Water Related Planning and Design at Energy Firms

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Preface

The Office of Environmental Assessments improves the understanding of the impacts of environmental policies and rules on energy development, and assesses the impact of energy development on the environment and the health and safety of our citizens. The Regional Impacts Division assesses energy policies and programs for specific regions and for environmental resources. The Division's water resources program addresses current and potential energy impacts on the Nation's water supply. Assessment information is used by the Department and other Federal agencies, and by regional, state, and local authorities to understand these impacts and to help plan future energy development.

The use of water by energy firms depends upon a number of factors subject to both planning and design. Under conditions of abundant, low-cost water supplies typical of the past, such planning and design was somewhat routine. With increasing concern and competition for water, there is now considerable interest in design and planning alternatives of energy firms in regard to water. This report provides an overview of such alternatives and assesses their significance.

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EXECUTIVE SUMMARY

Because energy production and conversion activities have historically been water intensive, a common consideration in discussing energy policy is the effect of accelerated domestic production on water resource allocation. In our view, much of this discussion concerning impacts, conflicts, and tradeoffs pays insufficient attention to the role of markets--of costs and prices and business behavior. Thus, this report examines water-related planning and design at energy firms. By identifying production alternatives and specifying the cost of these alternatives under a variety of conditions, one gains insight into a) the future pattern of water use in the energy industry and b) the response of industry to water-related regulation.

In Part II, we review the three principal decisions of industry that affect water allocation: where to build plants, where to get water, and how much water to use. The site selection methodologies of energy firms, and electric utilities in particular, typically assume plant water requirements based on use of evaporative cooling for waste heat rejection. Over the long run, however, as a consequence of increased water scarcity and development of dry cooling technologies for water conservation, one might expect firms to abandon or modify these requirements: to consider the cost of alternative water system designs rather than the physical availability of water as the relevant site-differentiating attribute.

Water acquisition occurs after site selection. The most important consideration is that a variety of water supply alternatives are available including unappropriated streamflows, groundwater, wastewater from sewage treatment plants, seawater, and water used by irrigators. Uncertainty, risk, and transaction costs as well as engineering costs figure in the selection of plant water supplies.

Water system design entails the evaluation of tradeoffs among water intake, water treatment, and wastewater disposal costs. While the design choices are constrained by the prior selection of such parameters as energy conversion process and fuel quality, water recirculation, treatment, reuse, and dry cooling alternatives allow great variation in plant intake, discharge and consumption rates.

In Part III, we review the cost of water use alternatives. Part III allows no easy summary because of the site-specificity of water supply costs and the variety of design alternatives available. Nevertheless, we draw some very general but important conclusions. First, if water intake or disposal costs are non-zero, recirculating systems are less costly than once-through systems. Second, while treatment costs favor the use of freshwater, the incremental treatment costs for brackish or saline water compare favorably with the cost of conveying water great distances or conserving water with dry cooling. Third, stringent discharge standards and land disposal costs promote the maximum degree of recirculation, reuse, and treatment. Short of process change, further reduction in water use requires substitution of dry cooling for evaporative cooling. Fourth, over the intermediate term, considering some representative water supply costs and the breakeven cost of saving water, dry cooling has great potential for application at synthetic fuel plants and very limited potential at electric plants.

Part IV presents empirical data to substantiate the inferences derived from engineering/economic analysis. We report the source of water, type of cooling system, and pattern of discharge for electric plants constructed

during the 1970s or projected to come on line in this decade. In the 1970s in the US, there was a trend away from once-through cooling toward use of evaporative cooling. Freshwater, as a source of supply, and discharge of effluent were standard practice. In the 1980s, almost all new capacity in the states and basins surveyed will use evaporative cooling. In Ohio, Texas, and the Upper Missouri River Basin, surface water will continue to be the dominant source of supply. But in the Great Basin and the Colorado River Basin over 80 percent of the projected capacity will use wastewater, groundwater, or water purchased from irrigators. In Florida, almost half of the capacity will use seawater, wastewater, or groundwater. A number of plants, especially in the Western US, will achieve zero discharge with treatment and recirculation of cooling water and reuse of cooling tower blowdown.

In conclusion, a thorough understanding of industrial water use economics and water markets is a precursor to successful regulation. We suggest that: 1) most water use conflicts involving the energy industry are tractable because of the availability of design alternatives and the relatively small incremental cost of the most expensive of these alternatives; 2) while industry may attach insufficient weight to social costs, they are most knowledgeable about engineering costs; and 3) industry would be wise to pay greater attention to public concerns in the water-related planning and design process. These recommendations are not earth-shattering; rather they are a note for restraint in resource regulation.

I. INTRODUCTION

There is a widespread perception that the availability and use of water resources determines the level and mix of economic activity in a given region. Because energy production and conversion activities have historically been water intensive,* a common consideration in discussing energy policy is the effect of accelerated domestic production on water resource allocation (see for example Harte and El-Gasseir, 1978).

At a recent workshop sponsored by the Office of Environmental Assessment of the US Department of Energy (DOE), one participant noted that:

Conflicts over resource use are resolved through the action of four principal social mechanisms: the courts, the legislatures, the markets, and the administrative bureaucracy. Each mechanism needs to be understood for the roles it has been assigned, what it does and how it is best employed. Most conflict resolution is the product of the interaction of the four social mechanisms.**

In our view, much of the discussion concerning tradeoffs and conflicts associated with energy and water policy pays insufficient attention to the role of markets--of costs and prices and business behavior. We feel that market factors affect the acquisition and exchange of water supplies as well as the substitution of other inputs such as capital and energy for these supplies. To be sure, state bureaucracies administer water permit systems; federal agencies construct reservoir storage projects; environmental legislation regulates the disposal or discharge of effluents; quantification of Federal and Indian reserved rights involves the courts, and so on. Ultimately, however, firms make the decisions that directly affect water allocation: where to build the plants, where to get water, and how much water to use.

This report, then, examines water-related planning and design at energy firms. Parts II and III are driven by the proposition that, subject to resource and regulatory constraints, energy firms attempt to minimize production costs. Under this proposition, one can understand or project

*Thermo-electric power, for example, accounted for 45 percent of total water withdrawals in the United States in 1975 (Murray and Reeves, 1977).

**Statement of Robert K. Davis, Office of Policy Analysis, US Dept. of Interior at DOE Workshop, "The Nation's Groundwater Resources and Energy Production," Albuquerque, NM, January 1980.

business behavior by identifying production alternatives and specifying the cost of these alternatives under a variety of conditions. Thus, Part II describes procedures and considerations for site selection, water acquisition, and the design of the water use system. Part III reviews the cost of water use alternatives for energy conversion activities. Part IV presents survey data of water system elements at new and proposed energy conversion facilities. This empirical evidence allows corroboration of the inferences following the engineering/economic analysis of Parts II and III. In summary, this report provides insight into a) the future pattern of water use in the energy industry and b) the response of industry to water-related regulation.

