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9. ABSTRACT
(Engineering--Hydraulics R&D)
Volumes I & II; Supplements to Volumes I & II
A PROJECT: Intended to guide the officers of the Agency for International Developmen in evaluating and determining the technical and economic feasibility of desalination projects for which U.S. Government assistance may be sought. The original two-volume Manual -- one volume on technology and one on economics -- was prepared by Kaiser Engineers of Oakland, California in April, 1967. In October, 1972, Burns and Roe Inc., of Oradell, New Jersey produced a supplement to each volume.
Duration: 1967: 1972
DEVELOPMENTS: Technical improvements and cost reductions of desalination have added a new dimension to water supply planning: This method of supplementing freshwater supplies demands prominent consideration as a means of meeting future water needs. The Manual reviews various desalination processes and presents economic and technical guidelines for gathering and analyzing data on energy and water resources and requirements -- data that must be considered in deciding whether water desalination is a viable solution to an area's water shortage problem. Volume I discusses eight desalination methods and describes a typical plant for each: Distillation processes - 1. vertical falling and rising film, 2. multistage flash, 3. multieffect multistage flash, 4. vapor compressions, and 5. solar stills; Non-distillation processes - 6. vacuum-freezing vapor-compressions, 7. electrodialysis, and 8. reverse osmosis. It includes a feasibility study on combining desalination

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plants with electric power generating plants, and a discussion on combining desalination with production of chemical by-products. Volume II gives guidelines for studies to determine if desalination is the optimum solution to an area's water shortage problem. An Appendix lists existing plants, technical data on properties of seawater and brackish water, and sample survey questionnaires. The Supplements to Volumes I & II do not present new technologies but rather refinement and commercialization of the material in the two volumes. They update technical and economic guides - often pointing to the increased viability of desalination solutions. The Supplements describe typical plants built since 1967 and provide sections on conceptual designs, water development planning, and updated budget water plant pricing. They add as well some environmental considerations, and feed treatment and brine disposal methods. Whereas the Manual provides information for evaluation and determination of the feasibility of desalination programs, it does not provide the detailed technical data required by a desalination plant designer. Volumes I & II can be used independently of each other; the Supplements, however, do require reference to Volumes I & II.

A MANUAL ON WATER DESALINATION

SUPPLEMENT NO. 1
TO

VOLUME TWO - ECONOMICS

OCTOBER 1972

PREPARED FOR
UNITED STATES
DEPARTMENT OF STATE
AGENCY FOR INTERNATIONAL DEVELOPMEN
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ORADELL, NEW JERSEY
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Notice

"This manual was prepared for the Agency for International Development (AID), to guide its officers as well as to aid foreign administrators and technicians involved in water resources development in formulating and evaluating desalination programs and projects for which United States Government assistance may be furnished or sought. The information contained herein is not sufficient for and is not intended to be the sole basis for design or construction of a project at any particular location, or as a substitute for professional judgment, advice and assistance as required for development of technical and economic feasibility, plans and designs, construction, and the initiation of operation of such a project.

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VIII. SOLUTION OF WATER SHORTAGE PROBLEMS

A. Typical Water Development Program

Volume II of this manual has provided guidelines for the initiation of a program for defining and solving the water shortage problems of a particular nation or region. Figure VIII-1, (reproduced herein with revisions shows that this AID Manual is useful throughout the Preliminary Feasibility Studies "stage of the program, if reasonable engineering capability exists in the country or general water development engineering consultants are available. Volume II should be consulted for information regarding study organizations, study objectives, and plans of action for determining the technical and economic feasibility of a water development plan.

This Supplementary Manual updates the above information and also provides guidelines in the following areas of interest:

1. Environmental questions and considerations. (See Section IX)

2. Advancements in desalting technology, principally in reverse osmosis and in enhanced-surface heat-transfer equipment. (See Section V, Typical Plants)

3. Specific budget costing procedures for various desalting methods including multi-stage flash evaporation. (See Section X and Appendix C)

4. The use of ENR building cost indices for keeping the herein-presented cost information up to date. (See Appendix C)

B. The Needs of Small Inland Rural Communities

In addition, increased emphasis has been placed on brackish water sources and on units smaller than 1 million gpd, inasmuch as there is a real need for consideration of agricultural and potable water needs

AID MANUAL APPLICABLE

STUDY ORGANIZATION

Organize Study Organization to conduct surveys and prepare preliminary feasibility studies.

WATER DEVELOPMENT PLAN

Conduct surveys of requirements and resources for water and energy and survey of economic conditions.

Define water shortage problems and select possible alternative solutions.

Formulate Water Development Plan.

Water Development Board Review and Approval

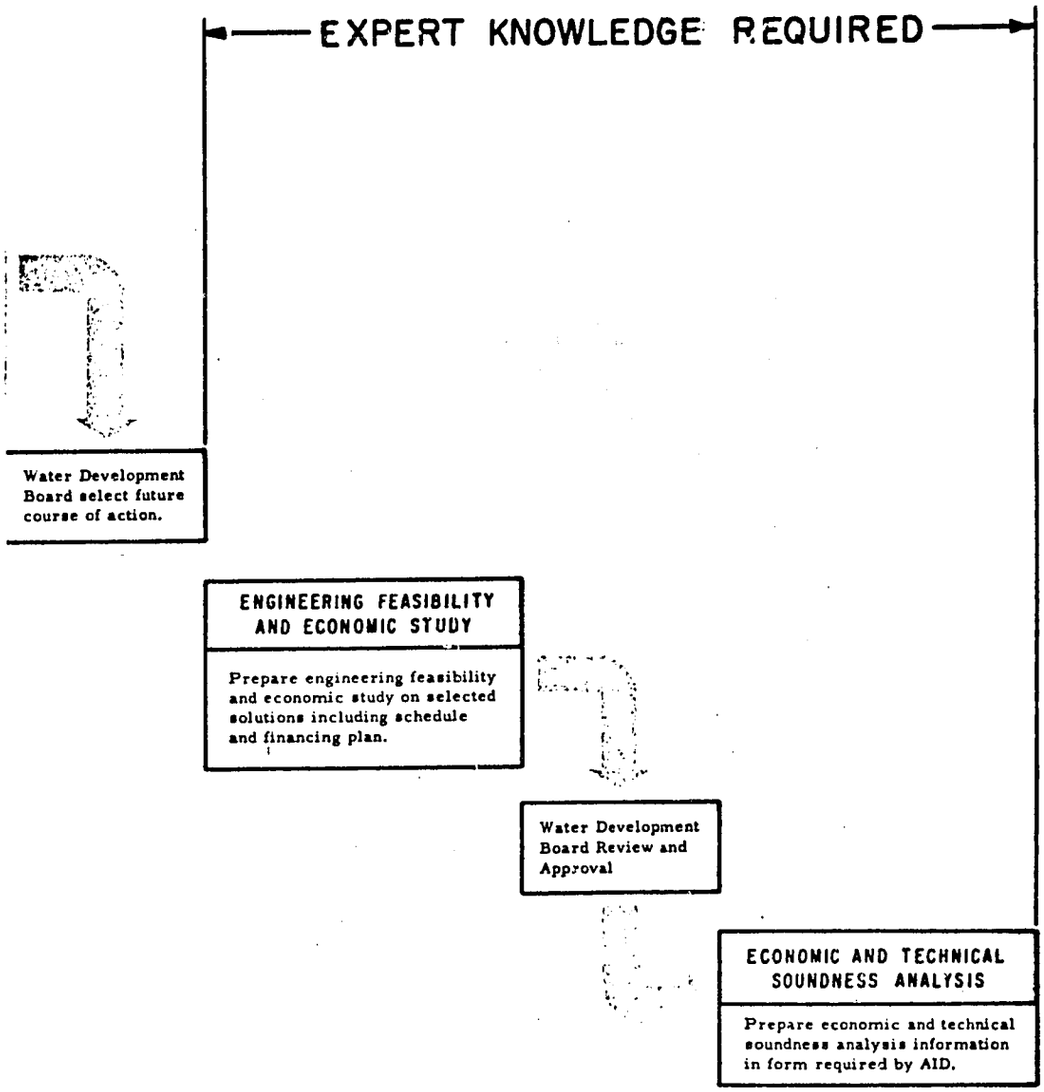
PRELIMINARY FEASIBILITY STUDIES

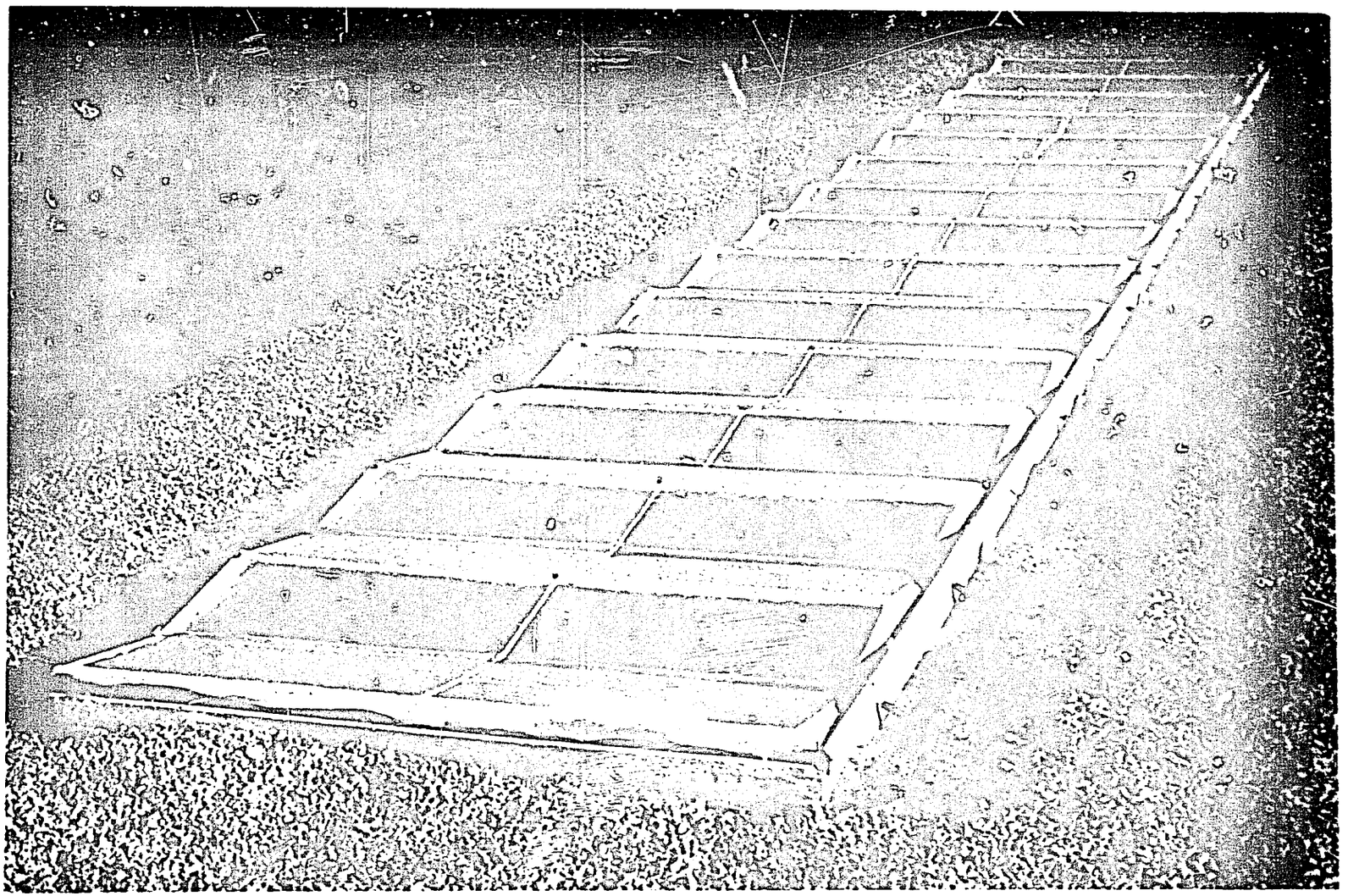
Prepare preliminary feasibility studies on selected alternative solutions from seawater, brackish water and freshwater sources and from water reuse.

Prepare preliminary feasibility summary and recommend future course of action.

FIGURE VIII-1

TYPICAL WATER DEVELOPMENT PROGRAM

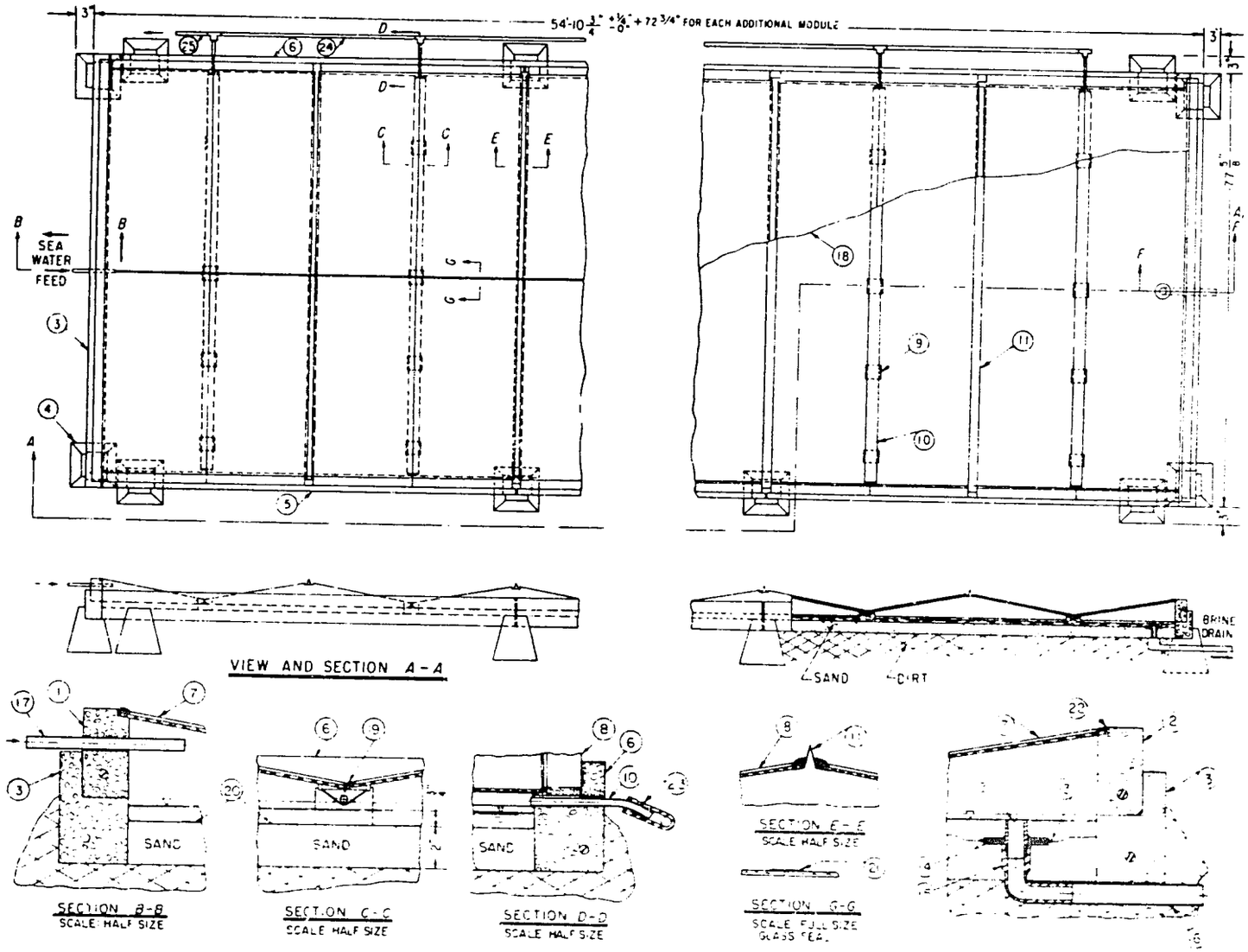




SAWTOOTH-TYPE RECTANGULAR GLASS-COVERED SOLAR STILL

Figure VIII-2

Source: Reference 54



LIST OF MATERIAL		
ITEM	DESCRIPTION	REQ'D
1	END GLASS SUPPORT	1
2	END GLASS SUPPORT	
3	END FRAME	2
4	SUPPORT PIER	24
5	LOWER FRAME	9
6	LOWER FRAME	9
7	EXTREME SIDE GLASS SUPPORT	4
8	GLASS SUPPORT (SIDE)	34
9	PRODUCT TROUGH SUPPORT	72
10	PRODUCT TROUGH	18
11	METAL GLASS SUPPORT	17
12	DP IN	1
13	RUBB'R GASKET 3"OD x 1 1/8"ID x 1/16"TK	2
14	COPPER WASHER 2 3/4"UD x 1 1/16"ID x 1/16"TK	1
15	1/4" FPT 3/4" TUBE PLASTIC ELBOW	1
16	1/4" DIA PLASTIC PIPE 10' LONG	1
17	1/4" DIA 10" LG COPPER FEED TUBE	1
18	15" 36" DOUBLE STRENGTH GLASS	72
19	1/8" THK x 3/4" WIDE x 5" LG VINYL ADHESIVE TAPE	36
20	TYPE 65 GRIFFOLYN B W x 55 LG (BLACK)	1
21	3/4" W BLACK VINYL ELECTRICIAN TAPE	1 ROLL
22	"DAP" CAULKING COMPOUND	10 FL YES
23	1/2" PLASTIC TEE	18
24	1/2" PLASTIC PIPE x 55' LONG	17
25	1/2" PLASTIC PIPE x 10' LONG	1

NOTE:
THIS DRAWING IS MADE FOR A 9 MODULES STILL. EACH MODULE IS 72 3/4" LG TO ADD OR DELETE A MODULE DO THE FOLLOWING.

ITEM	ADD or DELETE	ITEM	ADD OR DELETE
4	2	11	2
5	1	8	8
6	1	9	4
8	4	20	72 3/4" LENGTH
9	8	23	2
10	2	24	2

SAWTOOTH-TYPE RECTANGULAR GLASS-COVERED SOLAR STILL (Schematic only)

Figure VIII -3

Source: Reference 54

of small rural communities which can be easily overlooked in the general effort to meet the needs of large urban centers. Indeed, the needs for drinking water of villages at latitudes of less than 35°, North and South, can sometimes be met by the use of simple backyard or roof-type solar stills, as shown in Figures VIII-2 and 3. A resident can augment his drinking water supply by about 1 gpd for every 12 square feet of solar-still area that he installs. Solar evaporation lends itself most readily to hand operation.

1. Sawtooth-type Glass-covered Still (Reference #54)

This still, shown in Figures VIII-2 and VIII-3, is designed for ease of construction with readily available, durable materials. The frame, six feet wide with a multiple of six-foot-long modules, is made of cast concrete. The basin-liner is made of Griffolyn fabric film. The product troughs are formed of brass strips, 0.016 inch thick. The troughs are supported on precast concrete blocks, laid on top of the basin-liner. The cover is made of window-glass sheets, 18 inches wide by 36 inches long by 1/8 inch thick (25 ounces per square foot). The glass-to-glass joints are sealed with black vinyl electrician's tape, and the glass-to-concrete joints with a bead of calking compound laid on the concrete surface.

Product water drains from the collection troughs through 1/2-inch plastic pipe into a 5-gallon carboy. Saline water is added to basin as needed for replenishment and flushing.

2. Package Vapor Compression Units

The above still is not competitive with vapor compression in sizes over 5000 gpd, as its water costs are too high, ranging from $3.20 to $12/Kgal (54). In the range of sizes from 4800 to 60,000 gpd, diesel-driven vapor compression units, either with or without associate power generation, are available at costs of about $3 to $3.50 per daily gallon

of capacity. These can produce water as cheaply as $2/Kgal based on an 18:1 performance ratio.

C. Desalting Alternatives for Larger Communities

The above alternatives have been presented herein as a potential solution for the water shortage problem of very small communities. Larger communities, particularly those in inland agricultural areas, where brine disposal from desalting plants operating on local brackish water sources may constitute a significant project cost item, must consider the full Water Development Plan presented in the following Sections.

IX. THE WATER DEVELOPMENT PLAN

A. Introduction

The first step in the search for the solution to the water shortage problems of a country or region is the assembly and evaluation of background information on the water and energy resources of the area. The Study Organization should carry out a number of concurrent surveys to obtain this information as well as information on possible solutions to the problems; it should then summarize all the information in a document called the Water Development Plan. The suggested sequence for the surveys, definitions and evaluations which culminate in the formulation of the Water Development Plan is shown in Figure IX-1. Since the Water Development Plan is to be the basis for subsequent work it should include all the descriptions, maps, tables, graphs, evaluation materials and references necessary to present a clear and detailed picture of the water shortage problems and of their possible solutions.

Evaluations of energy requirements and resources should be an integral part of the Water Development Plan since the solution of water shortage problems is, in general, related to the production or use of energy. The development of rivers or the use of dual-purpose power-desalination plants (refer to Section VI) can result in the production of considerable quantities of electrical power; this can reduce substantially the cost of water at the point of use. Moreover, most desalination processes require large amounts of mechanical or electrical power for their operation (e.g., for pumping, for feedwater or brine heating, for vapor compressors, for freezing apparatus, etc.).

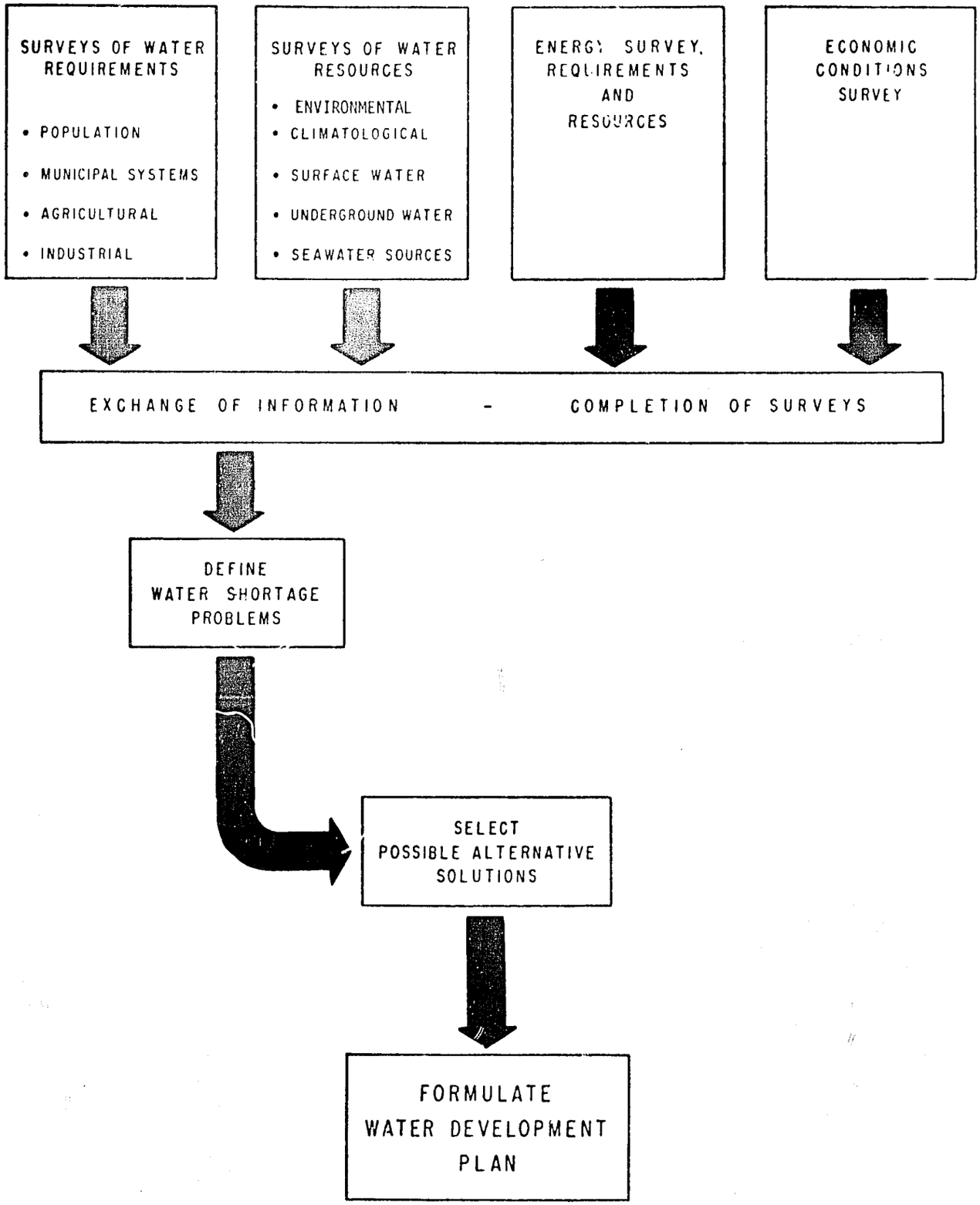
B. Surveys of Requirements and Resources

1. General

The definition and solution of water shortage problems require a considerable amount of background information concerning present and future

FIGURE IX-1

FORMULATION OF THE WATER DEVELOPMENT PLAN



water requirements and sources, as well as comprehensive information concerning the methods by which additional water supplies can be made available.

Solutions of water shortage problems either by desalination methods or by development and utilization of natural water resources usually involve the use or production of energy; therefore, the background information should also include comprehensive data on present and expected power requirements.

To provide the background information necessary in determining the water and energy needs of an area and in determining the resources that are available to meet these needs, the following surveys must be made:

- A Population Survey to determine the locations, timing and amounts of water required to support the population projections

- A Municipal Water Systems Survey to determine the present capabilities and projected requirements of the systems used to convey and distribute water for municipal needs

- Agricultural Surveys to determine the influence of food production on the entire economic and population structure of the region or nation

- An Industrial Survey to determine the water needs resulting from industrial development

- A Climatological Conditions Survey of the nation or region

- A Surface Water Resources Survey, which should include both the fresh and brackish water surface flows, and locations of potential non-leaching sumps for brine disposal.

- An Underground Water Resources Survey (or a

survey of aquifers) which also should include fresh and brackish water aquifers and aquifers suitable for brine disposal

- A Seawater Sources Survey and a study of the problems associated with possible sites for desalination plants

- An Energy Survey of present and projected energy needs and availability

- An Economic Conditions Survey to investigate the economic climate of the nation or region

- An Environmental Survey which lists the expected benefits and detriments of the proposed Water Development Plan.

For optimum results, these surveys should be concurrent, and information collected by one survey group should be made available to other groups as quickly as possible in the form of preliminary interim reports. Using these reports, the parallel survey groups may revise their own projections.

The contents and factors that should be considered in each of these surveys of water requirements, water resources, energy requirements and resources and economic conditions are given in Volume II. Contents and factors that should be considered in the Environmental Survey are given below.

2. Environmental Survey

a. Under the United States Environmental Policy Act of 1969, all agencies of the Federal Government, under Title I, Sect. 102 C, D and E, shall:

"(C) include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on--

(i) the environmental impact of the proposed action,
(ii) any adverse environmental effects which cannot be avoided should the proposal be implemented,
(iii) alternatives to the proposed action,
(iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
(v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

"Prior to making any detailed statement, the responsible Federal official shall consult with and obtain the comments of any Federal agency which has jurisdiction by law or special expertise with respect to any environmental impact involved. Copies of such statement and the comments and view of the appropriate Federal, State, and local agencies, which are authorized to develop and enforce environmental standards, shall be made available to the President, the Council on Environmental Quality and the public as provided by section 552 of title 5. United States Code, and shall accompany the proposal through the existing agency review processes;

(D) study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources;

(E) recognize the worldwide and long-range character of environmental problems and where consistent with the foreign policy of the United States, lend appropriate support to initiatives, resolutions, and programs designed to maximize international cooperation in anticipating and preventing a decline in the quality of mankind's world environment;"

b.. While all of the above steps are not specifically applicable to foreign situations, it is imperative that an environmental impact statement be developed and presented in conjunction with any project in which AID may be required to participate. Typical questions that can be expected to arise in selecting a site for a single purpose water desalting plant or a dual

purpose water and electric power plant have been developed by AID and are presented herein.

C. Environmental Considerations for Construction Projects

1. Introduction

The quest by the developing nations of the world for higher standards of living often involves the deliberate modification of the natural environment to achieve economic objectives. However, construction of roads, dams, airports, irrigation and sewage systems, water and power plants, and industrial facilities sometimes results in concomitant losses of ecological or social/cultural values. Such losses, which vary widely in magnitude, may be the result of failure to adequately consider environmental consequences during project planning and design; the lack of knowledge and information necessary to predict the eventual impact; or the absence of cost-effective environmental safeguards or economically-competitive project alternatives even if undesirable effects are forecast.

Regardless of why the losses are incurred, it is essential that all who are involved in a proposed project--planners, decision-makers, engineers, lending institutions--have as clear an understanding as possible of the potential environmental consequences of a development activity at an early stage of project planning. Based on such knowledge, it may be possible to mitigate or prevent undesirable effects by incorporating pollution control technologies, redesigning the project, or selecting another site. In those instances where the magnitude of the impact is judged to be extreme, the environmental analysis may indicate that an alternative to the proposed development activity is warranted.

It is within this context that the following Environmental Considerations have been prepared for construction projects typically financed by international development institutions. They are designed to serve as general points of departure

for analyzing the potential environmental conquences of proposed projects. Used in conjunction with the information sources cited, they are useful indicators of the types of expertise and information required for the development of procedures and guidelines for systematic review and consideration of environmental factors. This, in turn, should lead to more rational decision-making based on a clearer understanding of total short and long-term project costs in relation to anticipated benefits.

It should be recognized that the Considerations identified herein should be individually tailored to respond to the unique physical, economic, and social conditions encountered in a particular project. For example, roads that are constructed in arid regions of the world clearly affect that environment differently than those through tropical rain forests. In some instances, individual Environmental Considerations may not be relevant to a specific project being planned or reviewed.

2. Desalting and Power Plants: Fossil Fuel, Hydro and Nuclear

a. What site selection criteria will be used? Will they include environmental considerations such as effects on air and water quality, noise and the resulting impact on residents of the area, fish, wildlife and vegetation? Will alternative sites and alternative orientations of the plant on the selected site be considered?

b. What disposition will be made of solid and liquid residues (ashes, chemical and nuclear wastes)? Does the disposal method include adequate cassetting or neutralization to minimize the danger of soil or water pollution? What steps are planned to contain and reclaim ash dumps, chemical and oil spills to avoid pollution of surface and ground water by acid-laden runoff? What provision has been made for the disposal of waste concentrated brines? If waste and concentrated brine disposal

into water bodies is planned, what will be the effects on aquatic life? To what degree will tidal action and currents dilute plant effluents? What disposition will be made of potentially harmful corrosion products occurring in the plant effluents? Can brines be evaporated to dryness? Can they be injected into underground aquifers? What provision will be made for controlling the release of radioactive waste material into water bodies? If additional units are constructed, what will the total load of radioactive waste materials be? Is the makeup of the plant's gaseous emissions known in terms of chemistry and volume? What downwind environmental effects can be anticipated with respect to humans, crops, forests, and wildlife? How can such effects be minimized?

c. What impact will thermal effluents have on the receiving waters? What temperature increase can be anticipated and how will this affect indigenous biota? Is there sufficient water motion in the receiving bodies to dissipate heat effectively? Has the use of cooling towers been sufficiently explored? What is the probability of producing undesirable fog conditions through the dissipation of waste heat?

d. What impact will the impoundment for a hydroelectric plant have in terms of the destruction of agricultural and forest lands and habitat for fish and wildlife? What measures are planned to mitigate the loss of natural habitats for fish and wildlife? To what degree will archaeological and scenic values be affected? How will the reservoir and downstream flow affect water quality parameters, i.e., temperature, dissolved oxygen, nutrients, nitrogen concentration, hydrogen sulfide, and color?

e. How vulnerable is the facility to surface subsidence, earthquakes, hurricanes, and other catastrophes? What is the extent and impact of the environmental degradation which could be expected in the event of such catastrophes? What preventative

and remedial safeguards for downstream inhabitants will be incorporated in plant design and construction? What provisions are made for training plant operators in environmental protection?

f. Have the environmental consequences of pipeline and power transmission been considered in site selection? What steps are planned to avoid soil erosion and the silting of streams as pipelines, transmission facilities and access roads are constructed?

g. What provision has been made for industrial and by-product development associated with the facility? What impact will that activity have on the environment?

