Water Supply for Power in Texas-Gulf Region

By Benjamin F. Hobbs,[1] Aff. ASCE

Abstract: Most water-energy assessments have considered only a few water supply types and conservation technologies. Yet utilities are not only developing traditional surface sources, but are also using ground and waste water and buying water rights from irrigators. A linear program is developed that incorporates: (1) Supply curves for several water sources that reflect institutional constraints; and (2) water demand curves based on the cost of alternative power plant cooling methods. The purpose of the model is to aid the Electric Power Research Institute in strategic planning on water availability issues. For the Texas-Gulf region in the year 2000, it is found that the high cost of dry or mixed wet/dry cooling is unjustified unless: (1) New technologies lower the incremental cost of wet/dry cooling by more than 80%; or (2) unforeseen institutional restrictions prevent utilities from securing economic surface and ground water supplies. This conclusion contradicts previous studies which projected serious water-energy conflicts for the region.

Introduction

Thermal electric power plants use large amounts of water. For example, a 600-MW coal-fired power plant with evaporative cooling towers and sulfur scrubbers can consume up to 12,000,000 gal/day (31). Concern over whether there will be enough water for new plants or whether utilities will crowd out other users has motivated a number of "water for energy" assessments. Most compare the projected water demand by energy industries for a scenario year (e.g., 1995) with either stream flows or the firm yield of a basin's reservoirs (7,12,13,15–17,20,26,27,30,40). Dobson and Shepherd (8), for example, compare low flows with projected demands for 1985 and 1990 for each of 99 "aggregated subareas" that comprise the continental United States. Their analysis indicates that in order for Texas to accommodate projected growth in generating capacity, a large portion of the region's irrigated agriculture may have to be retired. Many of these water for energy studies conclude that water availability will constrain energy production or force adoption of expensive dry cooling systems. For instance, Sonnichsen (32) states that by the year 2000, most generation capacity additions in the Texas-Gulf region will require dry or mixed wet/dry cooling towers.

The pessimistic conclusions of these studies may be due to their disregarding of alternative water supply and conservation measures (28). Some analyses do not consider nontraditional water sources, such as ground water or rights transfers. Others exclude the options of wet/dry and dry cooling. A reason for this in the case of several studies (e.g., 8) is that consistently formatted data on nontraditional water supplies for the entire nation is unavailable.

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Yet electric utilities have proven to be creative in resolving water supply problems. Tucker et al. (37) note that in addition to traditional surface sources, power plants now or will soon use: (1) Ground water; (2) irrigation return flows; (3) sewage treatment plant effluent; (4) brackish or saline supplies; (5) water rights purchased from irrigators; and (6) interbasin transfers. Abbey and Lucero (2) report that in the Colorado and upper Missouri river basins, 80% of new generation capacity will use one of these alternative sources. Several water for energy studies have considered the costs of a more realistic range of options, including alternative water supplies and dry cooling (1,4,9,11,18,22,23,38). But none give a detailed representation of a region while simultaneously including: (1) Subbasin-specific estimates of the availability and cost of several types of water sources; and (2) demand functions reflecting the expense of dry and wet/dry cooling.

This paper presents a linear program which includes a variety of water sources and cooling techniques. By focusing on a single region, the model can incorporate cost information for several types of water supplies for each of a large number of subbasins. The following section summarizes the model. The following questions are then addressed.

1. To what extent will water shortages in the Texas-Gulf region force utilities to adopt wet/dry and dry cooling over the next 50 years?
2. What would be the benefits of advanced less expensive dry cooling technologies, such as those based on an ammonia secondary loop?

After presenting assumptions concerning costs of water supply and use by utilities for the region, a base case model solution for the year 2000 is discussed. Sensitivity analyses and scenarios for the year 2030 are also presented. The results indicate that future water-energy conflicts in the region are unlikely to be as acute as other studies have predicted.

Model

The model is a static linear program which allocates firm water supplies and applies conservation measures so that the cost in a scenario year of water supply and condenser cooling for power plants built after

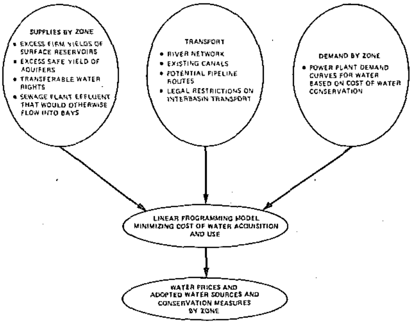

FIG. 1.—Inputs and Outputs of the Model

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1980 are minimized. Fig. 1 summarizes the inputs and outputs of the model. The amount and locations of generation capacity are assumed fixed, but the amount of water they demand depends on the cost of water. Supply curves represent the expense of water acquisition and treatment. Only firm water supplies available during low flows are considered. To fit supply and demand curves into the linear programming framework, piecewise linear approximations of their integrals are incorporated using a method described in Ref. 24.