II. DECISIONMAKING AT ENERGY FIRMS

In the Introduction we stated the proposition that energy firms are cost minimizers. This is useful because, after a review of the cost of production alternatives, one might anticipate what decisions business may make. The proposition has two principal shortcomings. First, firms may have other objectives besides profit maximization. In particular, some have argued that regulated electric utilities attempt to maximize their capital investment or rate base. Nevertheless, the supply of electricity is subject to competition from energy alternatives such as conservation, solar energy, synthetic fuels, and oil and natural gas. Also, the regulatory commissions examine utility operations. Thus, there must be some incentives to minimize costs. Second, under the strong climate for environmental and energy regulation, firms face great uncertainties that contribute to project delay and cost overruns. In an engineering economic analysis there is a tendency to overlook the influence of uncertainty on business behavior.

Morganstern (1950) suggests that, "economic theory has in its various parts, as all other theory in any field, either more of a fine or more of a coarse structure." The necessary degree of "finess" depends on the use or application of a particular theory and set of data, on the desired accuracy of results. Clearly, cost minimization is on the "coarse" side of the theoretical spectrum, but for the present purpose this seems reasonable. The objective is not to predict the source of water supply and rate of water use for a particular plant, but to provide a framework for understanding water use in the energy industry in the United States. The basis of this framework is a

review of cost considerations in site selection, water acquisition, and water system design.

Site Selection

In recent years, there has been a flood of interest in the topic of energy facility siting. A large body of literature addresses the impacts resulting from particular siting patterns as well as the evaluation of economic tradeoffs resulting from alternative siting patterns and policies. Kolstad (1980) finds three broad approaches or modeling techniques applied to this subject. The first approach, the simplest and most common, is the projection of historical experience into the future. Thus, by consideration of water system elements for energy plants constructed in the 1970s, one would assume that streamflows will be the predominant source of water supply and evaporative cooling the predominant method of waste heat rejection at new plants. Bower (1966) warned that this exercise promotes undue pessimism concerning the prospect of shortages and constraints.

The second approach, which is related to multi-objective programming, relies on weighting schemes. The analyst assigns weights to selected criteria, evaluates these criteria at alternative sites, and then ranks sites according to desirability. This method allows for comparison of specific sites and may include explicit treatment of risk and uncertainty. Typically, the availability of water resources is a heavily weighted criterion.

The third approach is in the spirit of location theory, a branch of economic theory. Location theory accounts for the dispersion and concentration of economic activities with particular emphasis on the spatial distribution and cost of natural resources and on transportation costs of raw materials and finished products (see for example Alonzo, 1975). Thus, in spatial economic equilibrium models, a transportation network connects producers and consumers, and the solution algorithm minimizes the cost of supplying energy products to demand centers subject to resource and policy constraints. The key advantage of this approach is that it allows for substitution of inputs in response to resource scarcity.

Despite the abundance of literature concerning energy facility siting, few analysts have empirically studied the question of how firms actually make siting decisions. On the basis of economic theory, a few siting studies, and conversations with a number of planners at energy firms, we attempt to

describe the process of site selection with emphasis on water supply considerations.

A preliminary consideration is that, while energy plants require a water supply, water use costs represent a small fraction of energy product costs.* Besides water, then, a number of factors influence the cost of delivering energy products from a particular site to a particular market.

The site screening and selection procedure directs attention at those factors that account for significant cost differentials among alternative sites. For example, with railway construction costs of \$1 million/mile, for a plant with coal as a raw material, distance from an existing rail line is obviously an influential cost variable. On the other hand, given uniform new source performance standards for NO_x emissions, cost of NO_x control is location independent. Generally, firms select site-differentiating attributes according to cost-based rules of thumb, so a list of relevant attributes varies by geographic region, by energy product, and by firm. Seismic stability is a critical consideration for nuclear plants; distance from high terrain may be important for siting near Class I air quality areas; licensability is a key consideration in California and more and more so elsewhere; access to the transportation grid (oil and gas pipelines, electricity transmission lines, etc.) is always important.

Given a set of cost-differentiating attributes and some ranking or weighting of their importance, firms use a variety of screening and selection procedures ranging from map overlays (see NUS, 1974) to decision analysis (see Keeney and Nair, no date). Siting may even be a trivial exercise as with synthetic fuel or lignite-fired electric plants where transportation costs probably favor a mine-mouth site.

Now consider the role of water resources in this process. Waste heat rejection is the major water use at an energy conversion plant. The capital costs of once-through, evaporative (all-wet), and 40% wet/60% dry cooling systems at coal-fired electric plants are about 15-20, 21-25, and 40-60 \$/Kw respectively (Hu, Pavlenko, and Englessen, 1978). Thus, many firms employ site screening and selection criteria which insure that sufficient water for at

*The Electrical World 21st Steam Station Cost Survey reported average costs of water, lubrication, and supplies for new electric plants of about 0.5 mills/Kwh compared to average busbar costs of almost 28 mills/Kwh. By comparison fuel costs averaged 13.65 mills/Kwh (Friedlander, 1979).

least evaporative cooling, perhaps even for once-through cooling, be available at the plant site. In addition, firms tend to determine water requirements for evaporative cooling quite conservatively: for example, by making optimistic assumptions about plant capacity factors (80-90 percent for coal electric plants), in a few cases even by assuming a constant cooling tower evaporation rate for the entire year based on the maximum expected temperature.

As long as abundant, inexpensive water supplies are available at most candidate sites, water supply criteria based on evaporative or once-through cooling requirements are useful. As water becomes more scarce, however, adherence to conservative water supply criteria for plant siting could cause permitting delays or cost increases for other factors of production (especially transportation as plant sites range farther and farther from mines and existing rail lines and powerlines). Then, one would expect energy firms to abandon or modify these criteria: to consider the costs of water supply and the water use system rather than the physical availability of water as the relevant cost-differentiating attributes. The potential for power cost savings allowed by greater siting flexibility ought to justify the increased cost of site screening and selection.

In fact, an informal survey of water-related siting criteria indicates that most Western utilities continue to consider only those sites with enough water available for evaporative cooling (see Table I). One exception is Tri-State Generation and Transmission Association, a participant in the Missouri Basin Power Project whose water use plans aroused considerable opposition and caused a two-month halt in plant construction (see next section). Currently, Tri-State is considering four alternative sites for a new coal-fired plant, two of which would require dry or wet/dry cooling.

In summary, then, the current site selection practices of electric utilities are not necessarily restrictive as to the source or quality of water supply, but they do practically guarantee the continued use of the most water intensive cooling technologies. One cannot say whether this reflects the poor economics of dry or wet/dry cooling and the presence of adequate water supplies at most candidate sites, even in states like Nevada; or whether utilities have been slow to respond to the increased siting flexibility allowed by dry or wet/dry cooling. In any case, with increasing development and water scarcity in the semi-arid West, the possible application of dry cooling must be considered in long run analysis of business behavior.

