**4.2)
```

```
0031              H=R.+RA
                C      CIKE MATERIAL VOLUME
0032              IF (AE-175.) 8001,8001,8002
0033           8001 XL=(.0154*AE)+.6
0034              GO TO 8003
0035           8002 XL=(.0066*AE)+2.85
0036           8003 IF (H-6.) 11,11,12
0037             11 VL=2.25*H-2.
0038                GO TO 13
0039             12 VL=5.74*H-22.54
0040             13 VT=XL*VL
0041                AT=(((.03*AE)*(RA+2.))/10.)+(1.02*AE)
0042                AL=((((.01111*AE)+6.)*(RA+2.))/10.)+(1.01111*AE)
0043                VF=(((35.*AE)+1500C.)*(RA+3.))/10.)+(16.25*AE)+5000.
0044                DI=((XC**.45)*.017)+.5
0045                CC=(1.055*DI)+.2225
0046             16 IF (DI-5.5) 17,17,18
0047             17 PWRAC=3.84*DI-1.15
0048                GO TO 22
0049             18 PWRAC=7.57*DI-21.62
0050             22 VERAC=104.5*DI+3068.
0051                F=5280.*FF
0052                CPU=.109*PWRAC*.506
0053                HF=.003*F
0054                DH=EL-HF
0055             30 IF (DH) 8,9,9
0056              8 DH=-DH
0057                RRP=.434*DH
0058                HHP=(XC*RDRF)/ 746*000.
0059                RHP=HHP/.85
0060                KW=RHP*.8
0061                GPM=XC/1440.
0062             55 PCU=10.**(3.-(.525*DLOG10(RHP))      )
0063                PC=PCL*RHP
0064                STR=PC
0065                GO TO 97
0066              9 STR=0.0
0067                KW=0
0068             97 CL=CLL*AT
0069                CS=AT*100.
0070                CLL=AL*.031
0071                CF=VF*.40
0072                CC=VT*1.00
0073             84 ST1=CL+CS+CLL+CF+CC
0074                TLCST=TLCST+CL
0075                STIR=CS+CLL+CF+CC
0076                CCU=CC*.7
0077                CR=F*CPU
0078                CC=F*CCL
0079                STA=(((CR+CC)*PCI)/57C.
0080                CI=F*.60
0081                CR=F*.075
0082             85 ST2=STA+CI+CR
```

```
0083              ST2R=CP+CC+CI
0084               RWY=RWY+CP
                C     PCWD COSTS
0085               CTG=ST1*.10
0086               CONT=CONT+CTG
0087               ENG=.10*(ST1+CTG)
0088               AEF=AEF+ENG
0089               XNT=.01625*(ST1+CTG+ENG)
0090               XIC=XIC+XNT
0091            80 CC1=ST1+CTG+ENG+XNT
0092               A1=CC1*AMORT(ZI,Y)
0093               CUM1=CC1*.005
0094               CUM2=CUM1*.15
0095               CUM3=.30*(CUM1+CUM2)
0096               CUM4=.007*(A1+CUM1+CUM2+CUM3)
0097            81 AC1=A1+CUM1+CUM2+CUM3+CUM4
                C    PIPE COSTS
0098               CUM1=ST2*.10
0099               CUM2=.10*(ST2+CUM1)
0100               CUM3=.01625*(ST2+CUM1+CUM2)
0101            92 CC2=ST2+CUM1+CUM2+CUM3
0102               A2=CC2*AMORT(ZI,Y)
0103               CUM1=.0025*CC2
0104               CUM2=.007*(A2+CUM1)
0105            83 AC2=A2+CUM1+CUM2
                C    PUMP STATION COSTS
0106               IF (STP) 24,24,25
0107            24    CONTINUE
0108               GO TO 27
0109               25 CUM1=.10*STP
0110               CUM2=.10*(STP+CUM1)
0111               CUM3=.01625*(STP+CUM1+CUM2)
0112               CC3=STP+CUM1+CUM2+CUM3
0113               A3=CC3*AMORT(ZI,Y)
0114               CUM1=.0025*CC3
0115               EC=KW*ECL*8760.
0116               GO TO 300
0117            27 CC3=0.