The model is based on two networks which interconnect nodes where water is supplied from several sources and withdrawn by power plants. One network represents interbasin transfers via existing or potential canals and pipelines. The other consists of the region's rivers and permits flows in only one direction. The model is presented in the following. Lower case symbols represent variables while fixed parameters are given by upper case letters. The indices h, i, and j refer to nodes on the network. Specific types of water supplies are designated by the index s. The model is:

$$\text{MIN} \quad -\sum_i \sum_k BD_{ik} wd_{ik} + \sum_i \sum_s \sum_k CS_{isk} ws_{isk} + \sum_i \sum_{j\epsilon j(i)} T_{ij} q_{ij} \quad \ldots\ldots\ldots \quad (1)$$

subject to:

1. *Water balances.* For each node i:

$$\sum_s \sum_k S_{isk} ws_{isk} + \sum_{j\epsilon j(i)} (q_{ji} - q_{ij}) + \sum_{h\epsilon h(i)} f_h - f_i - \sum_k D_{ik} wd_{ik} = FD_i - I_i \quad \ldots\ldots \quad (2)$$

2. *Demand curve approximations.* For each node i where water is demanded by new power plants:

$$\sum_k wd_{ik} = 1.0 \quad \ldots\ldots\ldots \quad (3)$$

3. *Supply curve approximations.* For each node i and supply type s:

$$\sum_k ws_{isk} = 1.0 \quad \ldots\ldots\ldots \quad (4)$$

plus the usual nonnegativity constraints. The parameters and variables are:

BD_{ik} = Benefit, in dollars per year, of water demand at node i when the quantity demanded equals D_{ik}. This is the integral of the demand curve from zero–D_{ik}, which represents the cost savings relative to the most expensive cooling option, dry cooling.

CS_{isk} = Cost, in dollars per year, of water supply type k at node i when the quantity supplied equals S_{isk}. This is the integral of the marginal cost curve from zero to S_{isk}.

D_{ik} = A specific level k of water demand, in acre-feet per year, at node i.

FD_i = Fixed water demand, in acre-feet per year, by new power plants at node i.

I_i = Increment in dependable streamflow, in acre-feet per year, available for consumption by new power plants at node i. The sum of the I_j

for all nodes j upstream of i plus I_i equals the total dependable streamflow available for new power plants located at or above node i in the river basin.

S_{isk} = A specific level k of dependable supply, in acre-feet per year, of type s at node i.

T_{ij} = Per unit cost, in dollars per acre-foot, of water transport by pipe or canal from i to j.

f_i = Dependable flow, in acre-feet per year, passed from node i to the next node downstream which is available for use by new power plants.

$h(i)$ = The set of nodes h immediately upstream of node i.

$j(i)$ = The set of nodes j directly connected to node i by a canal or potential pipeline routes.

q_{ij} = Water, in acre-feet per year, transported by pipeline or canal from node i to node j.

wd_{ik} = Weight number k used in the convex separable approximation of demand and demand integral at node i.

ws_{isk} = Weight number k used in the convex separable approximation of supply type s at node i.

The largest version of the model for Texas had 350 constraints and 1,000 variables, and took 25 seconds of CPU time to set up and solve on an IBM 360/91 using the MPSX linear programming package.

Water demands in the model represent average water consumption by new plants. This presumes that higher water use rates do not coincide with times of low supplies. To be conservative, only firm water supplies are included in the model. Surface supplies are based upon the worst drought of record. In the case of ground water, however, average safe yield is used because of the large amount of storage in aquifers.

A single solution of the model will be given the cost-minimizing configuration from the utilities' standpoint. This will be a meaningful representation of future conditions only if: (1) Supply and demand curves reflect costs as utilities perceive them; and (2) Utilities are cost minimizers. Condition 1 can hold only if water availabilities and costs reflect political and institutional realities in addition to the prevailing hydrology. In general, supply curves reflecting institutional constraints will show less water available to utilities at a greater cost than curves based solely on hydrology and topography (such as those used in Ref. 4). Condition 2 is assumed to hold here; hence, productive inefficiencies that regulation may induce are disregarded.

Water Supply in Texas-Gulf Region

In its recent report on possible threats to the state's economic well-being, the Texas 2000 Commission (34) found that water supply is the single most important issue. They reported both "present and foreseeable acute water shortages affecting urban life, agriculture and industry." Because water requirements in many areas are growing and locations of supplies do not always match those of demands, several basins now or may soon face surface water shortages. Groundwater supplies are grossly overdrawn in several areas in the state. Declining water tables and well yields now cause higher pumping costs in several impor-

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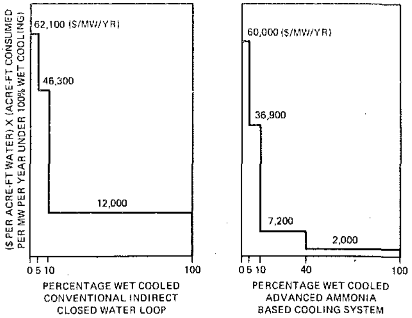

FIG. 2.—Model Nodes and Assumed Stream Courses, Texas-Gulf Region

tant agricultural areas and land subsidence in Gulf Coast urban areas.

The Texas-Gulf region is defined here as the river basins in Texas between the Red and Rio Grande rivers (Fig. 2), excluding the Nueces-Rio Grande Coastal basin, Zone 2. It encompasses a wide range of hydrologic conditions and water demand patterns. Rainfall averages only 12 in. (0.3 m) per year on the High Plains, but it exceeds 55 in. (1.4 m) near the Louisiana border. For this reason, western basins, such as the Brazos and Colorado, have low, unreliable flows, while eastern rivers, such as the Sabine and Neches, are water rich. In the year 2000, the firm yield of the region's surface supply systems is projected to equal 8,600,000 acre-ft/yr (1.1×10^{10} m^3/yr), while the total safe yield of the region's major and minor aquifers will be circa 4,100,000 acre-ft/yr (5.1×10^9 m^3/yr) (5). Surface water consumption in the region was approximately 3,400,000 acre-ft (4.2×10^9 m^3) in 1974, while 7,300,000 acre-ft (9.0×10^9 m^3) of ground water was used (5). Population and industry are concentrated in the eastern part of the state, yet the most water use is in the arid west. Irrigated agriculture predominates in the west and is responsible for five-sixths of the entire region's water consumption.

