Energy and Water

John Harte and Mohamed El-Gasseir

Providing energy for human use consumes water and providing water consumes energy. We discuss here only the consumption of water for energy. Our objective is to assess the constraints that limited and unpredictable supplies of freshwater in the United State may place on energy development.

Summary. The geographic and temporal variability of freshwater supply in the United States constrains the choice and level of use of future energy sources. Ecological criteria for acceptable freshwater consumption, together with hydrological data on stream flow, provide a framework for estimating these constraints. The water consumption requirements for a variety of energy options are presented, and comparative judgments drawn. Attention is focused on problems resulting from synthetic, gaseous, and liquid fuel production. Scenarios describing possible future levels of coal and electricity use are analyzed. They point to the importance of water supply constraints in both the eastern and western United States.

Energy technologies use water resources in numerous ways. For example, the cooling of electric generating plants or coal gasification and liquefaction plants may consume freshwater. Coal and oil shale conversion processes require water as a chemical feedstock. Coal mining and land reclamation subsequent to surface mining require water. Solar bioconversion plantations are likely to require irrigation water. Hydroelectric power consumes water in the sense that artificial lakes enhance evaporation losses. In fact, nearly every imaginable energy system demands water. Because of the limited freshwater supply in many regions of the United States, and because of the unpredictable nature of precipitation, it is important to understand the freshwater requirements for each of the many energy technologies available to society during the next several decades. We will demonstrate here that water consumption requirements place serious constaints on the future level of development of many of this country's energy options.

One energy technology that we will discuss in some detail is the production of synthetic gaseous and liquid fuels. During the coming decades, the United States will have to find energy sources that can replace natural gas and petroleum. Because many end uses, especially transportation and home heating, rely today on these two fuels, it appears that only three paths are available. One option is to adapt such end uses to electricity. The second is to replace dwindling gas and petroleum supplies with synthetic gaseous and liquid fuels. A third path, which could ease the demand on gaseous and liquid fuels for space heating and cooling, is to expand active and passive use of the sun. Part of our concern here will be with the comparative impacts of these three paths on water consumption.

First we set the background for a quantitative discussion of energy and water scarcity and develop a framework for evaluating the impacts of water consumption. In the third section we estimate water requirements, on a per unit energy basis, for those energy options that are candidates for major expansion in the United States and that are likely to require large quantities of water. Based on these estimates, we make some comparative judgments about water impacts of competing technologies. We then analyze a number of energy scenarios, looking on a regional level at the constraints on energy growth likely to be imposed by limited freshwater supplies.

Freshwater Supply and Demand

Withdrawal and consumption. To estimate the consequences of the water requirements for energy production, a distinction must be made between water withdrawal and water consumption. Water withdrawn is water taken from a water supply but not necessarily consumed. Water consumed is water rendered unavailable for specified further uses. The water consumption of a given activity depends on the ways water is used in the activity and the ways it is needed by downstream users, including the spatial distributions and time schedules of all such uses (*1*).

Thus, heavily polluted water that is discharged from a coal gasification plant is consumed water for many competing uses, although not, perhaps, for mine floor wetting. Water evaporated from a wet cooling tower or an artificial lake, or from surface-mined land under reclamation, is consumed water from the viewpoint of other users in the region because the evaporated water cannot be expected to fall as rain on the same region. Also, water used as a source of hydrogen for synthetic fuel production is consumed water—notwithstanding the fact that this water is regenerated when the fuel is eventually burned.

To clarify further our treatment of these issues, consider the following hypothetical and highly simplified case. Assume that a conversion plant takes 10^6 cubic meters of water per year (m^3/year) from a river (*2*). This is the withdrawal rate. The conversion process uses the hydrogen in 10^5 m^3/year during the hydrogenation-methanation steps. Another 3×10^5 m^3/year is lost by evaporative cooling. The remaining and now heavily polluted portion of the withdrawn water is delivered to a treatment facility where 10^5 m^3/year evaporates, 0.5×10^5 m^3/year is disposed of as waste product, and the rest (4.5×10^5 m^3/year) is treated and returned to the river 5 kilometers (*2*) downstream from the intake point. Assuming that the treated water is adequate for all downstream users, and that the outflow from the plant is staged in time so as to be compatible with downstream use, then the consumption rate for downstream users is the sum of what is used for chemical feedstock, plus the evaporated portion, plus what is disposed of as a concentrate, or 5.5×10^5 m^3/year. This remains valid as long as the plant operates in the prescribed fashion.