0118               A3=0.
                C     O+M CALCS
0119            300 IF (XC.GE.1000..AND.XC.LE.10.**9) GO TO 58
0120               WRITE (IPRNT,50) XC
0121            50 FORMAT (*X(0) OUTSIDE RANGE, X(0)=*, F10.1)
0122               GO TO 100
0123            58 CEM=10.**(.0251+.645*(ALOG10(XC)))
0124               CUM2=CEM*.15
0125               CUM3=(CEM+CUM2)*.3
0126               CUM4=.007*(A3+CUM1+CUM2+CUM3 +EC+CEM)
0127               AC3=A3+CUM1+CUM2+CUM3+CUM4+CEM+EC
                C
0128               TREND=RCI/570.
0129               TEST1=ST1R*TREND
0130               TEST2=ST2R*TREND
```

```
0131              TRSTE=STR*TREAC
0132              COST1=ST1R+ST2R+STR
0133              COST2=COST1*TREAC
0134              COSTTT=COST2+AEF+RWY+CCNT+XIC+TLCST
0135           1001 CONTINUE
0136              COSTAE=AC1+AC2+AC3
0137              COST3=COSTAE/(XC*.365)
0138              COST4=COSTAE*1.D-6
0139              COST99=COSTAE/(XB*.365)
0140              COST5=COSTTT*1.D-6
0141              XC=XC/1.D6
0142              XB=XB/1.D6
0143              ZI=ZI*100.
                  C
                  C  **** SUMMARY OF MODEL DATA
0144              WRITE(LIST,3000)          (   ANAME(J),J=1,10)
0145              WRITE( LIST,3001) XC        ,COST99,COST3,COST4,COST5
0146              WRITE(LIST,5) XC,XB,GE,PREC,EC,FF,FL,FCU,CLL,ZI,ECI,Y
                  C
                  C    **** COST PER MODEL
                  C
0147              WRITE(LIST,2000)             (ANAME(J),J=1,10)
0148              WRITE(LIST,2001) ST1R,TREAC,TRST1
0149              WRITE(LIST,2002) ST2R,TREAC,TRST2
0150              WRITE(LIST,2003) STR,TREAC,TRSTR
0151              WRITE(LIST,2007) COST11,COST2
                  C
                  C    *** ENG. COST
                  C
0152              WRITE(LIST,2050)
0153              WRITE(LIST,2051) AEF
0154              WRITE(LIST,2052) TLCST
0155              WRITE(LIST,2053)RWY
0156              WRITE(LIST,2054) CCNT
0157              WRITE(LIST,2055) XIC
0158              WRITE(LIST,2056) COSTTT
0159              WRITE(LIST,2100)
0160              WRITE(LIST,2101)AC1
0161              WRITE(LIST,2102)AC2
0162              WRITE(LIST,2103)AC3
0163              WRITE(LIST,2104)COSTAE
0164           5  FORMAT (/////'     1 SUMMARY OF MODEL DATA'//
                 1X,'CAPACITIES'//14X,'BRINE FLOW      ',40X,F10.3,' MGPD'/
                 214X,'PETROLE FLOW    ',41X,F10.3,' MGPD'///
                 214X,'BRINE CONCENTRATION',37X,F10.0,'PPM'///
                 214X,'PRECIPITATION       ',37X,F10.0,' IN '///
                 214X,'EVAPORATION RATE    ',37X,F10.0,' IN '///
                 2X,'DISCHARGE FIELD'//14X,'DISTANCE FROM POINT TO DISCHARGE STATIO
                 XN',16X,F10.2,' MILES'/14X,'ELEVATION OF DISCHARGE STATION FROM PO
                 XNT',15X,F10.2,' FEET'///
                 4X,'RATES'//14X,'POWER COST',46X,F10.4,' $/KWH'/14X,'LAND COST',
                 X47X,F10.0,' $/ACRE'/14X,'CAPITAL DISCOUNT RATE',35X,F10.3,' PERCEN
                 XT'/14X,'BUILDING COST INDEX',37X,F10.0/14X,'PROJECT LIFE',44X,
```

```
     XF10.0,' YEARS')
0165 2000 FORMAT('1', '  COST ESTIMATES FOR BRINE DISPOSAL BY EVAPORATION'
     1,          //2CX,1CA8///'   II  CONSTRUCTION COSTS'/
     274X,'CONSTRUCTION COST'/40X,'CONSTRUCTION COST    TREND        ',
     2'TRENDED TO'/1CX,'FACILITY',22X,'BEFORE TRENDING      FACTOR',
     37X,'CURRENT YEAR'/10X,'--------',22X,'-----------------',
     4'    ------',7X'-----------------'/ )
0166 2001 FORMAT(5X,'EVAPORATION POND                    $',F11.C,10X,F5.2,
     18X,'$',F11.0)
0167 2002 FORMAT(5X,'TRANSMISSION PIPE LINE              $',F11.C,10X,F5.2,
     18X,'$',F11.0)