D. References

Documents:

1. Electric Power and the Environment, 1970. (Executive Office of the President, Office of Science and Technology).

2. Environmental Criteria for Electric Transmission Systems, 1970. (U.S.Departments of Interior and Agriculture).

3. Environmental Effects of Producing Electric Power, Parts I, II, III, 1969-70. (Record of Hearings by the Joint Committee on Atomic Energy, Congress of the United States, 91st Congress).

4. Civil Works Construction Guide Specification for Environmental Protection, CE-1300, 1970. (Corps of Engineers, Department of the Army).

5. Report of the Committee on Water Quality Criteria, 1968. (U.S.Department of Interior, Federal Water Pollution Control Administration).

6. Air Quality Criteria (5 volumes) for (1) Photochemical

Oxidants; (2) Hydrocarbons; (3) Particulate Matter; (4) Carbon Monoxide; and (5) Sulfur Oxides, 1970. (U.S.Department of Health, Education, and Welfare, Public Health Service).

7. Disposal of Brine Effluents from Inland Desalting Plants; Review and Bibliography: OSW R&D Progress Report #454 (Supt. of Documents) Washington, D.C. $1.75.

8. TA/OST/71-1 Environmental Considerations for Construction Projects - OST/AID Washington, D.C.

9. Volume II, this manual, section IX - The Water Development Plan.

Agency Contacts:

10. Assistant Director of Civil Works for Planning and Environmental Programs, Corps of Engineers, Department of the Army, Washington, D.C. 20314.

11. Assistant to the Commissioner for Ecology, Bureau of Reclamation, U.S. Department of the Interior, Washington, D.C. 20240.

12. Office of Environmental Affairs, Atomic Energy Commission, Washington, D.C. 20545.

X. SELECTION OF MOST PROMISING SOLUTION

1. Preliminary Feasibility Study

Volume II, Section X, gave instructions for a preliminary feasibility study of seawater conversion from which the following Summary and Check List have been prepared. The original document should be referred to for all details. However, all nomograms and instructions necessary for the budget pricing of distillation plants, as given by Volume II, are reproduced for convenience in Appendix C of this Supplementary Manual.

A. Summary of Volume II Information

Include and compare for all alternatives studied:

1. Unit Water Costs, $/Kgal
2. Time schedules for availability of incremental water
3. Uncertainties in technology requiring additional information
4. Secondary benefits, possible by-products and enhancement of region under development
5. Specific recommendation of preferred alternative, plant capacity and performance
6. Time schedule for planning detailed design, completion of construction and commercial operation
7. Scope of work for detailed feasibility study by Architect-Engineer
8. All data necessary if A.I.D. review and approval is desired. (These should include the results of an environmental impact survey.)

B. Checklist for Coastal Desalting Plants from Volume II

1. Capital Cost Factors
   a. Local labor, equipment, materials and other costs (in U.S. Dollars)
   b. Imported labor, equipment, materials and other costs (in U.S. Dollars)
   c. Special local problems which increase capital costs.

2. Annual Cost Factors
   a. Interest and financing rates
   b. Expected lifetime of facility
   c. Assumed depreciation method and salvage value
   d. Costs of fuel, electricity, steam, etc.
   e. Operating and maintenance labor and supplies
   f. Assumed periodic replacement rates of components.
   g. Taxes and insurance.

3. Unit Cost of Water: Based on realistic average load factors over the lifetime of the facility, and suitable coupling parameters in the case of dual purpose plants.

4. Practicability Consideration: Based on years of proven commercial reliability of method or process.

5. Satisfactory Water Development Timetable: Anticipated costs of over-and-under supply as a function of time.

C. Additional Items for Updating Volume II Check List

1. Costs of water source development and transmission.

2. Costs of brine concentration and disposal.

3. Costs of any necessary environmental enhancement factors involving:

   a. Heat release.
   b. Noise reduction.
   c. Air, source and receiving water quality.
   d. Conservation of land and natural resources.
   e. Nuclear and fossil fuel materials handling.
   f. Liquid and solid waste disposal.

D. Inland Desalting Plants and Brackish Water Conversion

Volume II, Section X-A2, contains a detailed outline, together with estimating sheets, for a preliminary feasibility study of desalination by multi-stage flash evaporation at a coastal site. The desalting plant, whether or not it is associated with a steam-electric generating station, will require the circulation of large volumes of cooling water, and does not have any great problems associated with the disposal of concentrated brine resulting from seawater conversion. Thus, the desalting plant costs, while they seem to apply with sufficient accuracy for either the MSF or the VTE process and their hybrids at a coastal site as given in Appendix C by Figure C-1, Unit Desalination Plant Capital Cost Nomograph, will not be applicable at inland desalting plants, where cooling water is at a premium and brine disposal constitutes a serious problem.

Figure C-1 can be used for pricing MSF/VTE combinations at inland locations, provided that the above two problems do not exist. However, to bring the 1967 costs, so obtained, to a March, 1972 basis, they must be multiplied by the factor 1015/666 = 1.51 (Engineering News Record Building Cost Indices for March, 1972 and 1967, respectively). In addition, for MSF plants using upgraded construction (cupro-nickel lined shells in place of a corrosion allowance on carbon steel), which the U.S. Navy experience at Guantanamo, Cuba seems to indicate is necessary to prevent corrosion, a further 20% increase in cost would be required. This is an added reason why large size distillation plants do not appear attractive at inland sites by comparison to the membrane processes, which do not suffer from corrosion problems.

For budget pricing of membrane systems, vapor compression systems, and freezing systems, all of which seem very attractive at inland sites because of their smaller energy and cooling requirements, the reader is referred to the detailed procedures and instructions in Desalting Cost Calculating Procedures (OSW R&D Progress Report No. 555), the Reverse Osmosis section of which

is reprinted for quick reference in Appendix C of this Manual. Reverse Osmosis has been selected because in its new variety of configurations it is the most readily adaptable process for inland water plants up to 10 mgd throughput capacity, and it is the one with which any other proposed process must compete in order to be viable.

In short, we have two pricing methods at our disposal:

1. The Figure C-1 method, reproduced herein in Appendix C, which is suitable for pricing large distillation plants at coastal locations, and,

2. The Reverse Osmosis method, which has been abstracted from OSW R&D Report No. 555, which yields a base price for desalting plants, including feed pretreatment and brine disposal at inland locations. (See Appendix C).

For more accurate pricing, so as to allow a cost comparison at either coastal or inland sites of the competing desalting processes, one should procure OSW R&D Report No. 555 from the Superintendent of Document U.S. Government Printing Office, Washington, D.C. The price is $1.25. From this report, Table X-1 lists the capacities and salinity ranges for which the different processes are best suited. Table X-2 lists the input data required at either coastal or inland sites. (13)

To select the most promising solution for a given site, one should proceed as follows:

1. Complete Table X-2 for local conditions.

2. From Table X-1 select the practicable processes,

3. Determine expected capital cost ranges for these processes from Tables X-3, 4, and 5.

4. Follow instructions in Appendix C to obtain both capital and operating costs for the selected alternatives.

TABLE X-1.

SUMMARY OF GUIDELINES FOR DESALTING PROCESS SELECTION

Process	Design capacity (mgd) vs time period			Feed water characteristics presently favorable to economic applications		
	1972	1980	2000-2020	TDS (ppm)	Hardness	Temperature
Multistage Flash Distillation (MSF)	to 60	250	1/	10,000-50,000	soft	cold
Vertical Tube Evaporator-Multistage Flash Distillation (VTE-MSF)	to 10	50	1,000	10,000-50,000	soft	cold
Vapor Compression-Vertical Tube Evaporator-Multistage Flash Distillation (VC-VTE-MSF)	to 1	10	250	10,000-50,000	soft	warm
Vacuum Freeze-Vapor Compression (VF-VC)	to 1	5	2/	5,000-50,000	hard or soft	cold
Reverse Osmosis (RO)	to 3	50	2/	1,000-10,000	soft	warm
Electrodialysis (ED)	to 10	50	2/	1,000- 5,000	soft	warm
Ion Exchange (IX)	to 10	2/	2/	0- 2,000	soft	warm

1/ VTE-MSF is expected to supersede MSF for large plants by this time period.
2/ Technological developments will govern size in this time period.
3/ A (Applicable).
4/ NA (Not Applicable).
Source: USBR

Normal product water TDS (ppm)	Principal energy sources or prime movers applicable to process					Startup rar
	Low-pressure steam (under 50 psi-a)	High-pressure steam (over 100 psi-a)	Electricity	Diesel engines or gas turbines	Remarks	
5-50	A 3/	NA 4/	NA	NA		Slow
5-50	A	NA	NA	NA		Slow
5-50	NA	A	A	A	Four alternatives for the vapor compressor driver	Moderate
300-500	NA	A	A	A	Four alternatives for refrigeration and vapor compressor drivers	Moderate
100-500	NA	A	A	A	Four alternatives for the pump driver	Fast
350-500	NA	NA	A	NA		Fast
0-500	NA	NA	A	NA		Fast

Selection of Processes to Be Considered (From OSW R & D Progress Report No. 555)

Plant capacity and feedwater salinity limits for each process contained in this manual are listed in Table I. For valid results, the plant capacity and feedwater salinity must be within the prescribed ranges for the process selected. This is not to say that desalting plants cannot be smaller or larger, or cannot process feedwaters outside of the salinity ranges given. Rather, it means that cost data needed are not necessarily included in this manual. Two additional limitations exist for all processes: the feedwaters must contain less than 600 ppm calcium and less than 0.5 ppm hydrogen sulfide.

Table X

VALIDITY LIMITS OF THIS MANUAL

Process	Size Range, MGD	Salinity Range, TDS
Electrodialysis	0.144–10.0	1,000– 6,000
Reverse Osmosis	0.1 –10.0	1,000–10,000
Multistage Flash Distillation	1.0 –50.0	1,000–50,000
Vapor Compression-Vertical Tube Evaporator-Multistage Flash	1.0 –20.0	1,000–50,000
Vacuum-Freezing Vapor-Compression	0.1 – 5.0	1,000–50,000

Input Data Required

The input data required for the various complexes are shown in Table II. For the convenience of the reader, this table has been designed to serve as an input data form. All of the data shown are required (with the exceptions noted below Table II) for calculating the costs of any desalting system discussed in this manual.

Assumptions and Rationale

Load factor. On the recommendation of the Office of Saline Water, a plant load factor of 90 percent has been used. In other words, the plant is assumed to operate at full capacity 90 percent of the time. We have used 330 days per year as annual operating time in this manual.

Table X-2

INPUT DATA REQUIRED

Plant size–MGD (Volume of desalted water desired) . . . . . ____
Interest rate for financing, percent . . . ____
Current building cost index . . . . . ____
Current labor cost index . . . . . ____
Electric power cost–¢/KWH . . . . . ____
Fuel cost–cents per million Btu . . . . ____
Feedwater well pumping depth–ft . . . ____
Brine disposal well depth–ft . . . . . ____

Feedwater analysis (minimum data required)
Total dissolved solids–ppm . . . . . ____
Sodium and potassium–ppm (1, 2, 3, 4) . ____
Chloride–ppm (1, 2, 3, 4) . . . . . ____
Calcium–ppm (maximum allowed, 600 ppm) . . . . . ____
Iron–ppm (2, 3, 4) . . . . . ____
Manganese–ppm (2, 3, 4) . . . . . ____
Hydrogen sulfide–ppm (maximum allowed, 0.5 ppm) . . . . . ____
Temperature–°F (1, 2, 3) . . . . . ____

Land costs–$/acre
Feedwater supply . . . . . ____
Desalting plant . . . . . ____
Brine disposal facilities . . . . . ____
Right-of-way for pipelines . . . . . ____

Water transmission distance–miles
From feedwater supply to desalting plant ____
Desalting plant to city . . . . . ____
Desalting plant to brine disposal facilities. ____

Water transmission elevations–ft
Feedwater supply . . . . . ____
Desalting plant . . . . . ____
Municipality . . . . . ____
Brine disposal facilities . . . . . ____

1–Not required for RO
2–Not required for MSF
3–Not required for VC-VTE-MSF
4–Not required for VFVC

TABLE X-3. ESTIMATED INSTALLED COST OF MSF AND VTE DISTILLATION PLANTS*
(Cost in $/gpd of Installed Capacity)**

Capacity (MGD)	Performance Ratio (lb/1000 Btu) 6	10	14
0.1	1.80-2.00	2.40-2.60	2.75-3.00
0.5	1.40-1.60	1.90-2.10	2.40-2.60
1.0	1.15-1.25	1.50-1.60	2.20-2.30
5.0	0.90-1.00	1.10-1.20	1.60-1.75
10.0	0.75-0.85	0.90-1.00	1.30-1.40
50.0	0.60-0.70	0.75-0.85	1.05-1.15
100.0	0.55-0.65	0.70-0.80	0.95-1.00
250.0	0.50-0.60	0.65-0.75	0.85-0.95

* Cost of brine disposal and taxes not included.

** March 1972 prices for VTE and March 1969 prices of MSF.

Source: Reference #58

TABLE X-4. ESTIMATED INSTALLED COST OF MEMBRANE PLANTS*
(Cost in $/gpd of Installed Capacity)

Capacity (MGD)	Electrodialysis 1000 ppm Feed	Electrodialysis 2000 ppm Feed	Electrodialysis 3000 ppm Feed	Reverse** Osmosis (3000 ppm)
0.5	0.68-0.74	0.84-0.92	1.17-1.23	0.92-1.0[illegible]
1.0	0.62-0.68	0.77-0.84	1.05-1.17	0.80-0.9[illegible]
5.0	0.40-0.47	0.52-0.59	0.68-0.74	0.49-0.6[illegible]
10.0	0.31-0.37	0.40-0.47	0.49-0.62	0.43-0.4[illegible]
25.0	0.27-0.32	0.33-0.40	0.43-0.50	0.37-0.4[illegible]
50.0	0.23-0.28	0.27-0.33	0.37-0.43	0.35-0.4[illegible]
100.0	0.22-0.27	0.25-0.31	0.31-0.37	----

TABLE X-5. ESTIMATED INSTALLED COST OF VAPOR COMPRESSION (VC) AND FREEZING PLANTS (VFVC)**
(Cost in $/gpd of Installed Capacity)

Capacity MGD	
0.1	3.20-3.70
0.5	2.35-2.80
1.0	1.85-2.16
5.0	1.54-1.85

*Cost of brine disposal and taxes not included. March 1972 prices.

**Based on 60 percent recovery ratio. March 1972 prices.

Source: Reference #58

E. Use of Sewage Effluent and Irrigation Return Flow

Where a sizeable inland community exists it is possible to use the secondary sewage effluent for irrigation, provided crops are not raised which are eaten raw. An example of this practice is Tucson, Arizona, where the water is reused 100% on domestic crops. When irrigation is conducted in an arid region, however, over-irrigation must be provided so as to create a net runoff that prevents salt building.

Reverse osmosis, followed by a crystallizing VC unit (as described in Sec. IV-D), or by an electrodialytic concentrator, can drastically reduce the volume of these irrigation runoffs. At the same time, it will augment the water supply by providing potable water for reuse. For disposal the brine can go to subsurface injection or to evaporation ponds, the cost of which can be estimated by the methods shown in Appendix C. The irrigational use of municipal wastewater removes the heavy impurities and organic loadings that make it difficult to handle by the conventional desalting methods. In this way, desalting serves to furnish economical water for irrigation, though indirectly.

In 1967, a cooperative research study on the value of desalted water for irrigation was undertaken by the Bureau of Reclamation and the Office of Saline Water. The report was completed in 1969 and concludes that prospects for desalting saline irrigation water supplies are most favorable in areas capable of producing crops that yield high net farm incomes under almost year-long growing seasons. The work, as originally performed compared multi-stage flash evaporation and electrodialysis in three irrigated areas, but it is now being extended to compare the new VTE/MSF and reverse osmosis processes. (8)

2. Detailed Feasibility Study of Selected Solution

A. General

A detailed engineering feasibility and economic study having the following objectives and content should be carried out on the alternative (or alternatives) selected in the preliminary feasibility studies as the most promising solution (or solutions) to the water shortage problems of a country or region. The Study Organization should assign the performance of this detailed study to an architect-engineer firm, selected on the basis of its qualifications to perform the type of study required and its experience in the related technology.

B. Objectives

The objectives of this study would be:

1. To perform a detailed evaluation of the selected alternative (or alternatives), so that a decision on a specific proposed project can be made.

2. To develop all necessary technical, environmental and economic data on the proposed project, so that the financing agencies can evaluate requests for funding.

C. Scope

The initial step in this study should be a compilation of all necessary data. Much of these data would already be included in the Water Development Plan document; however, more specific information may be required in certain areas. Included in the Appendix is a Questionnaire which contains a comprehensive listing of the data required in performing a detailed engineering feasibility and economic study on a seawater desalination plant.

The detailed feasibility study should include:

1. The conceptual design for the plant and the selection of plant capacity, based on the water and environmental requirements in the area and the characteristics and limitations of the plant and site.

2. The solicitation and evaluation of preliminary proposals on equipment designed to meet the requirements of the conceptual design.

3. The evaluation of available sites for the plant, and the selection of preferred sites for preliminary plant layouts.

4. The identification of the possible problems associated with the construction of a plant on each of the preferred sites.

5. The analysis of the program schedule and the preparation of a more detailed schedule for the design and construction of the plant.

6. The preparation of the capital and annual cost estimates, and completed conceptual designs and plant layouts.

7. The selection of a probable plant operating factor, and the preparation of the unit water cost estimate.

8. A preliminary analysis of the construction and manufacturing problems which might be encountered in the construction of the proposed plant in the particular country or region.

9. A determination of the amount of local equipment, labor and materials which might be utilized in the construction and operation of the plant.

10. A report containing a summary of all the information developed in the study and recommendations for further action.

D. Subsequent Action

If, after review of the results of the engineering feasibility and economic study, the Agency using this Manual decides to proceed with the project and to request assistance from AID, it should prepare the material necessary to request this assistance; this would include preparation of the Economic and Technical Soundness Analysis, an Environmental Impact Analysis and the calculation of Benefit/Cost ratios

in the form required by AID. This material would be based primarily upon the information developed in the engineering feasibility and economic study. References may also be made to the surveys of background information included in the Water Development Plan.

LIST OF REFERENCES

Reference number	OSW R&D Progress Report number	Title or description
1	175	"Study of the Optimum Brine Heater Outlet Temperature in Sea Water Conversion Evaporators"-P. M. Rapier, Bechtel Corp., October 1965
2	264	"Guidelines for Uniform Presentation of Desalting Cost Estimates," Ralph M. Parsons Co., July 1967
3	316	"A Study of Disposal of Effluents From Large Desalting Plants," Dow Chemical Company, January 1968
4	415	"Disposal of Effluents from Desalination Plants into Estuarine Waters," Dow Chemical Company, March 1969
5	425	"A Cost Effectiveness Study on Pretreatment Methods Suitable for Integration to Membrane Desalting Plants," Kneale & Kelley, 1969
6	437	"Disposal of Effluents from Desalination Plants: The Effects of Copper Content, Heat and Salinity," Dow Chemical Company, March 1969
7	456	"Study of Deep Well Disposal," Dow Chemical Company, June 1969
8	489	"The Value of Desalted Water for Irrigation" Bureau of Reclamation, Denver, Colo., June 1969
9	490	"MSF Desalting State of the Art (1968)," Hittman Associates, Inc., October 1969
10	491	"VFVC Desalting State of the Art (1968)," Hittman Associates, Inc., October 1969
11	495	"Cost Analysis of Six Water Desalting Processes," Standford Research Institute, November 1969
12	528	"Optimum Operation of Desalting Plants as a Supplemental Source of Safe Yield," Utah State University, April 1970
13	555	"Desalting Cost Calculating Procedures," Southwest Research Institute, May 1970
14	570	"Bolsa Island Nuclear Power and Desalting Project Facilities (Cost and Description) and Cost of Desalted Water," Metropolitan Water District of Southern California, August 1970

15	580	"Evaluation of the Vertical Tube Evaporator and Multistage Flash Desalination Processes," The Fluor Corp., August 1970
16	587	"Systems Analysis of Brine Disposal from Reverse Osmosis Plants," Dow Chemical Company, August 1970
17	588	"Brine Disposal Pond Manual," Bureau of Reclamation, August 1970
18	610	"Electrodialysis Desalting State-of-the-Art (1969)," Hittman Associates, Inc., October 1970
19	611	"Reverse Osmosis Desalting State-of-the-Art (1969)," Hittman Associates, Inc., October 1970
20	616	"Survey of Ion Exchange Process for Desalination Applications," Control Systems Research, April 1970
21	617	"Economics of Combining Distilled Seawater and Renovated Waste Water," Bechtel Corporation, October 1970
22	634	"Cost of Steam Supply for Desalting Using Coal Fired Boilers," Sanderson and Porter, Inc., December 1970
23	638	"Economic Analysis of the Membrane Water Desalting Processes," Standford Research Institute, December 1970
24		"Special Report on Status of Desalting," ORNL and OSW for Pacific Southwest Inter-agency Committee, November 1970
25		"Water Users' Handbook of Desalting Processes," Hittman Associates, Inc., for OSW, publication pending
26		"Desalting as a Source of Water Supply," by E.F. Miller, paper delivered at the Denver meeting of AWWA, June 1971
27		"Briefing Session for the Desalting Industry," OSW, June 1971
28		"A Mathematical Model for Evaluating the Potential of Desalting," T.W. Rothermel, M.S. Sachs, and F. O'Shaughnessy, AWPA paper, October 1970
29		Universal Design: "Report on Design of a 2.5 MGD Universal Desalting Plant," Burns and Roe, INC. for Office of Saline Water U.S.D.I., Washington, D.C. Vols. I-V, July 1968.

30 "Studies of the Use of Desalted Water in Conjunction with Existing Natural Water Sources," S. Shiozawa and T. Spiewak, paper presented at the International Atomic Energy Agency Panel of Experts on Storage and Transport of Water from Nuclear Desalting Plants, April 1971

31 "A Study of Conjunctive Operation of Nuclear Dual Purpose Desalting Plants to Serve the New York City Metropolitan Region," by S. Shiozawa, paper presented at the International Atomic Energy Agency Panel of Experts on Storage and Transport of Water from Nuclear Desalting Plants, April 1971

32 "The Design of Water Supply Systems Based on Desalination," United Nations, New York, 1968

33 "Manual on Water," ASTM, STP No. 442, Third Edition

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35 "Sea Water Demineralization by Means of an Osmotic Membrane," S. Loeb and S. Sourirajan, Saline Water Conversion II, Advances in Chemistry Series No. 38, American Chemical Society, Washington, D.C. 1963

36 "Betz Handbook of Industrial Water Conditioning," Sixth Edition

37 "Water Quality and Treatment," the American Water Works Association, Third Edition

38 "Water Treatment for Industrial and Other Uses," E. Nordell, Second Edition

39 "Case Studies of Desalted Water for Irrigation," USBR and OSW, publication pending

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42 Cost data furnished with letter dated 12-2-68 to OSW from Union Carbide Corporation

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47 "New Water," OSW, 1970

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49 "Economics of Ion Exchange Technology for Municipal Water Quality Improvement," Bresler and Associates, Inc., OSW contract No. 14-30-2701, publication pending

50 "A Cost Allocation Procedure for Dual Purpose Power-Desalting Plants," C. C. Burwell and R. P. Hammond, Oak Ridge National Laboratory TM-1615, November 1966

51 462 "Communities of Over 1000 Population with Water Containing in Excess of 1000 ppm of Total Dissolved Solids," Black and Veatch, October 1969

52 "Water Quality and Treatment," AWWA Manual, 2nd Edition, 1950

53 "Solubility and Thermodynamic Relationship for $CaSO_4$ in $NaCl-H_2O$ Solutions from 40° to 200° C, 0 to 4 Molal NaCl," Marshall and Slusher, Journal of Chemical and Engineering Data, Vol. 9, p 187, 1964

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55 "Desalting Plants Inventory Report No. 3" - Frank O'Shaughnessy, Office of Saline Water, USDl Jan 1, 1970

56 "Potential Contribution of Desalting to Future Water Supply in New Mexico" - OSW and Office of State Engineer, State of New Mexico, July 1971.

57 "Ultimate Disposal of Brines from Municipal Wastewater Renovation" - P.M. Rapier - WATER 1970 - AIChE CH.E. Progress Symposium Series #107, Vol. 67, 1971, pp 340-351

58 Private communications from - Bureau of Reclamation and Office of Saline Water, USDI, May 1972

EXPLANATION OF CODES AND SYMBOLS

Key

CAPACITY

Total plant capacity in 1,000 U.S. gallons per day

UN

Unit-one complete unit and no stack or module thereof

STATUS

C - Plant under Construction
O - Plant in Operation

TYPE OF PROCESS

Distillation

F - Single-stage Flash-Distillation
MSF - Multi-stage Flash-Distillation
VTE - Long Tube Vertical
ST - Submerged Tube
VC - Vapor Compression

Membrane

ED - Electrodialysis
RO - Reverse Osmosis

Freezing

VF - Vacuum Freezing-Compression

YEAR

Year of beginning operation and/or year when construction was initiated.

WATER FEED

SW - Sea Water
ISW - Inland or Brackish Water

USE

MPA - Municipal
IND - Industrial
P - Power
TOUR - Tourism
DEMO - Demonstration
MIL - Military
M&IN - Municipal and Industrial

SD - SINGLE OR DUAL PURPOSE

W - Water plant only
WP - Water and Power

FUEL

GAS
OIL
COAL
URAN - Uranium
STM - Steam
ELEC - Rubbish
RUB - Cooling water and exhaust gases from diesel-engine
CW

Manufacturers Code

Aerojet General (Envirogenics)	02
Alton Co., Ltd., England	03
Alsthom, France	06
Aluminum Co of American	05
American Machine & Foundry Co., USA	07
Aqua-Chem, Inc., USA	11
Asahi Chemical Ind. Co., Ltd., Japan	15
Atlas-Mak Maschinenbau GmbH, West Germany	19
Babcock & Wilcox, Spain	20
Baldwin-Lima-Hamilton Corp., USA	22
Boby, England	26
British Aqua Chem, Ltd., England	27
Buckley & Taylor, Ltd., England	29
Chicago Bridge & Iron, USA	32
Colt Industries, USA	35
Compagnie Electro-Mechanique-SCAM, France	37
Condenseurs Delas, France	38
Continental Engineering	47
DEMAG, West Germany	39
De Pretto-Escher Wyss, Italy	40
Desalination Engineering, Ltd., Israel	44
du Pont Company, USA	45
Foster-Wheeler Corp., USA	46
Franco Tosi, Italy	48
George Clark & Sons, England	51
Gulf General Atomic, USA	53
Ionics, Inc., USA	55
Ishikawajima-Harima Heavy Industries Co., Ltd. Japan	59
The Lummus Co., USA	63
Lurgi, West Germany	67
Mechanical Equipment Co., USA	71
Negev Inst., Israel	72
Sasakura Engineering Co., Japan	73
Selas Corporation of America, USA	75
Sidem, France	76
Stearns-Roger Corp., USA	77
Struthers SC. International Co., USA	79
Union of Soviet Socialist Republics (USSR)	81
Universal Desalting, USA	82
Weir Westgarth, England	87
Werkspoor-Amsterdam V., Holland	91
Westinghouse, USA	95

REGION

NORTH AMERICA (U.S.)