TABLE I
AN INFORMAL SURVEY OF WATER SUPPLY CRITERIA
FOR ELECTRIC PLANT SITE SCREENING

Utility	Date of Site Selection	Water Supply Criterion
Washington Public Power Supply System	1973	rivers with $7Q_{10} > 50$ ft^3/sec^1
Arizona Public Service Co.	1974	groundwater basins with at least 35,000 a-ft/unit/yr (800 - 1200 Mw/unit) available for 40 years
Oak Ridge Siting Analysis Model	1979	$7Q_{10} > 125 \text{ ft}^3/\text{sec}$ or adjacent to Great Lakes, Gulf or Atlantic
Public Service Co. of Colorado	1979	14 a-ft/Mw/yr
Houston Light and Power Co.	1980	13.3 a-ft/Mw/yr
Tri-State Gen. and Trans. (Thornton, Co.)	1980	none: considering dry and wet/dry cooling if necessary at candidate sites.
Public Service Co. of New Mexico	1980	Multiple sources of water available at candidate sites
Sierra Pacific (Reno, Nevada)	1980	10 a-ft/Mw/yr

$17Q_{10}$ is the lowest flow rate, averaged over 7 consecutive days, expected, on the average, every 10 consecutive years.

Water Acquisition

Water acquisition begins upon selection of a site and must be complete or at least reasonably certain before initiation of plant design or architect-engineering work (4-5 years before projected operation). Two reasons for this are familiar. Energy plants require a water supply, and water acquisition costs are a small fraction of plant costs. (Thus, it would be imprudent to jeopardize a capital investment without assurance that water supplies are available.) A third reason is that the architect-engineers must know the quantity and quality of water available in order to design the water use system.

Generally, the water acquisition team works with a water supply requirement as shown in Table I. (In water scarce regions the team might work with design engineers to evaluate tradeoffs between the sources and quantity of water available and cooling system design.) Obviously, there is an engineering economic element: determining the acquisition, transportation, and treatment costs, and reliability of water from various sources. There is also a time consuming legal task that may include the filing of an appropriation permit, negotiation for sale of property with private parties, preparation of an environmental impact statement, and acquisition of water-related permits.

The permit requirements obviously cause considerable uncertainty and risk for developers. In turn, they foster the notion that water supplies constrain the development of energy resources. A recent example is the much publicized experience of the Missouri Basin Power Project (MBPP) in the construction of a coal-fired electric plant (see Harrington, 1980). Very briefly, a site was selected in mid-1973 on the Laramie River near Wheatland, Wyoming. Subsequently, a portion of the Platte River in central Nebraska (the Laramie is a tributary of the Platte) was proposed (in 1975) and designated (in 1978) as "critical habitat" for the whooping crane under the Endangered Species Act of 1973. In October, 1978 the US District Court set aside two critical Federal actions (a US Rural Electric Administration loan guarantee and an Army Corps of Engineers dredge and fill permit) and enjoined construction pending further evaluation of the impacts of the project on the whooping crane. With Unit 1 80 percent complete and thousands of workers idle, MBPP quickly settled out of court. The member utilities agreed to slightly curtail water use, to modify reservoir operating procedures, to cease further acquisition of irrigation rights, and to establish a \$7 million whooping crane habitat trust fund.

One might cite many other examples of difficulties encountered by energy firms in water acquisition. After considering eight case histories, however, Humm and Selig (1978) tentatively concluded that imaginative approaches and avoidance of injury to third parties greased the water acquisition process. They cited examples ranging from payments to modify an irrigation company's storage reservoir to use of seawater in cooling towers.

This view is echoed by Rod Clark, a water supply engineer for the Intermountain Power Project (IPP). Clark suggests that public acceptability is a

key issue in energy facility siting and that, especially in the West, the pattern of water use has a great influence on public acceptability.* In IPP's case, this strategy entailed paying an arguably extravagant \$70 million to irrigators in Millard County, Utah, for about 40,000 acre-feet (a-ft) of water. This dollar figure, however, represents only about 2 percent of total project costs.

In summary, recall the Western adage that water flows uphill to money. Energy firms have the money to drill deep wells, to construct treatment facilities for brackish water or sewage plant effluent, and to design porous dike intake structures to reduce impingement and entrainment of aquatic organisms, because, again, water use costs are a small fraction of investment costs. This is not to suggest that energy firms are not cost minimizers; they balance water use costs against transaction costs measured as the costs of project delay.

Water System Design

The design of the water use system establishes the plant water intake rate and the rate and quality of effluent discharge. Architect-engineering, including design of the water use system, takes 1-2 years. Aside from the quantity, quality, and cost of available intake water, other key inputs to water system design are the type of energy conversion process, effluent discharge regulations, fuel quality, and site-specific atmospheric conditions.

Energy conversion type determines the waste heat load, the process water requirements, and residuals generation rates. As examples, the cooling load at a coal-fired electric plant is about one-third lower than for an equivalent nuclear electric plant due to stack gas losses and slightly higher conversion efficiencies; most second generation coal gasification processes require a dry coal feed, whereas moisture in the raw coal feed to a Lurgi gasifier can be recovered to reduce net feedstock or process water requirements.

The effluent standards applicable to energy plants exert a great influence on the pattern of water use. A brief review is useful. The Federal Clean Water Act (PL 92-500) states the noble objective of eliminating all discharges of pollutants by 1985 (see Arbuckle and Vanderver, 1979). The Act

*Presentation of Rodney Clark, Intermountain Power Project at US DOE Workshop, "The Nation's Groundwater Resources and Energy Production," Albuquerque, NM, January, 1980.

requires industrial point sources of residuals to obtain National Pollutant Discharge Elimination System (NPDES) permits and directs EPA to issue effluent guidelines or minimum standards for the issuance of these permits. The permit issuing authorities (state agencies and EPA regional administrators) may require more stringent practices where necessary to achieve water quality standards (see Sec. 402(a)1 of the Act).

At present, guidelines for effluent discharges from steam electric plants only limit discharges of conventional pollutants (oil and grease, suspended solids, chlorine, and several metals); however, 1977 Amendments to the Act require stringent control of toxic residuals (organics, heavy metals, and so forth). Accordingly, the EPA expects to propose revised guidelines for the steam electric plant industry by September, 1980. On the basis of proposed guidelines for petroleum refineries, which require zero discharge for new sources, one might surmise that zero discharge will be proposed for most waste streams at steam electric plants, and eventually, for synthetic fuel plants. The most likely exception is cooling system effluent since no EPA guidelines apply to the discharge of heat or dissolved solids. Recall, however, that more restrictive standards may apply in some regions. Thus, in the Colorado Basin, industrial salt loadings are effectively prohibited to limit the salinity of water delivered to Mexico.

Fuel quality determines the rate of residuals generation. Because gas cleaning and solid waste disposal systems often use water, the rate of residuals generation influences the rate of water use. Also, moisture in the raw energy feed may be used for process water.

Atmospheric and geographic conditions such as temperature, relative humidity, wind speed, and elevation influence the rate of evaporation or heat transfer from ponds, reservoirs, and cooling towers. Estimates of average cooling tower evaporation rates at 36 sites in the US (for 1000 Mw fossil plants at 80 percent capacity factor) ranged from 6.24×10^6 gal/day at Bangor, Maine, to 8.33×10^6 gal/day at Yuma, Arizona, with a mean value of 7.28 and a standard deviation of 0.55 (Hu, Pavlenko, and Englessen, 1978).