0168 2003 FORMAT(5X,'PIPE LINE PUMPING STATIONS          $',F11.C,10X,F5.2,
     18X,'$',F11.C)
0169 2007 FORMAT(/5X,'TOTAL                               $',F11.C,15X,
     18X,'$',F11.0/// )
017C 2050 FORMAT(2X,'III  CAPITAL INVESTMENT '//)
0171 2051 FORMAT(5X,'ENGINEERING, ADMINISTRATION AND FINANCING', 2CX,
     18X,'$',F11.0)
0172 2052 FORMAT(5X,'TOTAL LAND COST                        ', 20X,
     18X,'$',F11.0)
0173 2053 FORMAT(5X,'RIGHTS OF WAY                          ', 2CX,
     18X,'$',F11.0)
0174 2054 FORMAT(5X,'CONTINGENCIES                          ', 2CX,
     18X,'$',F11.0)
0175 2055 FORMAT(5X,'INTEREST DURING CONSTRUCTION           ', 20X,
     18X,'$',F11.0)
0176 2056 FORMAT(/5X,'TOTAL                                ',26X,
     18X,'$',F11.0/// )
0177 2100 FORMAT(           3X,'IV   ANNUAL EXPENDITURES'//
     110X,'FACILITY',56X,'COST'/10X,'--------',56X,'----'/)
0178 2101 FORMAT(5X,'EVAPORATION POND                      ',26X,
     18X,'$',F11.0)
0179 2102 FORMAT(5X,'TRANSMISSION PIPE LINE                ',26X,
     18X,'$',F11.0)
017C 2103 FORMAT(5X,'PIPE LINE PUMPING STATION             ',26X,
     18X,'$',F11.0)
0181 2104 FORMAT(///5X,'TOTAL                                 ',26X,
     18X,'$',F11.C)
0182 3000 FORMAT('1'///'  COST ESTIMATES FOR BRINE DISPOSAL BY EVAPORATION'
     1,          //                  2CX,1CA8///)
0183 3001 FORMAT( 'QUANTITY OF EFFLUENT                        MG',17X,
     8' ',F11.3/
     8         'QCOST PER THOUSAND GALLONS OF PRODUCT PETRO ',17X,
     A'$',F11.3/
     1'QCOST PER THOUSAND GALLONS OF EFFLUENT                ',1CX,
     A'$',F11.3/
     1'QANNUAL EXPENDITURES -- MILLION  OF DOLLARS          ',9X,' $',
     AF11.3/'QCAPITAL INVESTMENT -- MILLION  OF DOLLARS',15X,'$',F11.3/)
0184 1CC  IF(XLAST.EC.1.) GC TC 997
0185       GC TC 995
0186 997  RETURN
0187       END
```

```
0001            SUBROUTINE CONVEY                                                  0100
                C                                                                  0100
                C  ****************************************************************0200
                C  *                                                              *0300
                C  *                          MAINPC                              *0400
                C  *      PRIME DISPOSAL BY CONVEYANCE MAIN PROGRAM               *0500
                C  *                                                              *0600
                C  ****************************************************************0700
                C                                                                  0800
0002                 IMPLICIT REAL*8(A-H,O-Z)                                      1300
0003                 REAL*8 KW                                                     1400
0004                 DIMENSION ANAME(10)
                C    XC       PRIME FLOW                                          3900
                C    XW       PROJECT FLOW CAPACITY                               4000
                C    FF       DISTANCE FROM PLANT TO SOURCE                       4100
                C    EL       ELEVATION OF SOURCE                                 4200
                C    ECU      POWER COST                                          4300
                C    ZI       CAPITAL DISCOUNT RATE                               4400
                C    BCI      BUILDING COST INDEX                                 4500
                C    Y        PROJECT LIFE                                        4600
0005                 WRITE(6,7)(X*(1.+X)**Y)/((1.+X)**Y-1.)                        3600
0006            999  READ 51, (ANAME(J),J=1,10),XC,XW,ECU,PCI,FF,EL,Y,ZI,XLAST
0007              51 FORMAT(10A8/2F10.2,F10.3,4F10.2,F10.4/F10.0)