On the other hand, water could be conserved by eliminating all evaporation and extracting all water from the waste product, properly treating it, and returning it to the river. Then consumption

Dr. Harte is a physicist in the Energy and Environmental Division, Lawrence Berkeley Laboratory, University of California, Berkeley 94720; M. El-Gasseir is a graduate student in the Energy and Resources Program, University of California, Berkeley. This article is based on a study done in connection with the National Academy of Sciences' forthcoming CONAES report.

0036-8075/78/0210-0623$02.00/0

Table 1. Freshwater use in the United States, 1975, expressed as cubic kilometers per year.

Use category	Withdrawal	Consumption
Municipal use including domestic and commercial	40.0	9.2
Industrial mining and manufacturing	52.0	5.8
Thermal electric power plant cooling	180.0	2.6
Irrigation, livestock, and rural use	200.0	115.0
Evaporation from man-made reservoirs*	18.0	18.0
Total	490.0	151.0

*Data adapted from (34); all other data adapted from (35).

would be minimized to the rate at which water is used as chemical feedstock in the conversion process, or 10^5 m^3/year. However, for those water-dependent activities (including maintenance of ecological habitats) along the river between the point of withdrawal and the point of return, consumption is equal to withdrawal.

The above example illustrates that technical, economic, and policy considerations in the development of new energy sources can change the balance between water withdrawal and consumption. In this work we assume that the rate of consumptive use of water varies from the minimum rate believed to be achievable under strict conservation and purification efforts to the maximum rate where water-conserving practices and adequate water treatment are not even attempted. This maximum consumptive rate, in some instances, would simply be the withdrawal rate.

We are concerned here primarily with freshwater consumption requirements of alternative energy systems. Withdrawal, while less worrisome than consumption, is nonetheless an important environmental problem for several reasons. First, the rate at which water is withdrawn provides a rough measure of the rate at which aquatic habitat is temporarily destroyed and aquatic organisms are killed or injured. Organisms, for example, can be killed by entrainment in cooling condensers (3). Second, the larger the withdrawal, the greater is the need for a storage reservoir for operation in times of low flow. Because of the great range and intensity of environmental hazards associated with the damming of rivers to create reservoirs (4, 5), including, though by no means limited to, large consumptive losses caused by excessive evaporation and bottom seepage, the size of withdrawal requirements should not be overlooked in assessing possible future energy sources.

Aggregated supply and demand. A description of the amount of freshwater potentially available to users in the United States should include information about average flows available and also statistical data on regional fluctuations in water supply.

First, let us consider the average, aggregated water supply situation in the 48 conterminous states. Precipitation averages about 5600 cubic kilometers per year (km^3/year), about 70 percent of which either evaporates or is transpired by vegetation before it reaches the oceans (6). The remaining 30 percent, or 1700 km^3/year, is called runoff or stream discharge. Although runoff is the portion of precipitation often considered to be available for human use, it should not be thought of as lost or wasted when not consumed directly by humans; a major part of runoff maintains the health of streams, lakes, and estuaries. Maintenance of this health is likely to be of aesthetic, commercial, and recreational value to man (7) as well as of intrinsic value as ecological habitat. An important issue to which we will return shortly is the question of just what fraction of the runoff can be safely consumed.

The 1975 aggregate water demand in the United States is outlined in Table 1. At first glance, by comparing the averaged annual freshwater runoff of about 1700 km^3/year with the annual consumption of 151 km^3/year, water availability does not appear to be a major problem. Such a conclusion is erroneous, however, because the actual supply and demand of water are highly diverse across time and space. Precipitation and river flow can vary enormously from season to season and from year to year. In much of the West, for example, the precipitation rate for the past 2 years has averaged only about one-half of normal. In addition, time-averaged local runoff is neither distributed uniformly over the United States nor is it distributed in proportion to present-day demand. Finally, the location of many of the country's potential energy resources, such as coal, oil shale, uranium, sunlight, and geothermal energy, in the dry western regions of the country exaggerates the geographic unevenness of future water demand in relation to its supply.

Spatial and temporal variation. The principal water drainage regions of the 48 conterminous states provide a useful starting point for discussing geographic variation in water supply and demand. These regions, 18 in number, are hydrologically distinct entities that are relatively isolated from one another with respect to surface water flow, except for linkages along major rivers (as in the

Table 2. Regional runoff, 1975 consumption, per capita runoff, and consumption per unit runoff. Data adapted from (35).