In 1974, steam electric generation evaporated 173,200 acre-ft (2.14×10^8 m^3) of water in the region, only 1.5% of the total consumption. But power plants are projected to consume five times that amount in the year 2000, 6% of the total use (5). In both years, ground water meets one-fifth of the industry's needs (5). This growth in use, combined with the size of individual consumers, makes power plant proposals a focus of controversy over water supply adequacy and priorities.

Demand and Supply Assumptions

Projecting future water supplies is a risky art, as actual conditions are likely to differ greatly from those assumed. For this reason, the model is solved for both a base set of assumptions for the Texas-Gulf region and alternative, more restrictive assumptions. The base assumptions, summarized below and detailed in Ref. 19, are derived primarily from the 1977 Texas Water Plan (36). The solutions were also checked against the 1983 draft plan, which became available after the completion of the research, and were found to be unaffected by the revised projections.

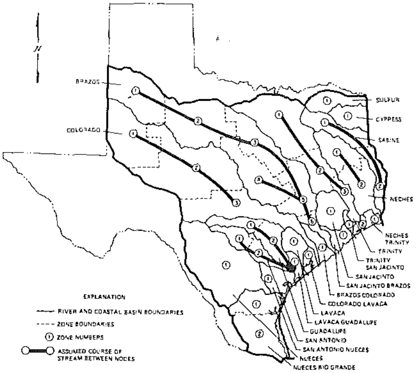

FIG. 3.—Demand Curves for Condenser Cooling Water (1 acre-ft = 1,233 m^3)

All costs given below are expressed in 1980 dollars. Fixed charge rate and inflation assumptions used to calculate levelized costs are consistent with those in Ref. 10.

Each river basin in Texas is divided by the Texas Water Development Board (36) into one or more zones which together cover the entire basin. Fig. 2 shows the 35 nodes used in the model, one per zone, and the assumed stream network. An additional node, Guadalupe 3, is placed at the junction of the San Antonio and Guadalupe rivers.

Water Demand by Power Plants.—Table 1 presents the assumed locations of generating capacity additions in the years 1991–2000. Their sum equals 29,150 MW, a third of the region's total projected year 2000 capacity of 90,542 MW (5). Water demands of plants built before 1991 are assumed to be fixed. The plant additions reflect an assumed growth rate in electricity demand of 4% per year, consistent with utility projections. Plant locations were estimated by Camp, Dresser, and McKee (5), considering patterns of power demands, lignite reserves, and water supply problems.

It is possible to instead allow plant locations to be optimized within this type of model; indeed, several water for energy studies have done so (9,18,23,38). But to do this requires data on siting factors such as transmission costs, demand locations, coal mining and transport expenses, and environmental regulations, in addition to water availability. Resources available to the study did not permit acquisition of this data. Because the model disregards the ability of utilities to trade off, say, transmission and water costs, the expense of water use and conservation will be overestimated and the conclusions of this research will be conservative.

Lignite-fired facilities require more water than coal-fired units, primarily because of mine reclamation needs. Water consumption rates for power plants given by Camp, Dresser, and McKee (5) are used here. Consumption by 1991–2000 plant additions, assuming evaporative cooling, is given in Table 1 by zone. Under 100% wet cooling, lignite plants consume an average of 9–11.5 acre-ft/MW/yr (11,100–14,200 m^3/MW/yr) while coal facilities evaporate 8.5–10 acre-ft/MW/yr (10,500–12,300

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TABLE 1.—Summary of Water Demand and Supply Assumptions

	1991–2000 Power Plant Additions			Surface Water Supply		Ground Water Supply		
Subbasin (1)	Lignite fired, in megawatts (2)	Coal fired, in megawatts (3)	Water consumption under 100% wet cooling, in acre-feet per year (4)	Developed, available for new plants, in acre-feet per year (5)	Irrigation use available for transfers, in acre-feet per year (6)	Safe yield available for new plants, in acre-feet per year (7)	Irrigation use available for transfers, in acre-feet per year (8)	Numbers of aquifers included (9)
Sulphur 1	1,000	0	9,000	230,300	0	0	0	0
Cypress 1	1,550	0	13,950	454,850	0	251,400	0	2
Sabine 1	3,150	0	28,350	233,150	0	169,600	0	2
Sabine 2	0	900	7,650	929,150	8,000	33,500	0	1
Neches 1	1,200	1,200	21,000	147,600	0	390,800	0	3
Neches 2	300	1,000	11,200	497,900	25,600	97,400	6,100	3
Neches-Trinity 1	0	0	0	0	142,000	0	0	0
Neches-Trinity 2	0	0	0	0	34,400	0	0	0
Trinity 1	5,450	0	54,500	112,700	0	16,000	0	1
Trinity 2	1,800	0	18,000	25,500	0	106,500	0	3
Trinity 3	0	1,000	9,500	437,100	63,500	22,000	19,300	1
Trinity-San Jacinto 1	0	0	0	0	24,800	30,100	0	1
San Jacinto 1	0	0	0	0	0	39,900	81,900	1
San Jacinto-Brazos 1	0	0	0	0	84,000	26,300	16,700	1
Brazos 1	0	0	0	0	7,600	0	0	0
Brazos 2	0	0	0	0	5,000	31,300	68,500	1
Brazos 3	0	500	5,000	0	11,500	15,200	0	2
Brazos 4	500	0	5,000	0	15,900	5,800	0	1
Brazos 5	4,500	0	45,000	0	12,800	139,700	25,800	3
Brazos 6	0	1,000	9,500	0	20,900	49,800	26,600	2
Brazos-Colorado 1	0	0	0	0	25,200	6,100	44,200	1
Colorado 1	0	0	0	0	0	0	0	0
Colorado 2	0	800	8,000	61,150	85,200	132,500	51,700	5
Colorado 3	0	650	6,175	40,475	65,600	157,700	20,200	6
Colorado-Lavaca 1	0	0	0	0	12,000	0	0	0
Lavaca 1	0	0	0	35,900	5,000	9,800	64,800	1
Lavaca-Guadalupe 1	0	0	0	0	0	15,500	28,500	1
Guadalupe 1	0	0	0	5,600	0	0	0	0
Guadalupe 2	0	550	5,500	0	0	26,600	0	3
San Antonio 1	0	1,600	16,000	35,000	16,500	0	20,200	1
San Antonio 2	0	0	0	171,800	6,700	45,500	7,000	3
San Antonio-Nueches 1	0	0	0	0	0	13,400	0	1
Nueces 1	500	0	5,750	162,100	30,000	77,500	0	3
Neuces-Rio Grande 1	0	0	0	0	0	93,800	6,200	1