0008                 IPRNT=6
0009                 LIST=6
0010                 XW=XW*1.06
0011                 XC=XC*1.06
0012                 ZI=ZI/100.
0013                 FC=0.00                                                       4800
0014                 CI=((XC**.45)*.017)+.5                                        4900
0015                 CF=(1.055*CI)+.2225                                           5000
0016              16 IF (CI-5.5) 17,17,18                                          5100
0017              17 PWRPC=3.64*CI-1.15                                            5200
0018                 GO TO 22                                                      5300
0019              18 PWRPC=7.57*CI-21.62                                           5400
0020              22 YPWRPC=104.5*CI**.068                                         5500
0021                 F=5280.*FF                                                    5600
0022                 CPW=.109*PWRPC*.506                                           5700
0023                 HF=.003*F                                                     5800
0024                 PH=EL-HF                                                      5900
0025              30 IF (PH) 8,9,9                                                 6000
0026               8 PH=-PH                                                       6100
0027                 PCP=.434*PH                                                   6200
0028                 HHP=(XC*PCP)/ 2468.0.                                         6300
0029                 BHP=HHP/.85                                                   6400
0030                 KW=BHP*.9                                                     6500
0031                 GPM=XC/144.                                                   6600
0032                 PCU=10.**(3.-(.525*DLOG10(BHP))      )                        6700
0033                 PC=PCU*BHP                                                    6800
0034                 STR=PC                                                        6900
0035                 GO TO 12                                                      7000
0036               9 STR=0.0                                                       7100
                C      SUPPLY PIPE COST                                          7200
```

```
0037          12 CP=F*CPL                                                    7300
0038             CCU=CP*.2                                                   7400
0039             CC=F*CCL                                                    7500
0040             STA=((CP+CC)*RCI)/57C.                                      7600
0041             CI=F*.60                                                    7700
0042             CR=F*.075                                                   7800
0043             ST2=STA+CI+CR                                               7900
0044             ST2R=CP+CC+CI                                               8000
0045             RWY=CR                                                      8100
0046             CUM1=ST2*.10                                                8200
0047             AFF=CUM1                                                    8300
0048             CLM2=.10*(ST2+CLM1)                                         8400
0049             CONT=CLM2                                                   8500
0050             CUM3=.01625*(ST2+CUM1+CUM2)                                 8600
0051             XIC=CUM3                                                    8700
0052             CC2=ST2+CUM1+CLM2+CLM3                                      8800
0053             A2=CC2*AMCRT(ZI,Y)                                          8900