COUNTRY/STATE	IC	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SC	FUEL
ALABAMA	1020	MOBILE	230.0	02	C	ST	1953	22				
ALASKA	1030	POINT BARROW (AF)	30.0	02	C	VC	1963	11	ISW	MIL	W	OIL
ALASKA	1040	FAIRBANKS	100.0	01	C	ST	1954	22				
ALASKA	1050	KOTZEBUE	30.0	04	C	VC		71				
ARIZONA	1060	BUCKEYE	650.0	3	C	ED	1962	55		MPAL	W	ELEC
ARIZONA	1080	HELENA	35.0	1	C	ST	1953	22				
ARIZONA	1090	TUSCON	45.0	2	C	ST	1953	22				
CALIFORNIA	1100	STOCKTON	65.0	1	C	ST	1936	22				
CALIFORNIA	1110	PITTSBURGH	180.0	2	C	ST	1966	22				
CALIFORNIA	1120	REDONDO	100.0	1	C	ST	1956	22				
CALIFORNIA	1130	EL CENTRO	40.0	1	C	ST	1956	22				
CALIFORNIA	1135	SAN ONOFRE (NUCLEAR)	172.5	2	C	F	1966	55	SW	F	WP	URAN
CALIFORNIA	1140	HUMBOLDT BAY	60.0	1	C	ST	1955	22				
CALIFORNIA	1150	ETIWANDA	165.0	2	C	ST	1952	22				
CALIFORNIA	1160	VERNON	100.0	1	C	ST	1932	22				
CALIFORNIA	1180	MORRO BAY A-NO. 1	72.0	1	C	ST	1955	63	SW	P	WP	
CALIFORNIA	1190	MORRO BAY B-NO. 2	72.0	1	C	ST	1955	63	SW	P	WP	
CALIFORNIA	1200	MORRO BAY C-NO. 3	123.0	1	C	F	1962	55	SW	F	WP	GAS
CALIFORNIA	1210	MORRO BAY D-NO.4	123.0	1	C	F	1963	55	SW	P	WP	GAS
CALIFORNIA	1220	SANTEE	45.0	01	C	ED	1968	55	ISW	DEMO	W	ELEC
CALIFORNIA	1230	MOSS LANDING A-NO.6	188.0	1	C	F	1965	55	SW	F	WP	GAS
CALIFORNIA	1240	MOSS LANDING B-NO.7	188.0	1	C	F	1966	55	SW	P	WP	GAS
CALIFORNIA	1250	COALINGA	23.0	1	C	ED	1955	55	ISW	MPAL	W	ELEC
CALIFORNIA	1270	LOS ANGELES (A-HOMEWOOD)	100.0	1	C	VC	1947	11	ISW	IND	W	ELEC
CALIFORNIA	1275	LOS ANGELES	36.0	1	C	VC	1967	11	ISW	IND	W	ELEC
CALIFORNIA	1280	PASADENA	58.0	2	C	ST	1965	46	ISW	IND	W	
CALIFORNIA	1290	SAN DIEGO,CLAIR ENGLE MEMS	1,000.0	1	C	MSF	1967	11	SW	DEMO	WP	STM
CALIFORNIA	1291	SAN DIEGO EFFECT 1A	65.0	01	C	MSF	1965	11	SW	DEMO	WP	
CALIFORNIA	1300	SAN DIEGO SOUTH BAY NO. 2	57.6	1	C	F	1962	55	ISW	F	WP	GAS
CALIFORNIA	1310	SAN DIEGO SOUTH BAY NO. 3	57.6	1	C	F	1964	55	ISW	F	WP	GAS
CALIFORNIA	1320	SAN DIEGO TEST MODULE	2,600.0	1	C	MSF	1967	46	SW	DEMO	WP	STM
CALIFORNIA	1321	SAN DIEGO VTE-X	300.0	01	C	VTE	1965	11	SW	DEMO	W	
CALIFORNIA	1325	SOUTH LAGUNA	50.0	01	C	RE	1967	02	ISW	DEMO	W	ELEC
CALIFORNIA	1340	CONTRA COSTA A-NO. 6	104.5	1	C	F	1964	55	ISW	F	WP	GAS
CALIFORNIA	1350	CONTRA COSTA B-NO. 7	104.5	1	C	F	1964	55	ISW	P	WP	GAS
CALIFORNIA	1360	BURBANK	27.2	1	C	MSF	1943	79	ISW	IND	W	STM
COLORADO	1380	DENVER A	87.0	2	C	ST	1954	22				
COLORADO	1390	DENVER B	60.0	1	C	ST	1951	22				
COLORADO	1400	DENVER C	70.0	1	C	ST	1944	22				
COLORADO	1410	LACOMBE	140.0	1	C	ST	1952	22				
COLORADO	1420	CHEROKEE	75.0	1	C	ST	1960	22				
COLORADO	1430	VALMONT	50.0	1	C	ST	1961	22				
COLORADO	1440	CAMEO STATION	29.0	1	C	ST	1955	22				
CONNECTICUT	1450	MONTVILLE A	35.0	1	C	ST	1953	22				
CONNECTICUT	1460	MONTVILLE B	41.0	1	C	ST	1936	22				
CONNECTICUT	1480	DEVON A	40.0	1	C	ST	1957	22				
CONNECTICUT	1490	DEVON B	35.0	1	C	ST	1952	22				
CONNECTICUT	1500	DEVON C	25.0	1	C	ST	1944	22				
CONNECTICUT	1510	DEVON D	29.0	1	C	ST	1941	22				
CONNECTICUT	1520	NEW HAVEN	50.0	1	C	ST	1952	22				
CONNECTICUT	1530	STAMFORD	42.0	1	C	ST	1940	22				
CONNECTICUT	1540	HARTFORD	43.0	1	C	ST	1938	22				
CONNECTICUT	1547	WATERFORD	116.0	2	C	ST	1968	46	SW	IND	W	
FLORIDA	1560	KEY WEST	2,620.0	1	C	MSF	1967	55	SW	MPAL	W	OIL
FLORIDA	1565	SIESTA KEY	1,200.0	7	C	ED	1969	55	ISW	MPAL	W	ELEC
FLORIDA	1570	TAMPA	44.0	2	C	ST	1954	22				
FLORIDA	1580	JACKSONVILLE	45.0	1	C	ST	1956	22				
FLORIDA	1590	ORLANDO	50.0	1	C	ST	1954	22				
FLORIDA	1610	FLORIDA POWER & LIGHT A	40.0	1	C	ST	1958	22				
FLORIDA	1620	FLORIDA POWER & LIGHT B	70.0	1	C	ST	1954	22				
FLORIDA	1630	AVON PARK	31.0	1	C	ST	1952	22				
FLORIDA	1640	OLDSMAR	50.0	2	C	ST	1953	22				
FLORIDA	1650	ELLAVILLE	30.0	1	C	ST	1953	22				
FLORIDA	1660	RIVIERA STATION	41.0	1	C	ST	1944	22				
FLORIDA	1661	LONGBOAT KEY	80.0	08	C	PD	1965	45	ISW	MPAL	W	ELEC
GEORGIA	1670	YATES	115.0	1	C	ST	1957	22				
GEORGIA	1680	GEORGIA POWER	115.0	1	C	ST	1956	22				
GEORGIA	1690	KRANNERT	200.0	2	C	ST	1953	22				
HAWAII	1695	KAHE NO. 1	52.6	01	C	F	1962	95	ISW	F	WP	OIL
HAWAII	1696	KAHE NO.2	52.6	01	C	F	1964	55	ISW	F	WP	OIL
HAWAII	1697	KAHE NO.3	48.0	1	C	F	1968	55	SW	IND	WP	OIL
HAWAII	1698	KAHE NO.4	48.0	1	C	F	1968	55	ISW	F	WP	OIL
ILLINOIS	1710	SPRINGFIELD	31.6	1	C	MSF	1963	79	ISW	IND	W	STM
ILLINOIS	1720	STICKNEY	120.0	2	C	ST	1952	22				
ILLINOIS	1730	DIXON	60.0	1	C	ST	1952	22				
ILLINOIS	1750	HUTSONVILLE	52.0	1	C	ST	1953	22				
ILLINOIS	1770	CHICAGO A	200.0	2	C	ST	1944	22				
ILLINOIS	1780	CHICAGO B	145.0	2	C	ST	1938	22				
ILLINOIS	1790	CHICAGO C	144.0	2	C	ST	1940	22				
ILLINOIS	1800	CHICAGO D	145.0	2	C	ST	1940	22				
ILLINOIS	1810	CHICAGO E	80.0	1	C	ST	1936	22				
ILLINOIS	1820	MERIDOSIA	44.0	2	C	ST	1944	22				
ILLINOIS	1830	JOLIET	72.0	2	C	ST	1940	22				
ILLINOIS	1850	PEORIA A	41.0	1	C	ST	1939	22				
ILLINOIS	1860	PEORIA B	29.0	1	C	ST	1937	22				
INDIANA	1870	TANNERS CREEK	145.0	1	C	ST	1961	22				
INDIANA	1890	MISHAWAKA A	54.0	1	C	ST	1943	22				
INDIANA	1900	MISHAWAKA B	52.0	1	C	ST	1944	22				
INDIANA	1920	SOUTH BEND A	150.0	1	C	ST	1956	22				
INDIANA	1930	SOUTH BEND B	150.0	2	C	ST	1958	22				
INDIANA	1940	CAMPBELLS	50.0	1	C	ST	1953	22				
INDIANA	1950	LAWRENCEBURG	80.0	1	C	ST	1953	22				
INDIANA	1970	INDIANAPOLIS A	50.0	1	C	ST	1951	22				
INDIANA	1980	INDIANAPOLIS B	50.0	1	C	ST	1953	22				
INDIANA	1990	FAYETTE	100.0	2	C	ST	1952	22				
INDIANA	2000	TERRE HAUTE	35.0	2	C	ST	1939	22				
IOWA	2005	BURLINGTON	166.0	1	C	F	1968	55	ISW	P	WP	COAL
KANSAS	2010	HUTCHISON NO. 4	57.6		C	F	1965	55	ISW	P	WP	GAS
KANSAS	2015	LAWRENCE NO.5	132.5	1	C	F	1968	55	ISW	F	WP	COAL
KENTUCKY	2020	BIG SANDY NO. 1	116.5	01	C	F	1962	55	ISW	P	WP	COAL
KENTUCKY	2030	OWENSBORO NO. 2	57.5	01	C	F	1964	55	ISW	P	WP	COAL
KENTUCKY	2050	LOUISVILLE A	95.0	1	C	ST	1953	22				
KENTUCKY	2060	LOUISVILLE B	70.0	1	C	ST	1954	22				
KENTUCKY	2070	LOUISVILLE C	58.0	1	C	ST	1944	22				

COUNTRY/STATE	IC	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	LSE	SO	FUEL
KENTUCKY	2080	TVA PARADISE NO.1	209.0	1	C	F	1963	55	ISW	F	WP	COAL
KENTUCKY	2085	TVA PARADISE NO.2	209.0	1	C	F	1963	55	ISW	F	WP	COAL
KENTUCKY	2087	TVA PARADISE NO.3	173.0	1	C	F	1968	55	ISW	IND	WP	COAL
LOUISIANA	2100	NEW ORLEANS A	100.0	1	C	ST	1961	22				
LOUISIANA	2110	NEW ORLEANS B	35.0	1	C	ST	1953	22				
LOUISIANA	2120	NEW ORLEANS C	80.0	1	C	ST	1955	22				
LOUISIANA	2130	NEW ORLEANS D	31.0	1	C	ST	1941	22				
LOUISIANA	2140	NEW ORLEANS E	26.0	1	C	ST	1937	22				
LOUISIANA	2150	NEW ORLEANS F	67.0	1	C	ST	1944	22				
LOUISIANA	2160	KAISER CHEMICAL	120.0	8	C	ST	1953	22				
LOUISIANA	2170	HARVEY	35.0	1	C	ST	1952	22				
LOUISIANA	2180	LAKE CHARLES	58.0	2	C	ST	1943	22				
LOUISIANA	2185	WILLOW GLEN NO.4	144.0	1	C	F	1968	55	ISW	F	WP	GAS
LOUISIANA	2190	WILLOW GLEN NO.3	144.0	1	C	F	1968	55	ISW	F	WP	GAS
LOUISIANA	2192	ROY S. NELSON	144.0	1	C	F	1968	55	ISW	P	WP	GAS
LOUISIANA	2195	VENICE	216.0	1	C	MSF	1966	46	ISW	IND	W	
MASSACHUSETTS	2220	BRAYTON POINT A-NO. 1	111.0		C	F	1963	55	SW	F	WP	COAL
MASSACHUSETTS	2230	BRAYTON POINT B-NO. 2	111.0		C	F	1964	55	SW	F	WP	COAL
MASSACHUSETTS	2240	SPRINGFIELD	70.0	1	C	ST	1956	22				
MASSACHUSETTS	2250	NEW BEDFORD	25.0	1	C	ST	1944	22				
MASSACHUSETTS	2270	EVERETT A	44.0	1	C	ST	1944	22				
MASSACHUSETTS	2280	EVERETT B	87.0	2	C	ST	1941	22				
MASSACHUSETTS	2290	LYNN	26.0	1	C	ST	1942	22				
MASSACHUSETTS	2300	FALL RIVER	35.0	1	C	ST	1944	22				
MICHIGAN	2320	DETROIT A	25.0	1	C	ST	1935	22				
MICHIGAN	2340	DETROIT B	30.0	1	C	ST	1944	22				
MICHIGAN	2350	DETROIT C	30.0	1	C	ST	1940	22				
MICHIGAN	2360	DETROIT D	30.0	1	C	ST	1938	22				
MICHIGAN	2370	DETROIT E	30.0	1	C	ST	1937	22				
MICHIGAN	2380	DETROIT F	27.0	1	C	ST	1936	22				
MICHIGAN	2390	BELLE RIVER	140.0	2	C	ST	1952	22				
MICHIGAN	2400	PORT HURON	30.0	1	C	ST	1940	22				
MICHIGAN	2410	TRENTON	137.0	1	C	ST	1940	22				
MICHIGAN	2430	COMSTOCK A	41.0	1	C	ST	1940	22				
MICHIGAN	2440	COMSTOCK B	41.0	1	C	ST	1937	22				
MICHIGAN	2460	BAY CITY A	41.0	1	C	ST	1938	22				
MICHIGAN	2470	BAY CITY B	82.0	1	C	ST	1937	22				
MICHIGAN	2480	WYANDOTTE	35.0	1	C	ST	1931	22				
MINNESOTA	2490	ST. PAUL	43.0	1	C	ST	1959	22				
MINNESOTA	2500	MINNEAPOLIS	40.0	1	C	ST	1957	22				
MINNESOTA	2510	TACONITE HARBOR	87.0	2	C	ST	1955	22				
MINNESOTA	2520	CLECKLET	250.0	1	C	ST	1930	22				
MISSISSIPPI	2530	GULF COAST STATION	100.0	1	C	ST	1961	22				
MISSISSIPPI	2540	MISSISSIPPI POWER	85.0	1	C	ST	1956	22				
MISSOURI	2550	SIBLEY	43.0	1	C	ST	1960	22				
MISSOURI	2555	ASBURY NO.1	86.5	1	C	F	1968	95	ISW	IND	WP	COAL
MISSOURI	2560	KANSAS CITY	115.0	1	C	ST	1956	22				
MISSOURI	2570	RAYTOWN	43.0	1	C	ST	1959	22				
MISSOURI	2580	ST. LOUIS	115.0	1	C	ST	1936	22				
MONTANA	2590	HAVRE (AF)	56.0	1	C	FD	1956	55	ISW	MPAL	W	ELEC
MONTANA	2600	SYDNEY	40.0	1	C	ST	1957	22				
NEBRASKA	2620	OMAHA A	85.0	1	C	ST	1961	22				
NEBRASKA	2630	OMAHA B	42.5	1	C	ST	1930	22				
NEW JERSEY	2660	VINELAND	28.8	1	C	MSF	1959	79	ISW	IND	W	STM
NEW JERSEY	2670	ATLANTIC CITY	45.0	1	C	ST	1944	22				
NEW JERSEY	2680	CAMDEN	100.0	1	C	ST	1930	22				
NEW MEXICO	2690	ROSWELL	1,000.0	1	C	VC	1963	32				
NEW MEXICO	2700	JAL	84.0	1	C	ST	1959	22				
NEW MEXICO	2710	REEVES	25.0	1	C	ST	1959	22				
NEW MEXICO	2720	NICHOLS	43.0	1	C	ST	1960	22				
NEW MEXICO	2740	ALBUQUERQUE A	50.0	1	C	ST	1956	22				
NEW MEXICO	2750	ALBUQUERQUE B	40.0	1	C	ST	1959	22				
NEW MEXICO	2760	ALBUQUERQUE C	150.0	3	C	ST	1951	22				
NEW MEXICO	2770	FARMINGTON	75.0	1	C	ST	1953	22				
NEW MEXICO	2771	SOCORRO WHITE SANDS	100.0		C	FC	1969	55	ISW	NIL	W	
NEW YORK	2780	HENPSTEAD	450.0	4	C	ST	1964	07	SW	IND	W	RUB
NEW YORK	2810	ROCHESTER A	136.0	1	C	MSF	1947	79	ISW	IND	W	STM
NEW YORK	2820	ROCHESTER B	29.0	1	C	ST	1935	22				
NEW YORK	2830	ROCHESTER C	27.0	1	C	ST	1932	22				
NEW YORK	2840	JAMESTOWN	36.0	1	C	MSF	1959	79	ISW	IND	W	STM
NEW YORK	2860	FORT JEFFERSON A	115.0	1	C	ST	1961	22				
NEW YORK	2870	FORT JEFFERSON B	58.0	1	C	ST	1959	22				
NEW YORK	2880	FORT JEFFERSON C	115.0	1	C	ST	1959	22				
NEW YORK	2890	EARRET	115.0	1	C	ST	1961	22				
NEW YORK	2900	NIAGARA FALLS	500.0	3	C	ST	1956	22				
NEW YORK	2910	INDIAN POINT	500.0	2	C	ST	1959	22				
NEW YORK	2912	INDIAN POINT NO.2	144.0	1	C	F	1968	55	ISW	IND	WP	URAN
NEW YORK	2914	INDIAN POINT NO.3	144.0	1	C	F	1968	55	ISW	IND	WP	URAN
NEW YORK	2920	TOMKINS COVE	64.0	1	C	ST	1953	22				
NEW YORK	2930	ASTORIA	440.0	2	C	ST	1957	22				
NEW YORK	2940	STATEN ISLAND	220.0	1	C	ST	1957	22				
NEW YORK	2960	FAR ROCKAWAY A	60.0	1	C	ST	1952	22				
NEW YORK	2970	FAR ROCKAWAY B	50.0	1	C	ST	1951	22				
NEW YORK	2980	GLENWOOD LANDING	94.0	1	C	ST	1953	22				
NEW YORK	3000	GLENWOOD	50.0	1	C	ST	1954	22				
NEW YORK	3020	HUDSON A	82.0	1	C	ST	1952	22				
NEW YORK	3030	HUDSON B	64.0	1	C	ST	1952	22				
NEW YORK	3035	JUNIUS POND	40.0	1	C	FD	1968	55	ISW	TCUS	W	ELEC
NORTH CAROLINA	3040	WRIGHTSVILLE BEACH	50.0	1	C	MSF	1967	11	SW	CEMI	W	STM
NORTH CAROLINA	3050	WRIGHTSVILLE BEACH B	50.0	01	C	MSF	1969	22	SW	CEMI	W	OIL
NORTH CAROLINA	3070	WRIGHTSVILLE BEACH C	60.0	1	C	VFVC	1974	35	SW	CEMI	WP	ELEC
NORTH CAROLINA	3080	CHARLOTTE	50.0	2	C	ST	1952	22				
NORTH CAROLINA	3090	ASHEVILLE	60.0	1	C	ST	1951	22				
NORTH DAKOTA	3110	GRAFTON	100.0	1	C	ST	1931	22				
OHIO	3120	ASHTABULA	57.5	1	C	MSF	1965	79	ISW	IND	W	STM
OHIO	3130	CINCINNATI	29.0	1	C	ST	1938	22				
OHIO	3140	MUSKINGUM (OHIO POWER)	140.0	1	C	ST	1958	22				
OHIO	3150	A.E.P.	135.0	1	C	ST	1956	22				
OHIO	3170	KAMMER A	270.0	2	C	ST	1958	22				
OHIO	3180	KAMMER B	140.0	1	C	ST	1956	22				
OHIO	3200	DAYTON A	80.0	1	C	ST	1957	22				
OHIO	3210	DAYTON B	80.0	1	C	ST	1956	22				
OHIO	3220	DAYTON C	115.0	1	C	ST	1954	22				
OHIO	3230	PHILLIP SPORN STATION	75.0	1	C	ST	1958	22				
OHIO	3240	WILLOUGHBY	87.0	1	C	ST	1952	22				
OHIO	3250	RELIEF	166.0	2	C	ST	1952	22				
OHIO	3260	TOLEDO	60.0	2	C	ST	1952	22				
OHIO	3280	CLEVELAND A	90.0	1	C	ST	1953	22				
OHIO	3290	CLEVELAND B	44.0	2	C	ST	1940	22				

COUNTY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	REC	WF	LS	SC	FUEL
OHIO	3300	EHILE	54.0	2	D	ST	1941	22				
OHIO	3310	BRILLIANT	67.0	1	C	ST	1943	22				
PENNSYLVANIA	3330	PHILADELPHIA A	144.0	1	C	MSF	1960	55	ISW	F	WP	COAL
PENNSYLVANIA	3340	PHILADELPHIA B	100.0	1	C	MSF	1962	55	ISW	F	WP	COAL
PENNSYLVANIA	3350	PHILADELPHIA C	115.0	1	F	MSF	1950	79	ISW	IND	W	STM
PENNSYLVANIA	3360	PHILADELPHIA D	72.0	1	C	ST	1933	22				
PENNSYLVANIA	3370	MARCUS HOOK	300.0	1	C	ST	1958	55	ISW	F	WP	OIL
PENNSYLVANIA	3380	ELRAMA	35.0	1	C	ST	1953	22				
PENNSYLVANIA	3390	PITTSBURGH ALLEGA	122.0	1	C	ST	1958	22				
PENNSYLVANIA	3400	PITTSBURGH (PHILLIP SPORN)	30.0	1	C	ST	1955	22				
PENNSYLVANIA	3410	PITTSBURGH	440.0	1	C	MSF	1968	11	ISW	IND	W	STM
PENNSYLVANIA	3420	PITTSBURGH A	26.0	1	D	ST	1940	22				
PENNSYLVANIA	3430	PITTSBURGH B	28.0	1	C	ST	1937	22				
PENNSYLVANIA	3445	CLAIRTON	1,440.0	1	C	MSF	1969	55	ISW	IND	WP	COAL
PENNSYLVANIA	3450	SCRANTON	36.0	1	C	ST	1944	22				
PENNSYLVANIA	3455	MIDDLETOWN	87.0	2	C	ST	1944	22				
PENNSYLVANIA	3460	NEW CASTLE	41.0	1	C	ST	1937	22				
PENNSYLVANIA	3470	HERSHEY	100.0	1	C	ST	1930	22				
PENNSYLVANIA	3480	SPRINGDALE	52.0	1	C	ST	1944	22				
RHODE ISLAND	3500	PROVIDENCE A	41.0	1	C	ST	1940	22				
RHODE ISLAND	3510	PROVIDENCE B	44.0	1	C	ST	1944	22				
RHODE ISLAND	3520	NEWPORT	115.0	1	C	MSF	1943	79	SW	IND	W	STM
SOUTH CAROLINA	3530	GREENWOOD	55.0	1	C	ST	1957	22				
SOUTH CAROLINA	3540	COLUMBIA	41.0	1	C	ST	1940	22				
SOUTH DAKOTA	3570	WEBSTER	325.0	1	C	FD	1965	15	ISW	GENO	W	ELEC
TENNESSEE	3610	TVA BULL RUN NO. 1	169.0		C	F	1965	55	ISW	F	WP	COAL
TENNESSEE	3620	WIDOWS CREEK	210.0	1	C	ST	1965	22				
TENNESSEE	3630	GALLATIN	300.0	2	C	ST	1958	22				
TENNESSEE	3640	GALLATIN STATION	150.0	2	C	ST	1954	22				
TENNESSEE	3650	KINGSTON	300.0	4	C	ST	1952	22				
TENNESSEE	3660	KNOXVILLE	67.0	1	C	ST	1944	22				
TENNESSEE	3680	PLAIN A	60.0	1	C	ST	1949	22				
TENNESSEE	3690	PLAIN B	145.0	2	C	ST	1951	22				
TEXAS	3700	BEEFORT	1,000.0	1	C	VTE	1971	32	SW	GENO	W	
TEXAS	3710	FORT MANSFIELD	250.0	1	C	ST	1965	55	ISW	MFAL	W	
TEXAS	3720	CHOCOLATE BAYOU	762.0	1	C	MSF	1974	55	ISW	IND	WP	GAS
TEXAS	3730	HANDLEY NO. 3	144.0	11	C	F	1963	55	ISW	F	WP	GAS
TEXAS	3740	SWEENY	150.0	2	C	MSF	1958	79	ISW	IND	W	STM
TEXAS	3750	OAK CREEK	45.0	1	C	ST	1960	22				
TEXAS	3760	GRAND PRAIRIE	160.0	1	C	ST	1959	22				
TEXAS	3770	SEALY SMITH	25.0	1	C	ST	1959	22				
TEXAS	3790	EL PASO A	30.0	1	C	ST	1956	22				
TEXAS	3800	EL PASO B	40.0	1	C	ST	1956	22				
TEXAS	3810	EL PASO C	75.0	1	C	ST	1952	22				
TEXAS	3820	SHERRIN	35.0	1	C	ST	1953	22				
TEXAS	3840	DALLAS A	74.0	1	C	ST	1957	22				
TEXAS	3850	DALLAS B	55.0	1	C	ST	1954	22				
TEXAS	3860	DALLAS C	50.0	1	C	ST	1952	22				
TEXAS	3870	HOUSTON	50.0	1	C	ST	1955	22				
TEXAS	3875	BROWNSVILLE	288.0	1	C	MSF	1968	22	SW	IND	W	OIL
TEXAS	3880	FORT STOCKTON	40.0	1	C	ST	1953	22				
TEXAS	3890	PECOS COUNTY	45.0	1	C	ST	1954	22				
TEXAS	3900	AUSTIN	55.0	1	C	ST	1954	22				
TEXAS	3910	SANDOW	214.0	3	C	ST	1952	22				
TEXAS	3920	EASTON	45.0	1	C	ST	1952	22				
TEXAS	3930	AMARILLO	31.0	1	C	ST	1941	22				
TEXAS	3940	CHAISON	28.0	1	C	ST	1937	22				
TEXAS	3945	DELL CITY	50.0	2	C	FD	1967	55	ISW	MFAL	W	ELEC
TEXAS	3950	TEXAS CITY	140.0	1	C	ST	1944	22				
TEXAS	3955	TEXAS CITY UNION CARBIDE	2,160.0	2	C	MSF	1967	55	ISW	IND	WP	GAS
UTAH	3960	MILL (AEC)	40.0	1	D	VC	1964	11	ISW	MIL	W	OIL
UTAH	3965	MAGNA	59.0	1	C	FD	1967	55	ISW	IND	W	
VIRGINIA	3980	POSSUM POINT A	100.0	1	C	ST	1960	22	SW	IND	W	COAL
VIRGINIA	3990	POSSUM POINT B	70.0	1	C	ST	1954	22	SW	IND	W	COAL
VIRGINIA	4000	POSSUM POINT C-AC. 4	187.0		C	F	1962	55	ISW	F	WP	COAL
VIRGINIA	4010	FORTSMOUTH	100.0	1	C	ST	1960	22				
VIRGINIA	4020	CHESTERFIELD	81.0	1	C	ST	1959	22				
VIRGINIA	4025	CHESTERFIELD NO.1	280.0	1	C	F	1968	55	ISW	F	WP	COAL
VIRGINIA	4030	BREMO	64.0	1	C	ST	1957	22				
VIRGINIA	4040	WHEELWRIGHT	130.0	2	C	ST	1941	22				
VIRGINIA	4050	NORFOLK	53.5	1	C	ST	1940	22				
VIRGINIA	4053	SURRY NO.1	173.0	1	C	F	1968	55	ISW	F	WP	URAN
VIRGINIA	4055	SURRY NO.2	173.0	1	C	F	1968	55	ISW	F	WP	URAN
VIRGINIA	4060	RICHMOND	58.0	2	C	ST	1939	22				
VIRGINIA	4070	GLENNLYN	52.0	1	C	ST	1944	22				
WEST VIRGINIA	4080	LOGAN	25.0	1	C	ST	1936	22				
WEST VIRGINIA	4100	MT STORM A-NO. 1	328.3	01	C	F	1965	55	ISW	F	WP	COAL
WEST VIRGINIA	4110	MT STORM B-NO. 2	330.3	01	C	F	1965	55	ISW	F	WP	COAL
WEST VIRGINIA	4130	A.E.P. A	140.0	1	C	ST	1956	22				
WEST VIRGINIA	4140	A.E.P. B	720.0	3	C	ST	1954	22				
WEST VIRGINIA	4150	A.E.P. C	470.0	6	C	ST	1952	22				
WEST VIRGINIA	4160	CHIC VALLEY ELECTRIC	50.0	1	C	ST	1954	22				
WEST VIRGINIA	4170	GLASGOW	100.0	1	C	ST	1952	22				
WEST VIRGINIA	4180	CABIN CREEK	65.0	1	C	ST	1944	22				
WEST VIRGINIA	4190	RIVESVILLE	70.0	1	C	ST	1936	22				
WEST VIRGINIA	4200	BOUCAR	30.0	1	C	ST	1930	22				
WISCONSIN	4210	FORT WASHINGTON	30.0	1	C	ST	1940	22				
WISCONSIN	4220	MILWAUKEE	29.0	1	C	ST	1932	22				

REGION TOTAL: 301 REGION CAPACITY: 43,091.2

U.S. TERRITORIES

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
JOHNSON ISLAND	4437	JOHNSON ISLAND	150.0	1	C	MSF	1964	11	SW	MIL	W	STM
MAJULIN-MARSHALL ISLES	4438	U.S. CORPS ENGINEERS	250.0	1	C	MSF	1967	22	SW	MIL	W	OIL
PUERTO RICO	4445	BERMUDAS	2,500.0	2	C	MSF	1965	11	SW	IND	W	STM
PUERTO RICO	4446	PONCE	250.0	01	C	F	1965	05	SW	ELM	W	
VIRGIN ISLANDS	4450	ST. THOMAS CHARLOTTE AMALIE A	1,000.0	1	C	MSF	1964	55	SW	MPAL	WP	OIL
VI-GIN ISLANDS	4460	ST. THOMAS CHARLOTTE AMALIE B	275.0	1	C	MSF	1962	11	SW	MPAL	WP	STM
VI-GIN ISLANDS	4475	V.I. WATER & POWER AUTHORITY	2,500.0	1		MSF	1967	22	SW	MPAL	WP	OIL
VI-GIN ISLANDS	4478	V.I. WATER & POWER AUTHORITY	1,000.0	1	C	VTE	1968	77	SW	MPAL	WP	OIL
VIRGIN ISLANDS	4480	ST. CROIX HARVEY ALUMINUM	1,000.0	1	C	MSF	1965	55	SW	IND	WP	OIL
VIRGIN ISLANDS	4483	ST. CROIX RESORT HOTEL	150.0	1	C	VFC	1968	77	SW	TCUR	W	ELEC
VIRGIN ISLANDS	4485	ST CROIX HESS OIL #1	172.0	1	C	MSF	1966	55	SW	IND	WP	OIL
VI-GIN ISLANDS	4486	ST CROIX HESS OIL #2	350.0	1	C	MSF	1968	11	SW	IND	W	STM
VIRGIN ISLANDS	4488	ST. CROIX (CHRISTIANSTED BAY HC.)	100.0	1	C	MSF	1967	22	SW	TCUR	W	OIL
WAKE ISLAND	4500	FAA	100.0	2	C	MSF	1959	11	SW	MIL	W	STM

REGION TOTAL: 14 REGION CAPACITY: 10,247.0

REGION

NORTH AMERICA EXCEPT USA

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
CANADA	4710	ALBERTA	35.0	2	C	ST	1956	22				
CANADA	4730	SASKATCHEWAN A	100.0	1	C	VTE	1956	03	15W	IND	W	COAL
CANADA	4732	SASKATCHEWAN	201.6	2	C	VTE	1967	03	15W	IND	W	COAL
CANADA	4740	SASKATCHEWAN B	50.0	1	C	ST	1956	22				
MEXICO	4750	TIJUANA	189.0	3	C	MSF	1963	55	SW	IND	WP	OIL
MEXICO	4755	CUAYMAS	93.0	1	C	MSF	1965	37	SW	IND	WP	STM
MEXICO	4760	TORREON AMPO	63.0	1	C	MSF	1963	15	15W	MPAL	WP	STM
MEXICO	4770	VERA CRUZ	35.0	1	C	ST	1957	22				
MEXICO	4780	ACAPULCO	25.0	1	C	ST	1959	22				
MEXICO	4790	SAN LUIS POTOSI	120.0	1	C	ST	1941	22				
MEXICO	4800	ROSARITA	7,500.0	2	C	MSF	1967	11	SW	MPAL	W	STM
PANAMA	4810	CIA PANAMENA DE FUERZA Y LUZ	44.0	2	C	ST	1957	22				

REGION TOTAL: 12 REGION CAPACITY: 8,457.3

REGION

CARIBBEAN

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
ANTIGUA (BRITISH)	5310	WEST INDIES OIL CO	180.0	1	C	MSF	1966	27	SW	IND	W	STM
ANTIGUA	5320	ST JOHNS	1,200.0	01	C	MSF	1969	11	SW	MPAL	WP	
ARUBA (NETH. ANT.)	5345	BALASHI GOVT WATER WORKS	2,688.0	5	C	ST	1955	87	SW	MPAL	WP	OIL
ARUBA	5346	BALSHI GOVT WATERWORKS #3	1,584.0	01	C	MSF	1965	11	SW	MPAL	WP	OIL
BAHAMAS	5359	DEPT PUBLIC WORKS	2,400.0	01	C	MSF	1969	27	SW	MPAL	W	OIL
ARUBA (NETH. ANT.)	5360	BALASHI GOVT. WATER WORKS	800.0	1	C	MSF	1965	11	SW	MPAL	W	STM
BAHAMAS	5361	NASSAU, CLIFTON PIER	86.4	01	C	VTE	1965	03	15W	IND	W	OIL
BAHAMAS (BRITISH)	5362	NASSAU,CLIFTON PIER	1,440.0	2	C	MSF	1962	87	SW	MPAL	WP	OIL
BAHAMAS (BRITISH)	5363	FREEPORT	1,267.0	1	C	MSF	1968	11	SW	IND	W	STM
BAHAMAS	5364	FREEPORT	70.0	01	C	MSF	1969	11	SW	TCUR	W	STM
BERMUDA	5365	KINGLEY AFB A	100.0	1	C	MSF	1965	11	SW	MIL	W	STM
BERMUDA	5366	KINGLEY AFB E	100.0	2	C	VC	1954	11	SW	MIL	W	OIL
BERMUDA	5367	KING EDWARD VII HOSPITAL	156.0	1	C	MSF	1964	11	SW	MPAL	W	STM
BERMUDA	5369	CAPLTON BEACH HOTEL	32.0	1	C	MSF	1961	11	SW	TCUR	W	STM
BERMUDA	5371	BERMUDIANA HOTEL C	48.0	1	C	EC	1966	55	15W	TCUR	W	ELEC
BERMUDA	5372	MCKINLEY FIELD	35.7	3	C	MSF	1943	79	SW	TCUR	W	STM
BERMUDA	5373	PRINCESS HOTEL	70.0	1	C	MSF	1964	11	SW	TCUR	W	STM
BERMUDA	5374	PRINCESS HOTEL	100.0	1	C	MSF	1967	22	SW	TCUR	W	OIL
BAHAMAS	5080	NORTH BIMINI	58.0	04	C	VC	1965	11	SW	MPAL	W	
BAHAMAS	5091	GRAND TURK AIRFIELD	36.0	05	C	VC	1955	11	SW	MIL	W	OIL
HONDURAS (NETH. ANT.)	5085	GOVT. WATER WORKS	134.4	1	C	MSF	1963	87	SW	MPAL	WP	OIL
CUBA	5090	GUANTANAMO	2,250.0	3	C	MSF	1965	55	SW	MPAL	WP	OIL
CURACAO	5100	MUNDO NOBO T G P	1,004.0	2	C	ST	1955	87	SW	MPAL	WP	OIL
CURACAO (NETH. ANT.)	5120	MUNDO NOBO C S G IC	3,440.0	2	C	MSF	1963	87	SW	MPAL	WP	OIL
CURACAO	5121	ENNASTAD	1,590.0	01	C	MSF	1965	51	SW	IND	W	STM
CURACAO (NETH. ANT.)	5130	SHELL PETROLEUM MAT.	1,584.0	1	C	MSF	1963	87	SW	IND	WP	OIL
CURACAO	5131	MUNDO NOBO	1,060.0	01	C	MSF	1969	87	SW	MPAL	W	OIL
ST MARTIN (FR. ANT.)	5145	ST MARTIN	132.0	1	C	MSF	1967	37	SW	TCUR	W	OIL
ST. MARTIN(NETH)	5146	HILLETTS POND RESORT	100.0	01	C	05071	1965	11	SW	TCUR	W	
ST MAARTEN(NETH. ANT.)	5150	ST.MARTIN	264.0	2	C	MSF	1968	19	15W	MPAL	W	OIL
TURKS ISLAND (BRITISH)	5160	WEST INDIES	30.0	4	C	VC		71				