Note: 1 acre-ft = 1,233 m^3.

m^3/MW/yr). Because evaporation rates are highest in the western part of the study area, plants sited there require the most water. Of the consumption by coal-fired plants, 79% is assumed to be for condenser cooling when 100% evaporative cooling is used (31). Lignite plants are presumed to consume the same quantity for cooling as coal plants sited in the same zone.

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The amount of cooling water consumed is assumed to depend on the price of water; if water costs are high enough, the model allows plants to adopt wet/dry or even 100% dry cooling. Wet/dry cooling consists of the substitution of some dry cooling for evaporative cooling. It can be characterized by the fraction of water consumed compared to 100% wet cooling. The smaller the percentage of wet cooling, the higher the cost. For example, 50% wet/dry cooling using conventional indirect dry cooling technology increases the cost of power production by over 1 mill/kWh, compared to an all evaporative system, while 0% wet/dry cooling (100% dry cooling) adds 3 mills (3). Using cost curves presented by Bartz and Maulbetsch (3), demand curves for cooling water were developed (Fig. 3). One curve reflects conventional indirect dry cooling technology, and the other is based on projected costs for an advanced dry cooling system that uses ammonia instead of water for the secondary loop. Both curves are based on a mean plant output of 60% of capacity. In the base case, use of conventional cooling technology is assumed. The ammonia technology demand curve is applied in sensitivity analyses to estimate the cost savings that might result from its introduction.

Uncommitted Surface Water.—Despite severe shortages in some Texan River basins the Texas Water Development Board (36) anticipates that many other basins will have excess firm surface water supplies available in the year 2000. For most basins, this presumes that certain authorized reservoir projects will be constructed and that owners of excess rights would be willing to transfer them to utilities. The assumed amounts of developed surface water available for post-1990 power plants (Table 1) are based on their figures, as modified by Camp, Dresser, and McKee (5). The supply in each zone available for new plants consists of the firm yields of its reservoirs in the year 2000 minus projected demands upon that zone's surface supply by nonpower water users and pre-1991 power plants (5). Many such users are in downstream zones or are supplied by interbasin diversions. If the available supply is less than 5,000 acre-ft/yr (6,200,000 m^3/yr), it is excluded from the model.

In most basins in Texas, local River Authorities charge surface water users for the cost of reservoir storage. Through interviews, applicable rates for large industrial users in each basin were obtained. Most River Authorities reported that water prices will increase in the future at the general inflation rate. Exceptions include the Brazos, Trinity, and Nueces basins, where new power plants would face much higher prices, corresponding to the cost of new reservoir capacity. For example, current industrial rates in the Brazos are 22–25 dollars/acre-ft (0.018–0.020 dollars/m^3), but little additional water is available at that price. Water from new large reservoirs in these basins will cost at least 200 dollars/acre-ft (0.16 dollars/m^3). Rates for the other basins vary from 20 to 100 dollars/acre-ft (0.016–0.081 dollars/m^3). As a sensitivity analysis, a cost of 350 dollars/acre-ft (0.28 dollars/m^3) is assumed for all basins in two runs of the model. This cost corresponds with the expense of small pump-in reservoirs which utilities in Texas and elsewhere are constructing (19).

To be conservative, three other possibilities for surface water supply were not included in the model. The first consists of saline inflows to the Colorado and Brazos rivers that create quality problems for other users. Such sources are too intermittent and too saline (≥100,000 ppm) to be used by power plants. The second possibility is the use of less reliable surface supplies while relying on ground water during dry spells. There are legal obstacles to such conjunctive management (33), and some River Authorities refuse to give permits for nonfirm surface water. The final surface source excluded is Gulf of Mexico water. This is consistent with the Texas State Water Plan (36), which projects that no new power plants will use Gulf water. This is assumed because of the difficulties presented by hurricane hazards, water quality problems, chloride drift from cooling towers, and barrier islands.

Uncommitted Ground Water.—Although several Texan aquifers suffer severe overwithdrawals, other aquifers have excess yields well in excess of anticipated demands (19,36). The Texas Water Development Board (36) has compiled information by zone on well yields, salinity, aquifer thickness, and safe withdrawal rates in the year 2000 for 24 major and minor aquifers in Texas. It also projects total ground-water pumpage for the year 2000 by type of user for each zone. This information is used together with well drilling, pumping, and water treatment cost functions to calculate the amount and cost of ground water available for new power plants by aquifer for each zone.