0054             CLM1=.0025*CC2                                              9000
0055             CUM2=.007*(A2+CUM1)                                         9100
0056             AC2=A2+CLM1+CUM2                                            9200
               C    PUMP STATION COSTS                                      9300
0057             IF (STP) 24,24,25                                           9400
0058           24   CONTINUE                                                9500
0059             CC3=0.                                                      9600
0060             A3=0.                                                       9700
0061             GO TO 99                                                    9800
0062          25 CLM1=.10*STP                                                9900
0063             CLM2=.10*(STP+CUM1)                                         A100
0064             CLM3=.01625*(STP+CLM1+CLM2)                                 A101
0065             CC3=STP+CUM1+CLM2+CUM3                                      A102
0066             A3=CC3*AMCRT(ZI,Y)                                          A103
0067             CLM1=.0025*CC3                                              A104
0068             EC=KW*ECL*876C.                                             A105
0069          27 CONTINUE                                                    A106
               C    O+M CALCS                                               A107
0070             IF (XC.GE.1000..AND.XC.LE.10.**9) GO TO 98                  A108
0071             WRITE (IPRNT,5C) XC                                         A109
0072          50 FORMAT (' X(C) OUTSIDE RANGE, X(C)=', F10.1)                A110
0073             GO TO 100                                                   A111
0074          98 CEM=10.**(.0291+.645*(CLOG10(XC)))                          A112
0075             CUM2=CEM*.15                                                A113
0076             CUM3=(CEM+CUM2)*.3                                          A114
0077             CLM4=.007*(A3+CLM1+CLM2+CLM3 +EC+CEM)                       A115
0078             AC3=A3+CLM1+CLM2+CLM3+CLM4+CEM+EC                           A116
               C      TOTALS                                                A117
               C                                                            0100
               C  ************************************************************0200
               C  *                                                          *C3CC
               C  *      PRINT DISPOSAL BY CONVEYANCE PRINT PROGRAM          *C5C0
               C  *                                                          *06CC
               C  ************************************************************07CC
               C                                                            0800
0079           99  CONTINUE
```

```
0080              TREAC=PC1/570.                                                4300
0081              TRST2=ST2R*TREAC                                              4400
0082              TRSTR=STR*TREAC                                               4500
0083              ST1R=0.00                                                     4600
0084              AC1=0.00                                                      4700
0085              TLCST=0.00                                                    4800
0086              CCST1=ST1R+ST2R+STR                                           4900
0087              CCST2=CCST1*TREAC                                             5000
0088              CCSTTT=CCST2+AEF+RWY+CCAT+XIC+TLCST                           5100
0089              CCSTAE=AC1+AC2+AC3                                            5200