REGION TOTAL: 31 REGION CAPACITY: 24,043.5

REGION

SOUTH AMERICA

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
ARGENTINA	5510	ALTO VALLE	40.3	2	C	ST	1966	03	15W	IND	W	OIL
ARGENTINA	5511	MAR DEL PLATA	86.4	02	C	VTE	1969	03	15W	IND	W	OIL
ARGENTINA	5515	RIO TRUNCADO	40.0	1	C	MSF	1962	37	15W	IND	WP	STM
ARGENTINA	5520	SAN NICHOLAS	190.0	2	C	VTE	1953	15	15W	IND	W	STM
CHILE	5550	CHANARAL	264.0	1	C	MSF	1965	87	SW	MPAL	W	OIL
CHILE	5560	QUINTERO	70.0	1	C	MSF	1964	11	SW	IND	W	STM
CHILE	5570	PIG BIC	31.7	1	C	ST	1963	87	SW	IND	W	OIL
CHILE	5580	TOCOPILLA	35.0	1	C	MSF	1958	11	SW	IND	WP	STM
CHILE	5590	PAROSA	40.0	1	C	MSF	1963	11	SW	MPAL	W	STM
HONDURAS	5610	PUERTO CORTES	172.0	1	C	MSF	1967	55	SW	IND	WP	OIL
ECUADOR	5620	ANGON	120.0	1	C	MSF	1966	03	SW	MPAL	WP	GAS

SOUTH AMERICA

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
ECUADOR	5640	SALINA A	100.0	2	C	VC	1956	11	SW	MPAL	W	OIL
ECUADOR	5650	SALINA B	50.0	1	C	MSF	1959	11	SW	MPAL	W	STM
ECUADOR	5660	LA LIBERTAD	60.0	1	C	MSF	1955	87	SW	IND	WP	OIL
ECUADOR	5665	CHAYAQUIL	35.0	2	C	ST	1961	22				
PERU	5670	SAN JUAN	41.0	2	C	VC	1954	11	SW	IND	W	OIL
PERU	5680	LARITOS A	73.0	1	C	ST	1957	87	SW	MPAL	W	OIL
CHILE	5695	ANACONDA COPPER	250.0		C	FD	1969	55	ISW	IND	W	ELEC
PERU	5700	LORITOS B	134.0	1	C	ST	1958	87	SW	MPAL	W	OIL
PERU	5710	ILO	720.0	1	C	MSF	1966	11	SW	IND	W	STM
VENEZUELA	5720	(PORT) CARDON	1,440.0	1	C	MSF	1961	29	SW	IND	W	OIL
VENEZUELA	5740	MARACAIBO	26.0	1	C	ST	1937	22				
VENEZUELA	5760	CARDON	25.0	1	C	ST	1930	22				

REGION TOTAL: 23 — REGION CAPACITY: 4,043.4

REGION

EUROPE - CONTINENTAL

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
AUSTRIA	6010	LINZ	110.0	1	C	MSF	1952	67	ISW	IND	WP	ELEC
BELGIUM	6020	WATERSCHEI	35.0	1	C	VTE	1947	47				
BELGIUM	6021	OSTEND	100.0	01	C	MSF	1969	82	SW	IND	WP	GAS
CAPE VERDI (PORTUGAL)	6030	PORTUGAL	582.0	2	C	MSF	1968	20	SW	MPAL	W	OIL
CYPRUS	6040	DEKHELIA	400.0	2	C	MSF	1964	29	SW	MPAL	WP	OIL
CYPRUS	6041	ELECTRICITY BOARD	104.0	02	C	MSF	1966	27	SW	P	W	OIL
CYPRUS	6050	DEKHELIA	28.8	1	C	ST	1962	87	SW	IND	WP	OIL
DENMARK	6060	AARHUS	64.0	1	C	VTE	1952	15	ISW	IND	W	STM
FINLAND	6070	HELSINKI	32.0	1	C	VTE	1951	19	ISW	IND	W	STM
FRANCE	6080	D HARMES	62.0	3	C	ST	1944	22				
FRANCE	6081	LE HARVE	153.0	4	C	MSF	1950	37	SW	IND	WP	STM
FRANCE	6082	MAUCONCOURT	444.0	1	C	ST	1968	37	ISW	IND	WP	STM
FRANCE	6083	VINCENNES	35.0	1	C	ST	1967	37	ISW	IND	W	STM
FRANCE	6084	GARDANNE	51.0	2	C	MSF	1952	37	ISW	IND	WP	STM
FRANCE	6085	MULHOUSE	396.0	2	C	MSF	1954	67	ISW	IND	WP	COAL
FRANCE	6086	CROSSPLIECERSTROFF(P.S.)	153.0	4	C	MSF	1951	37	ISW	IND	WP	STM
FRANCE	6087	HORNING (P.S.)	127.0	1	C	ST	1957	37	ISW	IND	WP	STM
FRANCE	6088	NANTES-CHEVIRE (P.S.)	53.0	1	C	MSF	1957	37	SW	IND	WP	STM
FRANCE	6089	VIOLAINES (P.S.)	127.0	1	C	ST	1955	37	ISW	IND	WP	STM
GERMANY, WEST	6090	BREMEN	132.0	1	C	MSF	1966	19	ISW	IND	W	STM
GERMANY, WEST	6100	STUTTGART	331.0	1	C	VTE	1950	19	ISW	IND	W	STM
GERMANY, WEST	6110	BARGE	127.0	1	C	VTE	1950	19	ISW	IND	W	STM
GERMANY, WEST	6130	FLINGERN	56.0	1	C	VTE	1952	19	ISW	IND	W	STM
GERMANY, WEST	6140	COLDENBERG	146.0	1	C	VTE	1957	19	ISW	IND	W	STM
GERMANY, WEST	6150	ELVERLINGSEN	65.0	1	C	VTE	1952	19	ISW	IND	W	STM
GERMANY, WEST	6160	ASCHAFFENBERG	64.0	1	C	VTE	1952	19	ISW	IND	W	STM
GERMANY, WEST	6170	HAGEN	152.0	2	C	VTE	1954	19	ISW	IND	W	STM
GERMANY, WEST	6180	BERLIN	48.0	1	C	VTE	1953	19	ISW	IND	W	STM
GERMANY, WEST	6190	GRYNHAUSEN	82.0	2	C	VTE	1953	19	ISW	IND	W	STM
GERMANY, WEST	6200	KIEL	32.0	1	C	VTE	1953	19	ISW	IND	W	STM
GERMANY, WEST	6210	DUSSELDORF	60.0	1	C	VTE	1954	19	ISW	IND	W	STM
GERMANY, WEST	6220	WEISWEILER	101.0	1	C	VTE	1954	19	ISW	IND	W	STM
GERMANY, WEST	6230	HAMBORN	39.0	1	C	VTE	1955	19	ISW	IND	W	STM
GERMANY, WEST	6240	REISHOLZ	50.0	1	C	VTE	1955	19	ISW	IND	W	STM
GERMANY, WEST	6250	HAGEN	39.0	1	C	VTE	1955	19	ISW	IND	W	STM
GERMANY, WEST	6260	ARNSBERG	76.0	1	C	VTE	1955	19	ISW	IND	W	STM
GERMANY, WEST	6270	HELMSTEDT	292.0	2	C	VTE	1955	19	ISW	IND	W	STM
GERMANY, WEST	6280	HATTINGEN	32.0	1	C	VTE	1957	19	ISW	IND	W	STM
GERMANY, WEST	6290	OFFEREN	152.0	2	C	VTE	1957	19	ISW	IND	W	STM
GERMANY	6291	HATTORF	515.0	3	C	MSF	1940	67	ISW	IND	WP	OIL
GERMANY	6292	LEHRTE	110.0	1	C	MSF	1953	67	ISW	IND	WP	OIL
GERMANY	6293	HERINGEN	390.0	1	C	MSF	1953	67	ISW	IND	WP	OIL
GERMANY	6294	HERINGEN	160.0	1	C	MSF	1963	67	ISW	IND	WP	OIL
GERMANY, WEST	6300	NEUMUNSTER	120.0	1	C	VTE	1960	19	ISW	IND	W	STM
GERMANY, WEST	6310	HOLS	76.0	2	C	VTE	1963	19	ISW	IND	W	STM
GIBRALTAR	6315	GIBRALTAR	270.0	1	C	MSF	1968	27	SW	MPAL	W	OIL
GIBRALTAR (BRITISH)	6330	THE ADMIRALTY A	261.0	2	C	ST	1947	87	SW	MPAL	W	OIL
GIBRALTAR (BRITISH)	6340	THE MINISTRY OF DEFENCE	60.0	1	C	MSF	1965	03	SW	MPAL	WP	OIL
GIBRALTAR (BRITISH)	6380	NATO	145.0	2	C	MSF	1960	22	SW	MIL	S	OIL
GIBRALTAR (BRITISH)	6390	CITY COUNCIL	84.0	1	C	MSF	1964	87	SW	MPAL	WP	OIL
GIBRALTAR (BRITISH)	6400	ARMY BASE	25.0	1	C	VC	1957	87	SW	MPAL	W	OIL
GREECE	6405	HERAKLION/KRETA	32.0	2	C	MSF	1968	15	ISW	IND	W	STM
ITALY	6410	GENOA	81.0	1	C	ST	1938	87	SW	IND	WP	OIL
ITALY	6412	GAETA	380.0	01	C	FD	1969	26	ISW	IND	W	ELEC
ITALY	6413	MANFREDONIA	32.0	01	C	ED	1969	26	ISW	IND	W	ELEC
ITALY	6430	ITALSIDER	1,200.0	2	C	MSF	1964	11	SW	IND	WP	STM
ITALY	6435	ITALSIDER # 3	725.0	1	C	MSF	1967	40	SW	IND	W	STM
ITALY	6440	SHELL OIL	600.0	3	C	MSF	1966	40				
ITALY	6451	PORTO VESME	192.2	02	C	MSF	1966	27	SW	IND	W	OIL
ITALY	6455	VIESTE	288.0	2	C	ED	1969	26	ISW	MPAL	W	ELEC
ITALY	6456	VIESTA	275.0	01	C	ED	1969	51	ISW	MPAL	W	ELEC
ITALY	6470	PRINCISI	70.0	1	C	MSF	1965	11	SW	IND	W	STM
ITALY	6475	BRINDISI	2,556.0	2	C	MSF	1968	48	SW	IND	W	OIL
ITALY	6490	NAPLES	80.0	1	C	ST	1936	22				
ITALY	6450	BARI	100.0	1	C	VFVC	1965	44	SW	DEMO	W	ELEC
MALTA	6530	VALETTA	1,260.0	1	C	MSF	1966	27	SW	MPAL	W	STM
MALTA	6531	ELECTRICITY BOARD	58.0	01	C	MSF	1967	27	SW	IND	W	OIL
MALTA	6535	VALETTA	4,385.0	3	C	MSF	1967	87	SW	MPAL	WP	OIL
NETHERLANDS	6550	FLUSHING	45.6	1	C	VTE	1954	03	ISW	IND	W	COAL
NETHERLANDS	6551	BOTLEK	100.0	01	C	MSF	1969	51	ISW	DEMO	W	STM
NETHERLANDS	6552	ROTTERDAM	250.0	01	C	FD	1969	51	ISW	IND	W	ELEC
NETHERLANDS	6553	ROTTERDAM	100.0	01	C	ED	1969	51	ISW	MPAL	W	ELEC
NETHERLANDS	6554	AMSTERDAM	50.0	01	C	ED	1969	51	ISW	DEMO	W	ELEC
NETHERLANDS	6555	EUROPOORT	1,140.0	2	C	VTE	1968	03	SW	IND	W	OIL
NETHERLANDS	6560	STAATSMIJN EMMA	59.0	1	C	VTE	1952	03	ISW	IND	W	COAL
NETHERLANDS	6570	FERNIS	762.0	1	C	MSF	1963	87	ISW	IND	WP	OIL
NETHERLANDS	6580	AMSTERDAM	43.0	2	C	VTE	1947	47				
NETHERLANDS	6590	ROTTERDAM	43.0	2	C	VTE	1950	47				
NETHERLANDS	6600	ROTTERDAM	178.0	1	C	FD	1965	26	ISW	IND	W	ELEC
NETHERLANDS	6610	FERNIS	700.0	1	C	VTE	1966	47				
NETHERLANDS	6620	THE HAGUE	43.0	2	C	VTE	1955	47				
NETHERLANDS	6630	UTRECHT	67.0	1	C	VTE	1955	47				
NETHERLANDS	6640	UTRECHT A	53.5	1	C	VTE	1956	47				

EUROPE - CONTINENTAL

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WP	USE	SO	FUEL
NETHERLANDS	6650	UTRECHT A	53.5	1	C	VTE	1967	47				
NETHERLANDS	6660	LEIDEN	177.0	1	C	VTE	1956	47				
NETHERLANDS	6670	HAARLEM	27.0	2	C	VTE	1958	47				
NETHERLANDS	6680	ARNHEM	53.5	1	C	VTE	1941	47				
NETHERLANDS	6690	LEEUWARDEN	27.0	2	C	VTE	1945	47				
NETHERLANDS	6700	HENGLO	32.0	1	C	VTE	1945	47				
NETHERLANDS	6720	TERNEUZEN	7,662.0	2	C	MSF	1967	51	SW	IND	WP	GAS
PORTUGAL	6725	BOA VISTA	25.0	01	C	VTE	1969	67	SW	TOUR	W	OIL
SPAIN	6730	SEVILLE	29.0	1	D	ST	1960	22				
SPAIN	6735	ALLUDIA (P.S.)	38.0	1	C	F	1966	55	SW	IND	WP	OIL
SPAIN	6740	BADALONA	90.0	2	C	VTE	1966	19	ISW	IND	W	STM
SWITZERLAND	6750		85.0	1	C	VTE	1953	15	ISW	IND	W	STM
SWEDEN	6760	GOTEBORG	64.0	1	C	VTE	1952	19	ISW	IND	W	STM
TURKEY	6770	ISTANBUL	129.0	2	C	ST	1952	87	SW	IND	WP	OIL

REGION TOTAL: 57 REGION CAPACITY: 11,689.1

REGION

ENGLAND & IRELAND

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WP	USE	SO	FUEL
CHANNEL ISLANDS (BRITISH)	6780	GUERNSEY	600.0	1	C	MSF	1960	87	SW	PPAL	W	OIL
CHANNEL ISLANDS (BRITISH)	6781	JERSEY	1,800.0	4	D	MSF	1968	87	SW	PPAL	W	OIL
ENGLAND	6800	SOUTH DENES, GREAT YARMOUTH A	176.0	3	C	ST	1955	02	SW	IND	W	COAL
ENGLAND	6810	SOUTH DENES, GREAT YARMOUTH B	29.0	1	C	MSF	1960	03	SW	IND	W	COAL
ENGLAND	6840	TILBURY, B	634.0	4	D	VTE	1966	03	SW	IND	W	COAL
ENGLAND	6850	CANVEY ISLAND ESSEX	115.0	2	C	MSF	1965	02	SW	IND	W	OIL
ENGLAND	6990	FLIXBOROUGH SCUNTHORPE	26.0	1	C	VTE	1940	03	ISW	IND	W	COAL
ENGLAND	6900	SHOTTON, CHESHIRE	173.0	2	C	VTE	1952	03	ISW	IND	W	COAL
ENGLAND	7060	A, BURTON-UPON-TRENT	216.0	3	C	VTE	1954	03	ISW	IND	W	COAL
ENGLAND	7070	B, BURTON-UPON-TRENT	460.8	8	D	VTE	1958	03	ISW	IND	W	COAL
ENGLAND	7080	C, BURTON-UPON-TRENT	295.2	4	C	VTE	1966	03	ISW	IND	W	COAL
ENGLAND	7082	DRAX	389.0	3	C	VTE	1967	03	ISW	IND	W	COAL
ENGLAND	7084	DUNCENESS -B-	652.0	3	C	VTE	1967	03	SW	IND	W	COAL
ENGLAND	7100	EGGBOROUGH, YORKS	403.2	4	C	VTE	1965	03	ISW	IND	W	COAL
ENGLAND	7130	FERRYBRIDGE C	748.8	1	C	VTE	1965	03	ISW	IND	W	COAL
ENGLAND	7220	IRONBRIDGE B	202.0	2	D	VTE	1966	03	ISW	IND	W	COAL
ENGLAND	7230	KEADBY, SCUNTHORPE	259.2	3	C	VTE	1952	03	ISW	IND	W	COAL
ENGLAND	7244	KENT OIL REFINERY	1,255.0	18	C	ST	1953	87	ISW	IND	W	OIL
ENGLAND	7332	MANNINGTREE, ESSEX	57.0	1	C	ED	1967	26	ISW	DEMO	W	ELEC
ENGLAND	7430	RATCLIFF-ON-SOAR	748.8	1	C	VTE	1967	03	ISW	IND	W	COAL
ENGLAND	7500	A, NEWARK-UPON-TRENT	432.0	6	D	VTE	1945	03	ISW	IND	W	COAL
ENGLAND	7510	B, NEWARK-UPON-TRENT	79.2	3	C	VTE	1960	03	ISW	IND	W	COAL
ENGLAND	7560	THORNHILL, DEWSBURY	115.0	2	C	VTE	1950	03	ISW	IND	W	OIL
ENGLAND	7580	TILBURY A	242.0	6	C	ST	1957	02	SW	IND	W	COAL
ENGLAND	7640	WEST THURROCK	562.0	5	C	VTE	1962	03	SW	IND	W	COAL
ENGLAND	7700	WORCESTER	43.2	1	C	VTE	1943	03	ISW	IND	W	COAL
ENGLAND	7710	MANVERS MAIN, KEYBOROUGH	385.2	5	C	VTE	1956	03	ISW	IND	W	COAL
ENGLAND	7720	GRIMETHORPE, BARNSLEY	216.0	3	C	VTE	1956	03	ISW	IND	W	COAL
ENGLAND	7730	MORTON, DERBY	144.0	2	C	VTE	1958	03	ISW	IND	W	COAL
ENGLAND	7740	STONEBRIDGE PARK, LONDON	53.0	2	C	VTE	1941	02	ISW	IND	W	OIL
ENGLAND	7770	ILKESTON, DERBY	230.4	4	C	VTE	1954	03	ISW	IND	W	COAL
ENGLAND	7790	DARWEN, LANCASHIRE	172.8	2	C	VTE	1964	03	ISW	IND	W	COAL
ENGLAND	7820	DUNSTON	265.0	5	C	ST	1947	87	ISW	IND	W	OIL
ENGLAND	7830	HAYLE	45.0	3	C	ST	1939	87	ISW	IND	W	OIL
ENGLAND	7835	DEPTFORD EAST	139.0	1	D	ST	1950	87	ISW	IND	W	OIL
ENGLAND	7840	DEPTFORD WEST	106.0	2	C	ST	1945	87	ISW	IND	W	OIL
ENGLAND	7850	BIRKENHEAD	30.0	1	C	ST	1948	87	ISW	IND	W	OIL
ENGLAND	7860	BATTERSEA B	213.0	2	C	ST	1947	87	ISW	IND	W	OIL
ENGLAND	7870	PERCIVAL LANE	45.0	1	C	ST	1940	87	ISW	IND	W	OIL
ENGLAND	7880	LEICESTER	50.0	2	D	ST	1950	87	ISW	IND	W	OIL
ENGLAND	7890	BRADFORD	45.0	1	D	ST	1940	87	ISW	IND	W	OIL
ENGLAND	7920	BANKSIDE	112.0	3	C	ST	1928	87	ISW	IND	W	OIL
ENGLAND	7930	PRINCE ROCK	58.0	1	D	VTE	1945	87	ISW	IND	W	OIL
ENGLAND	7940	ACTON LANE	173.0	2	C	VTE	1952	87	ISW	IND	W	OIL
ENGLAND	7950	SKELTON GRANGE	173.0	2	C	VTE	1952	87	ISW	IND	W	OIL
ENGLAND	7960	THAMES MILL	173.0	2	C	VTE	1955	87	ISW	IND	W	OIL
ENGLAND	7970	MERSEY MILL	173.0	2	C	VTE	1956	87	ISW	IND	W	OIL
ENGLAND	7980	IPSWICH	29.0	1	C	VTE	1945	87	ISW	IND	W	OIL
ENGLAND	8000	CORRINGTON	29.0	1	C	VTE	1947	87	ISW	IND	W	OIL
ENGLAND	8010	FULLHAM	106.4	2	C	ST	1945	87	ISW	IND	W	OIL
ENGLAND	8020	WILLINGTON	144.0	2	C	ST	1953	87	ISW	IND	W	OIL
ENGLAND	8030	BLACKBURN	35.0	1	C	ST	1941	87	ISW	IND	W	OIL
ENGLAND	8040	WEST HAM	63.0	2	C	ST	1947	87	ISW	IND	W	OIL
ENGLAND	8050	UPPER BOAT	39.0	1	C	ST	1941	87	ISW	IND	W	OIL
ENGLAND	8060	PRESTON	86.0	2	C	ST	1945	87	ISW	IND	W	OIL
ENGLAND	8070	RIBBLE	43.0	1	C	ST	1941	87	ISW	IND	W	OIL
ENGLAND	8080	BARKING	202.0	1	C	ST	1957	87	ISW	IND	W	OIL
ENGLAND	8090	CLARENCE DOCK	144.0	1	C	ST	1952	87	ISW	IND	W	OIL
ENGLAND	8100	SCUNTHORPE (LYSAGHT)	432.0	3	C	F	1960	87	ISW	IND	WP	OIL
ENGLAND	8110	SCUNTHORPE (RTB)	288.0	2	C	F	1960	87	ISW	IND	WP	OIL
IRELAND (NORTH)	8140	BELFAST CORP	144.0	2	C	VTE	1955	87	ISW	IND	W	OIL
IRELAND	8144	TARBERT	144.0	1	C	VTE	1967	03	SW	IND	W	OIL
SCOTLAND	8160	CLYDESMILL	81.0	4	C	ST	1950	87	ISW	IND	W	OIL

REGION TOTAL: 63 REGION CAPACITY: 15,841.2

REGION

AUSTRALIA

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WP	USE	SO	FUEL
AUSTRALIA	8410	MARALINGA	92.0	3	D	ST	1956	02	ISW	PPAL	WP	OIL
AUSTRALIA	8420	MORWELL	230.4	4	C	VTE	1958	02	ISW	IND	W	COAL
AUSTRALIA	8460	TALLAWARA	144.0	2	C	VTE	1954	03	ISW	IND	W	COAL
AUSTRALIA	8475	BRISBANE	216.0	1	C	MSF	1967	55	SW	IND	WP	GAS
AUSTRALIA	8480	EXMOUTH GULF	60.0	1	C	ED	1965	55	ISW	PPAL	W	ELEC
AUSTRALIA	8485	CIDEALPHA	60.0	01	D	MSF	1965	11	SW	IND	W	
AUSTRALIA	8490	HAMMERSLEY	480.0	2	C	MSF	1966	87	SW	PPAL	WP	OIL

REGION TOTAL: 7 REGION CAPACITY: 1,282.4

ASIA (INCLUDING INDONESIA)

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SC	FUEL
ANDAMAN IS.	8609	N.W. DOCKYARD	89.4	1	C	ST	1947	67	SW	MPAL	W	OIL
INDIA	8610	CAWNPORE	43.2	1	C	VTE	1945	63	ISW	IND	W	COAL
INDIA	8611	SINGARENI	25.9	1	C	VTE	1955	62	ISW	IND	W	OIL
INDIA	8613	DURGAPUR	95.0	2	C	VTE	1957	15	ISW	IND	W	STM
INDIA	8614	BHUSAVAL	88.0	1	C	VTE	1964	25	ISW	IND	W	STM
INDIA	8618	SINDRI	110.0	1	C	MSF	1959	57	ISW	IND	W	
INDIA	8618	COSSIPORE	185.0	4	C	ST	1945	83	ISW	IND	W	OIL
INDONESIA	8622	SURABAJA NO. 1	28.8	1	C	F	1963	55	SW	F	WP	OIL
INDONESIA	8623	SURABAJA NO. 2	28.8		C	F	1963	55	SW	F	WP	OIL
INDONESIA	8624	TANDJUNG GRIEK	76.0	1	C	MSF	1966	15	SW	F	W	STM
JAPAN	8630	KYUSHU	700.0	1	C	MSF	1965	55	SW	IND	WP	COAL
JAPAN	8631	SAKITI	640.0	01	C	VC	1956			IND	W	
JAPAN	8632	TOKYO	48.0	01	C	MSF	1965	55		CEMC	W	
JAPAN	8633	TAKETOYO CITY	115.2	1	C	MSF	1965	73	SW	IND	W	OIL
JAPAN	8635	TAKETOYO CITY	105.6	1	C	MSF	1965	73	SW	IND	W	OIL
JAPAN	8637	HIMEJI CITY	317.0	1	C	MSF	1965	72	SW	IND	W	OIL
JAPAN	8640	YUNG WOL	127.0	2	C	VTE	1962	19	ISW	IND	W	STM
KOREA (SOUTH)	8641	EAST PAKISTAN	80.0	2	C	F	1966	55	ISW	F	WP	GAS
PAKISTAN	8662		85.0	2	C	MSF	1964	75	ISW	IND	W	STM
PAKISTAN	8671	MANILA	80.0	2	C	F	1965	11	ISW	MPAL	W	STM
PHILLIPINE ISLANDS	8672	CEBU CITY	87.0	3	C	ST	1964	24				
PHILLIPINE ISLANDS	8673	CEBU CITY	70.0	1	C	MSF	1966	11	ISW	MPAL	W	STM
PHILLIPINE ISLANDS	8681		317.0	2	C	MSF	1966	37	SW	IND	WP	OIL
POLYNESIA (FR.)	8682		264.0	1	C	MSF	1966	37	SW	MPAL	WP	OIL
POLYNESIA (FR.)	8683		32.0	2	C	ST	1966	37	SW	IND	W	OIL
POLYNESIA (FR.)	8684		63.0	2	C	MSF	1965	37	SW	IND	W	OIL
POLYNESIA (FR.)	8690	SRIRACHA	275.0	01	C	MSF	1965	11		IND	W	
THAILAND												

REGION TOTALS 27 REGION CAPACITY: 4,186.5

REGION

MIDDLE EAST

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SC	FUEL
ADEN (BRITISH)	8701	P.P. REFINARY LITTLE ADEN	485.0	3	C	ST	1955	67	SW	IND	WP	OIL
ADEN (BRITISH)	8702	HEDJUFF	34.5	2	C	ST	1962	37	SW	IND	WP	OIL
ARABIA (SAUDI)	8712	SAFANUZA	50.0	1	C	MSF	1967	11	SW	IND	W	STM
ARABIA (SAUDI)	8714	CUHA	61.0	1	C	MSF	1967	11	SW	MPAL	W	OIL
ARABIA (SAUDI)	8716	DUPA-AL-WAJH	29.0		C	ED	1967	55	ISW	MPAL	W	ELEC
ARABIA (SAUDI)	8718	AL-WEJH	61.0	1	C	MSF	1967	11	SW	MPAL	W	STM
ARABIA (SAUDI)	8720	DHAHRAN ARINCO	115.2	2	C	ED	1961	55	ISW	MPAL	W	
SAUDI ARABIA	8725	AL KHOBAR-PEPSI COLA	28.0		C	ED	1967	55	ISW	IND	W	ELEC
ARABIA (SAUDI)	8730	AL KHOBAR	7,500.0	03	C	MSF	1965	11	SW	MPAL	W	GAS
ARABIA (SAUDI)	8770	RAS TANURA B	140.0	4	C	ST	1950	22	SW	IND	W	GAS
ARABIA (SAUDI)	8780	RAS TANURA C	130.0	1	C	ST	1956	22	SW	IND	W	GAS
ARABIA (SAUDI)	8790	RAS TANURA D	260.0	2	C	ST	1960	22	SW	IND	W	GAS
ARABIA (SAUDI)	8803	ARAMCO	288.0	1	C	MSF	1964	22	SW	IND	W	OIL
ARABIA (SAUDI)	8805	DAMMAM	346.0	1	C	MSF	1967	11	SW	IND	W	STM
SAUDI ARABIA	8806	DAMMAM	100.0		C	ED	1967	55	ISW	IND	W	ELEC
ARABIA (SAUDI)	8810	JIDDA	5,000.0	2	C	MSF	1958	11	SW	MPAL	W	STM
BAHREIN	8830	AWALI (MANAMA)	100.0	1	C	ED	1963	55	ISW	MPAL	W	
BAHREIN	8832	ARABIAN GULF	100.0	1	C	ED	1964	47				
BAHREIN	8833	HASSIN & HABIF	60.0		C	ED	1964	55	ISW	IND	W	ELEC
BAHREIN	8836	RAF BASE	50.0		C	ED	1963	55	ISW	MPAL	W	ELEC
IRAN	8864	AHWAZ	57.0	1	C	ST	1967	19	ISW	IND	W	STM
IRAN	8880	KHARG, ISLAND A	300.0	2	C	MSF	1960	87	SW	MPAL	W	OIL
IRAN	8885	KHARG, ISLAND B	300.0	1	C	MSF	1968	87	SW	MPAL	W	OIL
IRAN	8910	AGHA JARI	28.8	1	C	VTE	1950	03	SW	MPAL	WP	OIL
IRAN	8912	PERSIAN GULF	240.0	3	C	VC	1958	44	SW	MIL	W	ELEC
IRAN	8913	BID BOLAND	202.0	1	C	ED	1958	26	ISW	MPAL	W	ELEC
IRAN	8915	BID BOLAND	150.0	1	C	ST	1958	03	ISW	IND	W	GAS
IRAN	8920	KASHAN	130.0	3	C	ST	1959	03	ISW	IND	W	OIL
IRAN	8930	IMAM HASSAN	158.0	1	C	MSF	1963	87	SW	MPAL	W	OIL
IRAN	8931	IMFC	200.0	01	C	ED	1965	51	ISW	MPAL	W	ELEC
IRAN	8935	KHARG ISLAND	66.0	2	C	MSF	1965	73	SW	IND	W	OIL
IRAN	8936	KHARG ISLAND	239.0	1	C	MSF	1965	73	SW	IND	W	OIL
IRAN	8937	KHARG ISLAND	100.0	01	C	MSF	1965	11		IND	W	
IRAN	8940	TEHERAN	67.0	2	C	F	1967	11	SW	MPAL	W	STM
IRAN	8950	ABADAN	86.0	1	C	ST	1951	87	SW	IND	WP	OIL
IRAN	8955	ABADAN	100.0	1	C	MSF	1967	11	SW	IND	W	STM
IRAQ	8960	BAGHDAD	95.0	1	C	VTE	1958	03	ISW	IND	W	OIL
IRAQ	8961	BASRAH	57.6	1	C	VTE	1961	03	ISW	IND	W	OIL
ISRAEL	8970	EILAT A	1,000.0	1	C	MSF	1965	22	SW	MPAL	WP	OIL
ISRAEL	8971	ISRAEL	66.0	02	C	VC	1965	44	SW	MIL	W	ELEC
ISRAEL	8973	ZAALIM	130.0		C	ED	1966	72	ISW	CEMC	W	ELEC
ISRAEL	8975	YOTVATA	53.0	1	C	RC	1968	44	ISW	CEMD	W	ELEC
ISRAEL	8980	MASHABEI SADEN	630.0	01	C	ED	1969		ISW	MPAL	W	ELEC
ISRAEL	9000	DEAD SEA	260.0	2	C	ST	1961	22	SW	IND	W	OIL
KUWAIT	9050	SHUWAIKH C	1,260.0	2	C	MSF	1957	55	SW	MPAL	WP	GAS
KUWAIT	9060	SHUWAIKH D	1,260.0	2	C	MSF	1957	55	SW	MPAL	WP	GAS
KUWAIT	9070	SHUWAIKH E	2,400.0	2	C	MSF	1962	87	SW	MPAL	WP	GAS
KUWAIT	9080	SHUWAIKH F	2,400.0	2	C	MSF	1965	87	SW	MPAL	WP	GAS
KUWAIT	9090	SHUWAIKH G	4,800.0	2	C	MSF	1966	55	SW	MPAL	WP	GAS
KUWAIT	9100	COVT	240.0	3	C	ED	1963	55	ISW	MPAL	W	
KUWAIT	9110	SHUAIBA	4,800.0	2	C	MSF	1967	55	SW	MPAL	WP	GAS
KUWAIT	9112	SHUWAIKH	4,800.0	2	C	MSF	1967	55	SW	MPAL	WP	GAS
KUWAIT	9113	SHUWAIKH	30.0	1	C	MSF	1968	73	SW	IND	W	GAS
KUWAIT	9114	SHUWAIKH	4,800.0	1	C	MSF	1968	72	SW	MPAL	WP	GAS
KUWAIT	9120	SHUAIBA A	3,600.0	3	C	MSF	1966	87	SW	MPAL	WP	GAS
KUWAIT	9130	SHUAIBA B	2,400.0	1	C	MSF	1967	55	SW	MPAL	WP	GAS
KUWAIT	9140	WATER RESOURCES CENTER	48.0		C	MSF	1966		SW	CEMC	W	
KUWAIT	9150	MINA-AL-AHMADI A	960.0	8	C	ST	1954	95	SW	MPAL	WP	GAS
KUWAIT	9170	MINA-AL-AHMADI 10	720.0	1	C	MSF	1962	87	SW	MPAL	WP	GAS
KUWAIT	9180	MINA-AL-AHMADI 11	720.0	1	C	MSF	1966	87	SW	MPAL	WP	GAS
KUWAIT	9190	GETTY OIL CO	100.0	1	C	MSF	1964	11	SW	IND	W	STM
KUWAIT	9210	AMERICAN INDEPENDENT OIL CO. A	50.0	2	C	ST	1955	75	ISW	MPAL	W	GAS
KUWAIT	9220	AMERICAN INDEPENDENT OIL CO. B	50.0	1	C	MSF	1962	55	SW	IND	WP	GAS
KUWAIT	9240	RAS KHAFJI, NEUTRAL ZONE	500.0	1	C	MSF	1966	55	SW	MPAL	W	GAS
KUWAIT	9250	P RAS AL KHAFJI	500.0	1	C	MSF	1962	55	SW	IND	WP	GAS