Region	Mean annual runoff (km^3/year)	Data for 1975		
		Consumption (km^3/year)	Per capita runoff ($10^3 m^3$/person/year)	Consumption/mean annual runoff
New England	93.0	0.61	7.9	0.0066
Mid-Atlantic	120.0	2.2	3.0	0.018
South Atlantic Gulf	270.0	5.1	10.2	0.019
Great Lakes	100.0	1.5	4.5	0.015
Ohio	170.0	1.7	8.0	0.01
Tennessee	57.0	0.39	17.0	0.0068
Upper Mississippi	90.0	1.3	4.6	0.014
Lower Mississippi	100.0	7.6	17.0	0.069
Souris-Red-Rainy	8.6	0.17	12.0	0.016
Missouri	75.0	24.0	8.4	0.32
Arkansas	100.0	16.0	16.0	0.16
Texas Gulf	44.0	13.0	4.2	0.30
Rio Grande	6.9	6.0	3.5	0.87
Upper Colorado	18.0	3.4	40.0	0.19
Lower Colorado	4.4	10.0	1.7	2.3
Great Basin	10.0	5.5	7.0	0.55
Pacific Northwest	290.0	18.0	44.0	0.062
California	86.0	34.0	4.1	0.40
Alaska	800.0	0.0077	2000.0	9.6×10^{-6}
Hawaii	18.0	0.77	22.0	0.043
United States	2471.0	151.0	11.0	0.060
United States excluding Alaska and Hawaii	1653.0	150.0	7.8	0.091

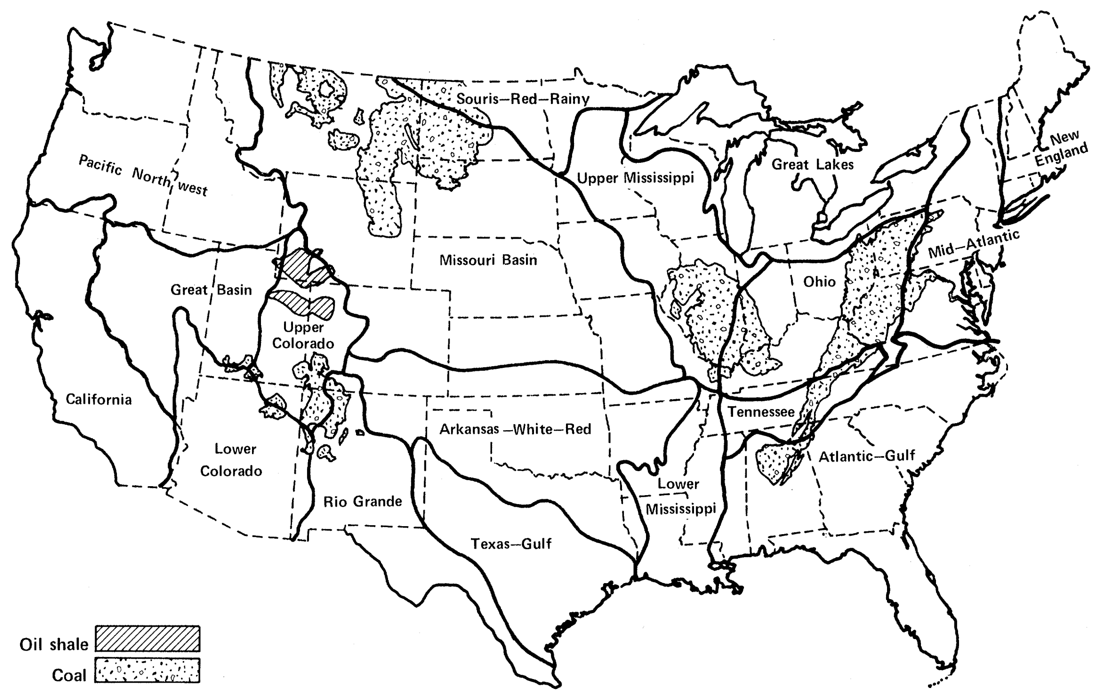

Fig. 1. Map of the conterminous United States showing Water Resources Council regions and major coal and oil shale deposits, adapted from (*37, 38, 45*). Recently found eastern oil shale deposits of uncertain commercial value are not shown.

case of the Upper and Lower Mississippi regions) (*8*). They are shown in Fig. 1. Regional mean annual runoff and 1975 consumption are shown in the first two columns of Table 2; also in Table 2 is a regional breakdown of runoff per person and of consumption per unit runoff. It is interesting that population is distributed more nearly in proportion to runoff than is consumption, a result largely due to heavy irrigation demands in the West. For future reference, note that the major coal deposits in the United States are located in the Missouri, the Upper Colorado, the Upper Mississippi, the Ohio, and the Tennessee regions (see Fig. 1).