0090              CCST99=CCSTAE/(XW*.365)                                       5300
0091              CCST3=CCSTAE/(XC*.365)                                        5400
0092              CCST4=CCSTAE*1.0-6                                            5500
0093              CCST5=CCSTTT*1.0-6                                            5600
0094              XC=XC/1.06                                                    5700
0095              XW=XW/1.06                                                    5800
0096              ZI=ZI*100.                                                    5900
                  C                                                             5900
                  C  **** SUMMARY OF MODEL DATA                                 6000
                  C                                                             6100
0097                   WRITE(LIST,3000)            (ANAME(J),J=1,10)
0098                   WRITE( LIST,3001) XC        ,CCST99,CCST3,CCST4,CCST5     6400
0099                   WRITE(LIST,5) XO,XW,FF,FL,ECL,ZI, BCI,Y
                  C                                                             6800
                  C    **** COST FOR MODELL                                     6900
                  C                                                             7000
0100                   WRITE(LIST,2000)            (ANAME(J),J=1,10)
0101                   WRITE(LIST,2002) ST2R,TREAC,TRST2                        7300
0102                   WRITE(LIST,2003) STR,TREAC,TRSTR                         7400
0103                   WRITE(LIST,2007) CCST1,CCST2                             7500
                  C                                                             7600
                  C    *** ENG. COST                                            7700
                  C                                                             7800
0104                   WRITE(LIST,2050)                                         7900
0105                   WRITE(LIST,2051) AEF                                     8000
0106                   WRITE(LIST,2053)RWY                                      8100
0107                   WRITE(LIST,2054) CCAT                                    8200
0108                   WRITE(LIST,2055) XIC                                     8300
0109                   WRITE(LIST,2056) CCSTTT                                  8400
0110                   WRITE(LIST,2100)                                         8500
0111                   WRITE(LIST,2102)AC2                                      8600
0112                   WRITE(LIST,2103)AC3                                      8700
0113                   WRITE(LIST,2104)COSTAE                                   8800
0114              5    FORMAT (/////'     I  SUMMARY OF MODEL DATA'//           8900
                     1X,'CAPACITIES'//14X,'ERING FLOW      ',40X,F10.2,' MGPD'//  9200
                     214X,'PETROLE FLOW    ',41X,F10.2,' MGPD'///               9300
                     3X,'DISCHARGE FIELD'//14X,'DISTANCE FROM POINT TO DISCHARGE STATIC9400
                     XN',16X,F10.2,' MILES'/14X,'ELEVATION OF DISCHARGE STATION FROM PO19500
                     XAT',15X,F10.2,' FEET'///                                  9600
                     4X,'RATES'//14X,'POWER COST',46X,F10.4,' $/KWH'/           9700
                     X                14X,'CAPITAL DISCOUNT RATE',35X,F10.3,' PERCEN9800
                     X1'/14X,'BUILDING COST INDEX',37X,F10.0/14X,'PROJECT LIFE',44X,  9900
                     XF10.0,' YEARS')                                           10000
```

```
0115        2000 FORMAT('1', '  COST ESTIMATES FOR BRINE DISPOSAL BY CONVEYANCE '  X101