Given design conditions determined by the parameters discussed above, the principal water system design decisions are the rate of recirculation for each process, the type and degree of process intake and effluent treatment, and the disposition of process and plant effluent (reuse or disposal). These design variables determine the plant intake, consumption, and discharge

rates. Figure 1 illustrates these relationships by focusing solely on the cooling system of a hypothetical plant. For a once-through system, intake equals discharge. Recirculating or closed cycle cooling systems use either air cooled or evaporative heat exchangers to reject waste heat to the atmosphere and to avoid thermal pollution. An evaporative cooling system, as shown in Fig. 1, greatly reduces intake and discharge rates, but increases water consumption. This reduces the assimilative or dilutive capacity of water bodies for other residuals such as suspended and dissolved solids and water treatment chemicals. Treatment of evaporative cooling system intake or effluent (blowdown) allows a greater recirculation rate (indicated by the

Fig. 1. The effect of design alternatives on intake, consumption, and discharge rates for cooling at a coal-fired electric plant (gal/m/1000 Mw at 100 percent capacity factor).

greater number of cycles of concentration) and a further reduction in intake or discharge rates. If land disposal is substituted for effluent discharge, water consumption increases slightly. Substitution of air cooling for evaporative cooling (not shown in Fig. 1) allows 100 percent recirculation of the condenser cooling water and eliminates both thermal pollution and water consumption. A plant may use either 100 percent dry cooling or partial dry cooling in series or parallel with evaporative cooling.

For plants with multiple water uses, effluent from one process as an alternative to disposal. Cooling tower blowdown, for example, is particularly suitable as a source of makeup water for processes such as ash disposal or flue gas desulfurization with low quality intake requirements. Figure 2, a sample and over-simplified water

Fig. 2. Sample water balance for a Hygas plant producing 250 MMscf/day (million standard cubic feet) at Colstrip, Montana, (10^3 lb $H_2O/hr.$)

balance for a coal gas plant, illustrates the relation between the cooling system and other water-using processes at an energy conversion plant and the opportunities for recycling process effluents.

In summary, water system design entails the evaluation of tradeoffs among water intake, water treatment, and wastewater disposal costs. Water use rates may vary greatly with design alternatives. Because, historically, water use costs were a small fraction of energy product costs, water system design ordinarily occurred after other critical production parameters such as site, conversion process type, fuel supply, and the cost, quality and availability of intake water have been determined. If as a consequence of increased water scarcity, plant water use accounts for a substantially greater proportion of engineering costs or contributes to costly project delays, one might expect water system designers and the water acquisition team to play a more integral role in total project planning.

With this review of engineering/design alternatives, let's consider the cost of water use alternatives.

III. THE COST OF WATER USE ALTERNATIVES

Water Intake

Water intake costs, which include acquisition, conveyance, and storage costs, are site-specific. In the riparian states and in the appropriation states where unappropriated surface or groundwater is available, water is essentially free other than permitting or transaction costs. These may easily run into the millions of dollars per project.

In the appropriation states the cost of acquiring water rights from other users varies over a wide range depending on the demand for water in both the energy and nonenergy sectors. Furthermore, little empirical data concerning the cost of transferring water rights to large industrial users is available. Nevertheless, we note that wastewater from sewage treatment plants and mining operations, for which there is little demand in nonindustrial sectors, is quite inexpensive. Arizona Public Service Co., for example, acquired 106,000 a-ft/yr of treatment plant effluent from the City of Phoenix at \$30/a-ft ($\$0.09/10^3$ gal). On the other hand, two western utilities paid about \$1,300/a-ft and \$1,750/a-ft in separate transfers of water rights from irrigators (Abbey and Loose, 1980). On an annual, unit cost basis, that figures to about $\$0.50/10^3$ gal. Transaction costs, which include the cost

of gaining approval for change of use and point of diversion and the cost of risk, may also be substantial. For example, the Missouri Basin Power Project attempted to transfer 4,940 a-ft/yr from irrigated ranch lands served by the Boughton Ditch. The Wyoming Board of Control effectively reduced the consumptive use right to about 1,800 a-ft/yr (Humm and Selig, 1978).

Wellfield capital costs and energy costs dominate the cost of pumping groundwater. Wellfield costs depend on the yield of individual wells, which in turn depends on aquifer-specific, hydrogeologic conditions. No data is available to authors to make meaningful generalizations about groundwater costs.

Conveyance or pipeline costs depend particularly on distance, lifting height, and rate of flow. Gold and Goldstein (1978) estimate conveyance costs to 28 potential sites for individual synthetic fuel plants in the Intermountain region. The mean distance is 30 miles. The mean cost estimate is \$0.92 /10³ gal, with a standard deviation of 0.72. Unit conveyance costs would be lower for electric plants which use more water, for sites with multiple plants, and generally, for plants in water abundant regions where conveyance distances are likely to be much shorter.

Recirculation

When intake, treatment, and disposal costs are nil, once-through water use systems are most economical. Because of the large intake and effluent requirements, however, if a firm must pay for the water, pipe it to the plant, or treat the effluent before disposal, recirculating systems are economic. For example, at a fossil-fueled electric plant, a once-through cooling system requires an intake rate of about 21 gal/Kwh* compared to only about 0.45 gal/Kwh for a closed or recirculating system. Assuming that a recirculating system has an incremental cost of about 0.65 mills/Kwh (Hu, Pavlenco, and Englessen, 1978), the breakeven water use cost, the cost at which savings in intake or effluent treatment and disposal costs equal the incremental capital and operating costs of the recirculating system, is only \$0.03/10³ gal.

Water Treatment and Disposal

The cost of water treatment depends on the type of treatment and the quality and flow rate of the feed. In Table II we present treatment cost

*About 350,000 gal/min for a 10° F temperature rise at the condenser for a 1,000 Mw plant.

TABLE II
SELECTED WATER TREATMENT COST ESTIMATES

A. Treatment of Brackish Water and Seawater (\$1979)

Process	Feed Quality (mg/l TDS)	Recovery Rate (%)	Output Rate (10 ⁶ gal/d)	Product Quality (mg/l TDS)	Product Cost (\$/10 ³ gal)
Vertical Tube Evaporation (distillation)	35,000 (seawater)	N.A.*	10	nil	3.50
Reverse Osmosis	35,000	30	5	500	3.90
Electrodialysis	2,000-3,700	78-87	10	nil	0.8-1.10**
Reverse Osmosis	2,000-5,000	80	1-30	500	0.55-0.67

*N.A. - Not available.

**Costs vary depending on constituents of feedwater.

References: LARSON ASSOC., 1979. "Desalting Seawater and Brackish Water: Cost Update, 1979," Oak Ridge National Laboratory, ORNL/TM-6912 (August).

B. Cooling Water Treatment (intake and sidestream) (\$1975)

Type of Treatment	Intake Quality (mg/l TDS)	Cycles of Concentration	Intake Rate (10 ⁶ gal/d)	Cost (\$/10 ³ gal feed)
1. Sidestream line softening with clarifier	171 (Lake Ontario)	53	15	0.15
2. Acid intake treatment for bicarbonate; lime- soda sidestream softening	426 (Tongue R.)	45	15	0.33
3. Softening and NH ₃ stripping of intake; side-stream clar- ification for dust and heavy metal removal.	721 (Dallas Sewage Plant Effluent)	15	15	0.30
4. Ion exchange treat- ment of intake and sidestream silica removal	2,000-7,000 (agricultural wastewater)	N.A.	11.5	0.34*

*\$1976.