Water availability by aquifer and zone is estimated by first subtracting, for each zone, pumpage by nonpower water users and pre-1991 power plants from the total safe yield of the zone's aquifers. "Safe yield" is defined as the sum of the natural recharge rate and a set percentage of recoverable storage. The remainder, given in Table 1, is then allocated among aquifers in proportion to their safe yields in that zone, except where the Texas Water Development Board (36) defines a different use pattern. Aquifers with estimated available safe yields less than 5,000 acre-ft/yr (6,200,000 m^3/yr) are then dropped. This procedure assumes that power plant withdrawals cannot cause total pumpage to exceed an aquifer's safe withdrawal rate. Although present Texas water law does not prohibit such overpumping, statewide regulation of ground-water use is a possibility in the near future, and the Texas State Water Plan (36) is based on the assumption that future pumpage will not exceed its safe rate.

Ground-water costs include the expense of well construction, pumping, and treatment for salinity. A function describing the cost of wells was obtained by applying multiple regression to survey data collected by the National Water Well Association (25,29). Data on wells in New England were excluded because of their anomolous high costs, as was one apparently erroneous observation. The wells range in yield from 30–6,500 gal/min (0.1–25 m^3/min) and their depths are between 85 and 1,000 ft (26 and 300 m). The best model, based on 23 observations, is

$$\underset{}{\textit{Cost (dollars/well)}} = \underset{(14{,}410)}{25{,}000} + \underset{(0.0319)}{0.111}\ D^2 + \underset{(0.0423)}{0.0582}\ D^2\mathrm{GEOL},\ R^2 = 0.78 \quad \ldots\ldots (5)$$

in which GEOL = 0 if well is drilled solely through sand or gravel, 1 if well is drilled in sandstone, limestone, basalt, shale, or any other consolidated medium; and D = well depth, in ft. The parentheses contain the associated standard errors. Inclusion of well yield, bore diameter, or linear depth terms failed to improve the equation's fit significantly. The equation shows that wells in consolidated rock are more expensive to

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construct. This is realistic if, as is the case in Texas, well casings are not required for wells in unconsolidated media. The energy cost of pumping is calculated assuming that: (1) Pump efficiency equals 50%, which is typical of high-yield electric wells in Texas; and (2) the cost of power in the year 2000 is 0.083 dollars/kWh (35). The cost of water treatment by reverse osmosis, net of treatment costs required for high-quality supplies, is estimated using a function developed by Israelson et al. (21).

Using these well, pumping, and treatment cost functions, the cost of using ground water from each of the aquifers in each zone is calculated. The resulting year 2000 levelized cost varies from 150–1,100 dollars/acre-ft (0.12–0.89 dollars/m^3). Because the ratio of pumpage to consumption for Texas power plants using ground water is approximately 1.2 (W. Hoffman, Texas Department of Water Resources, Personal Communication), these costs are increased by 20%, and the amount of water available from each aquifer for consumption is divided by 1.2.

Water Rights Transfers.—In basins which are fully or over-appropriated, water supplies can often be obtained by purchasing water rights or the land to which they are attached. Abbey and Loose (1) list 12 recent transfers of water rights to energy firms in the Western United States, totaling 265,000 acre-ft/yr (327×10^6 m^3/yr). In Texas, the Central Power and Light Corporation bought Rio Grande irrigation water for use by two power stations, and another utility has purchased the ground-water rights of a large amount of ranchland in the High Plains region. Surface rights transfers are possible upon the approval of the Texas Water Rights Commission and, sometimes, the relevant River Authority.

It is assumed in this analysis that utilities purchase water rights only from irrigated agriculture, and that such transfers represent firm water supplies. The cost and availability of transfers in the Texas Gulf Region is calculated in four steps, described in the following.

In Step 1, the amount of irrigation water available for transfer is estimated separately for surface and ground water. In the case of surface water, available irrigation rights in each zone (Table 1) are set equal to the minimum of: (1) Regulated, nonlocal irrigation supplies in the year 2000 (5); and (2) presently authorized or claimed irrigation rights (36). Total ground water available for transfer by zone is adapted from projections of year 2000 ground-water use by irrigators (5). Irrigation withdrawal by aquifer by zone is estimated by assuming that withdrawals are proportional to aquifer safe yield in that zone. Aquifers which are estimated to supply more than 5,000 acre-ft/yr (6,200,000 m^3/yr) of irrigation water are included. Exceptions include aquifers in the Winter Gardens and High Plains regions. They are excluded because ground-water overdrafts there present serious technical and political problems.

In Step 2, a demand curve for irrigation water is estimated, relating the amount of irrigation water demanded in Texas to price per acre-ft. The Texas Department of Water Resources (35) has projected: (1) Irrigation water costs by irrigation region as a function of energy price in the year 2000; and (2) total irrigation water use in Texas as a function of energy price in the year 2000. Total use at a water cost of 150 dollars/acre-ft (0.12 dollars/m^3) was also projected. A linear demand curve for the entire state was estimated using these data. The integral of that function is assumed to equal the change in net income (except for the cost

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of water) of irrigators due to changes in quantity of water supplied.