                1,          //20X,1CAB///'   II  CONSTRUCTION COSTS'//           X102
                274X,'CONSTRUCTION COST'/40X,'CONSTRUCTION COST    TREND       ', X103
                2'TRENDED TO'/1CX,'FACILITY',22X,'BEFORE TRENDING      FACTOR',   X104
                37X,'CURRENT YEAR'/10X,'---------',22X,'------------------',      X105
                4'    ------',7X,'------------------'/ )                          X106
0116        2002 FORMAT(5X,'TRANSMISSION PIPE LINE              $',F11.C,10X,F5.2,  X107
                18X,'$',F11.0)                                                    X108
0117        2003 FORMAT(5X,'PIPE LINE PUMPING STATIONS          $',F11.C,10X,F5.2,  X109
                18X,'$',F11.0)                                                    X110
0118        2007 FORMAT(/5X,'TOTAL                               $',F11.C,15X,      X111
                18X,'$',F11.0/// )                                                X112
0119        2050 FORMAT(2X,'III  CAPITAL INVESTMENT '//)                          X113
0120        2051 FORMAT(5X,'ENGINEERING, ADMINISTRATION AND FINANCING', 20X,      X114
                18X,'$',F11.0)                                                    X115
0121        2053 FORMAT(5X,'RIGHTS OF WAY                          ', 20X,      X116
                18X,'$',F11.0)                                                    X117
0122        2054 FORMAT(5X,'CONTINGENCIES                          ', 20X,      X118
                18X,'$',F11.0)                                                    X119
0123        2055 FORMAT(5X,'INTEREST DURING CONSTRUCTION           ', 20X,      X120
                18X,'$',F11.0)                                                    X121
0124        2056 FORMAT(/5X,'TOTAL                                 ',26X,       X122
                18X,'$',F11.0/// )                                                X123
0125        2100 FORMAT(           3X,'IV   ANNUAL EXPENDITURES'//                X124
                11CX,'FACILITY',56X,'COST'/10X,'---------',56X,'----'/)           X125
0126        2102 FORMAT(5X,'TRANSMISSION PIPE LINE                 ',26X,       X126
                18X,'$',F11.0)                                                    X127
0127        2103 FORMAT(5X,'PIPE LINE PUMPING STATION              ',26X,       X128
                18X,'$',F11.0)                                                    X129
0128        2104 FORMAT(///5X,'TOTAL                                  ',26X,    X130
                18X,'$',F11.0)                                                    X131
0129        3000 FORMAT('1'///'  COST ESTIMATES FOR BRINE DISPOSAL BY CONVEYANCE '  X132
                1,          //                2CX,1CAB///)                        X133
0130        3001 FORMAT( 'QUANTITY OF EFFLUENT                        MG',17X,    X134
                A' ',F11.3/                                                       X135
                A       'QCOST PER THOUSAND GALLONS OF PRODUCT WATER ',17X,       X136
                A'$',F11.3/                                                       X137
                1'QCOST PER THOUSAND GALLONS OF EFFLUENT              ',1CX,      X138
                A'$',F11.3/                                                       X139
                1'QANNUAL EXPENDITURES -- MILLION  OF DOLLARS         ',9X,' $',  X140
                AF11.3/'QCAPITAL INVESTMENT -- MILLION  OF DOLLARS',15X,'$',F11.3/)X141
0131        3002 FORMAT(2CX,1CAB/)                                                X142
0132        100  IF(XLAST.EQ.1.) GO TO 987
0133             GO TO 985
0134        987  RETURN
0135             END                                                              X143
```

TT1

3.3010	-2.152C
3.6990	-2.0530