References: H. Gold, D. Goldstein, and D. Yung, 1976. "The Effect of Water Treatment on the Comparative Costs of Evaporative and Dry Cooled Power Plants." US ERDA, COO-2580-1 (July); the State of California Department of Water Resources, 1978. "Agricultural Waste Water for Power Plant Cooling: Development and Testing of Processes," Vol. II, Dept. of Water Resources (June) p. 101.

C. Boiler Feedwater Treatment

Process	Feed Rate (10 ⁶ gal/d)	Cost (\$/10 ³ gal feed)
Mixed Bed Ion Exchange	3	0.88

D. Treatment of Synthene Foul Process Effluent (\$1977)

Process	Feed Rate (10 ⁶ gal/d)	Cost (\$/10 ³ gal feed)
phenol extraction	5.4	1.90
NH ₃ Separation	5.4	-0.24
Biological Treatment	5.4	3.02

Reference: H. Gold and D. Goldstein, 1979. "Wet/Dry Cooling and Cooling Tower Blowdown Disposal in Synthetic Fuel and Steam-Electric Plants." EPA-600/7-79-085 (March) p. 177.

estimates for a variety of conditions. Part A presents cost and other data for treatment of seawater and brackish water. Part B presents cooling water treatment cost estimates for two freshwater and two wastewater samples. Treatment includes both intake and sidestream options. Part C presents a cost estimate for treatment of boiler feedwater by a mixed-bed ion-exchange process. Part D presents cost estimates for treatment of effluent from a coal gasifier (removal of phenol, ammonia, and BOD). While costs of treating cooling tower effluent for concentration of salts are not shown, these would be comparable to the costs shown in Part A (see Houle and others, 1979). Finally, given net evaporation rates ranging from 20-50 in/yr (1-2.5 gal/min/acre) and assuming lined evaporation pond costs of \$50,000/acre, the cost of land disposal ranges from about \$8-20/10³ gal.

We did not normalize these cost estimates in terms of a common pricing year, capital recovery factor, steam cost, and so forth. Much more importantly, these costs apply to specific treatment processes, water use functions (for example, power plant cooling), intake qualities, and flow rates. Obviously, there are many possible permutations for the mix and application of water treatment processes at energy conversion plants. Direct reuse of process effluent and operation of increasingly efficient treatment processes in succession (for example, reverse osmosis followed by distillation) may allow great savings in total plant water treatment costs. Nevertheless, we offer several general observations concerning the influence of water treatment and disposal costs on water system design.

First, while treatment costs favor the use of freshwater, use of wastewater or brackish water is quite acceptable; that is, the incremental treatment costs compare favorably with the cost of conveying freshwater long distances or conserving water with dry cooling (see Table III). While the cost of desalinization appears prohibitive except for low volume uses such as boiler makeup or potable water, seawater may be used for once-through cooling at an incremental capital cost of 20 percent (relative to once-through cooling with freshwater) (Hu, Pavlenko, and Englessen, 1978).*

Second, stringent discharge standards and water treatment costs may induce process modification. For example, a lime injection/spray dry flue gas desulfurization system (FGD) produces a dry solid waste and obviates the need for sludge dewatering and the disposal ponds that are common to conventional

* The principal incremental cost is for use of corrosion-resistant titanium in the condenser tubing.

FGD systems. This technology is gaining widespread use in the West (see PEDCo, 1980). As another example, the cost of water treatment for Lurgi coal gasification may represent as much as 7% of energy product cost, two to three times higher than for second generation gasification processes (Gold and Goldstein, 1978).

Third, and most important, stringent discharge standards and land disposal costs promote the maximum recirculation, reuse, and treatment of water (see Maulbetsch, 1980 and Abbey, 1979). This is because the most efficient treatment option for saline wastewater streams, distillation, is less expensive than land disposal. Distillation achieves about 97 percent feedwater recovery and yields a highly concentrated waste stream of about 100,000 mg/l TDS. Land disposal of the waste stream from a distillation unit is likely to represent less than 2 or 3 percent of total water consumption at an energy plant.

Assuming the exhaustive application of water treatment technologies, further reduction in water consumption requires either process modification or substitution of dry (air) cooling for wet (evaporative) cooling. Relative to process change, dry cooling for water conservation is very sensitive to the cost of water use. It also offers much greater potential for water conservation, because cooling water evaporation accounts for at least 90 percent of water consumption at a nuclear plant, at least 80 percent at a coal-electric plant, and probably over half at a synthetic fuel plant.

Cooling Alternatives for Water Conservation

The standard description of alternative cooling systems for water conservation is in terms of water consumption relative to an all-wet, evaporative cooling system. Thus, a 40% wet/60% dry cooling system is a configuration of wet and dry cooling towers or cells designed to use, on an annual average, 40 percent of the water of an all-wet cooling system. Cost evaluations include capital costs for the cooling system, operating and maintenance costs (including the cost of electricity to operate fans and pumps), and penalty costs for backup capacity.

Table III presents cost estimates of cooling alternatives for 1,000 MW fossil-fueled electric plants at three sites in the US. The cost of cooling at nuclear plants is about 50 percent greater. This data does not completely reflect the variety of operating conditions in the electric utility industry across the US. Dry cooling costs could be lower for a winter peaking utility or a utility with exceptionally low fuel costs. Nevertheless, considering the

TABLE III
COST OF COOLING ALTERNATIVES AT FOSSIL PLANTS
AT 3 SITES IN THE US
(\$1978)

	<u>% Wet</u>	<u>\$/Kw</u>	<u>mills/Kwh*</u>	<u>Breakeven Water Cost** (\$/10³ gal)</u>
	100	23	1.11	--
Farmington,	40	44	2.21	3.70
New Mexico	10	57	2.86	4.81
	0***	48	4.07	26.89
	100	27	1.18	
New Hampton,	40	43	2.16	3.62
New York	10	56	2.66	3.70
	0***	45	3.87	26.89
	100	23	1.14	
Colstrip,	40	43	2.16	3.70
Montana	10	57	2.68	3.85
	0***	47	4.02	29.33

*At 80% annual capacity factor; exclusive of water use costs.

**Assumes evaporation of 0.45 gal/Kwh with 100% wet cooling.

***High back pressure turbine.

Reference: Hu, Pavlenko, and Englessen, 1978, "Water Consumption and Costs for Various Steam Electric Power Plant Cooling Systems," US EPA, EPA-600/7-78-157, Washington, DC (August) pp. 51, 52.

breakeven water cost for even 40% wet/60% dry cooling, the explanation for the reluctance of the utility industry to adopt dry cooling technologies is quite obvious. Even in water scarce regions, most water supply alternatives such as purchasing water rights from irrigators at prices up to \$2,000/a-ft, pumping deep groundwater, piping water from distances of 30 miles or more, and treating brackish water and wastewater are less costly than dry or wet/dry cooling for water conservation. On the other hand, dry cooling does appear competitive with grandiose schemes to convey water hundreds of miles (for example, from Lake Oahe in South Dakota to the Powder River Basin). Also, advanced dry cooling concepts under investigation by the DOE, the Electric Power Research Institute, and others appear to offer potential cost savings up to 40 percent (Johnson and others, 1979).