MIDDLE EAST

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
KUWAIT	9260	WAFRA (NEUTRAL ZONE)	48.0	1	C	ED	1965	55	ISW	MPAL	W	
KUWAIT	9265	MINA ABDULLA	450.0	1	C	MSF	1967	11	SW	IND	W	STM
LEBANON	9268	CENTRAL (CICEEIFUT)	137.4	1	C	MSF	1965	71	SW	IND	WP	OIL
OMAN	9270	MASIRAH AIR FORCE BASE	29.0	2	C	MSF	1963	87	SW	MPAL	W	OIL
OMAN (TRUCIAL)	9280	DAS ISLAND	50.0	3	C	MSF	1962	87	SW	MPAL	W	GAS
OMAN (TRUCIAL)	9290	ABU DHABI	30.0	1	C	MSF	1965	27	SW	MPAL	W	OIL
OMAN (TRUCIAL)	9291	ABU DHABI	7,200.0	2	C	MSF	1965	87	SW	MPAL	WP	GAS
OMAN (TRUCIAL)	9300	ABU DHABI	26.0	2	C	MSF	1963	29	ISW	MPAL	W	OIL
OMAN (TRUCIAL)	9310	SHARJAH AIR FORCE BASE	58.0	4	C	MSF	1963	87	SW	MPAL	W	OIL
QATAR	9330	DOHA A & B	1,800.0	2	C	MSF	1963	87	SW	MPAL	WP	GAS
QATAR	9331	DOHA	238.0	6	C	ST	1963	87	SW	IND	W	OIL
QATAR	9332	DOHA CED	2,516.0	2	C	MSF	1967	87	SW	MPAL	WP	GAS
QATAR	9333	DOHA	360.0	02	C	MSF	1955	87	SW	MPAL	W	OIL

REGION TOTAL: 78 REGION CAPACITY: 65,041.8

REGION

AFRICA

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
ALGERIA	9340	ARZEW	154.0	3	C	ST	1964	37	SW	IND	WP	STM
ALGERIA	9341	ARZEW	396.0	1	C	MSF	1968	37	SW	IND	WP	GAS
ALGERIA	9342	BONE (P.S.)	76.0	4	C	MSF	1953	37	SW	IND	WP	STM
ALGERIA	9343	ORAN (P.S.)	76.0	4	C	MSF	1953	37	SW	IND	WP	STM
ALGERIA	9344	SKIKDA	381.0	01	C	MSF	1965	37	SW	IND	WP	STM
ALGERIA	9345	SKIKDA	191.0	01	C	MSF	1969	37	SW	IND	WP	STM
CAIRO	9350	CAIRO	60.0	01	C	MSF	1968	11	SW	RTL		
ASCENSION ISLAND	9351	AUXILIARY AIRFIELD	103.6	01	C	VC	1957	71	SW		W	OIL
ASCENSION ISLAND (BRITISH)	9352	ZRUPA STANDARD OIL C	360.0	2	C	MSF	1955	87	SW	MPAL	W	OIL
ASCENSION ISLAND (BRITISH)	9353	BRITISH MINISTRY OF WORKS	30.0	1	C	F	1965	51	SW	MPAL	W	OIL
ASCENSION ISLAND (BRITISH)	9355	BRITISH MINISTRY OF WORKS	25.0	1	C	MSF	1966	51		MPAL	W	OIL
ASCENSION ISLAND (BRITISH)	9356	BRITISH MINISTRY OF WORKS	30.0	1	C	MSF	1967	51		MPAL	W	OIL
CANARY ISLANDS (SPAIN)	9358	LAS PALMAS	5,284.0	4	C	MSF	1967	51	SW	MPAL	WP	OIL
CANARY ISLANDS (SPAIN)	9359	PUERTOVENTURA	33.0	1	C	VC	1969	44	SW	TCOM	W	ELEC
EGYPT (U.A.R.)	9360	ABU ZENIMA (SINAI)	600.0	1	C	MSF	1966	87	SW	MPAL	WP	GAS
EGYPT (U.A.R.)	9370	CAIRO SOUTH	201.6	2	C	VTE	1964	03	ISW	IND	W	OIL
EGYPT (U.A.R.)	9384	MERSA MATROUH	264.0	2	C	MSF	1967	19	SW	MPAL	WP	OIL
EGYPT	9385	MOBILE PLANT	27.0	01	C	MSF	1965	15	SW	IND	W	OIL
EGYPT (U.A.R.)	9390	SIDUF	51.0	1	C	VTE	1959	15	ISW	MPAL	W	STM
EGYPT (U.A.R.)	9404	CHARRAGA	264.0	2	C	MSF	1967	15	SW	MPAL	WP	OIL
EGYPT (U.A.R.)	9410	SAFAGA BAY	40.3	2	C	ST	1930	87	SW	MPAL	W	OIL
EGYPT	9415	SAFAGA	75.5	03	C	MSF	1964	73	SW	IND		
LYBIA	9420	BENGHAZI	5,073.0	16	C	ED	1965	26	ISW	MPAL	W	ELEC
LIBYA	9430	FORT BREGA A (ESSO)	200.0	1	C	MSF	1965	11	SW	IND	W	STM
LIBYA	9440	FORT BREGA B (ESSO)	50.0	1	C	MSF	1963	11	SW	IND	W	STM
LIBYA	9445	FORT BREGA	200.0	1	C	MSF	1965	11	SW	IND	W	STM
LYBIA	9446	FORT BREGA	200.0	01	C	MSF	1969	11	SW	IND	W	STM
LIBYA	9450	MARSA BREGA	60.0		C	F		71				
LIBYA	9460	ES SIDER	100.0	2	C	MSF	1962	55	SW	IND	WP	GAS
LIBYA	9462	ZLITAN	115.0	1	C	ED	1964	26	ISW	MPAL	WP	OIL
LIBYA	9472	EL-ADEM	25.0	1	C	ED	1961	26	ISW	RTL	W	ELEC
LIBYA	9473	AGEDABIA	720.0	1	C	MSF	1968	11	SW	MPAL	W	OIL
LYBIA	9476	AIR BASE	70.0		C	ED	1960	55	ISW	IND	W	ELEC
LIBYA	9490	TRIPOLI	30.0	3	C	VC		71				
LIBYA	9490	MORRA	45.0	3	C	VC		71				
MAURITANIA	9495	FORT ETIENNE	57.0	2	C	VC	1954	11	SW	IND	W	OIL
MAURITANIA	9498	NOUAKCHOTT	753.0	1	C	MSF	1968	37	SW	MPAL	WP	OIL
MOROCCO (SPANISH)	9500	CEUTA	1,055.0	2	C	MSF	1965	19	SW	MPAL	W	OIL
NIGERIA	9510	IJORA	115.0	2	C	VTE	1962	87	ISW	IND	W	OIL
SPANISH SAHARA	9520	EL AIUN	26.0	2	C	MSF	1966	19	SW	IND	W	
SPANISH SAHARA	9530	EL AIUN EMPRESA MINERA	925.1	01	C	MSF	1969	20	SW	IND	WP	
SPANISH SAHARA	9540	VILLA CISNEROS	30.0	3	C	VC		71				
SPANISH SAHARA	9545	EN MINSA	26.5	1	C	ED	1966	55	ISW	MPAL	W	
SUDAN	9550	KHARTOUM	60.0	02	C	MSF	1968	27	ISW	IND	W	OIL
TUNISIA	9581	SHERRCUCH	77.0	02	C	ST	1969	37	ISW	IND	WP	STM
TUNISIA	9585	A.C.I.P.	28.0	1	C	ED	1967	55	ISW	MPAL	W	ELEC
SOUTH AFRICA	9592	ANCOR	25.0	1	C	ST	1960	03	ISW	IND	W	OIL
SOUTH AFRICA	9594	LUDERITZ	144.0	1	C	MSF	1961	87	SW	MPAL	W	OIL
SOUTHWEST AFRICA	9595	LUDERITZ	61.0		C	ST	1954	19	ISW	MPAL	W	STM
CANARY ISLAND	9997	LANSAROTE	650.0	01	C	MSF	1965	55	SW	MPAL	WP	OIL

REGION TOTAL: 56 REGION CAPACITY: 19,692.6

REGION

USSR

COUNTRY/STATE	ID	LOCATION	CAPACITY	UN	ST	TYPE	YEAR	MFG	WF	USE	SD	FUEL
U.S.S.R.	9730		25.0		C	ST		22				
U.S.S.R.	9732	CASPIAN SEA	26.0	1	C	ED	1961	26	ISW	MPAL	W	ELEC
U.S.S.R.	9740		233.0		C	ST		22				
U.S.S.R.	9750		290.0		C	ST		22				
U.S.S.R.	9760	SHEVCHENKO #1	1,200.2		C	VTE	1963	81	SW	DEMC	W	OIL
U.S.S.R.	9761	SHEVCHENKO #2	3,500.5		C	VTE	1967	81	SW	MGIR	WP	OIL
U.S.S.R.	9762	SHEVCHENKO #3	3,500.0		C	VTE	1968	81	SW	MGIR	WP	OIL
U.S.S.R.	9763	SHEVCHENKO #4	3,500.0			VTE	1969	81	SW	MGIR	WP	OIL
U.S.S.R.	9800	KHASHLVDESK	317.0		C	VTE	1969	81				

REGION TOTAL: 9 REGION CAPACITY: 12,591.7

GRAND TOTAL: 712 GRAND TOTAL: 244,604.8

APPENDIX B

TECHNICAL DATA

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7-1750 (3-71)
Bureau of Reclamation

CONVERSION FACTORS—BRITISH TO METRIC UNITS OF MEASUREMENT

The following conversion factors adopted by the Bureau of Reclamation are those published by the American Society for Testing and Materials (ASTM Metric Practice Guide, E 380-68) except that additional factors (*) commonly used in the Bureau have been added. Further discussion of definitions of quantities and units is given in the ASTM Metric Practice Guide.

The metric units and conversion factors adopted by the ASTM are based on the "International System of Units" (designated SI for Systeme International d'Unites), fixed by the International Committee for Weights and Measures; this system is also known as the Giorgi or MKSA (meter-kilogram (mass)-second-ampere) system. This system has been adopted by the International Organization for Standardization in ISO Recommendation R-31.

The metric technical unit of force is the kilogram-force; this is the force which, when applied to a body having a mass of 1 kg, gives it an acceleration of 9.80665 m/sec/sec, the standard acceleration of free fall toward the earth's center for sea level at 45 deg latitude. The metric unit of force in SI units is the newton (N), which is defined as that force which, when applied to a body having a mass of 1 kg, gives it an acceleration of 1 m/sec/sec. These units must be distinguished from the (inconstant) local weight of a body having a mass of 1 kg, that is, the weight of a body is that force with which a body is attracted to the earth and is equal to the mass of a body multiplied by the acceleration due to gravity. However, because it is general practice to use "pound" rather than the technically correct term "pound force," the term "kilogram" (or derived mass unit) has been used in this guide instead of "kilogram-force" in expressing the conversion factors for forces. The newton unit of force will find increasing use, and is essential in SI units.

Where approximate or nominal English units are used to express a value or range of values, the converted metric units in parentheses are also approximate or nominal. Where precise English units are used, the converted metric units are expressed as equally significant values.

Table I

QUANTITIES AND UNITS OF SPACE

Multiply	By	To obtain
	LENGTH	
Mil	25.4 (exactly)	Micron
Inches	25.4 (exactly)	Millimeters
Inches	2.54 (exactly)*	Centimeters
Feet	30.48 (exactly)	Centimeters
Feet	0.3048 (exactly)*	Meters
Feet	0.0003048 (exactly)*	Kilometers
Yards	0.9144 (exactly)	Meters
Miles (statute)	1,609.344 (exactly)*	Meters
Miles	1.609344 (exactly)	Kilometers
	AREA	
Square inches	6.4516 (exactly)	Square centimeters
Square feet	*929.03	Square centimeters
Square feet	0.092903	Square meters
Square yards	0.836127	Square meters
Acres	*0.40469	Hectares
Acres	*4,046.9	Square meters
Acres	*0.0040469	Square kilometers
Square miles	2.58999	Square kilometers
	VOLUME	
Cubic inches	16.3871	Cubic centimeters
Cubic feet	0.0283168	Cubic meters
Cubic yards	0.764555	Cubic meters
	CAPACITY	
Fluid ounces (U.S.)	29.5737	Cubic centimeters
Fluid ounces (U.S.)	29.5729	Milliliters
Liquid pints (U.S.)	0.473179	Cubic decimeters
Liquid pints (U.S.)	0.473166	Liters
Quarts (U.S.)	*946.358	Cubic centimeters
Quarts (U.S.)	*0.946331	Liters
Gallons (U.S.)	*3,785.43	Cubic centimeters
Gallons (U.S.)	3.78543	Cubic decimeters
Gallons (U.S.)	3.78533	Liters
Gallons (U.S.)	*0.00378543	Cubic meters
Gallons (U.K.)	4.54609	Cubic decimeters
Gallons (U.K.)	4.54596	Liters
Cubic feet	28.3160	Liters
Cubic yards	*764.55	Liters
Acre-feet	*1,233.5	Cubic meters
Acre-feet	*1,233,500	Liters

QUANTITIES AND UNITS OF MECHANICS

Multiply	By	To obtain
MASS		
Grains (1/7,000 lb)	64.79891 (exactly)	Milligrams
Troy ounces (480 grains)	31.1035	Grams
Ounces (avdp)	28.3495	Grams
Pounds (avdp)	0.45359237 (exactly)	Kilograms
Short tons (2,000 lb)	907.185	Kilograms
Short tons (2,000 lb)	0.907185	Metric tons
Long tons (2,240 lb)	1,016.05	Kilograms
FORCE/AREA		
Pounds per square inch	0.070307	Kilograms per square centimeter
Pounds per square inch	0.689476	Newtons per square centimeter
Pounds per square foot	4.88243	Kilograms per square meter
Pounds per square foot	47.8803	Newtons per square meter
MASS/VOLUME (DENSITY)		
Ounces per cubic inch	1.72999	Grams per cubic centimeter
Pounds per cubic foot	16.0185	Kilograms per cubic meter
Pounds per cubic foot	0.0160185	Grams per cubic centimeter
Tons (long) per cubic yard	1.32894	Grams per cubic centimeter
MASS/CAPACITY		
Ounces per gallon (U.S.)	7.4893	Grams per liter
Ounces per gallon (U.K.)	6.2362	Grams per liter
Pounds per gallon (U.S.)	119.829	Grams per liter
Pounds per gallon (U.K.)	99.779	Grams per liter
BENDING MOMENT OR TORQUE		
Inch-pounds	0.011521	Meter-kilograms
Inch-pounds	1.12985×10^6	Centimeter-dynes
Foot-pounds	0.138255	Meter-kilograms
Foot-pounds	1.35582×10^7	Centimeter-dynes
Foot-pounds per inch	5.4431	Centimeter-kilograms per centimeter
Ounce-inches	72.008	Gram-centimeters
VELOCITY		
Feet per second	30.48 (exactly)	Centimeters per second
Feet per second	0.3048 (exactly)*	Meters per second
Feet per year	$*0.965873 \times 10^{-6}$	Centimeters per second
Miles per hour	1.609344 (exactly)	Kilometers per hour
Miles per hour	0.44704 (exactly)	Meters per second
ACCELERATION*		
Feet per second^2	*0.3048	Meters per second^2
FLOW		
Cubic feet per second (second-feet)	*0.028317	Cubic meters per second
Cubic feet per minute	0.4719	Liters per second
Gallons (U.S.) per minute	0.06309	Liters per second
FORCE*		
Pounds	*0.453592	Kilograms
Pounds	*4.4482	Newtons
Pounds	$*4.4482 \times 10^5$	Dynes
WORK AND ENERGY*		
British thermal units (Btu)	*0.252	Kilogram calories
British thermal units (Btu)	1,055.06	Joules
Btu per pound	2.326 (exactly)	Joules per gram
Foot-pounds	*1.35582	Joules
POWER		
Horsepower	745.700	Watts
Btu per hour	0.293071	Watts
Foot-pounds per second	1.35582	Watts
HEAT TRANSFER		
Btu in./hr ft^2 degree F (k, thermal conductivity)	1.442	Milliwatts/cm degree C
Btu in./hr ft^2 degree F (k, thermal conductivity)	0.1240	Kg cal/hr m degree C
Btu ft/hr ft^2 degree F	*1.4880	Kg cal m/hr m^2 degree C
Btu/hr ft^2 degree F (C, thermal conductance)	0.568	Milliwatts/cm^2 degree C
Btu/hr ft^2 degree F (C, thermal conductance)	4.882	Kg cal/hr m^2 degree C
Degree F hr ft^2/Btu (R, thermal resistance)	1.761	Degree C cm^2/milliwatt
Btu/lb degree F (c, heat capacity)	4.1868	J/g degree C
Btu/lb degree F	*1.000	Cal/gram degree C
Ft^2/hr (thermal diffusivity)	0.2581	Cm^2/sec
Ft^2/hr (thermal diffusivity)	*0.09290	M^2/hr
WATER VAPOR TRANSMISSION		
Grains/hr ft^2 (water vapor transmission)	16.7	Grams/24 hr m^2
Perms (permeance)	0.659	Metric perms
Perm-inches (permeability)	1.67	Metric perm-centimeters

Table III

OTHER QUANTITIES AND UNITS

Multiply	By	To obtain
Cubic feet per square foot per day (seepage)	*304.8	Liters per square meter per day
Pound-seconds per square foot (viscosity)	*4.3824	Kilogram second per square meter
Square feet per second (viscosity)	*0.092903	Square meters per second
Fahrenheit degrees (change)*	5/9 exactly	Celsius or Kelvin degrees (change)*
Volts per mil	0.03937	Kilovolts per millimeter
Lumens per square foot (foot candles)	10.764	Lumens per square meter
Ohm circular mils per foot	0.001662	Ohm square millimeters per meter
Millicuries per cubic foot	*35.3147	Millicuries per cubic meter
Milliamps per square foot	*10.7639	Milliamps per square meter
Gallons per square yard	*4.527219	Liters per square meter
Pounds per inch	*0.17858	Kilograms per centimeter

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Table IV

SOME FREQUENTLY USED CONVERSION FACTORS

Multiply	By	To obtain
	FLOW	
Million gallons per day (mgd)	694.444	Gallons per minute (gpm)
Thousand gallons per day	.6944	Gallons per minute (gpm)
Million gallons per day (mgd)	1.5472	Cubic feet per second
Million gallons per day (mgd)	3.0689	Acre-feet per day
Million gallons per day (mgd)	2,628.69	Liters per minute
Million gallons per day (mgd)	3,785.41	Cubic meters per day
Million gallons per day (mgd)	2.6287	Cubic meters per minute
Cubic feet per second (second feet)	.6463	Million gallons per day (mgd)
Gallons per minute (gpm)	1.4400	Thousand gallons per day
	COST	
Cents per 1,000 gallons	3.2585	Dollars per acre-foot
Cents per 1,000 gallons	.2642	Cents per cubic meter

ESTIMATING AIDS
SEAWATER CONVERSION PLANTS

Capital costs of possible natural freshwater facilities can be made by engineers experienced in similar construction projects. Because of the limited experience in construction of desalination facilities, however, it may be more difficult to secure rough estimates for desalination. In such cases the following procedure and accompanying notes and nomographs (found at the end of this appendix) may be utilized to determine approximate capital costs and unit costs of water for seawater desalination facilities under conditions which will be used in the preliminary feasibility studies.

Most of the seawater desalination plants built or proposed in the past several years have utilized the multistage flash evaporation process and were designed for a top brine temperature of 200F to 250F. Other leading seawater desalination processes, however, have capital and operating costs generally comparable to those of the multistage flash plants. Therefore, while the Unit Desalination Plant Capital Cost Nomograph is based on multistage flash evaporator plants, it may be utilized for other leading seawater desalination cost approximations.

Estimating aids for brackish water desalination facilities have not been included, as the variation in costs due to local water conditions requires a more detailed approach; however, a listing of typical costs of electrodialysis plants ranging in nominal capacity from 250,000 to 2,500,000 gpd is shown in Table C-5. It should be noted that this table is based on plants using Webster, South Dakota water which has a salinity of approximately 1,400 ppm and a product water salinity of approximately 500 ppm. This 60% reduction in salinity required 3 stages. A more saline brackish water supply or a less saline product water requirement would require more stages and, therefore, a more costly installation.

Since seawater desalination processes may be utilized on brackish water sources, the seawater desalination costs may be used as the upper limit of the costs of brackish water desalination.

DESALINATION FACILITY CAPITAL COSTS

The first step in preparing the capital cost approximations is to establish the following preliminary design conditions (Notes 1 and 2 at the end of this appendix may be useful in establishing these values):

(Source: Volume II, Appendix C, Estimating Aids.)

1. Plant capacity in gallons per day (gpd) -- see Note 1, C-5.

2. Plant operating factor -- see Note 1.

3. Economy ratio -- see Note 2, C-5

Having selected the nominal plant capacity, the plant operating factor and several economy ratios (in accordance with the preliminary feasibility study requirements and the corresponding notes), one may begin the determination of the estimated desalination facility capital cost. This is accomplished in the following manner:

1. Determine the unit desalination plant capital cost for each economy ratio by utilizing the Unit Desalination Plant Capital Cost Nomograph, Figure C-1.

2. Determine the desalination plant capital cost for each economy ratio by multiplying the unit desalination plant capital cost determined above by the nominal plant capacity. Tabulate the results in Table C-1 below.

3. Determine and tabulate the heat source capital cost for each economy ratio, as described in Note 3, page C-6.

4. Determine and tabulate the product water conveyance capital cost, as described in Note 4, page C-6.

5. Determine and tabulate the land capital cost, as described in Note 5, page C 6.

6. Determine and tabulate the other capital costs and contingency, as described in Note 6, page C-7.

7. Complete Table C-1 and determine the unit facility capital cost by dividing the total desalination facility capital cost by the nominal plant capacity.

For examples, see Table C-3, page C-8.

TABLE C-1

DESALINATION FACILITY CAPITAL COST

Economy ratio				
Desalination plant capital cost				
Heat source capital cost				
Product water conveyance capital cost				
Land capital cost				
Subtotal				
Other capital costs and contingency				
Total Desalination Facility Capital Cost				
Unit facility capital cost, $ per daily gallon				

UNIT COST OF WATER

Before utilizing the nomographs and notes (at the end of this appendix) to estimate the unit cost of water, it is necessary to establish the following preliminary feasibility study conditions:

1. Fixed charge rate -- see Note 7, C-7.

2. Unit cost of fuel -- see Note 8, C-9.

3. Hourly labor cost -- see Note 9, C-10.

4. Chemicals and other costs -- see Note 10, C-10.

Having determined the fixed charge rate, the unit cost of fuel and the hourly labor cost, the estimating of the unit cost of water may be accomplished in the following manner:

1. Determine, and tabulate below, the fixed cost component (for each economy ratio) by utilizing the Fixed Cost Component Nomograph, Figure C-2.

2. Determine, and tabulate below, the fuel cost component (for each economy ratio) by utilizing the Fuel Cost Component Nomograph, Figure C-3.

3. Determine, and tabulate below, the labor cost component by utilizing the Labor Cost Component Nomograph, Figure C-4.

4. Determine, and tabulate below, the chemical and other unit costs, as described in Note 10.

5. Total the above to determine the unit cost of water. The economy ratio that results in the lowest unit cost of water will then be evident.

TABLE C-2

UNIT COST OF WATER

Economy ratio				
Fixed cost component				
Fuel cost component				
Labor cost component				
Chemical and other unit costs				
Total Unit Cost of Water				

Note: The above approximations used in determining the unit cost of water treat the nondepreciable items of land and working capital as though they were depreciable items, whereas a lower fixed charge rate (excluding depreciation and insurance) should be used on these items. This error, however, is small in relation to the other uncertainties of this estimate.

NOTES AND NOMOGRAPHS

Note 1 - Nominal Plant Capacity and Plant Operating Factor

The nominal plant capacity is usually expressed in gallons per day--the amount of product water that will be produced when the plant is running at design conditions. Every desalination plant, however, must be shut down occasionally for preventive maintenance and for repair of tube leaks and other unscheduled outages. The water that a plant can be expected to produce each year is not 365 times its design daily capacity, but is some factor (less than 1) multiplied by 365 times its design daily capacity. This factor is the plant operating factor, which is defined as the ratio of actual annual water production to the quantity of water that could be produced annually if the plant were operated continuously at full rated output. The plant operating factor usually is expressed as a percentage value. A plant operating factor of 90% has been assumed to be achievable in some feasibility studies for single-purpose plants.

Therefore, the nominal plant capacity should be selected to secure the required annual product water production with a reasonable plant operating factor (usually 90% for single-purpose plants or 80% to 85% for dual-purpose electric-power water-desalination plants).

The Unit Desalination Plant Capital Cost Nomograph is based on desalination plants consisting of only one module (module capacity and nominal capacity are the same). When plants of several modules are being considered, the unit desalination plant capital cost and the desalination plant capital cost should be determined for each module (by using module capacity for nominal capacity). The sum of the capital costs of the modules should be used as the desalination plant capital cost in Table C-1.

Note 2 - Economy Ratio

Seawater distillation plants require saturated steam at approximately 25 psig. (Low cost steam to as low a pressure as 10 psig may be utilized with only a small increase in desalination plant capital cost.) One measure of plant performance is the economy ratio--defined as the pounds of product water produced per pound of steam supplied to the plant. The appropriate economy ratio to use in the plant design must be determined by optimizing the design for lowest unit water cost. For low unit cost of fuel and relatively high fixed charge rates, a low economy ratio (4 to 6) may be optimum. For high fuel costs and low fixed charges, a higher economy ratio may be optimum.

The nomographs may be used as a means of approximating the optimum economy ratio by selecting a value (usually about 8) and performing the necessary calculations to determine the unit cost of water. Then, values of economy ratio higher and lower than 8, say 6 and 10, should be selected and the new unit cost of water determined for each. These calculations should be continued until an economy ratio is found that results in the lowest unit cost of water.

Note 3 - Heat Source Capital Cost

The approximate capital cost of an oil or gas fired boiler may be determined by the following empirical equation:

$$\text{Heat source capital cost} = 0.55^{*} \times \frac{\text{nominal plant capacity (gpd)}}{\text{economy ratio}}$$

*An empirical value determined by boiler cost-capacity correlations.

Note 4 - Product Water Conveyance Capital Cost

To determine the approximate capital cost of the product water conveyance, determine the miles of conveyance required and multiply by the typical cost per mile, from the table below.

Nominal Plant Capacity, gpd	Pipe Diameter, Inch	Typical Cost/Mile
100,000	4	$ 6,500
200,000	6	18,000
300,000	8	22,000
500,000	8	22,000
1,000,000	10	27,000
2,000,000	12	32,000
3,000,000	16	43,000
4,000,000	20	57,000
5,000,000	20	57,000
7,500,000	24	71,000
10,000,000	24	71,000

Note 5 - Land Cost

The desalination plant capital cost estimates determined by use of the nomograph include typical cost of on-site improvements such as surveys, roadways and paved areas but excludes land cost.

The land required to accommodate a desalination facility of 1 million gpd capacity is approximately 2 acres. For a desalination plant facility of 10 million gpd approximately 10 acres are required. In addition to the cost of the land itself, the land cost should include allowance for site access and such costs as surveys, right of ways, access roadways, and unusual site development work. Since these capital costs vary greatly with location and site conditions, estimates should be prepared by those familiar with the proposed site and with local site development costs.

Note 6 - Other Capital Costs and Contingency

Other costs required to construct and operate a desalination facility are:

a. The cost of engineering, design, inspection and procurement

b. The owner's expenses prior to commercial operation of the facility including start-up

c. Interest during construction

d. Working capital including allowances for inventory costs of fuel, chemicals, materials, and supplies; for insurance prepayment; for spare parts inventory and for accounts receivable.

While the nomograph used in estimating the desalination plant capital cost is based on actual plants and estimates of proposed plants, which may in some cases include contingency, it is appropriate to include a contingency in this cost estimate as well.

To provide an allowance for other costs and contingency, a percentage of the cost of the desalination facility may be used. A value of 20% of the cost estimate of the desalination facility (sum of desalination plant capital cost, heat source capital cost, product water conveyance capital cost and land capital cost) is recommended as the allowance for other capital costs and contingency.

Note 7 - Fixed Charge Rate

Whenever possible, the fixed charge rate on capital investment should be based on factual information for the specific project. For study evaluations and projects on which the actual fixed charge rate is not available, a fixed charge rate may be developed by the method outlined below.