4.0000	-3.5920
4.6990	-3.8150
5.0000	-3.7480
5.6990	-3.6420
6.0000	-3.6020
6.3010	-3.5680
6.6990	-3.5050
7.0000	-3.4310

TT2

3.0000	315C.0000
3.5000	2775.0000
4.0000	255C.0000
5.0000	229[illegible].0000
6.0300	210C.0000
8.0000	186C.0000
10.0000	165C.0000
12.0000	147C.0000
16.0000	120C.0000
18.0000	108C.0000
20.0000	975.0000

TT3A

800.0000	6.0000
1100.0000	8.0000
1750.0000	8.0000
2300.0000	8.1000
3000.0000	9.5000
3800.0000	10.0000
4300.0000	10.5000
4700.0000	11.1000
5300.0000	12.0000
6000.0000	13.5000
6500.0000	14.4000
7000.0000	15.5000
7800.0000	17.4000
8600.0000	19.5000
9400.0000	22.3000
10300.0000	24.7000
10500.0000	26.5000
14600.0000	38.5000
15100.0000	50.7000

TT3B

700.0000	16.4000
1850.0000	12.4000
2400.0000	12.0000
2950.0000	11.6000
3500.0000	11.4000
4150.0000	10.5000
4750.0000	10.0000
5550.0000	10.0000
6350.0000	11.0000
7550.0000	12.2000
11800.0000	23.4000
14000.0000	34.5000
15000.0000	55.4000

TT3C

700.0000	6.7000
1700.0000	6.2000
4000.0000	6.3000
5000.0000	6.4000
6000.0000	7.5000
7200.0000	8.0000
8000.0000	13.6000
9000.0000	18.2000
10000.0000	17.0000
10600.0000	14.8000
11300.0000	14.4000
12700.0000	18.5000
15000.0000	22.3000

TT3D

700.0000	19.2000
1200.0000	19.2000
1600.0000	19.1000
2100.0000	19.6000
2600.0000	20.4000
3200.0000	21.0000
3500.0000	20.4000
4500.0000	17.7000
5950.0000	18.3000
7400.0000	21.2000
8750.0000	24.9000
10100.0000	26.5000
13800.0000	47.5000
15000.0000	68.0000

TT3F

800.0000	6.8000
1800.0000	6.9000
3200.0000	7.4000
4250.0000	7.7000
5200.0000	8.0000
6500.0000	8.4000
7500.0000	9.2000
8550.0000	11.4000
10300.0000	13.3000
13700.0000	26.5000
15000.0000	37.7000

TT3F

300.0000	15.6000
600.0000	15.5000
1100.0000	15.3000
1500.0000	14.7000
2000.0000	13.8000
3000.0000	11.6000
5000.0000	13.7000
7000.0000	14.3000
7700.0000	15.0000
8500.0000	15.6000
9000.0000	16.0000
9500.0000	16.3000
12500.0000	20.0000
13500.0000	22.6000
15000.0000	21.2000

TT4

0.0	1000.0000
5000.0000	1000.0000
6000.0000	1020.0000
16000.0000	2020.0000

TT5J

C.C	C.C
C.5000	C.2CCC
1.0000	C.4CCC
1.5000	C.56CC
2.0000	C.75CC
2.5000	C.9000
3.0000	1.0500
3.6000	1.26CC
4.5000	1.8000
6.1000	2.3000
7.1000	2.6500
8.0000	3.2500
9.8000	4.4000
11.5000	5.45CC
13.2000	6.4800
15.6000	8.0500
17.0000	8.56CC
18.0000	9.9300
19.0000	10.6700
20.0000	11.5000

TT5N

C.C	C.C
C.5000	C.35CC
1.0000	C.62CC
1.5000	C.84CC
2.0000	1.02CC
2.5000	1.23CC
3.0000	1.4500
3.6000	1.7000
4.5000	2.35CC
5.7000	2.8400
6.2000	3.16CC
7.0000	3.72CC
7.7000	4.3300
8.4000	4.88CC
9.7000	6.0000
10.5000	7.1300
12.1000	8.25CC
13.3000	9.38CC
14.4000	10.5100
17.0000	13.10CC
18.0000	14.25CC
19.0000	15.3000
20.0000	16.3000

TTE

C.C	C.C
6.7000	1.6000
12.8000	2.5000
13.0000	2.6000
18.0000	3.6000
19.0000	3.8000
20.0000	4.0000

TTF

C.C	3.1140
1.0000	2.3800
1.3010	2.1760
1.6990	1.9540
2.0000	1.8130
2.3010	1.6990
2.4770	1.6720
2.6450	1.6230
3.0000	1.5150
3.3010	1.3010
3.4770	1.1760
3.6990	1.0000
4.0000	0.7780

TTP

C.C	12000.0000
50000.0000	13000.0000
100000.0000	20000.0000
200000.0000	30000.0000
500000.0000	40000.0000
1000000.0000	80000.0000

TT9

38000.0000	1000.0000
100000.0000	1825.0000
200000.0000	2715.0000
300000.0000	3560.0000
600000.0000	5475.0000
1000000.0000	7300.0000
1500000.0000	9310.0000
2500000.0000	12590.0000
3500000.0000	15970.0000
4000000.0000	18260.0000
5000000.0000	21900.0000
6000000.0000	25750.0000
8000000.0000	33300.0000
10000000.0000	40150.0000
20000000.0000	65700.0000
30000000.0000	87550.0000
40000000.0000	110680.0000
50000000.0000	127750.0000

TT10

3.0000	3.1000
3.3010	3.1300
3.6020	3.1840
4.0000	3.2860
4.3010	3.3900
4.6020	3.5180
4.8450	3.6440
5.0000	3.7130
6.3010	4.7110
7.0000	4.6700
8.0000	5.1640
	5.5040

TT11

0.0	0.0
10.0000	4.4500
12.0000	5.8600
14.0000	7.4200
22.0000	20.9100
26.0000	23.7000
35.0000	26.1800
60.0000	52.0700