In Step 3, the state's demand is disaggregated to individual aquifers and zones. This is done by first estimating the average cost of water in the year 2000 to irrigators in each aquifer or zone as equal to the water charge levied by the relevant River Authority, in the case of surface water, or the cost of pumping ground water. This cost is taken as the base 'price' of irrigation water $P*$ for the aquifer or zone. The quantity of water projected to be demanded in the year 2000, as estimated in Step 1, is then taken as the quantity demanded $Q*$ associated with $P*$. The linear demand function is then calibrated as:

$$\textit{Price (dollars/acre-ft)} = 173 - \frac{[(173 - P*)]Q}{Q*} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (6)$$

in which 173 dollars/acre-ft (0.140 dollars/m^3) is the price intercept of the irrigation water demand function for the state and Q is quantity demanded. The integral of the demand function is taken as the change in net income, excluding water cost, due to a change in irrigation water supply in the particular zone or aquifer. This procedure assumes that production functions, crops, and factor prices are the same in all irrigated areas in Texas. In the absence of location-specific demand studies, this approach serves as an approximation.

In Step 4, the price of water transfers from irrigators to utilities is estimated as a multiple of the foregone net revenue to irrigators. By the foregoing demand function, a transfer of Q_T from irrigation means that irrigators use only $Q = (Q* - Q_T)$ acre-ft. If irrigators pay $P*$ dollars/acre-ft for water, then the foregone net income equals \$0.5 $[(173 - P*)/Q*]Q_T^2$. This represents the integral of the irrigator's demand curve from Q–$Q*$ minus the amount $P*Q_T$ irrigators would pay for the water transferred Q_T. The foregone income is also adjusted to account for return flows and extra ground-water pumpage required by power plants. A final modification is made because irrigators generally demand higher prices than what the water is worth to them. For example, the 1,750 dollars/acre-ft/yr (1.42 dollars/m^3/yr) price paid to irrigators by the Intermountain Power Project in Utah (6) is significantly higher than the net worth of that water for agriculture. As a conservative estimate, it is assumed here that utilities will have to pay double the foregone net income.

Since the model is a linear program, quadratic terms cannot be directly included in the objective function. Instead, they must be approximated as piecewise linear functions. Here, a five-segment approximation is used. Other costs of using transferred water are also included in the objective function. These include, for surface water, fees for water storage paid to the River Authorities and, in the case of ground water, the cost of wells, pumping energy, and treatment.

Sewage Plant Effluent.—Power plants in Denton, Lubbock, and Amarillo, Texas now use treated sewage for cooling water (29). Because of the size of new thermal power plants, only the wastes of large cities are considered here. An additional conservative assumption is that only effluents that would not otherwise reach stream courses can be used. This is because downstream water users often depend on sewage plant effluent. For example, Dallas's effluent constitutes most of the Trinity River flow during dry spells. Under these assumptions, Corpus Christi and Houston are the major potential sources of sewage effluent (W. Hoffman, Personal Communication). Approximately 100,000–130,000 acre-ft/yr ($1.2–1.6 \times 10^8$ m^3/yr) of Houston effluent, which now reaches Galveston Bay via the Houston Ship Canal, might be diverted immediately for consumption by power plants. To use it would cost approximately 46–98 dollars/acre-ft (0.037–0.079 dollars/m^3) for treatment and 33–49 dollars/acre-ft (0.027–0.040 dollars/m^3) for delivery. A total cost of 150 dollars/acre-ft (0.12 dollars/m^3) is used here for applications of sewage effluent throughout the state. Corpus Christi is in a situation similar to Houston's, as its effluent now flows into Nueces Bay. Some of it is required to control salinity in the bay, but a significant amount could be diverted to power plants. The model assumes that 100,000 acre-ft/yr (1.2×10^8 m^3/yr) would be available in the year 2000 from both Corpus Christi (Nueces-Rio Grande 1) and Houston (San Jacinto 1).

Water Transport Costs.—A utility can transport water long distances to a power plant using either: (1) Large-scale diversion facilities owned by a public agency, if available; or (2) a pipeline constructed especially for the plant. The model can choose to use such facilities if it is not possible to utilize the stream network.

Not all physically possible transfers are legally permissible. According to Article III, Section 49-D, of the State of Texas Constitution and legislation passed in 1965, a basin can be protected from diversions to other basins until its needs are assured for the next half century. The Texas Water Plan (36) is the basis of decisions as to whether or not a basin's needs will be met. A recent updating of the plan (5) finds that Brazos, Trinity, Colorado, and Lavaca basins will have supply shortfalls by the year 2030. Thus, the model does not permit diversions from those basins.

Several large interbasin diversion facilities with spare capacity exist in transport additional water from the Brazos to the San Jacinto-Brazos basin. Ten existing and proposed facilities are assumed to have spare capacity in the year 2000 and to be unaffected by the Article III prohibition (Table 2). In the absence of diversion-specific data on prices, transfer costs via existing facilities are conservatively estimated as 2 dollars/acre-ft/mile (0.001 dollars/m^3/km). Buras (4) summarizes several engineering

TABLE 2.—Large Scale Diversion Facilities Included in the Model

Source zone (1)	Sink zone (2)
Sulphur 1	Cypress 1
Sabine 1	Sulphur 1
Sabine 1	Trinity 1
Sulphur 1	Trinity 1
Neches 1	Trinity 1
Neches 2	Neches-Trinity 1
Guadalupe 3	Lavaca-Guadalupe 1
Guadalupe 3	San Antonio-Nueces 1
San Antonio-Nueces 1	Nueces 1
Nueces 1	Nueces-Rio Grande 1

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studies of large-scale diversion costs, and this figure falls in the high range of these values (when expressed in 1980 dollars).