The fixed charge rate on depreciable capital comprises the following elements:

a. Interest charges

b. Depreciation

c. Interim replacements

d. Property insurance

e. Federal income taxes (none in the case of a municipal utility)

f. State and local taxes

In the case of a utility operated by a government entity, the interest charges would be representative of the interest rate at which bonds could be sold by that government agency. Once the interest rate and plant life is known, the depreciation can be determined. Table C-3 gives the sinking fund depreciation for different interest rates and depreciation periods. For depreciable capital, the sum of the interest rate plus depreciation is the amortization rate that will recover the capital investment over the depreciation period. Note that in the case of nondepreciable capital, such as land and working capital, no depreciation or interim replacement is applied and insurance is applied only to inventory items such as spare parts.

TABLE C-3

ANNUAL SINKING FUND DEPRECIATION FOR DIFFERENT PERIODS (YEARS)

Interest Rate, %/Yr	10 Yr	15 Yr	20 Yr	25 Yr	30 Yr	35 Yr	40 Yr
2	9.13	5.78	4.12	3.12	2.46	2.00	1.66
3	8.72	5.37	3.72	2.74	2.10	1.65	1.32
4	8.33	4.99	3.35	2.40	1.78	1.38	1.05
5	7.95	4.63	3.02	2.10	1.51	1.11	0.83
6	7.59	4.30	2.72	1.82	1.26	0.90	0.65
7	7.24	3.98	2.44	1.58	1.06	0.72	0.50
8	6.90	3.68	2.19	1.37	0.88	0.58	0.39

For a detailed engineering study of a proposed desalination plant, the allowance for interim replacements of tubes and other plant components may be based on a detailed projection of tube failure rates (for a distillation plant) as a function of plant life. Lacking such a detailed analysis, a value of 1% may be added to the fixed charge rate to allow for interim replacement. This value is approximately correct for a 15-year tube life and a 30-year plant life. It should be noted that interim replacements are sometimes included as an operating cost element, rather than as a component of fixed charges for the approximate cost estimates outlined herein.

Annual property insurance cost may be taken as 0.2% of the depreciable capital cost--this is a typical average value for utilities such as fossil-fueled power plants.

A municipally-owned utility does not pay federal income taxes but may incur state and local taxes, or costs in lieu of local taxes.

Tabulated below is a typical breakdown of fixed charge rates for a municipally-owned utility, assuming 4% interest rate and a 30-year plant life.

	Depreciable Capital, %	Nondepreciable Capital, %
Interest charges	4.0	4.0
Depreciation (30-year sinking fund basis)	1.8	-
Interim replacements	1.0	-
Insurance, property	0.2	-
State and local taxes (or costs in lieu of local taxes)	1.4	1.4
Total Fixed Charge Rate	8.4%	5.4%

Note 8 - Unit Cost of Fuel

The unit cost of fuel (oil or gas) is the cost (in cents per million Btu--higher heating value) at the plant site. The unit cost should include transportation and unloading costs and demand charges.

Note 9 - Hourly Labor Cost

The hourly labor cost is the wages paid each hour to the plant staff plus allowance for overhead and for general and administrative expenses. Because the day shift may include an operator and several maintenance men, whereas the night shifts may have only operators, the wages should be determined by dividing the weekly or monthly total wages (including overhead and general and administrative expense) by the total hours in the same period.

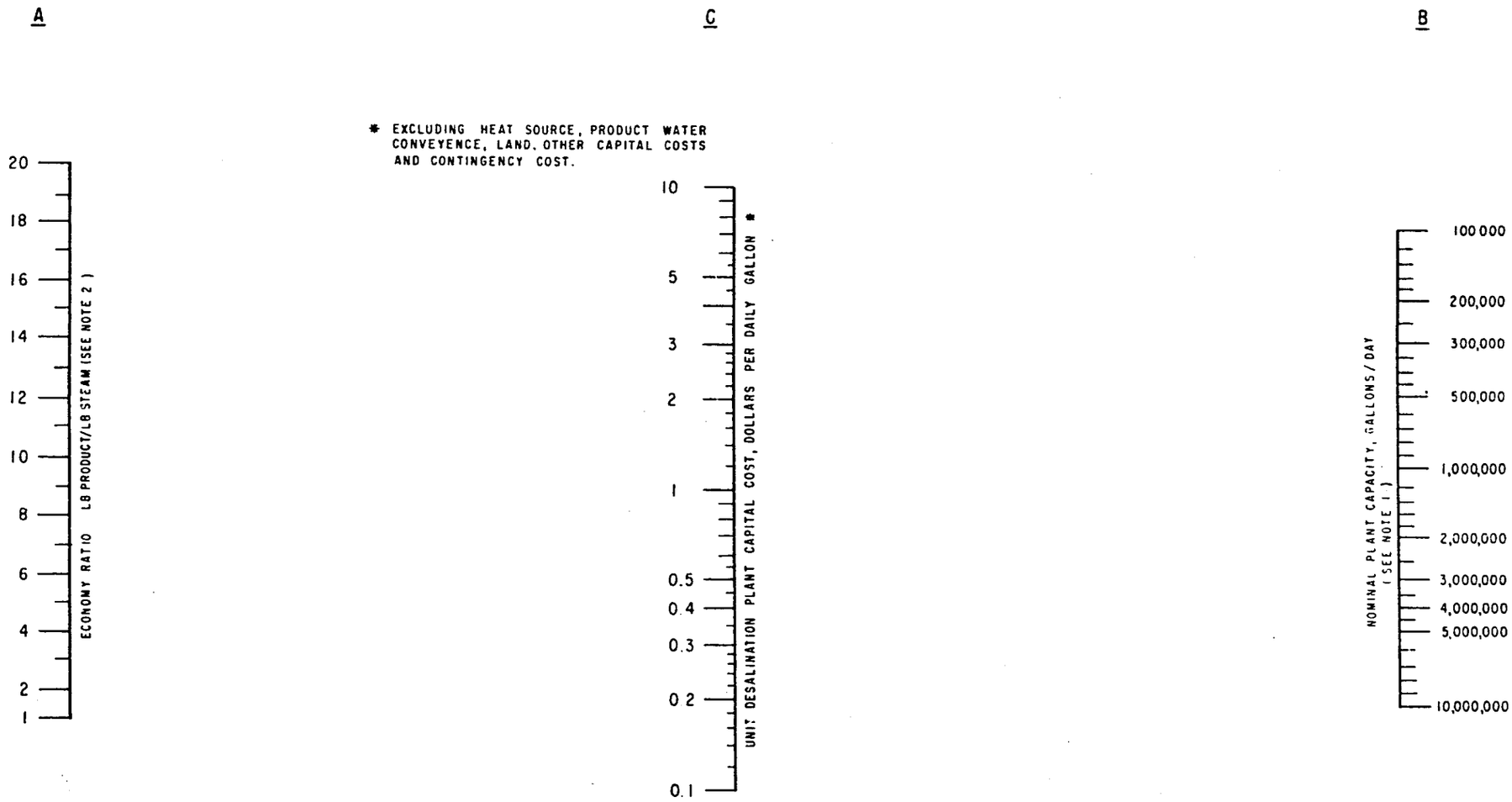
Note 10 - Chemicals and Other Unit Costs

The chemicals required for a seawater desalination facility include H_2SO_4, chlorine and caustic. The other unit costs include electric power for pumps, instruments and lighting. An allowance of $0.08 per 1,000 gallons should be made for the chemical and other unit costs.

Note 11 - E. N. R. Building Cost Indices

To bring the 1967 costs used in the foregoing nomograms to a March 1972 basis, they must be multiplied by the ratio of 1972 to 1967 prices as given by the Engineering News Record Building Cost Indices, or 1015/666 = 1.51.

UNIT DESALINATION PLANT CAPITAL COST NOMOGRAPH

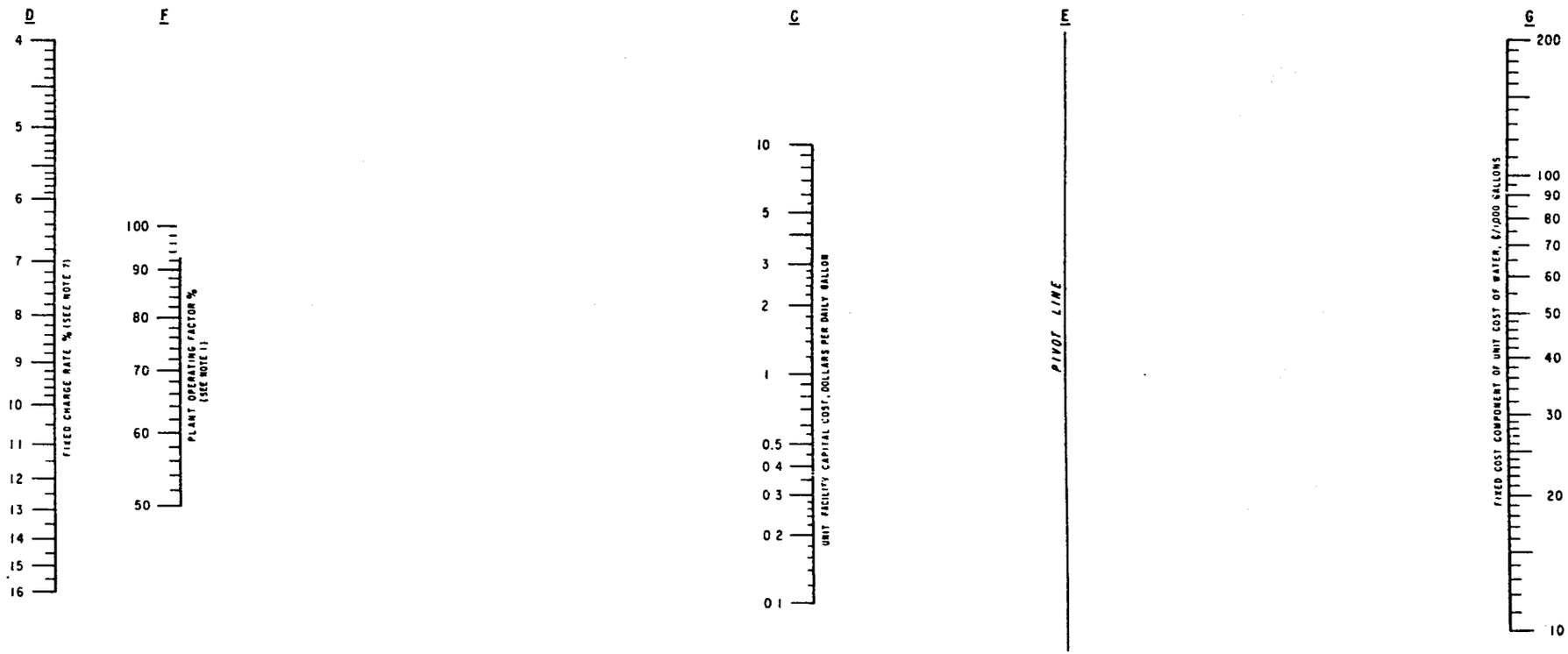


1. Connect the selected economy ratio on Scale A and nominal plant capacity on Scale B by a straight line, and note where this line crosses Scale C.

2. To obtain the desalination plant capital cost, multiply the unit capital cost value noted on Scale C by the nominal plant capacity (gpd), and record it in Table C-1, Desalination Facility Capital Cost.

FIGURE C - 2

FIXED COST COMPONENT NOMOGRAPH



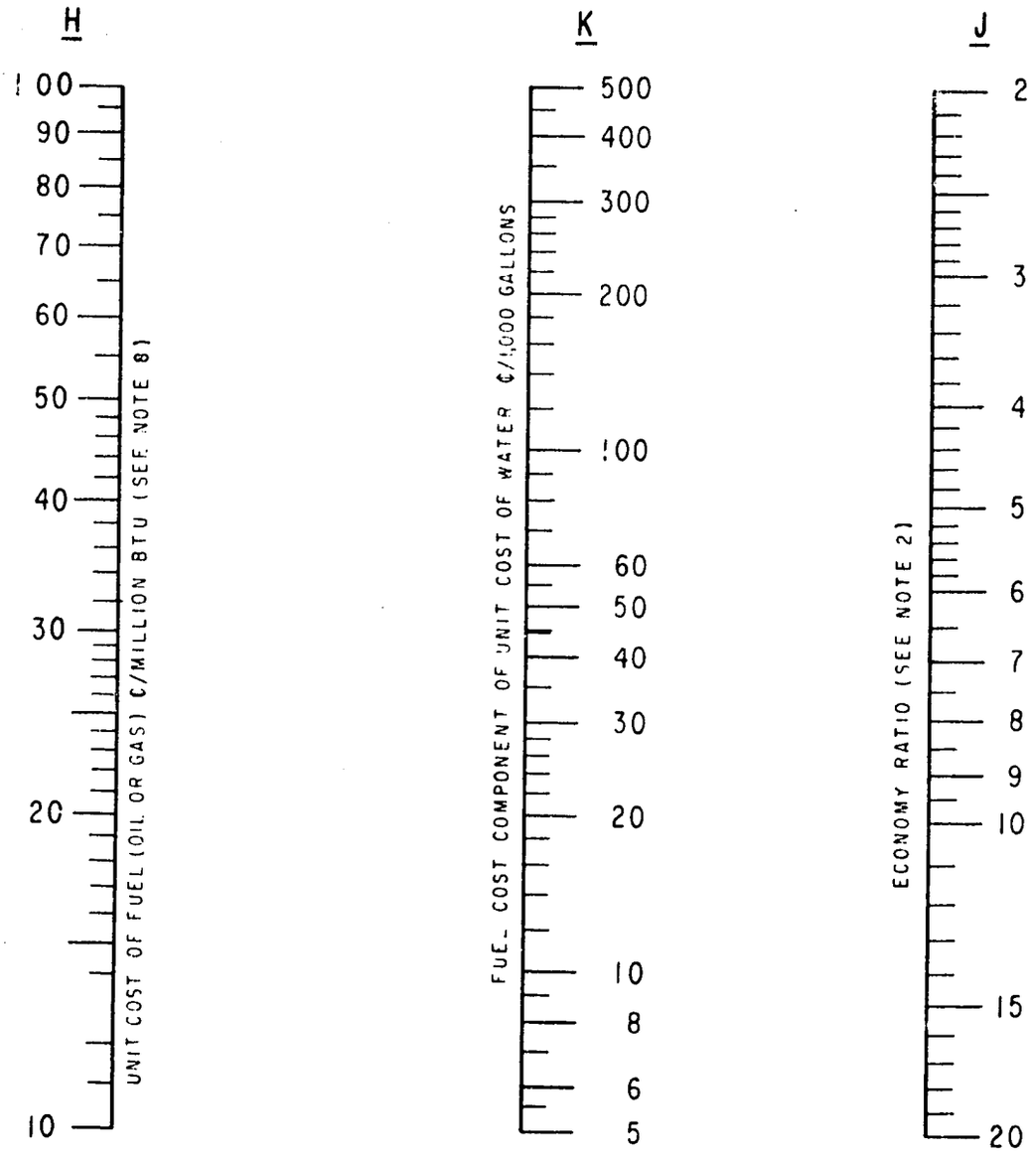
1 Draw a straight line from the unit facility capital cost (as determined in Table C-1) on Scale C to the fixed charge rate on Scale D and note where the extension of this line crosses the pivot line E.

2 Draw a straight line from the plant operating factor on Scale F through the point on the pivot line on Scale E and note where Scale G is crossed

3 Read the value of the fixed cost component on Scale G and record it in Table C-2. Unit Cost of Water

FIGURE C - 3

FUEL COST NOMOGRAPH

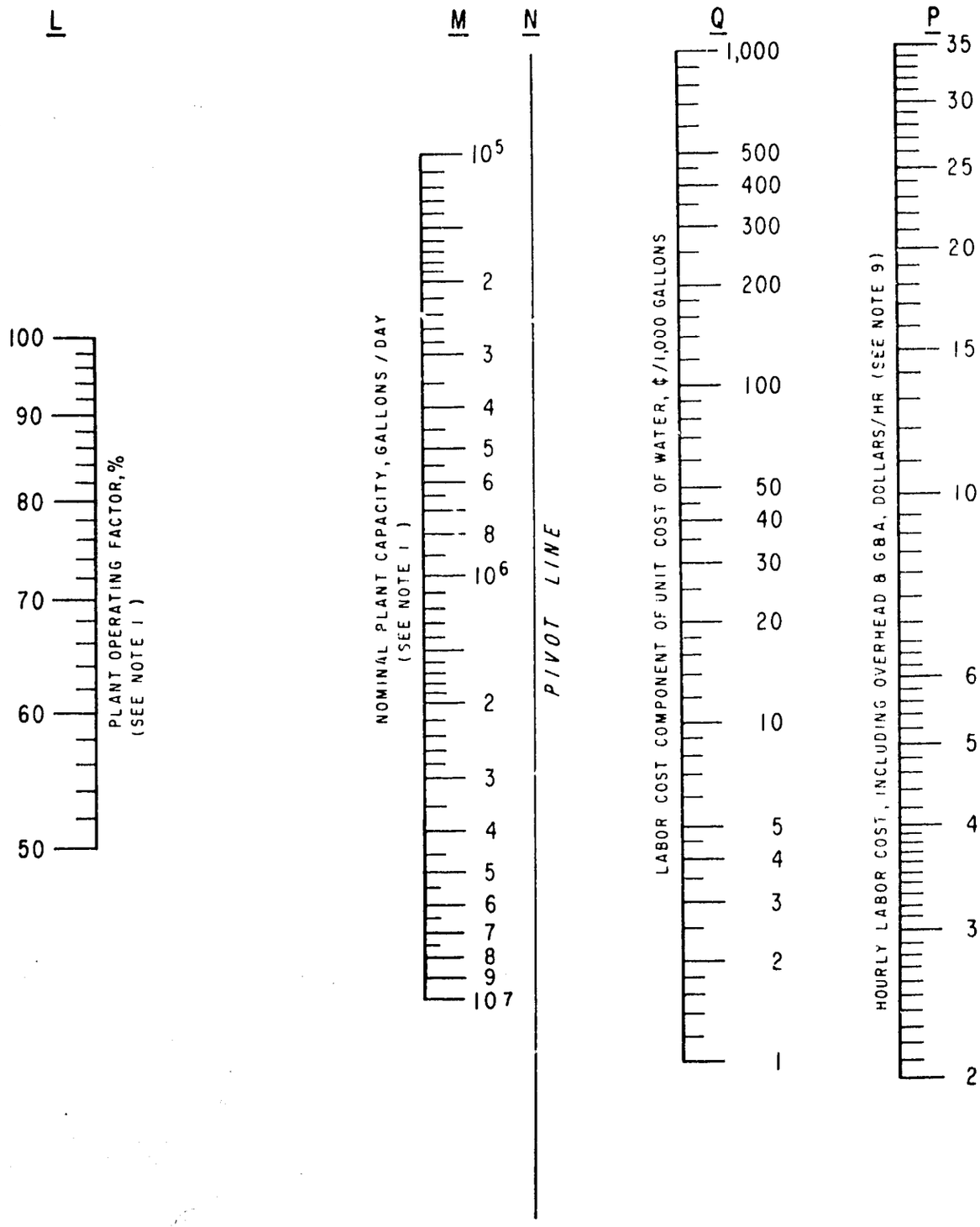


1. Draw a straight line from the unit cost of fuel on Scale H to the economy ratio on Scale J, and note the crossing of Scale K--fuel cost component of unit cost of water.

2. Read the value on Scale K, and record it in Table C-2, Unit Cost of Water.

FIGURE C - 4

LABOR COST NOMOGRAPH



1. Draw a straight line connecting the plant operating factor on Scale L with the nominal plant capacity on Scale M and note where an extension of this line crosses the pivot line, Scale N.

2. Draw a straight line connecting this point on the pivot line, Scale N, with the hourly labor cost on Scale P, and note where Scale Q--labor cost component--is crossed.

3. Read the labor cost component at this point and tabulate it in Table C-2, Unit Cost of Water.

ESTIMATING AIDS
INLAND AND BRACKISH WATER DESALTING PLANTS

General

Volume II, Appendix C, presented a rapid means for calculating costs of seawater conversion by multi-stage flash evaporation, which in 1967 was the only commercially available process for producing large volumes of water. This calculation method, using Nomograph C-1, is still valid for coastal sites where large volumes of cooling water are available and where brine disposal is not a problem. The original Nomograph C-1 is also adaptable to the new, enhanced-tube VTE process, simply by escalating costs from their 1967 base of 666 to the March 1972 value of 1015 (ENR Building Cost Index). Thus for seawater conversion and for coastal locations, the original costing methods of the AID Manual suffice.

For inland locations, however, highly efficient saline conversion methods, which do not require large volumes of cooling water, and which can concentrate the brines almost to dryness in order to minimize the disposal problem, must be employed. Such processes are reverse osmosis, electrodialysis, vapor compression, and vapor-compression vacuum-freezing. These and their combinations, or hybrids, have all been considered in OSW R&D Report No. 555, Desalting Cost Calculating Procedures, prepared by Southwest Research Institute and published by OSW in February 1970. It is not the purpose of this Appendix or of this manual to reproduce OSW No. 555. However, to allow quick pricing of the reverse osmosis process, which can serve as a standard with which all other potential inland saline water conversion schemes can be compared, certain data, formulae, curves and illustrations are reproduced herein, as necessary to achieve this end.

The Cost Summary Worksheet for 1970 which has been reproduced herein utilizes an ENR Building Cost Index of 825 and a Labor Cost Index of 321, which are assumed base values for May 1970. Following the 1970 Worksheet is a 1972 Reverse Osmosis Cost Summary Worksheet, which has been obtained from the former by multiplying all 1970 capital costs by 1015/825 = 1.23 and all operating and maintenance labor costs by 360/321 = 1.12. By following this procedure, the calculations are simplified, since all items are first calculated upon 1970 base costs exactly as given by Report No. 555, and then the assembled data are escalated all at once, rather than piecemeal.

Desalting Processes and Costing Procedures for Inland Desalting Plants

When background data have been collected for each study community, and when projections of water demands have been made, then desalt plant capacities can be designated and calculations made for each process. It is the purpose of this section of the report to describe the basic assumptions used, the processes considered, how plant capacities are determined, cost methodology, and the procedures used for disposal of desalt plant brine effluents. Appendix C includes descriptions, sample worksheets, graphs and related data.

Factors used in calculating 1972 desalt plant costs include:

Interest rates for financing public works is 4-7/8 percent, in keeping with municipal experience in the particular locale.

Equipment life is 30 years for desalt plant and brine disposal equipment and for water transmission plants. Annual equipment capital costs are calculated using appropriate amortization rates which are 0.0641 for 30 years.

Capital cost data provided by OSW 555 must be updated by a factor of 1.23 which represents the ratio of 1015:825, the Building Cost Indices for March 1972 and January 1970 (OSW 555), respectively. These indices are published by the Engineering News Record and afford an opportunity to correct later calculations for increased construction costs.

A labor rate of $3.60 per hour is used based on average hourly earnings of nonsupervisory workers in water and sewage treatment plants. This correlates well with United States averages published by the Bureau of Labor Statistics. The January 1970 labor rate given in OSW 555 was $3.21 per hour; therefore, operation and maintenance labor costs in OSW 555 are corrected by the factor 3.60:3.21, or 1.12.

In keeping with OSW 555, cost of pretreatment chemicals

for inhibition of scaling and/or pH control is estimated at 3.0¢/kgal of product water.

Local costs for chemicals used in the United States are:

Lime	$24 per ton
Ammonia	$60 per ton
Sulfuric Acid	$40 per ton
Salt	$20 per ton

Local land, fuel, and electricity costs are used for each study community.

Right-of-way costs for pipelines are computed on the basis of 1.5 acres per mile.

In keeping with OSW 555, an annual maximum load factor of 90 percent is used.

All unit costs are calculated on a product water basis. Annual costs for amortization of capital are divided by total annual product water production in order to obtain unit costs.

Where blending of desalt plant product water with feedwater or other water will yield a final product within the required quality specifications, blending has been assumed and unit costs reported are those of the final blended water. The National Water Institute has suggested that blending to achieve a minimum hardness of 120 to 150 ppm as calcium carbonate will serve to minimize distribution system corrosion.

Preheating of feedwater for membrane processes is assumed where the net effect is the reduction of unit costs. Preheater capital and operating cost data can be developed from OSW 273 and updated.

Where possible, some of the brine is added to sewage plant effluents to a limit somewhat less than the current salt burden. The remaining brine volume is directed to evaporation ponds, or to irrigation runoff canals.

A total dissolved solids buildup of 250 ppm is assumed for sewage effluents as compared to community water system quality.

Water Quality Standards. The United States Public Health Service has established standards for drinking water, and these have served as a basis for this study in calculating quality goals for desalting. The recommended USPHS maximum concentrations are summarized below.

Constituent	Maximum Concentration, ppm
Chloride	250
Fluoride	1.0
Iron	0.3
Magnesium Salts	125
Manganese	0.05
Nitrate	45
Sulfate	250
$CaCO_3$ Hardness	100
TDS	500

The following pages, including Section X, Brine Disposal, are reproduced directly from OSW R&D Report 555.

APPENDIX C

SAMPLE HAND CALCULATION

REVERSE OSMOSIS DESALT PLANT COMPLEX

REVERSE OSMOSIS PROCESS
SUMMARY WORKSHEET

Cost Elements	10^3	Annual Cost $	Water Costs ¢/kgal
Capital Costs			
1. Plant and Equipment	2,250	144,225	8.7
2. Feedwater Pretreatment	-	-	-
3. Feedwater Supply	280	17,948	1.1
4. Water Transmission	259	16,615	1.0
5. Brine Disposal	580	37,178	2.3
Total Capital Costs	3,369	215,966	13.1
Operation and Maintenance Costs			
6. Operating and Maintenance Labor			
a. Plant and Equipment			4.2
b. Feedwater Pretreatment			-
c. Feedwater Supply			1.6
d. Water Transmission			1.0
e. Brine Disposal			6.1
Total Operating and Maintenance Labor			12.9
7. Other Operation and Maintenance Costs			
a. Payroll Extras (15% of 6a)			0.6
b. General and Administrative Overhead (30% of 6a + 7a)			1.4
c. Supplies and Maintenance Materials			1.4
d. Membrane Assembly or Replacement Tubing			10.0
e. Chemicals			3.0
f. Fuel or Steam			n.r.
g. Electric Power			
Plant and Equipment			11.0
Feedwater Supply			2.1
Water Transmission			0.1
Total Other Operation and Maintenance Costs			29.6
Total Operation and Maintenance Costs			42.5
Total Water Cost (Total Capital Plus O. & M. Costs)			55.6

n.r. - none required

1972 PRICES
REVERSE OSMOSIS PROCESS
SUMMARY WORKSHEET

(1970 Capital Costs Multiplied by 1.23)
(1970 O&M Labor Costs " " 1.12)

Cost Elements	10^3	Annual Cost $	Water Costs ¢/kgal
Capital Costs			
1. Plant and Equipment	2770	177,500	10.75
2. Feedwater Pretreatment	--	--	--
3. Feedwater Supply	345	22,100	1.34
4. Water Transmission	318	20,400	1.24
5. Brine Disposal	714	45,700	2.8
Total Capital Costs	4147	265,700	16.13
Operation and Maintenance Costs			
6. Operating and Maintenance Labor			
a. Plant and Equipment			4.72
b. Feedwater Pretreatment			--
c. Feedwater Supply			1.8
d. Water Transmission			1.12
e. Brine Disposal			6.85
Total Operating and Maintenance Labor			14.49
7. Other Operation and Maintenance Costs			
a. Payroll Extras (15% of 6a)			0.7
b. General and Administrative Overhead (30% of 6a + 7a)			1.6
c. Supplies and Maintenance Materials			1.4
d. Membrane Assembly or Replacement Tubing			10.0
e. Chemicals			3.0
f. Fuel or Steam			n.r.
g. Electric Power			
Plant and Equipment			11.0
Feedwater Supply			2.1
Water Transmission			0.1
Total Other Operation and Maintenance Costs			29.9
Total Operation and Maintenance Costs			44.4
Total Water Cost (Total Capital Plus O. & M. Costs)			60.5

n.r. - none required

REVERSE OSMOSIS PROCESS

Reverse osmosis, a relatively new process for the conversion of saline water to potable water, appears to have considerable potential for economic application for desalting slightly to moderately brackish water. The theoretical energy requirements for RO are considerably less than those for distillation or freezing, both of which require a phase change.

Reverse osmosis drinking water purifiers have been in operation since 1967. The largest RO system installed to date is a 100,000-GPD plant at Plains, Texas. Plains is using this plant to improve the quality of the present city water supply.

Since June 4, 1965, the city of Coalinga, California has been operating a 5,000-GPD reverse osmosis pilot plant designed by the University of California at Los Angeles. The Water Desalination Research Group at UCLA conducted field tests on this unit until December 31, 1968.

Reverse Osmosis Plant Capital Cost Determination

A precise composite economic analysis of reverse osmosis desalting plants is difficult to make because of several factors. There are four basic configurations of RO membranes: plate and frame, tubular, spiral wound, and hollow fiber. The membrane surface area for a given volume throughput and the module size vary considerably for each of these configurations. Different membrane materials, feedwater salinities, and system pressures cause variations in recovery factors (percent of feedwater recovered as product water) and rejection factors (percent of feedwater salinity, ppm rejected).

Thus, for a given feedwater and desired product water, the correct membrane and operating conditions must be selected to obtain the lowest product water cost. Recovery factors range from 50 to 80 percent; in this manual, a recovery factor of 75 percent is assumed. System operating pressure is assumed to be 800 psig.

Plant and equipment capital costs are obtained from Figure 13. This is a composite curve of RO plant and equipment, land, and indirect capital costs versus plant capacity, based on costs prepared by leading RO developers.

Land costs are included at $2,000 per acre. If land costs vary substantially from this amount, the difference can be multiplied by the land requirements obtained from Figure 14 to arrive at a capital cost correction.

Indirect capital costs of 20 percent have been included to cover interest during construction (5%), engineering and design (5%), and contingency costs (10%). Contingency costs include such items as construction supervision, administration, and miscellaneous expenses.

Amortization of the debt. The capital cost should be amortized and converted to ¢/kgal. Use the procedures set forth in Section II, "How to Use Manual."