The potential for dry cooling for water conservation at synthetic fuel plants is more promising because some waste heat loads occur at higher temperatures than the range typical of steam turbine condensers at electric plants (100° - 130° F). Thus, the incremental cost of dry-cooled heat exchangers is relatively smaller. Also, there is no loss of performance at extremely high ambient temperatures. Table IV illustrates the breakeven costs of dry or wet/dry cooling at Casper, Wyoming for a variety of cooling applications common to synthetic fuel plants; it also shows the fraction these applications represent of the total cooling load at a Synthane coal gasification plant. Of the other two major waste heat loads at synthetic fuel plants, process gas cooling is likely to be mostly dry cooled; cooling at acid gas absorption units is likely to be either all-wet or all-dry depending on the type of acid gas cleaning.

TABLE IV
BREAKEVEN WATER COSTS FOR SOME COOLING APPLICATIONS
COMMON TO SYNTHETIC FUELS PLANTS
(CASPER, WYOMING, \$1978)

	<u>% Wet</u>	<u>Breakeven Water Cost (\$/10³ gal)</u>	<u>% of Total Waste Heat Load at a Synthane Plant</u>
<u>Interstage Cooling for Gas Compression</u>			9
Air	100	-	
	47	1.75	
	26	2.70	
	12	4.40	
Hydrogen	0	0	
Synthesis Gas	0	0	
Oxygen	0	0	
<u>Steam Turbine Condensers</u>	13	-	28
	1	0.25	
	0	6.25	

Refs: Probstein, R. and H. Gold 1978, Water in Synthetic Fuel Production, MIT Press, p. 113. Goldstein, D. and others, 1979, "Waste Disposal, Cooling and Related Environmental Impacts Associated With Synthetic Fuel Plant Siting and Design Criteria," Draft, prepared for US DOE under Contract No. ET-78-C-01-3182, Project Officer, John Nardella (December) pp. 11, 35, 42, 45, and 57.

Part III allows no easy summary because of the site-specificity of water supply costs and the great variety of options for water treatment, reuse, and disposal. However, we can reiterate two important observations. First, in the energy-rich Western region under the assumption of a zero-discharge constraint, water use economics promotes exhaustive treatment and reuse. Further reduction in water consumption requires dry cooling. Second, considering the breakeven cost of water conservation (Tables III and IV), partial dry cooling has great potential for application at synthetic fuels plants and very limited promise for electric utilities.

Given this review and discussion of the cost and promise of water use alternatives, let us now consider some empirical data.

IV. PLANT SURVEY DATA

A basic thesis of this report is that the pattern of water use varies over time and space with changes in technology, regulation, and water supply conditions. In this section, we report water system elements of energy facilities constructed during the 1970s or planned for the period 1980-1989. The key elements are source of water, type of cooling system, and pattern of discharge.

Figures 3A-3C report water system data for coal-fired plants constructed in the 1970s. Figure 3A illustrates that over the decade there was a trend away from once-through cooling toward recirculating systems. In the period 1970-1973 about 53 percent of the new plants used once-through cooling. In the periods 1974-1977 and 1978-1979, the percentage of new plants with once-through cooling declined to about 40 percent. Evaporative cooling towers were the predominant choice among recirculating systems. Use of freshwater (Fig. 3B) and, to a lesser degree, discharge of effluent (Fig. 3C) were standard practice throughout the decade. No attempt was made to disaggregate the data by region.

Table V presents water system data for individual coal-fired and nuclear electric plants planned to come on line in selected states and basins during the period 1980-1989. The states and basins were selected by consideration of regions reputed to be "water-for-energy problem areas" (see for example US DOE, 1979). Figures 4A-4C summarize these survey data.

Figure 4A shows that evaporative cooling ponds or towers are the predominant choice for new electric plants in all states and basins surveyed.

Fig. 3A. Types of cooling systems at selected coal-fired power plants constructed in the US, 1970-1979.

Once-through cooling is planned at 3 sites in Nebraska, Ohio, and Florida. No plans for dry or wet/dry systems were identified. In the 80s in Ohio, Texas, and the Upper Missouri River Basin, surface water will continue to be the dominant supply category. In Florida, almost half of the electric plant capacity will use seawater from the Atlantic Ocean or the Gulf of Mexico, wastewater, or groundwater. In the Colorado and Great Basins over 80 percent of the projected capacity will use wastewater, groundwater, or water purchased from irrigators. This is not surprising because the Colorado Basin provides a classic example of an over-appropriated river basin with "water requirements" exceeding "surface water availability." Discharge patterns (Fig. 4C) vary greatly by state and region. The feasibility of wastewater evaporation in terms of cost of land and net evaporation rates is the most likely explanation

Fig. 3B. Water supplies at selected coal-fired power plants constructed in the US, 1970-1979.

for variation. For those plants planning to discharge effluent, we did not distinguish between discharge of saline streams (for example, cooling tower blowdown) and the effluent streams containing toxic pollutants (for example, boiler blowdown). For those plants planning to achieve zero discharge, a high rate of cooling water recirculation (indicated by the cycles of concentration) and recycle of cooling tower blowdown are standard practice.

Table VI presents water system elements for coal gas plants planned in the Western US. All plants will use the commercially available Lurgi gasification process and surface water and are designed for zero discharge. The Panhandle Eastern plant represents an imaginative approach in which the firm acquired water rights from irrigation by financing modifications to a reservoir to increase its storage capacity (Humm and Selig, 1978). Cooling

*Discharge data not available for 5.4% of capacity.

**Data not available for 37.7% of cap.

***Data not available for 19.5% of cap.

SOURCES FOR FIGS. 3a-3c: Electrical World, 10th-15th "Steam Station Design Survey," Oct. 21, 1968; Oct. 15, 1970; Nov. 1, 1972; Nov. 15, 1974; Nov. 15, 1976; and Nov. 15, 1978.

Fig. 3C. Discharge at selected coal-fired power plants constructed in the US, 1970-1979.

water evaporation, surrogate for dry cooling fraction, varies greatly. For the upper range (Great Plains and Peoples) this reflects either a conservative overestimation of water use or a conservative reluctance to employ air-cooled heat exchangers. The variation in net process use reflects variation in the moisture content of the coal feed.