New pipelines are another alternative for transporting water. Pipeline routes are defined in the model between adjacent subbasins which are not immediately up or downstream from each other. Diversions prohibited by Article III are excluded. The cost of transporting water by pipe depends on distance traversed and the height differential. Gold and Goldstein (14) developed an engineering cost equation for pipe and pumps based on an optimization of pipe diameter and water velocity. Applying their formula using coefficient values appropriate for Texas in the year 2000 yields a levelized cost of 12.9 dollars/acre-ft/mile (0.0065 dollars/m^3/km). This figure is used in the model, and assumes that height differentials can be disregarded.

Results for Texas-Gulf Region

Each solution of the model presents a least cost mix of water supplies and cooling technologies that meets the condenser cooling and fixed water needs of a predefined set of power plants. Table 3 summarizes the base case, which relies on the assumptions outlined in the foregoing, and five sensitivity analyses.

The Base Case.—In the base case, power plants built between 1991 and 2000 rely upon local uncommitted surface water supplies where possible, in preference to other, more expensive sources. The levelized average cost of surface water is merely 137 dollars/acre-ft (0.111 dollars/m^3). Only in the Brazos basin where no uncommitted surface water is available are ground water and water rights transfers resorted to. Ground water provides 44,000 acre/ft (54,000,000 m^3), and 20,500 acre-ft (25,000,000 m^3) of irrigation rights are transferred. Half the transfers represent ground water, and half surface water.

TABLE 3.—Summary of Model Results

(1)	Base case (2)	Ammonia-based cooling (3)	Halved surface and ground-water availability (4)	No inter-basin or rights transfers (5)	Year 2030 conventional cooling (6)	Year 2030 ammonia-based cooling (7)
Cost of water supply, in 10^6 dollars per year	46.02	37.40	48.74	48.30	498.80	239.09
Cost of wet/dry and dry cooling, in 10^6 dollars per year	0	7.52	0	0.30	24.64	156.47
Total water supplied, in acre-feet per year	279,075	251,032	279,075	278,889	1,143,100	620,400
Surface water, as a percentage	77	86	76	77	38	25
Ground water, as a percentage	16	13	16	23	49	62
Rights transfers, as a percentage	7	1	8	0	11	9
Sewage, as a percentage	0	0	0	0	2	4
Interbasin transfers, in acre-feet per year	0	0	3,444	0	211,518	96,217
Capacity using wet/dry or dry cooling, in megawatts	0	6,500	0	500	2,250	120,200

Note: 1 acre-ft/yr = 1,233 m^3/yr.

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If the primal solution is not degenerate, the dual solution to the model gives the marginal cost of supplying water to each of the network nodes. The highest marginal cost of water for any power plant is observed in Brazos 4, where only transferred surface water rights are used. Of the marginal cost of 465 dollars/acre-ft (0.377 dollars/m^3), about half is paid to the Brazos River Authority for storage, and half accrues to the irrigators who sold their rights.

Sewage plant effluent is not used anywhere in the base case, as its cost of 150 dollars/acre-ft (0.12 dollars/m^3) exceeds that of local uncommitted surface supplies. No interbasin transfers are made because differences in water costs between basins are too small to overcome even the small expense of existing transfer facilities, generally 100 dollars/acre-ft (0.1 dollars/m^3) or less.

Neither conventional dry nor mixed wet/dry cooling is resorted to by any plant. Nowhere does the cost of water approach even one-third of the level (1,600 dollars/acre-ft, 1.3 dollars/m^3) required to induce utilities to adopt 40% wet/dry cooling, the cheapest of water-conserving cooling technologies. Thus, the conclusion by Sonnichsen (32) that water shortages by the year 2000 will force most new plants in the region to use wet/dry or dry cooling seems too pessimistic.

Ammonia-Based Cooling Technology.—Unconventional wet/dry and dry cooling methods now under development may drop the cost of water conservation significantly. One solution for the year 2000 was obtained assuming that the ammonia-based technology will be available at the costs shown in Fig. 3. Even though the anticipated marginal cost of this technology for 40% wet/dry cooling is approximately one-sixth of that for conventional wet/dry cooling, the solution changes only in the Brazos basin. Mixed wet/dry cooling is adopted there because the marginal cost of water exceeds the 269 dollars/acre-ft (0.218 dollars/m^3) required to justify the technology. As a result, 28,403 acre-ft/yr (35,020,000 m^3/yr) of water is saved. Savings in the total cost of water supply and use compared to the base case are just over a million dollars per year. This is a measure of the potential benefit to the region's utilities of having the technology available *at that cost*. Because costs of technologies under development tend to be underestimated by a factor of two or more for the first few commercial applications (10), the initial incremental costs assumed here are probably low. Since the expense of the first commercial units could be significantly higher than subsequent more mature units, these few units would have to be either subsidized or located in an area where the value of wet/dry cooling is greater than in the Texas-Gulf region.

Restrictive Supply Assumptions.—Table 3 summarizes two solutions with more restrictive supply assumptions than the base case. The first scenario results from presuming that only half of the uncommitted surface and ground-water supplies of the base case are available. This could result from a greater than forecast increase in demand in other sectors, a failure to bring surface water supply projects on line, an unwillingness of holders of excess surface water to transfer their rights, or a shortage of power plant sites within economic distance of water sources. The second restrictive scenario is based on the assumptions that: (1) Political opposition, perhaps rooted in Article III of the Texas Constitution, prevents plants from using interbasin diversions; and (2) irrigators are unwilling or unable to sell their water rights. As Clark (6) and Weatherford et al. (39) note, irrigators resist rights transfers in many parts of the West.