Reverse Osmosis Plant Operation and Maintenance Costs Determination

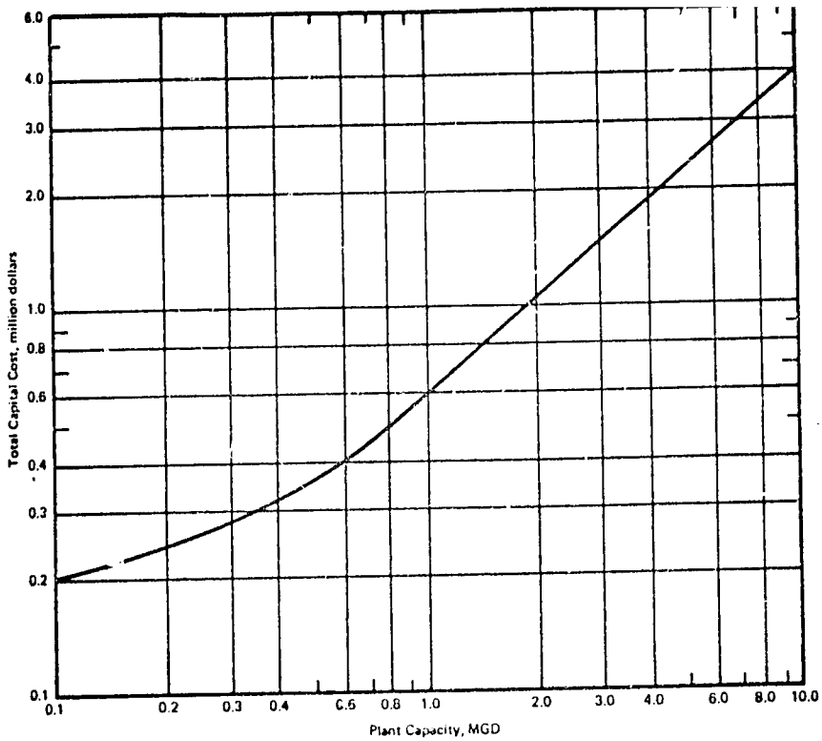
Operation and maintenance costs for a RO plant include the following seven elements:

(1) Operating and maintenance labor,

(2) Payroll extras (fringe benefits),

(3) General and administrative overhead,

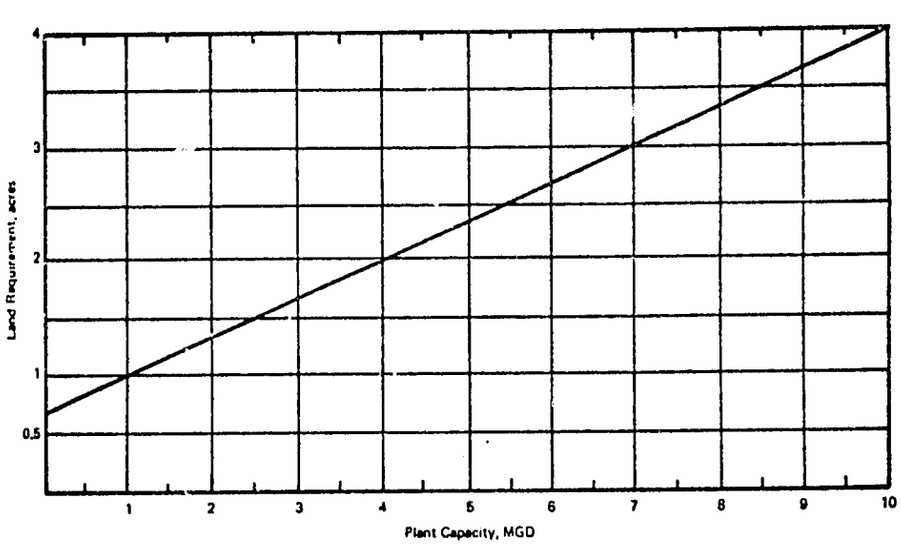
(4) Supplies and maintenance materials,



Source: Office of Saline Water and Southwest Research Institute

Figure 13

REVERSE OSMOSIS PLANT CAPITAL COSTS



Source: Southwest Research Institute

Figure 14

REVERSE OSMOSIS PLANT LAND REQUIREMENTS

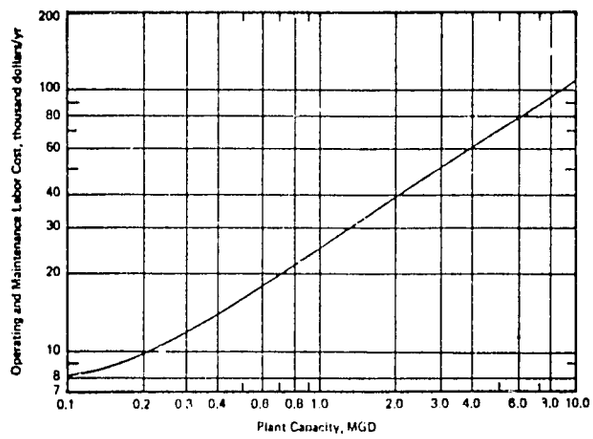
(5) Membrane assembly replacement,

(6) Chemicals, and

(7) Electric pumping power.

Each of these items must be expressed as cents per thousand gallons (¢/kgal).

(1) **Operating and maintenance labor** costs for RO plants are shown in Figure 15. These costs include the labor and supervision of membrane replacement. Costs have been adjusted using a projected labor cost index of 3.21 for December 1969 as shown on Figure A-2, Appendix A. Future estimates should be updated in accordance with the most recent labor cost index information available from the U.S. Department of Labor.



Source: Southwest Research Institute

Figure 15

REVERSE OSMOSIS OPERATING AND MAINTENANCE LABOR COSTS

(2) **Payroll extras** include the allowance for vacation, sick leave, and company contributions to insurance and retirement funds. Payroll extras are calculated at 15 percent of the combined operating and maintenance labor costs.

(3) **General and administrative overhead** costs are calculated at 30 percent of the total of (a) operating and maintenance labor, and (b) payroll extras.

(4) **Supplies and maintenance materials** include all expendable materials other than fuel, chemicals, and membranes. The annual cost is calculated as 1 percent of plant and equipment capital costs, based on information furnished by the Office of Saline Water.

The above four cost elements have been derived on an annual cost basis and must be reduced to unit cost by dividing the annual cost by the annual water production. As derived in Section II, "How to Use Manual," this is done by using equation (2):

$$¢/\text{kgal} = \frac{\text{annual cost in dollars}}{\text{MGD} \times 3300} \qquad (2)$$

(5) **Membrane assembly replacement** cost is estimated at 10 cents per thousand gallons of product water. This estimate is based on Reference 1 which assumed an annual market demand of 50 MGD for reverse osmosis plants. The vendors of these assemblies should be contacted for more accurate estimates.

(6) **Chemical** costs, on the basis of information furnished by the Office of Saline Water, are estimated at 3 cents per thousand gallons of product water. This includes the cost of pre- and post-treatment chemicals.

(7) **Electric pumping power** is estimated at 11 kilowatt hours (KWH) per thousand gallons (kgal) of product water. This estimate includes cell pumping power (10 KWH/kgal) and power for pumping product water against a 250-ft head to elevated storage tanks (1 KWH/kgal). The gross input to the RO system is 13 KWH/kgal, but 2 KWH/kgal are recovered from the brine stream by the power recovery turbine. These power estimates are based on pump and power turbine efficiencies of 85 percent and motor efficiencies of 93 percent. Power costs in ¢/kgal can be obtained by multiplying power requirement by cost of electric power in ¢/KWH.

Summary of operation and maintenance cost elements. The total of the above seven individual cost elements constitutes the total operation and maintenance cost for a reverse osmosis desalting plant.

The costs of the following ancillary facilities must be added to plant costs to obtain the cost for a reverse osmosis complex. The sections which describe the method for calculating these segments of the total complex cost are listed below:

Facility	Section
Feedwater pretreatment	This section
Feedwater supply	VIII
Water transmission	IX
Brine disposal	X

A sample calculation of the total capital and operating costs for a complete reverse osmosis complex with ancillary facilities will be found in Appendix C of this manual. Before the costs of a reverse osmosis complex can be calculated, the plant intake and brine discharge requirements must be known.

Plant Intake and Brine Discharge Requirements

The equation for the material balance of water in a RO plant is as follows:

$$C_i = C_p + C_b \tag{13}$$

where

C_i = feedwater intake rate, MGD
C_p = product water rate, MGD (design capacity)
C_b = brine effluent rate, MGD

The following equation can be used to calculate plant intake requirements:

$$C_i = \frac{C_p}{R} \tag{17}$$

where

R = Recovery factor, the percent of intake water recovered as product water.

Substituting a water recovery factor of 75 percent for R

$$C_i = \frac{C_p}{0.75}$$

For example, the intake requirements for a 5.0-MGD plant would be

$$C_i = \frac{5.0 \text{ MGD}}{0.75} = 6.7 \text{ MGD}$$

Rearrangement of equation (13) to solve for C_b yields:

$$C_b = C_i - C_p$$

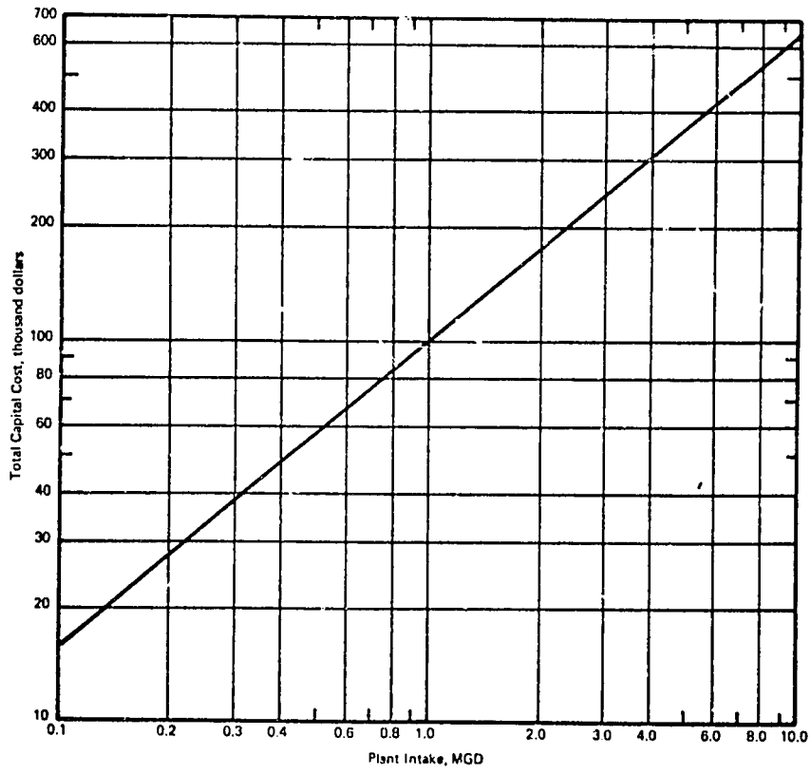
Brine discharge requirements for this example would be:

$$C_b = 6.7 \text{ MGD} - 5.0 \text{ MGD} = 1.7 \text{ MGD.}$$

Feedwater Pretreatment

Manufacturers of reverse osmosis equipment should be consulted when brackish feedwaters containing high concentrations of some constituents are encountered. For example, Capitan Reef water in West Texas contains high concentrations of calcium and hydrogen sulfide. Manufacturers of RO equipment to be used in this area should recommend the pretreatment methods applicable to the problem.

The presence of iron and manganese in the feedwater can lead to a serious reduction in efficiency and a subsequent rise in desalting water cost. These two metallic ions must be removed if their total concentration is greater than 0.3 ppm.



Source: Southwest Research Institute

Figure 16

IRON AND MANGANESE REMOVAL EQUIPMENT CAPITAL COSTS

Feedwater pretreatment costs. Pretreatment costs to remove the iron and manganese ions include capital cost and operation and maintenance costs.

Capital cost of iron and manganese removal equipment can be obtained from Figure 16. The relationship can be expressed mathematically as:

$$\text{capital cost} = \$100{,}000 \times (\text{plant intake, MGD})^{0.80} \tag{14}$$

The capital cost must be amortized and converted to ¢/kgal.

Operation and maintenance costs include operating and maintenance labor and chemicals. Operating and maintenance labor costs are estimated at 10 percent per year of capital costs. These costs include payroll extras and general and administrative overhead costs.

Chemical costs for potassium permanganate, the compound necessary for iron and manganese removal, are relatively small and are included in the chemical costs shown on page 28.

Summary of Reverse Osmosis Desalting Complex Costs

The total reverse osmosis desalting unit cost in cents per thousand gallons (¢/kgal) is the sum of the individual cost elements of plant and equipment, and any ancillary facilities required.

REVERSE OSMOSIS PROCESS
SUMMARY WORKSHEET

Cost Elements	10^3	Annual Cost $	Water Costs ¢/kgal
Capital Costs			
1. Plant and Equipment			
2. Feedwater Pretreatment			
3. Feedwater Supply			
4. Water Transmission			
5. Brine Disposal			
Total Capital Costs			
Operation and Maintenance Costs			
6. Operating and Maintenance Labor			
a. Plant and Equipment			
b. Feedwater Pretreatment			
c. Feedwater Supply			
d. Water Transmission			
e. Brine Disposal			
Total Operating and Maintenance Labor			
7. Other Operation and Maintenance Costs			
a. Payroll Extras (15% of 6a)			
b. General and Administrative Overhead (30% of 6a + 7a)			
c. Supplies and Maintenance Materials			
d. Membrane Assembly or Replacement Tubing			
e. Chemicals			
f. Fuel or Steam			n.r.
g. Electric Power			
Plant and Equipment			
Feedwater Supply			
Water Transmission			
Total Other Operation and Maintenance Costs			
Total Operation and Maintenance Costs			
Total Water Cost (Total Capital Plus O. & M. Costs)			

n.r. - none required

SAMPLE HAND CALCULATION: REVERSE OSMOSIS DESALT COMPLEX

Feedwater: Rio Grande Ground Water Reservoir

Facilities required:
1. Reverse osmosis plant and equipment
2. Feedwater supply (well field)
3. Transmission (feedwater)
4. Brine disposal (subsurface injection)

Input information:

Plant capacity	5.0 MGD
Current Building Cost Index	825
Current Labor Cost Index	321
Interest rate	4-7/8%
Cost of electric power	1.0¢KWH
Length of feedwater pipeline	2 miles
Elevation of desalt plant	3750 ft
Elevation of well field	3650 ft
Well pumping depth–feedwater supply	300 ft
Well depth–brine disposal	3000 ft
Land cost	$2,000/acre
Right-of-way charge	$2,000/acre
Water analysis	
Total dissolved solids	3610 ppm
Iron	0 ppm
Manganese	0 ppm

The costs calculated in this section are recorded on the Reverse Osmosis summary worksheet on p. 111.

I. ESTIMATION OF REVERSE OSMOSIS PLANT AND EQUIPMENT CAPITAL COST AND OPERATION AND MAINTENANCE COSTS

A. Calculation of RO Plant and Equipment Capital Cost

1. From Figure 13, at 5.0 MGD, the plant and equipment capital cost is $2,250,000.

2. Calculate building cost correction factor (BCCF).

$$BCCF = \frac{\text{current or projected ENR building cost index}}{825}$$

$$BCCF = \frac{825}{825} = 1.0$$

3. Calculate current capital cost.

current capital cost = capital cost X BCCF
current capital cost = $2,250,000 X 1.0
current capital cost = $2,250,000

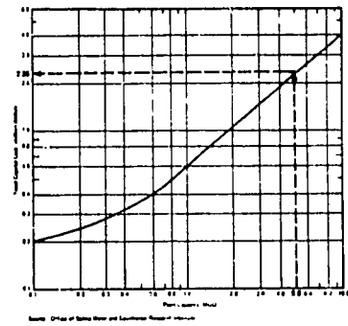


Figure 13

4. If land costs vary considerably from $2,000 per acre, obtain land requirements from Figure 14 and calculate the land cost correction (LCC).

   LCC = no. of acres X (actual land cost, $/acre - $2,000/acre)
   LCC = 2.3 acres ($2,000/acre - $2,000/acre) = 0.0

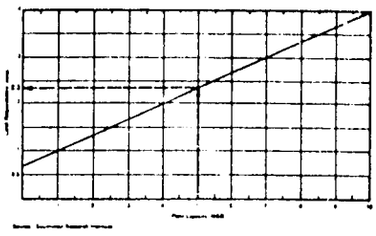


Figure 14

5. Apply land cost correction to current capital cost obtained in I.A.3. to arrive at a final capital cost.

   final capital cost = current capital cost + LCC
   final capital cost = $2,250,000 + 0.0
   final capital cost = $2,250,000

6. Amortization of the debt is

   amortization factor X final capital cost = annual cost
   $0.0641/yr/$ X $2,250,000 = $144,225

   Converting the annual cost to ¢/kgal,

$$\frac{\$144{,}225}{5.0\ \text{MGD} \times 3300} = 8.7¢/\text{kgal}$$

Calculation of RO Plant and Equipment Operation and Maintenance Costs in ¢/kgal

All costs calculated on an annual basis must be reduced to ¢/kgal for comparison purposes. As derived in Section II, "How to Use Manual," this is done by using equation (2):

$$¢/\text{kgal} = \frac{\text{annual cost in dollars}}{\text{MGD} \times 3300} \qquad (2)$$

Using the product water volume for this example of 5.0 MGD, a conversion factor may be derived which can be expressed as follows:

$$¢/\text{kgal} = \frac{\text{annual cost in dollars}}{5.0 \times 3300} = \frac{\text{annual cost in dollars}}{16{,}500}$$

$$= \frac{\text{annual cost in dollars} \times 6.06}{100{,}000}$$

$$= \text{annual cost in dollars} \times 6.06 \times 10^{-5}$$

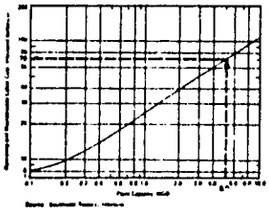


Figure 15

1. Operating and maintenance labor costs for a 5.0-MGD plant are $70,000/yr from Figure 15. Labor costs in ¢/kgal are

   $70,000/yr X 6.06 X 10^{-5} = 4.2¢/kgal

   No labor cost correction required.

2. Payroll extras are

   15% X I.B.1. =
   0.15 X 4.2¢/kgal = 0.6¢/kgal

3. General and administrative overhead is

   30% (I.B.1. + I.B.2.) =
   0.30 (4.2¢/kgal + 0.6¢/kgal) = 1.4¢/kgal

4. Supplies and maintenance materials costs are

   1%/yr X final capital cost (I.A.5.)
   ¢/kgal = 0.01/yr X $2,250,000 X 6.06 X 10^{-5} = 1.4¢/kgal

5. Membrane replacement costs (estimated as 10¢/kgal) = 10.0¢/kgal

6. Chemical costs (estimated as 3¢/kgal) = 3.0¢/kgal

7. Electric pumping power requirement is 11 KWH/kgal. Power cost in ¢/kgal would be

   power requirement X power cost =

   11 KWH/kgal X 1.0¢/KWH = 11.0¢/kgal

II. CALCULATION OF RO PLANT INTAKE AND BRINE DISCHARGE REQUIREMENTS

A. Intake Requirements

$$C_i = \frac{C_p}{0.75} = \frac{5.0 \text{ MGD}}{0.75}$$

C_i = 6.7 MGD

B. Brine Discharge Requirements

$C_b = C_i - C_p$
C_b = 6.7 MGD - 5.0 MGD = 1.7 MGD

III. CALCULATION OF RO FEEDWATER PRETREATMENT CAPITAL COST AND OPERATION AND MAINTENANCE COSTS

No pretreatment is required since total iron and manganese content in the feedwater is less than 0.3 ppm.

IV. CALCULATION OF RO FEEDWATER SUPPLY CAPITAL COST AND OPERATION AND MAINTENANCE COSTS

From previous calculation, total plant intake is 6.7 MGD.

A. Well Field Capital Cost

1. From Figure 41, at 6.7 MGD, well field capital cost is $280,000.

2. Calculate the current capital cost using the building cost correction factor (BCCF) calculated in I.A.2.

current capital cost = capital cost X BCCF
current capital cost = $280,000 X 1.0
current capital cost = $280,000

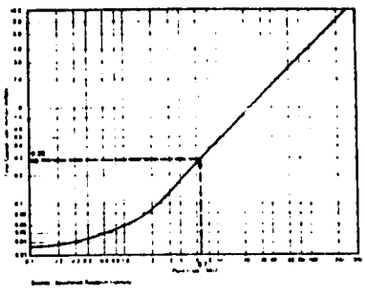


Figure 41

3. Amortization of the debt is

amortization factor X current capital cost = annual cost
$0.0641/yr/$ X $280,000 = $17,948

Converting the annual cost to ¢/kgal,

$17,948 X 6.06 X 10^{-5} = 1.1¢/kgal

B. Operation and Maintenance Costs

1. Operating and maintenance labor costs, from Figure 42, at 6.7 MGD, are 1.20¢/kgal.

Costs based on product water capacity are:

$$1.20¢/\text{kgal} \times \frac{\text{plant intake rate}}{\text{product water rate}} =$$

$$1.20¢/\text{kgal} \times \frac{6.7\ \text{MGD}}{5.0\ \text{MGD}} = 1.6¢/\text{kgal}$$

2. Electric power is

$$\text{TDH} \times 0.004 \frac{\text{KWH/kgal}}{\text{foot TDH}} \times \text{power cost} \times \frac{\text{plant intake rate}}{\text{product water rate}}$$

where TDH (total dynamic head) is

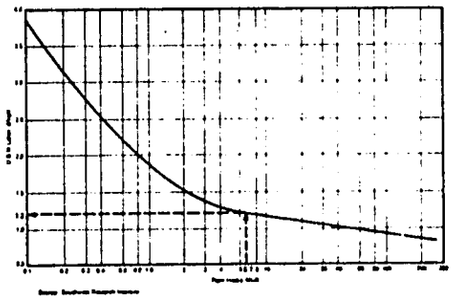


Figure 42

well pumping depth + 100 ft
300 ft + 100 ft = 400 ft

Therefore, electric power is

$$400\ \text{ft} \times 0.004 \frac{\text{KWH/kgal}}{\text{foot TDH}} \times 1.0¢/\text{kgal} \times \frac{6.7\ \text{MGD}}{5.0\ \text{MGD}} = 2.1¢/\text{kgal}$$

V. CALCULATION OF RO WATER TRANSMISSION CAPITAL COST AND OPERATION AND MAINTENANCE COSTS

A. Feedwater Transmission

1. Capital cost

a. From Figure 43, at 6.7 MGD, feedwater pipeline and pumping station capital costs are $120,000 per mile.

capital cost = $120,000/mile X 2 miles
capital cost = $240,000

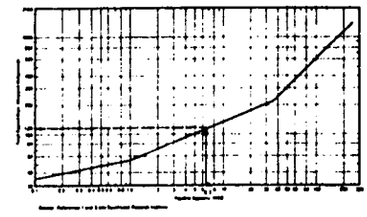


Figure 43

b. Calculate average total dynamic head (TDH) per mile.

$$\text{average TDH per mile} = \frac{\text{TDH}}{\text{length of pipeline}}$$

where

TDH = difference in elevation – available head + friction losses
TDH = 3750 – 3650 – 100 + (8 X 2)
TDH = 16 ft

Therefore

$$\text{average TDH per mile} = \frac{16\text{ ft}}{2\text{ miles}} = 8.0\text{ ft/mile}$$

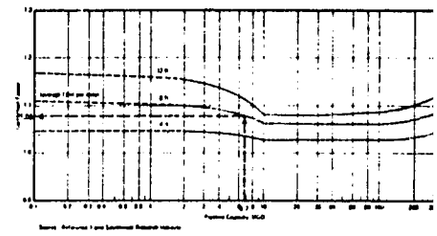


Figure 44

c. Obtain capital cost correction factor from Figure 44. At 6.7 MGD, with an average TDH of 8 ft per mile, the correction factor is 1.08.

d. Compute corrected capital cost.

corrected capital cost = capital cost X correction factor
corrected capital cost = $240,000 X 1.08
corrected capital cost = $259,200

e. Calculate current capital cost using the building cost correction factor (BCCF) calculated in I.A.2.

current capital cost = corrected capital cost X BCCF
current capital cost = $259,200 X 1.0
current capital cost = $259,200

f. If right-of-way land costs vary considerably from $2,000 per acre, calculate a right-of-way cost correction (RCC).

RCC = 1.5 acres/mile X length of pipeline in miles X (actual land cost, $/acre – $2,000/acre)
RCC = 1.5 acres/mile X 2 miles X ($2,000/acre – $2,000/acre)
RCC = 0.0

g. Apply the right-of-way land correction to current capital cost to arrive at a final capital cost.

final capital cost = current capital cost + RCC
final capital cost = \$259,200 + 0.0
final capital cost = \$259,200

h. Amortization of the debt is

amortization factor X final capital cost = annual cost
\$0.0641/yr/\$ X \$250,200 = \$16,615

Converting the annual cost to ¢/kgal,

$\$16{,}615 \times 6.06 \times 10^{-5}$ = 1.0¢/kgal

2. Operation and maintenance costs

a. Operating and maintenance labor costs from Figure 45, at 6.7 MGD, are 0.78¢/kgal per pumping station.

$$\text{number of pumping stations} = \frac{\text{total dynamic head (TDH)}}{230\text{ ft}}$$

$$\text{number of pumping stations} = \frac{16\text{ ft}}{230\text{ ft}} = 0.07$$

Rounding to the next highest whole number, one pumping station is required and operating and maintenance labor are 0.78¢/kgal.

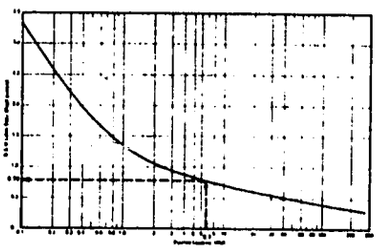


Figure 45

Costs based on product water capacity are:

$$0.78¢/\text{kgal} \times \frac{\text{plant intake rate}}{\text{product water rate}} =$$

$$0.78¢/\text{kgal} \times \frac{6.7\text{ MGD}}{5.0\text{ MGD}} = 1.0¢/\text{kgal}$$

b. Electric power is

$$\text{TDH} \times 0.004 \frac{\text{KWH/kgal}}{\text{foot TDH}} \times \text{power cost} \times \frac{\text{plant intake rate}}{\text{product water rate}}$$

$$16\text{ ft} \times 0.004 \frac{\text{KWH/kgal}}{\text{foot TDH}} \times 1.0¢/\text{KWH} \times \frac{6.7\text{ MGD}}{5.0\text{ MGD}} = 0.1¢/\text{kgal}$$

B. **Product Water Transmission** – none required for sample problem.

C. **Brine Discharge Transmission** – none required for sample problem.

If product water transmission or brine discharge transmission are required, the costs of these elements should be added to the costs of feedwater transmission. The total costs should be recorded on the summary worksheet under Water Transmission.

VI. CALCULATION OF BRINE DISPOSAL CAPITAL COST AND OPERATION AND MAINTENANCE COSTS

From previous calculation, brine volume is 1.7 MGD.

A. Subsurface Injection Capital Cost

1. From Figure 46 at 1.7 MGD, capital cost is $580,000.

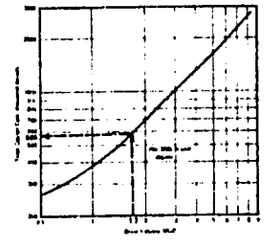


Figure 46

2. Obtain well depth correction factor (WDC) from Figure 47 at 3,000 ft and compute corrected capital cost.

   corrected capital cost = capital cost X WDC
   corrected capital cost = $580,000 X 1.0
   corrected capital cost = $580,000

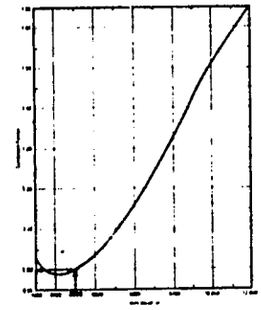


Figure 47

3. Calculate the current capital cost using the building cost correction factor (BCCF) calculated in I.A.2.

   current capital cost = capital cost X BCCF
   current capital cost = $580,000 X 1.0
   current capital cost = $580,000

4. Amortization of the debt is

   amortization factor X current capital cost = annual cost
   $0.0641/yr/$ X $580,000 = $37,178

   Converting the annual cost to ¢/kgal,

   $37,178 X 6.06 X 10^{-5} = 2.3¢/kgal

B. Operation and Maintenance Costs

1. Operation and maintenance costs from Figure 48, at 1.7 MGD, are 18.0¢/kgal based on brine volume.

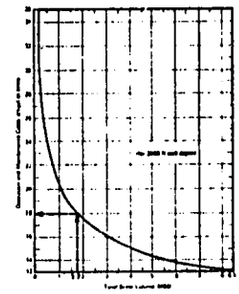


Figure 48

2. Convert to ¢/kgal product water

$$¢/kgal_{(product)} = ¢/kgal_{(brine)} \times \frac{\text{brine discharge rate}}{\text{product water rate}}$$

$$¢/kgal_{(product)} = 18.0¢/kgal \times \frac{1.7\ MGD}{5.0\ MGD}$$

$¢/kgal_{(product)}$ = 6.1¢/kgal

X. BRINE DISPOSAL

Introduction

Subsurface injection and evaporation ponds are the two brine disposal methods considered in this study. Simplified procedures for estimating brine disposal costs for these methods are presented in this section. Detailed procedures for estimating the cost of brine disposal are included in Office of Saline Water Research and Development Report No. 257–Part II (by Texas Water Development Board).

Application of the procedures is dependent upon the input of technical data related to meteorologic or subsurface geologic conditions in the particular area of investigation. If complete data are available, the reader may wish to use the detailed procedures contained in OSW Report No. 257.

Another method of brine disposal is direct discharge to surface water. Detailed procedures for estimating the costs of this type of disposal have not been investigated; however, once the brine discharge has been conveyed to the surface body of water, the costs associated with this type of disposal are assumed to be negligible (less than 1.0¢/kgal).

Based on the data as presented, subsurface injection is less expensive than evaporation ponds. However, many factors can reverse this situation, such as: (1) physical location of the brine facility relative to the plant; (2) land costs; (3) evaporation pond liner costs; (4) state and local laws; (5) climatic conditions; and (6) geologic subsurface characteristics. For example, land costs at $2,000/acre are 20 to 25 percent of total evaporation pond costs.

If brine volume exceeds the limits of this manual, additional injection well fields or evaporation ponds will be required. Maximum brine volume of 8.5 MGD for subsurface injection is based on a well field with a maximum of 25 wells. Maximum brine volume of 5.0 MGD for ponds is based on a net evaporation rate of 60 in. per year and a maximum pond size of 1,000 acres.

Brine volume must be determined before brine disposal costs can be calculated. The brine discharge calculation procedure for each desalting process is shown on the following pages.

Process	Page
ED	18
RO	29
MSF	44
VC-VTE-MSF	53
VFVC	63

Subsurface Injection

It is generally assumed that the most economical way to dispose of brine from a desalting plant is by subsurface injection, providing zones or formations exist with suitable geologic characteristics for receiving the injected waste.

Subsurface injection is not actually a disposal process, but rather a storage process. If an injection program is properly planned and implemented, the injected brine should remain in the receiving formation indefinitely, with little danger of pollution or destruction of other natural resources. In order to implement a successful injection program, however, the planning, construction, and operation of the injection system requires the technical services of qualified geologists and engineers.

Very stringent criteria for disposal wells are needed to prevent pollution where subsurface injection is selected as a means of disposal. State regulations usually require that the injection well must be drilled and constructed in such a manner as to prevent brine from escaping from the disposal zone, or well, and polluting usable ground or surface waters. In part, this requires that surface casings be set through formations containing fresh ground water and fixed permanently by circulation of cement from the bottom of the casing to the ground surface. The injection zone selected should not be one containing water of usable quality. It should have ample holding capacity for the injected waste. Casings should be set and cemented in such a manner as to insure that the disposed brine will be confined in the injection zone. Where applicable, existing oil and gas reservoirs must be adequately protected.

The geological characteristics of a zone or formation described as suitable are:

(1) The zone must be deep enough to prevent communication of fluids between the injection zone and aquifers containing usable ground water,

(2) The fluid in the reservoir and the fluid to be injected must be compatible,

(3) The reservoir must be capable of receiving and containing the brine from the desalting plant over the life of the plant, and

(4) The zone must have sufficient porosity, permeability, thickness, areal extent, and low reservoir pressure in order to act as a storage reservoir at safe injection pressure.

As porosity, permeability, and formation thickness increase, annual disposal cost will decrease. However, as reservoir pressure and depth of the well increase, the injection cost will increase. Conversely, the opposite trend will occur in each case for decreases in these formational characteristics.

The subsurface injection cost procedures outlined in this section are a simplification and condensation of the method outlined in OSW Report No. 257, Part II.

Detailed information on the formation characteristics is not necessary for preparation of preliminary cost estimates for injection. However, the reader is cautioned that these characteristics may have a profound effect on the final cost. For known characteristics outside the ranges listed below, the reader is referred to procedures outlined in OSW Report No. 257.

Detailed investigation reveals that a reservoir pressure of less than 500 lb per sq in., a zone thickness greater than 150 ft, a permeability above 135 millidarcies, and a porosity above 5 percent will not appreciably affect the final cost of brine disposal. If the characteristics of this injection zone lie outside these limits, it should be assumed that the cost of brine disposal will increase by at least 10 percent. The procedures outlined in OSW Report No. 257 should be applied to achieve more precise estimates.

Total brine volume and well depth are the required input variables utilized in the following procedure.

Subsurface Injection Capital Costs

Subsurface injection capital costs can be obtained from Figure 46. This curve is based on a 3,000-ft well depth. For well depths other than 3,000 ft, obtain a correction factor from Figure 47. Capital costs should be multiplied by the correction factor obtained.

Capital costs include wells, well field distribution system, pumping station, storage, and treatment. Costs also include allowances for engineering and design, interest during construction, and contingency costs.

Amortization of the debt. The capital costs should be amortized and converted to ¢/kgal. Use the procedures set forth in Section II, "How to Use Manual."