Industrial survey data, of course, suffers from the problem of self-reporting. Moreover, utility plans are subject to change. For example, Table V includes neither a Basin Electric plant near Mobridge, South Dakota, proposing to use once-through cooling from Lake Oahe (a Missouri River reservoir), nor two additional units at Pacific Power and Light's Wyodak plant

TABLE V

WATER SYSTEM ELEMENTS FOR COAL-FIRED AND NUCLEAR ELECTRIC PLANTS
IN SELECTED STATES AND BASINS IN THE UNITED STATES, 1980-1989

	Company Name	Plant Name	Location	MWe ^a	Date of First Unit	Principal Source of Supply	Intake Water Quality (mg/ TDS)	Type of ^b Cooling System	Cycles of Concentration	Recycle CT Blow-down	Discharge
Florida	Seminole Elec. Coop., Inc.	Palaatka 1 & 2	30 mi. West of St. Augustine	2x600(c)	1983	St. John's River	578	CT	4	Yes-to FGD	No
	City of Lakeland, Dept. of Electricity and Water	C.D. McIntosh 3	Polk County	364(c)	1981	Treated Sewage Effluent	Secondary treatment with trickling filters--90% removal of BOD and suspended solids.	CT	3-4	Yes-to process water, FGD, and possibly for land spreading	No
	Gainesville-Alachua County Florida	Deerhaven 2	Gainesville	251(c)	1981	Deep Wells (Floridian Aquifer)	150-1000	CT	60	Yes-to brine concentrator	No
	Florida Power & Light	St. Lucie 2	Between Ft. Pierce and Stewart	850(n)	1983	Atlantic Ocean	35,000	OT	N.App. ^c	N.App.	Yes
	Florida Power Corp.	Crystal River 4 & 5	Citrus County	2x640(c)	1982	Gulf of Mexico Via man-made canal system	15,000 to 36,000	CT	1.1 to 1.2	No	Yes
		Fossil 1,2&3	Port St. Joe, FLA	$\frac{3x660(c)}{5,925}$	1986	Lake Wimico	varies seasonally from fresh water to brackish; 115 to 250 during freshwater period.	CT	.3 to 8	Yes-to flue gas desulfurization except during period of brackishness	Yes
Ohio	Dayton Power & Light	Killen Station 1 & 2	Manchester	2x661(c)	1981	Ohio River	250 (avg)	CT	3	Yes-to ash sluicing	Yes
	Columbus & Southern Ohio Elec. Co.	Poston 5	Athens	444(c)	1987	Wells	NA ^d	CT or CP	NA	NA	NA
	Cleveland Elec. Illum Co.	Ferry 1&2	Lake County	2x1,205(n)	1981	Lake Erie	260	OT	N.App.	N.App.	Yes
	Toledo Edison Co.	Davis-Besse 1 & 2 (cancelled)	Ottawa Cty.	2x925(n)	1985	Lake Erie	234 (avg)	CT	2	No	Yes

TABLE V (CONT.)

Texas	Ohio Edison Co.	Erie 1 & 2	Erie County	2x1,280(n)	1986	Lake Erie	216 (max)	CT	2	No	Yes
	Cincinnati Gas & Elec. Co.	W.H. Zimmer 1	Moscow	$\frac{878(n)}{9,464}$	1980	Ohio River	NA	CT	~8	No	Yes
	Gen & SW: Southwestern Elec. Power Co.	Welsh 2 & 3	Titus County	2x558(c)	1980	Lake O the Pines (Red River Drainage)	110	CP	N.App.	N.App.	No
	Texas Utilities: Texas Power & Light	Pirkey 1	Harrison County	719(c)	1984	same as above	140	CP	N.App.	N.App.	No
		Sardow 4	Milam County	591(c)	1981	Trinity River	NA	CP	N.App.	N.App.	No
		Forest Grove 1	Henderson County	793(c)	1984	Cedar Creek Res. (Cedar Creek/Trinity River Basin)	NA	CP	N.App.	N.App.	No
		Twin Oak 1 & 2	Robertson County	2x793(c)	1984	Navasota River (Brazos River Basin)	NA	CP	N.App.	N.App.	Yes
		Martin Lake 4	Rusk County	793(c)	1985	Martin Creek (Sabine River Basin)	NA	CP	N.App.	N.App.	Yes
		Comanche Peak 1 & 2	Somervell County	1,150; 1,215	1985	Squaw Creek and Lake Granbury	Squaw Creek-275-325; Lake Granbury-1,200	CP	N.App.	N.App.	No
	Lower Colorado River Authority	Fayette 2	La Grange	603(c)	1980	Colorado River	300-380	CP	N.App.	N.App.	No
	Gen. & SW: West Texas Utilities Co.	Diversion/Kemp 1	Oklahoma	640(c)	1987	Lake Kemp & Lake Diversion (Wichita River-Red River Basin)	Lake Kemp-3,207; Lake Diversion-2,838	CT	>10	Yes	No
	Houston Lighting & Power	W.A. Parish	Near Thompson, Texas	2x600(c)	1980	Dry Creek Area Runoff or Brazos River to Smithers Lake	<50G	CT	1.2 to 4	No	Yes
		Allen Creek 1	Austin County	1200(n)	1985	Allen Creek Watershed and Brazos River	NA	CP	N.App.	N.App.	No
		South Texas 1 & 2	Matagorda County	2x1,250 (n) 14,103	1980	Reservoir (Colorado River)	<2000	CP	N.App.	N.App.	Yes

TABLE V (CONT.)

Upper Missouri River Basin	Basin Elec. Power Coop.	Laramie River 1,2&3	Wheatland, Wyo.	3x550(c)	1980	Grayrocks Dam & Res. (Laramie River)	NA	CT	Unit 1= 1-2 Unit 2= 2-3 Unit 3= 3-30	Yes-plant intake	No
		Antelope Valley 1&2	Beulah, N.D.	2x438(c)	1981	Lake Sakakawea (Missouri River)	NA	CT	10-12	Yes-to FGD system	No
	Platte River Authority	Rawhide 1	Ft. Collins, Colo.	255(c)	1985	Sewage effluent from the City of Ft. Collins	350	CP	N.App.	N.App.	No
	Otter Tail Power Co.	Coyote 1	Beulah, N.D.	414(c)	1981	Missouri River	400-500	CT	7-8	No	Yes
	Nebraska Public Power District	Gentleman 2	Sutherland, Neb.	650(c)	1981	Sutherland Res. (South Platte Basin)	NA	OT	N.App.	N.App.	Yes
		Fossil 3	Lincoln County, Neb.	650(c)	1986	Well Fields	NA	CT	~22	Yes-to FGD and bottom ash disposal	No
	Montana Power Co.	Colstrip 3 & 4	Colstrip, Mont.	778(c)	1982	Yellowstone River	300-500	CT	10-15	Yes	No
	Public Service Co. of Colorado	Pawnee 1	Brush, Colo.	552(c)	1980	South Platte River	1700-1900	CT	11	Yes-to boiler makeup	No
	Cooperative Power Assoc.	Coal Creek 2	McLean County, N.D.	550(c) 6,375	1980	Missouri River	NA	CT	NA	Yes-to ash disposal	No
	Colorado Basin	Arizona Public Service Co.	Cholla 4 & 5	Navajo Cty, Ariz.	2x375(c)	1980	Wells	NA	CT	Unit 4 4-14 Unit 5-NA	Yes
		Palo Verde 1-4	Maricopa Cty., Ariz.	4x1,333 (n)	1982	Municipal wastewater	NA	CT	11	No	No
Salt River Project		Coronado 2	Apache Cty., Ariz.	395(c)	1980	Wells	NA	CT	4	Yes	No
Tucson Gas & Electric		Springerville 1	NA	350(c)	1985	Wells	NA	CT	NA	Yes	No

TABLE V (CONT.)