Table 3 reveals that halving uncommitted water supplies alters the solution only slightly. Total water acquisition costs are 6% higher than the base case. Surface supply constraints bind in the Trinity and Guadalupe basins, causing 2,000 acre-ft/yr (2,470,000 m^3/yr) more ground water to be used and 3,777 acre-ft/yr (4,660,000 m^3/yr) of water to be provided by interbasin diversions. Only the Sulphur to Trinity 1 transfer is significant. In general, marginal costs are increased only slightly; nowhere do they make conventional wet/dry cooling economic.

The effect of banning interbasin diversions and water rights transfers is also mild (Table 3). The increase in the expense of water supply and use equals 5% of the base case cost. Most of that increase is due to the substitution of more expensive ground-water sources in the Brazos for 20,000 acre-ft/yr (25,000,000 m^3/yr) of water rights transfers in the base case. Because uncommitted ground water is inadequate in Brazos 4, a small amount of wet/dry cooling is adopted there, saving 186 acre-ft/yr (230,000 m^3/yr).

In a third sensitivity analysis, the cost of surface water supplies was assumed to be 350 dollars/acre-ft (0.28 dollars/m^3). This equals the cost of constructing small, single-purpose pump-in reservoirs. It is well below the marginal expense of conventional wet/dry cooling; hence, plants are still evaporatively cooled. But ground water is substituted for now-expensive surface water in many places.

Year 2030 Scenarios.—Even if wet/dry cooling appears unjustified in the Texas-Gulf region in the year 2000, continued growth in the demand for water may make it useful soon thereafter. To examine this possibility, solutions are obtained for the year 2030. A power plant siting and water use scenario prepared by Camp, Dresser, and McKee (5) is used here. Its 122,750 MW of capacity is based on a 1% annual growth rate in total generation capacity between the years 2000 and 2030. All plants, including those built before the year 2000, are included in the model. Their total water demand under 100% wet cooling would be 1,158,000 acre-ft/yr (1.428×10^9 m^3/yr), or 6% of the region's consumption (5). Estimates of the amounts of uncommitted water supplies and irrigation water available for transfer are derived using the methods discussed here and are summarized elsewhere (19). The only difference in cost assumptions is that the cost of storage for surface water is presumed to be 350 dollars/acre-ft (0.28 dollars/m^3) in all basins.

The first of two solutions for the year 2030 summarized in Table 3 includes only conventional wet/dry and dry cooling technology. Because of the high cost of new reservoirs, ground water is favored more than in the year 2000. Surface sources (including sewage plant effluent and rights transfers) provide 45% of the water, while aquifers supply the rest. Transfers from surface and ground-water irrigators represent a somewhat greater percentage than in the year 2000. In contrast to the year 2000 scenarios, 25,000 acre-ft (31×10^6 m^3) per year of sewage plant effluent is used. Most is from Houston. Interbasin transfers provide a significant amount of water, mostly to Zone 1 of the Trinity basin.

Nevertheless, as in the year 2000, very little conventional wet/dry cooling is adopted. Only a 2,250 MW plant in Brazos 1 uses it. This is because the marginal cost of water is everywhere else short of the level needed to induce even 40% wet/dry cooling. Thus, if interbasin diversions and rights transfers remain politically feasible, conventional wet/dry cooling systems will be of little use in the Texas-Gulf region through the year 2030. This conclusion is contrary to that of Sonnichsen (32), who projects that two-thirds of the post-2000 plant additions in the region will use wet/dry or dry cooling.

But if ammonia-based cooling systems are available at the costs given in Fig. 3, then most plants adopt wet/dry cooling (Table 3). Water consumption plummets by 46% compared to the conventional cooling technology case. So many plants use wet/dry cooling because the assumed cost of small reservoirs (350 dollars/acre-ft, 0.28 dollars/m^3) exceeds the marginal cost of 40% wet/dry ammonia-based cooling (about 270 dollars/acre-ft or 0.22 dollars/m^3). Nearly as much is expended on ammonia-based cooling systems as on water supply. The total cost decrease relative to the base case is 127,885,100 dollars/yr, one hundred times the savings in the year 2000. This amount is sensitive to the relative cost of new surface water storage and 40% wet/dry ammonia-based cooling. If, for example, the marginal cost of 40% wet/dry cooling was instead 400 dollars/acre-ft (0.32 dollars/m^3), the number of plants using the technology would shrink by one-half.

Conclusions

A model is developed that by its focus on a single region and its use of linear programming is capable of balancing the cost and availability of a range of water sources with the expense of wet/dry and dry cooling. In its application to the Texas-Gulf region, it is found that, based on State of Texas Projections, sufficient water supplies should be available in the years 2000 and 2030 to avoid the high cost of conventional wet/dry cooling in nearly all basins. Even if less expensive advanced cooling methods become available, wet/dry cooling becomes economically attractive only in one of the region's several river basins in the year 2000. This contradicts other studies which project severe energy-water conflicts for Texas (8,32). This study finds differently because it considers alternative water sources that utilities are beginning to use throughout the West, including ground water, water rights transfers, interbasin diversions, and sewage plant effluent.

The conclusion that wet/dry cooling is at best weakly justifiable in the Texas Gulf region for the year 2000 does not mean that it will not be useful elsewhere. Institutional restrictions and political attitudes towards utility use of water in the West vary in severity (6,39); thus, the water rights transfers and interbasin transfers that are feasible in Texas may not be so everywhere. Hence, before definitive conclusions are made on the usefulness of wet/dry cooling, other regions of the country should also be investigated.

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