The temporal variation of runoff and river flow can also be quite large. A useful statistical quantity, which can be used to describe unusually low flow conditions, is the *x*-day, *y*-year low flow. This is defined as the lowest flow rate, averaged over *x* consecutive days of the year, expected, on the average, every *y* consecutive years. We denote it by the symbol ${}_xQ_y$ (*9*). From a table of daily river flow rates over a period of many years, ${}_xQ_y$ is easily computed. One first determines for each year the lowest *x*-consecutive-day flow rate. For each consecutive *y*-year period one then takes the lowest of the *x*-day low flow rates during that period and averages them over all possible consecutive *y*-year periods for which data are available. Note that ${}_{365}Q_1$ is the mean annual flow rate.

We have taken five rivers and compiled some illustrative river flow statistics on each (*10*). There are two in the West—the Yellowstone and the Colorado—and three in the East—the Ohio, the Kanawha, and the Wabash. These particular rivers are chosen because they are located in coal-rich regons and, along with nearby and hydrologically similar rivers, are among the likely sources of water for coal-related activities in the United States. Figure 2 shows representative values of ${}_xQ_y$ at specific U.S. Geological Survey stations on each of the five rivers. These stations were chosen sufficiently upstream to reflect primarily precipitation and watershed conditions, although the presence of man-made storage projects does influence the flows. It can be noticed that the values of ${}_7Q_{10}$ range from 7 to 16 percent of the mean annual flow. The ratio of 7-day, 10-year low runoff to mean runoff is also roughly in the same range for the 18 hydrological regions (*11*). The ratios of the ${}_7Q_{10}$'s to the ${}_7Q_{20}$'s or ${}_7Q_{40}$'s are fairly uniform from river to river. To the extent that there are variations, it appears that ${}_7Q_{10}$ is a higher fraction of the mean flow in the West and that ${}_xQ_y$ is a slightly more rapidly decreasing function of *y* in the West. Despite the obvious temptation to do so, quantitative extrapolation of curves like these to values of *y* larger than those for which data are available can be a very ambiguous procedure (*12*).

The importance of the concept of ${}_xQ_y$ is based on two considerations. First, in siting a water-consuming facility along a river, it is important that not only the mean flow be adequate but also that the actual instantaneous flow be nearly always adequate. The practical meaning of "nearly always" will depend on storage capacity and acceptable shutdown time when drought conditions prevail. For a given acceptable amount of shutdown, knowledge of the ${}_xQ_y$'s allows the minimum storage capacity to be determined. For example, consider a facility that consumes river water at a rate *C*. In order for the facility to continue operation through a particular ${}_xQ_y$ low flow period, where $C \geq {}_xQ_y$, the required storage capacity would have to exceed $(x)(C - {}_xQ_y)$. It is clear that when *C* only slightly exceeds ${}_xQ_y$, even a small percentage increase in the consumption rate can necessitate the construction of greatly increased storage.

Second, ecological considerations point to the importance of these statistical parameters. Adequate river flow is necessary for maintaining riparian and estuarine habitats. The flushing and transport of minerals and organic materials, the dilution of pollutants, the maintenance of adequate oxygen levels, and the thermal structure of rivers and estuaries are dependent upon the magnitude and timing of river flow (*13*). The taxonomic diversity of river zooplankton (*14*) and the ability of benthic organisms to secure nest sites in river bottoms (*13*) also are flow rate dependent. Lower than normal flows during any stage of the annual flow cycle can cause significant loss of aquatic habitat and increase the level of toxic substances. The river water may become undesirably hot and oxygen levels may drop. Adverse impacts on fish populations are reported (*15*). Hynes (*13*) has thoroughly described the role of river current in maintaining ecological balance as well as the sensitivity of river organisms to a prolonged decrease in river flow. In estuaries, as in rivers, the time dependence and magnitude of freshwater flow is also critical. The life cycles of numerous estuarine organisms are intimately linked to the circulation of freshwater, which in turn is linked to river inflow. Moreover, pollution levels in estuaries are regulated in part by river flow (*16*).