San Diego Gas & Electric	Sundesert 1 & 2 (Cancelled)	Riverside Cnty., Calif.	2x1,000 (n)	1984	Pala Verde out-fall drain (return flows from irrigated agriculture)	NA	CT	16	No	No
Colorado-Ute Electric Association	Craig 3 & 4	Moffat County, Colo.	2x380(c)	1983	Yampa River	NA	CT	13	Yes	No
Nevada Power Co.	Allen 1-4	Clark County, Nev.	4x500(c)	1985	Municipal wastewater	NA	CT	NA	Yes	No
Public Service Co. of New Mexico	San Juan 4	San Juan County, New Mexico	534(c)	1981	San Juan River	NA	CT	10.5	Yes	No
	New Mexico 1 & 2	San Juan County, New Mexico	2x500(c)	1983	Wastewater from Uranium Mines	NA	CT	NA	Yes	No
Utah Power & Light	Emery 2,3,4	Emery County, Utah	3x400(c)	1980	Purchased water from 2 ditch companies and a conservancy district	NA	CT	15	Yes	No
Nevada Power	Werner Valley 1 & 2	Washington County, Utah	2x250(c)	1983	Virgin River	NA	CT	NA	Yes	No
Los Angeles Dept. of Water & Power	Intermountain Power Project (cancelled)	Wayne County, Utah	4x820(c) 18,141	1985	1/2 wells & 1/2 Fremont River	NA	CT	NA	Yes	No
Great Basin Sierra Pacific Power Co.	North Valley 1 & 2	Humboldt Cnty., Nevada	2x275(c)	1981	Wells	350	CT	17-20	Yes	No
Los Angeles Dept. of Water & Power	Intermountain Power Project	Millard Cnty., Utah	3000	1984	Purchased water from 5 ditch companies.	Sevier River 1000-1500; groundwater 400	CT	~13	Yes	No

SOURCES AND REFERENCES: List of plants from US Department of Energy, 1979. "Inventory of Power Plants in the United States," DOE/EIA-0095, Wash., DC (April). Unsited plants and those with insufficient data are not included. Water system elements for Florida, Ohio, Texas, the Great Basin and the Upper Missouri River Basin obtained from Environmental Impact Statements and from telephone conversations with utility personnel conducted in January and February, 1980. Data for the Colorado Basin from Abbey, D. 1979. "Energy Production and Water Resources in the Colorado River Basin," Natural Resources Journal, Vol. 19, No. 2.

a (c) - coal-fired; (n) - nuclear

b CT - cooling tower; CT - once through cooling; CP - cooling pond.

c Not Applicable.

d Not Available.

Fig. 4A. Cooling systems at coal-fired and nuclear power plants in selected states and basins in the US, 1980-1989.

for which dry cooling is apparently under consideration. Nevertheless, we find general confirmation of the initial thesis of this section and of the inferences of the previous section derived from engineering economic analysis. First, the pattern of water use varies widely from region to region reflecting differences in effluent discharge regulations and water supply conditions. Second, in the most water scarce region of the US, the Southwest, electric utilities will rely on a variety of water supply alternatives to streamflows—wastewater from mines and sewage treatment plants, groundwater in deep, consolidated aquifers, and water purchased from irrigators. Third, a high degree of cooling water recirculation and reuse of cooling tower blowdown

¹ Upper Missouri River Basin.

² Colorado Basin and Great Basin (Nev.).

Fig. 4B. Water sources for coal-fired and nuclear power plants in selected states and basins in the US, 1980-1989.

ordinarily accompanies land disposal of liquid effluents (zero discharge). This reduces plant intake requirements. Fourth, at least for the next decade, the potential application of dry or wet/dry cooling for water conservation at electric plants is quite limited. This reflects the site selection methodologies used by utilities as well as higher costs for dry cooling. Fifth, partial dry cooling has great potential for cost savings at synthetic fuel plants.

Fig. 4C. Discharge at coal-fired and nuclear power plants in selected states and basins, 1980-1989.

V. CONCLUSIONS

Many times in recent years, water use practices proposed for new energy conversion facilities have been the subject of great controversy. Many people anticipate that the frequency and bitterness of these conflicts will increase. Thus, they perceive the need for greater public control of the allocation of water resources and the use of water in the energy industry.

A precursor to successful regulation is an understanding of the present method of resource allocation. In this report, we consider the role of energy firms in water resource allocation. We described the process of site selection and water system design; we discussed the cost of water use alternatives and drew inferences concerning the probable pattern of water use

TABLE VI
WATER SYSTEM ELEMENTS FOR PROPOSED COAL
GAS PLANTS IN THE WESTERN US

Firm	Site	Capacity ($10^6 \text{ft}^3/\text{day}$)	Source of Water	Raw Water Intake (A-ft/yr)	Net Process Use (A-ft/yr)	Cooling Water Evaporation (A-ft/yr)
El Paso Nat. Gas. Co.	Bisti, NM	72	San Juan R. (Bu. Rec. reservoir)	7,870	1,280	3,950
Wesco	Burnham, NM	250	San Juan R.	5,850	810	3,200
Panhandle Eastern	Douglas, Wyo.	137.5	La Prele Cr. (Douglas Res- ervoir Water Users Assoc.)	5,710	680	2,680
Great Plains Assoc.	Beulah, ND	137.5	Missouri R. (Bu. Rec. reservoir)	12,380	575	11,530
Peoples Gas. Co.	Dunn Center, ND	250	Missouri R. (permit denied by North Dakota)	9,610	(810)	8,610
Lurgi (hypothetical)	Eastern Montana	250	-	4,890	800	2,520

^aWater use estimates scaled to 250 $10^6 \text{ft}^3/\text{day}$, 365 days/yr; equivalent to a plant with 275 $10^6 \text{ft}^3/\text{day}$ capacity at 91% annual capacity factor.

^bHypothetical plant designed to minimize water consumption.

SOURCE: David Abbey, 1979. "Water Use for Coal Gasification: How Much Is Appropriate," Los Alamos Scientific Laboratory report LA-80-60-MS, Los Alamos, NM (October) pp. 12, 13.

at new plants; finally, we presented empirical data concerning water system elements at new plants. In conclusion, we make three general observations.

First, although almost any activity results in winners and losers, most water use conflicts involving the energy industry are tractable. This is because of the variety of water use alternatives available and the relatively small incremental cost of the most expensive of these alternatives. For example, 90% dry/10% wet cooling at coal-fired electric plants costs about \$60/Kw compared to total plant capital costs of \$1,000/Kw.

Second, the optimal water use pattern depends on a number of specific conditions including cost and quality of water available, process type, cost of water conservation, and environmental and social costs. While industry may not attach sufficient importance to external costs, they are most knowledgeable about engineering costs. Uniform controls on industrial water users may result in unnecessary and even counter-productive expenditures for pollution control and water conservation. Reynolds (1980) points out that with proper management and design, the risk of damages to aquatic ecosystems from once-through cooling and thermal discharges may be minimal. Closed-cycle cooling not only increases power costs, but causes other more irreversible environmental damages.

Third, industry may obtain considerable advantage by applying greater sophistication to water-related planning and design. Ortolano (1980), for example, suggests that utilities increase public participation in the planning process. The benefits are two fold: a potential for reduction in the cost of regulatory delay and the foreclosure of more stringent public controls in the future.

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