Subsurface Injection Operation and Maintenance Costs

Operation and maintenance costs based on brine volume can be determined from Figure 48. This curve is also based on a 3,000-ft well depth. The correction factor for well depth from Figure 47 must be applied to these costs for well depths other than 3,000 ft.

These costs include pumping power, supplies, and operating and maintenance labor for each capital cost element. They also include payroll extras and general and administrative overhead.

For comparative purposes, these costs should be reduced to unit costs for product water by multiplying costs in ¢/kgal by the ratio of brine-to-product water.

Thus

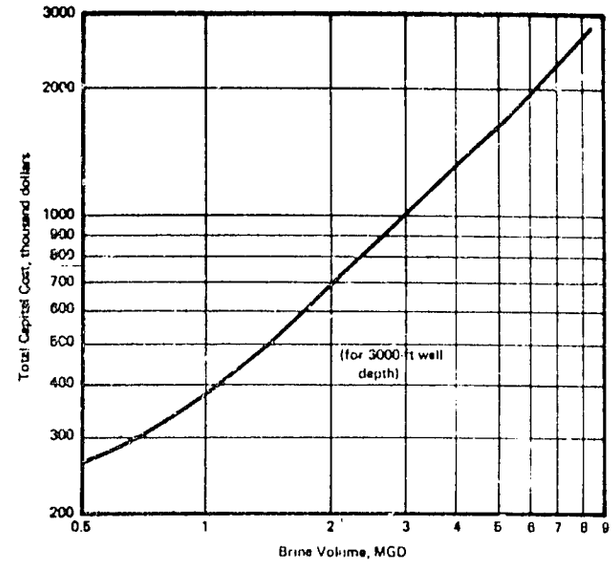
$$¢/\text{kgal}_{(\text{product})} = ¢/\text{kgal}_{(\text{brine discharge})} \times \frac{\text{brine discharge rate } (C_b)}{\text{product water rate } (C_p)} \quad (20)$$

Summary of Subsurface Injection Costs

The sum of the above individual costs elements constitutes the total costs for subsurface injection. A sample calculation for subsurface injection capital and operating costs can be found in Appendix C.

Evaporation Pond

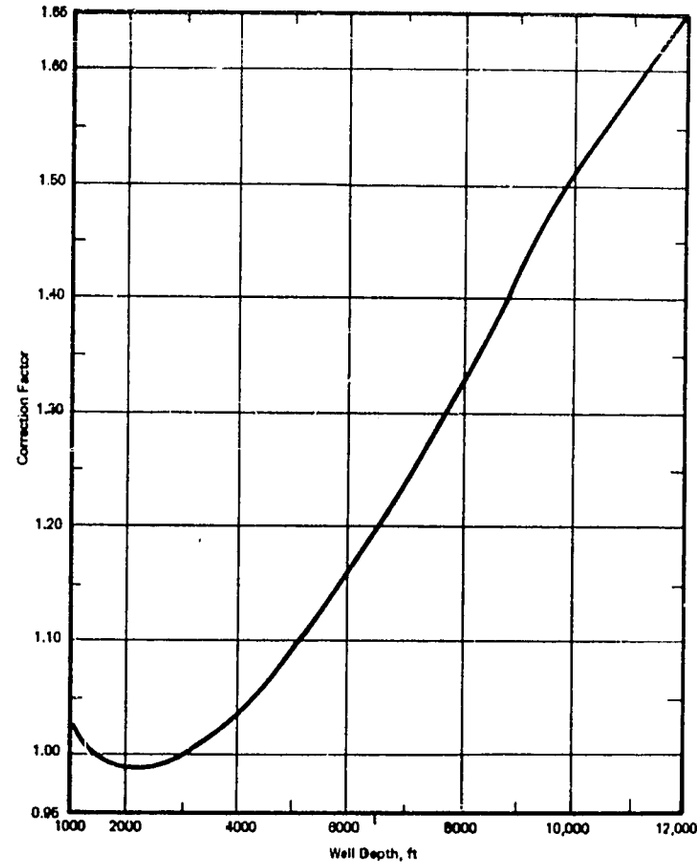
Evaporation ponds may afford an effective method of brine disposal if the following conditions exist: (1) the net evaporation rate (gross annual evaporation minus annual rainfall) exceeds approximately 40 in. per year; (2) the net evaporation



Source: Texas Water Development Board and Southwest Research Institute

Figure 46

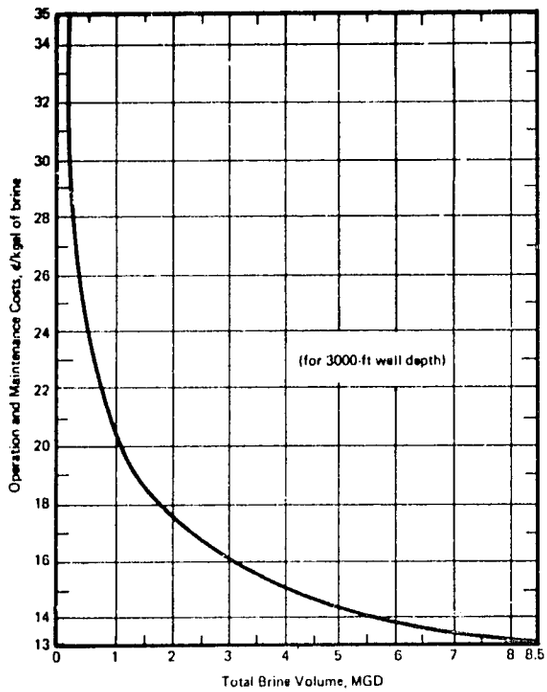
SUBSURFACE INJECTION CAPITAL COSTS



Source: Texas Water Development Board and Southwest Research Institute

Figure 47

COST CORRECTION FACTOR FOR WELL DEPTH



Source: Texas Water Development Board and Southwest Research Institute

Figure 48

SUBSURFACE INJECTION OPERATION AND MAINTENANCE COSTS

occurs at a uniform rate throughout the year; and (3) the impounded water is kept at shallow depths. These conditions are determined for fresh water. Since the effect of salinity increase in brine disposal ponds will reduce the rate of evaporation, disposal ponds must be designed to account for the difference in evaporation rate between fresh and saline water.

A dike height of 8 ft was selected for this study and is based on the following design criteria:

Assumed depth of effluent	4.0 ft
Depth to accommodate precipitate	0.5 ft
Freeboard for rainfall	0.5 ft
Freeboard for wind	2.0 ft
Soil cover over liner	1.0 ft
Total dike height	8.0 ft

The procedure covers pond sizes up to one thousand acres. In all cases, the pond is assumed to be square, as this configuration yields minimum costs.

Only lined ponds are considered for brine effluent disposal. Generally, unlined ponds permit wastes to either seep downward, contaminating usable-quality ground water, or move laterally through the pond dike and subsequently into surface water courses.

Evaporation Pond Capital Costs

In order to determine capital costs, the number of acres required must be obtained from Figure 49. Evaporation pond capital costs can be determined from Figure 50.

Capital costs include land at $2,000 per acre, and 20-mil polyvinyl chloride (PVC) liner at 11 cents per sq ft (this amounts to approximately $4,800 per acre). Also included are land stripping, liner fill, and dike costs which are consistent with OSW Report No. 257. These costs include allowances for engineering and design, interest during construction, and contingency costs.

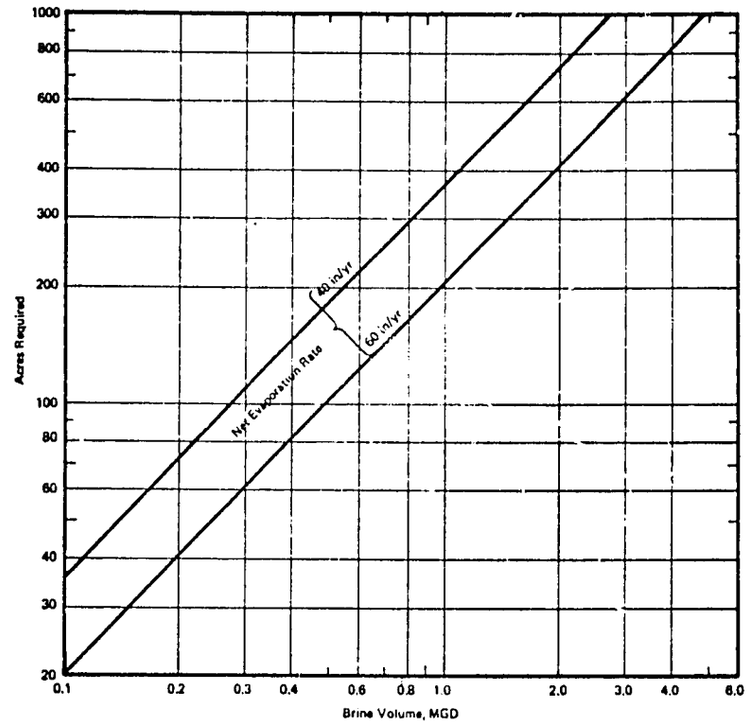
Amortization of the debt. The capital costs should be amortized and converted to ¢/kgal. Use the procedures set forth in Section II, "How to Use Manual."

Evaporation Pond Operation and Maintenance Costs

Operation and maintenance costs are calculated at 0.75 percent of capital costs. These costs include payroll extras and general and administrative overhead.

Operation and maintenance costs have been derived on an annual basis and must be reduced to unit cost by dividing the annual cost by the annual water production. As derived in Section II, "How to Use Manual," this is done by using equation 2:

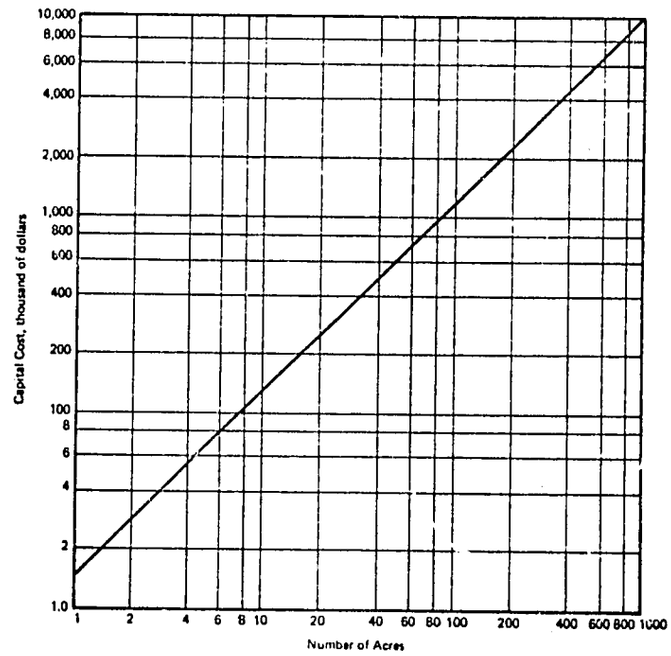
$$¢/\text{kgal} = \frac{\text{annual cost in dollars}}{\text{MGD}_t \times 3300} \qquad (2)$$



Source: Texas Water Development Board and Southwest Research Institute

Figure 49

NUMBER OF ACRES REQUIRED FOR EVAPORATION PONDS



Source: Texas Water Development Board and Southwest Research Institute

Figure 50

EVAPORATION POND CAPITAL COSTS

Convert this to unit cost of product water by multiplying by the ratio of brine discharge rate to product water rate

$$¢/\text{kgal}_{(\text{product})} = ¢/\text{kgal}_{(\text{brine discharge})} \times \frac{\text{brine discharge rate } (C_b)}{\text{product water rate } (C_p)} \tag{20}$$

Summary of Evaporation Pond Costs

The sum of the above individual cost elements constitute the total costs for evaporation ponds. A sample calculation for evaporation pond capital and operating costs can be found in Appendix B.

NOTES ADDED IN PROOF

New information shows that three of the above costing procedures may be too conservative. For more accurate costs, one may elect to use the following procedures:

REVERSE OSMOSIS OPERATING AND MAINTENANCE LABOR COSTS.
(Figure 15)

For mgd plant capacities of greater than unity and where the annual labor cost in dollars is $L, use the equation:

$$\$L = \$18,000\,(\text{mgd})^{0.46}$$

IRON AND MANGANESE REMOVAL EQUIPMENT CAPITAL COSTS.
(Figure 16)

For all mgd's of plant intake capacity and where the capital cost in dollars is $C, use the equation:

$$\$C = \$12,800\,(\text{mgd})^{0.81}$$

EVAPORATION POND CAPITAL COSTS VERSUS ACREAGE REQUIRED.
(Figure 50)

Divide the capital costs given by Figure 50 by the factor 1.65 to get the revised evaporation pond capital costs.

Table A-I

TABLE OF AMORTIZATION FACTORS
(30-year, 40-year and 50-year periods
3- to 6-percent interest rates)

Interest Rate, %	Amortization Factor*		
	30 years	40 years	50 years
3	0.051 019	0.043 262	0.038 865
3-1/8	0.051 847	0.044 141	0.039 793
3-1/4	0.052 682	0.045 028	0.040 730
3-3/8	0.053 523	0.045 923	0.041 677
3-1/2	0.054 371	0.046 827	0.042 634
3-5/8	0.055 226	0.047 739	0.043 599
3-3/4	0.056 088	0.048 659	0.044 574
3-7/8	0.056 956	0.049 588	0.045 558
4	0.057 830	0.050 523	0.046 550
4-1/8	0.058 711	0.051 467	0.047 551
4-1/4	0.059 598	0.052 418	0.048 560
4-3/8	0.060 492	0.053 377	0.049 577
4-1/2	0.061 392	0.054 343	0.050 602
4-5/8	0.062 297	0.055 316	0.051 635
4-3/4	0.063 209	0.056 297	0.052 675
4-7/8	0.064 127	0.057 284	0.053 722
5	0.065 051	0.058 278	0.054 777
5-1/8	0.065 981	0.059 279	0.055 838
5-1/4	0.066 917	0.060 286	0.056 906
5-3/8	0.067 858	0.061 300	0.057 981
5-1/2	0.068 805	0.062 320	0.059 061
5-5/8	0.069 758	0.063 347	0.060 148
5-3/4	0.070 716	0.064 379	0.061 241
5-7/8	0.071 680	0.065 417	0.062 340
6	0.072 649	0.066 462	0.063 444

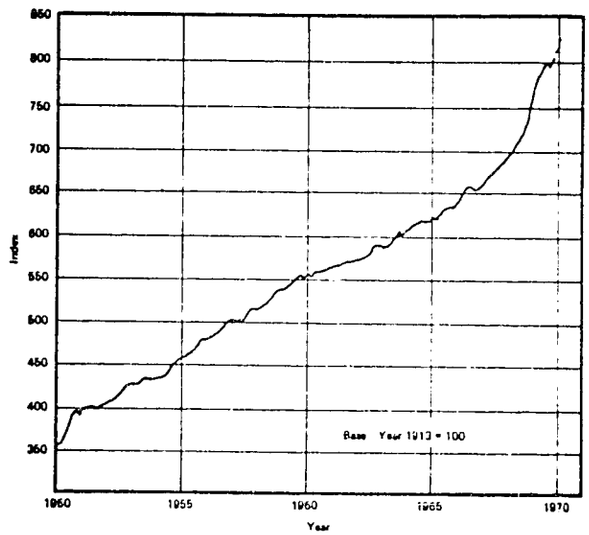
*Annual payment necessary per $1.00 of debt for number of years shown to repay the debt.
Source: *Financial Compound Interest and Annuity Tables*, Third Edition, Boston: Financial Publishing Company, 1964.

Table A-II

ENGINEERING NEWS-RECORD BUILDING COST INDEX
1950 through 1969
(Base: Year 1913 = 100)

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual Average
1950	356	356	360	363	364	373	378	383	393	397	390	391	375
1951	393	398	399	400	401	401	400	400	400	403	404	406	401
1952	406	406	407	408	410	412	414	422	424	425	426	425	416
1953	425	425	425	426	426	426	435	437	436	436	436	435	431
1954	436	437	437	437	438	440	444	456	454	455	456	457	446
1955	458	459	460	461	462	464	468	478	479	480	479	479	469
1956	480	483	483	486	487	489	489	491	500	500	500	500	491
1957	502	502	501	501	503	504	507	517	516	517	517	516	509
1958	517	516	516	517	519	521	524	526	535	537	535	535	525
1959	536	537	540	543	544	548	552	554	556	555	554	553	548
1960	554	555	555	556	560	561	563	562	563	561	561	562	559
1961	563	563	563	565	569	570	572	571	571	571	571	570	568
1962	571	573	575	576	579	580	583	586	586	585	584	584	580
1963	584	585	586	586	588	590	596	602	602	604	602	603	594
1964	604	604	606	607	609	612	615	616	617	617	616	617	612
1965	616	621	622	621	621	626	628	630	633	634	633	634	627
1966	635	641	643	649	652	656	653	655	656	655	655	655	650
1967	656	657	659	660	666	671	673	678	681	684	685	687	672
1968	692	695	698	701	710	718	721	729	741	747	747	755	721
1969	764	770	780	n.a.*	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	825†	n.a.

*Not available.
†Projected.
Source: *Engineering News-Record*, March 20, 1969.



Note: Monthly values have been plotted, the year grid lines are for January of the year indicated.
Source: Engineering News Record and Southwest Research Institute

Figure A-1

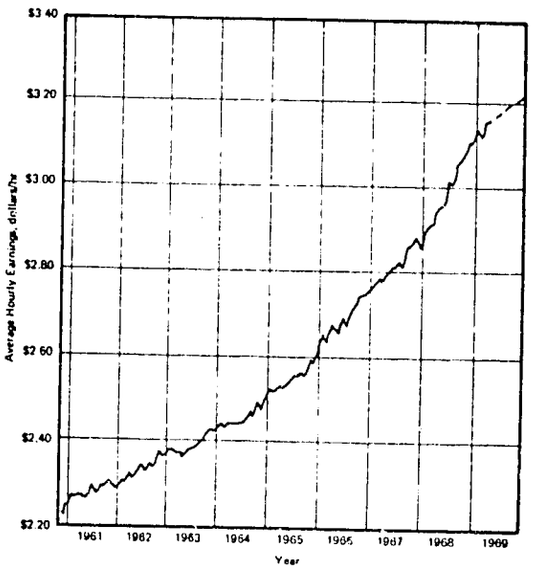
ENGINEERING NEWS-RECORD BUILDING COST INDEX–TREND OF MONTHLY VALUES

Table A-III

LABOR COST INDEX
U.S. Employment and Earnings Statistics,
Water, Steam, and Sanitary Systems Nonsupervisory Workers
1958 to 1969

Year	Average Earnings by Month in Dollars per Hour												Annual Average $/hr
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	
1958	1.96	2.00	1.97	1.96	1.96	2.00	2.00	2.00	2.02	2.03	2.08	2.05	2.00
1959	2.07	2.06	2.05	2.02	2.03	2.04	2.06	2.08	2.09	2.10	2.13	2.09	2.07
1960	2.11	2.12	2.12	2.14	2.13	2.15	2.18	2.18	2.18	2.21	2.23	2.22	2.17
1961	2.25	2.27	2.26	2.27	2.26	2.26	2.29	2.27	2.29	2.29	2.30	2.29	2.27
1962	2.28	2.30	2.30	2.32	2.31	2.33	2.34	2.32	2.34	2.33	2.37	2.36	2.33
1963	2.37	2.38	2.37	2.37	2.35	2.37	2.38	2.38	2.39	2.40	2.42	2.43	2.38
1964	2.42	2.44	2.43	2.44	2.44	2.44	2.44	2.43	2.46	2.45	2.48	2.47	2.44
1965	2.49	2.51	2.50	2.51	2.51	2.53	2.54	2.55	2.56	2.55	2.59	2.58	2.54
1966	2.62	2.65	2.63	2.67	2.66	2.65	2.69	2.67	2.70	2.72	2.74	2.74	2.68
1967	2.76	2.79	2.77	2.79	2.80	2.81	2.83	2.81	2.86	2.86	2.88	2.85	2.82
1968	2.89	2.91	2.91	2.95	2.96*	2.97*	[illegible]*	3.00*	3.05*	3.07*	3.10*	3.09*	3.00*
1969	3.13*	3.12*	3.14*	n.a.†	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.21‡	n.a.

*Estimated.
†Not available.
‡Projected.
Source: U.S. Department of Labor, Bureau of Labor Statistics, *Employment and Earnings Statistics for the United States, 1909-67* (Bulletin No. 1312-5), 1967 through 1969 data are based on *Employment and Earnings and Monthly Report on the Labor Force*, Vol 14 and Vol 15.



Source: U.S. Department of Labor, Bureau of Labor Statistics, Employment and Earnings Statistics for the United States, 1909-67 (Bulletin No. 1312-5). 1967 through 1969 data are based on Employment and Earnings and Monthly Report on the Labor Force, Vol 14 and Vol 15 and Southwest Research Institute

Figure A-2

LABOR COST INDEX
Average Hourly Earnings of Nonsupervisory
Workers in Water, Steam, and Sanitary
Systems, 1961 to 1969

APPENDIX D, in VOLUME II of this manual included a comprehensive questionairre for seawater desalting plants at coastal locations. A short-form questionairre of the same type is presented in this Supplememtary Manual. It has been reproduced from the OSW 2.5 MGD Universal Desalting Plant Manual, and because it was not intended for inland sites, it does not include any environmental considerations or questions concerning brine disposal. Such questions, therefore, are now asked in the following paragraphs:

Remembering that for salt, the ultimate natural sump for disposal is the ocean, one should ask the following preliminary questions regarding brine disposal:

1. What is the minimum pretreatment required in order to render the brine compatible with the intended receiving waters, geological formations, etc.? Are there any toxic residues?

2. Is direct discharge into surface waters, or oceans, permissible?

3. Can deep well injection into underground reservoirs be done?

4. Is disposal by evaporation ponds possible?

5. Is forced evaporation to crystalline salt possible?

6. Which of the above four methods of disposal is most economically, technically and legally attractive?

7. Are there any irretrievable commitments of natural resources, or permanent damage to them, associated with the contemplated operations?

For additional environmental questions, please see Section IX-C-2.

QUESTIONNAIRE

QUESTIONNAIRE ON SALINE WATER CONDITIONS FOR THE DESIGN OF A UNIVERSAL DESALTING PLANT

A. Water Temperature

The design of a desalting plant is dependent on the temperature of the saline water fed to the plant. While the maximum and minimum temperatures are useful, daily and seasonal temperature profiles are desirable. Please furnish as much information relative to seawater temperature variation as is available.

	WINTER	SUMMER
1. Maximum seawater temperature	_____ ° F	_____ ° F
	_____ ° C	_____ ° C
2. Minimum seawater temperature	_____ ° F	_____ ° F
	_____ ° C	_____ ° C

3. Furnish temperature profile for one year, if data is available. (Use attached profile charts to plot data.)

Please specify location where temperatures are recorded.

City_____ Body of water (source)_____

Exact location: (Street or other descriptive data)

_____

_____

_____

B. Seawater Analysis

The design of the desalting plant will be affected by the analysis of the saline feed. While a simple statement of the salinity in terms of ppm of Total Dissolved Solids (TDS) can be used for the preliminary design, the actual water conditions, particularly if they vary from clean seawater, should be known in detail so that the plant design may be able to efficiently handle all impurities in the seawater.

1. **Saline water salinity** _____ ppm (TDS) (Winter)

   _____ ppm (TDS) (Spring)

   _____ ppm (TDS) (Summer)

   _____ ppm (TDS) (Fall)

2. Saline water analysis

   If more detailed information is available, it is suggested that the analysis be presented in the form shown on the attached sheet. The most economic materials and water treatment equipment can be selected if this information is available.

C Cost Of Fuel

The cost of the various fuels should be quoted as-delivered at the plant site.

1. Coal _____
2. Heavy fuel oil (Bunker "C") _____
3. Diesel oil _____
4. Other fuel _____

Cost should be reported on a unit weight basis, as for example, U. S. Dollars ($) per ton (2000 lbs.). If national currency is used, give exchange rate.

D. Cost Of Electric Power

The cost of electric power for use at the desalting plant should be quoted as-delivered to the plant transformers.

1. Electric Energy Charge Schedule U.S. $/kw-hr.

   a. _____ U.S. $/kw-hr for _____ kw-hr.

   _____ U.S. $/kw-hr for _____ kw-hr.

   _____ U.S. $/kw-hr for _____ kw-hr.

   _____ U.S. $/kw-hr for _____ kw-hr.

2. Electric Demand Charge Schedule:

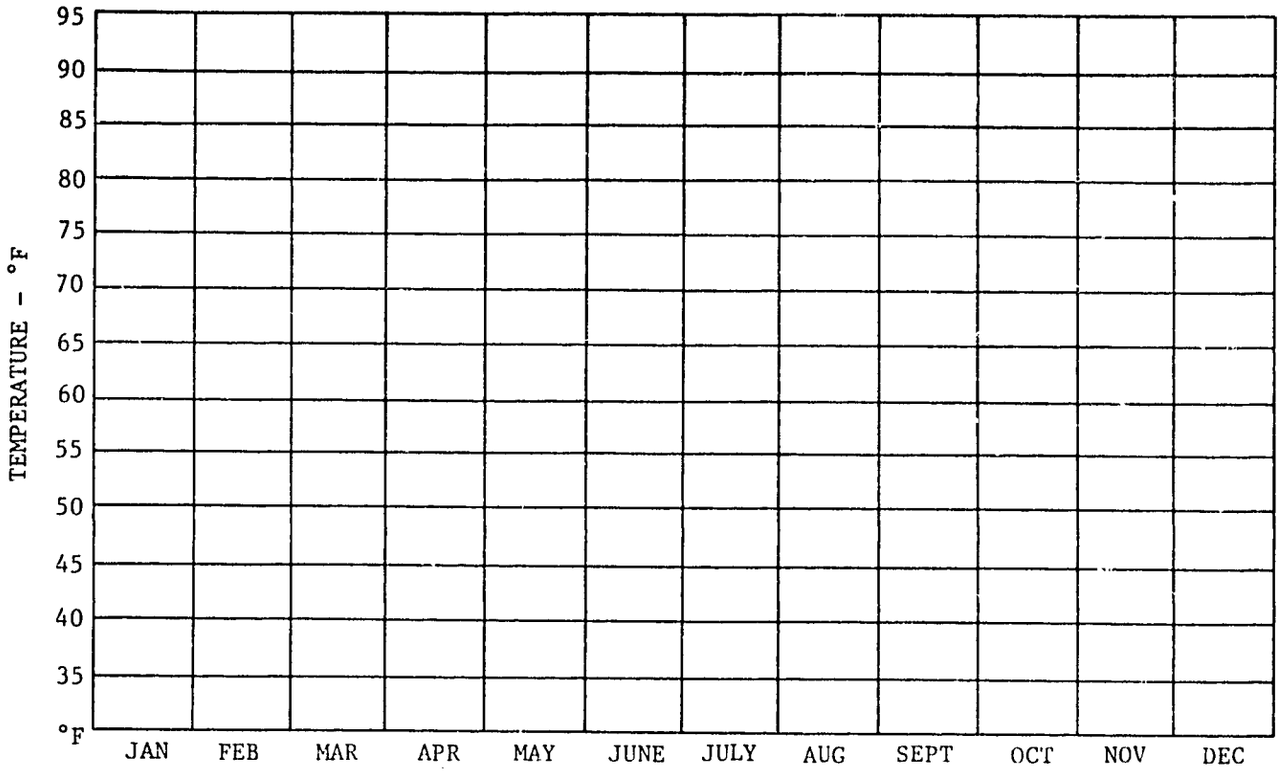
   Please list in terms of U.S. Dollars per kw for industrial plant consumption.

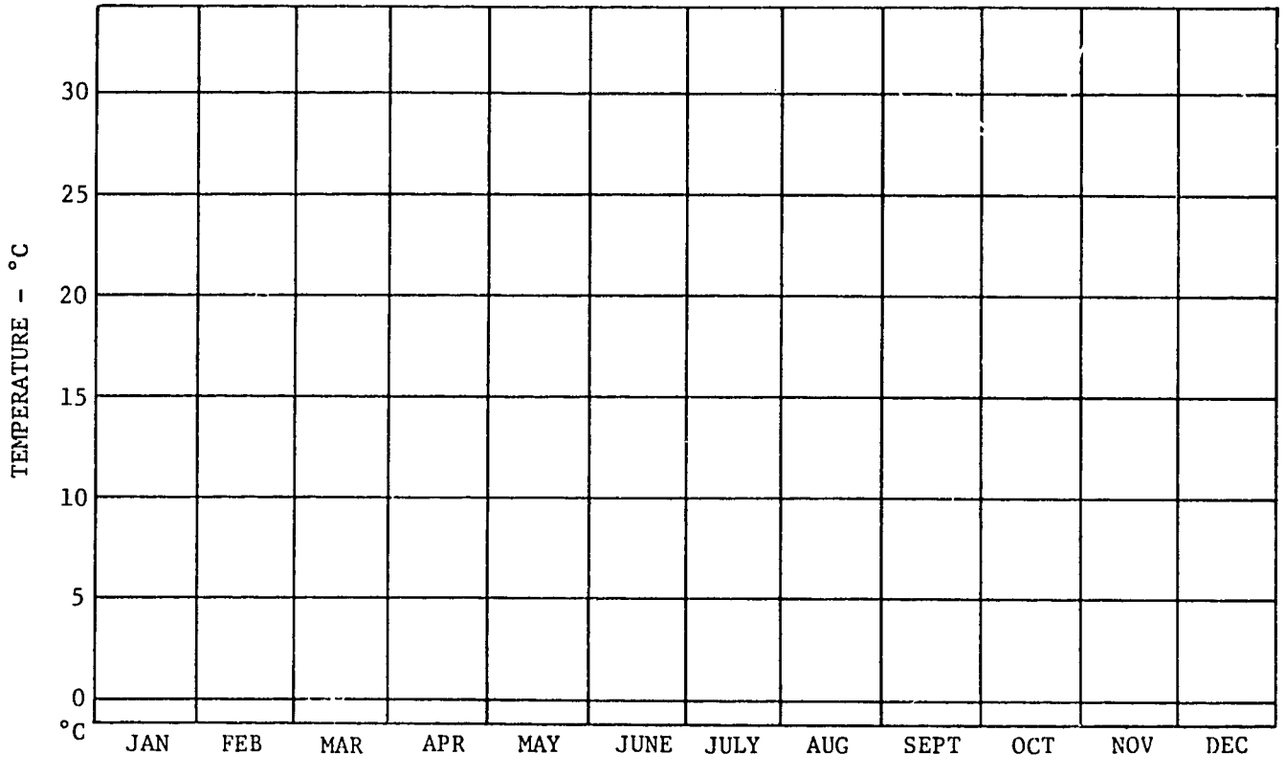
E. Prevailing Cost Of Money

Please list here the expected or usual annual charges made on plant capital investment, such as:

_____ % Interest and Amortization on plant investment

_____ % Insurance





TEMPERATURE PROFILE - SEAWATER AT (LOCATION) _____ YEAR _____

WATER ANALYSIS

Date _____

Analysis No. _____

Name of Analyzing Agency _____

Water Source Country _____

City _____

Location _____

	Constituent	PPM as	A	B	Remarks
CATIONS	Calcium (Ca^{++})	$CaCO_3$			
	Magnesium (Mg^{++})	$CaCO_3$			
	Sodium (NA^{+})	$CaCO_3$			
		$CaCO_3$			
		$CaCO_3$			
TOTAL CATIONS		$CaCO_3$			
ANIONS	Bicarbonate (HCO_3^{-})	$CaCO_3$			
	Carbonate (CO_3^{--})	$CaCO_3$			
	Hydroxide (OH^{-})	$CaCO_3$			
	Chloride (Cl^{-})	$CaCO_3$			
	Sulfate (SO^{--})	$CaCO_3$			
TOTAL ANIONS		$CaCO_3$			
Total Dissolved Solids		(TDS)			
P - Alkalinity		$CaCO_3$			
Methyl Orange Alkalinity		$CaCO_3$			
Iron Total		Fe			
Carbon Dioxide, free		CO_2			
Silica		SiO_2			
Turbidity					
Color					
pH					
TOTAL HARDNESS gr./gal as $CaCO_3$					