Water consumption criteria. To protect rivers and estuaries from excess consumption of runoff, criteria must be developed to evaluate how much decrease in natural water flow can be permitted. One type of criterion might allow a fixed percentage of the mean flow to be consumed. The problem with this can be seen by referring to Fig. 2. Suppose that consumption were limited to 15 percent of the mean flow. Then on the Upper Colorado this would allow total depletion of river flow on the average for 90 consecutive days every 40 years, or 7 consecutive days every 12 years. In contrast, the flow of the Wabash could be totally depleted for 90 consecutive days every 3 years, or 7 consecutive days every year. Thus, the criterion would have very different implication for the two regions, both for consumers and ecosystems. On the other hand, if the criterion were formulated in terms of an allowed percentage of some x-day, y-year low flow, where $y > 1$ and $x < 365$, then the criterion would account better, although by no means perfectly, for supply limitations and ecological impacts intrinsic to the hydrological characteristics of the two regions. For example, if consumption were limited to, say, 40 percent of the ${}_{90}Q_3$ low flow, then flow would be totally consumed on both the Upper Colorado and Wabash rivers for about 7 consecutive days every 30 years.

These considerations, combined with the fact that organism tolerances to stress are often limited to days or weeks rather than to years (*13*), suggests that limits to consumption be based on a percentage of some x-day, y-year low flow.

In a paper on water requirements and water consumption criteria for electric power-plant cooling, Samuels (*11*) reviewed water flow data in the United States and proposed ecological criteria for permissible water use by nuclear power plants. From these criteria, Samuels then identified those rivers where five or more 1200 megawatt electric (MWe) nuclear plants could be located. Samuels' criteria would permit water use for nuclear power up to a fixed percentage of certain ${}_xQ_y$'s. For rivers without significant water storage facilities, two of his criteria would allow consumption of up to 10 percent of ${}_7Q_{10}$ and withdrawal

Table 3. Some useful energy quantities for the United States in 1975. Data adapted from (*25*).

Energy category	Energy (10^{18} joule/year)
Total energy consumption	72.7
Liquid fuels consumption	34.5
Natural gas consumption	21.3
Coal consumption	14.1
Steam-generated electricity output	6.1
Energy yield from 1 km^2 average western surface-mined coal	0.1 to 0.2
Annual average sunlight on 1 km^2	0.0056

of up to 15 percent of ${}_7Q_{10}$. Samuels' criterion for rivers with storage assumes that the storage is for seasonal variations only, and states that consumption should not exceed 10 percent of ${}_{365}Q_{20}$. Note that this standard is considerably more lenient than that for the no-storage case.

If the aim is solely to ensure that a shortfall in industrial water supply does not occur too frequently, then this is a reasonable way to determine a standard

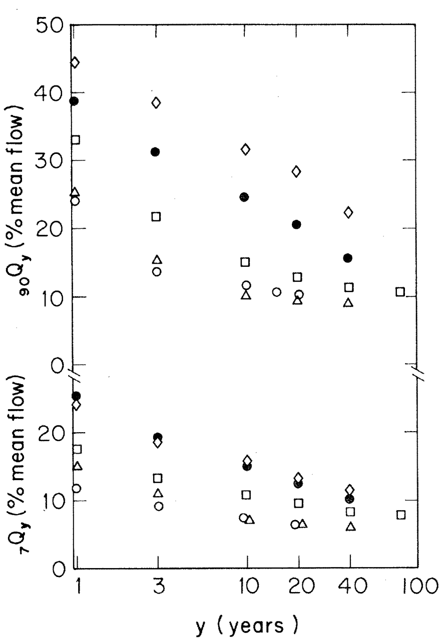

Fig. 2. Values of ${}_7Q_y$ for five rivers in the United States. The rivers and the U.S. Geological Survey measuring station at which the data were taken from which these flows were calculated are: the Yellowstone River (◇) at Miles City, Montana; the Colorado (●), near Cisco, Utah; the Kanawha (□) at Kanawha Falls, West Virginia ; the Wabash (△) at Mount Carmel, Illinois; and the Ohio (○) at Huntington, West Virginia. The mean annual flows of these five rivers at the designated measuring stations and the period of time over which the daily measurements were taken were as follows: Yellowstone, 10.4 km^3/year, 1930 to 1977; Colorado, 6.9 km^3/year, 1924 to 1976; Kanawha, 11.2 km^3/year, 1878 to 1976; Wabash, 24.1 km^3/year, 1929 to 1976; and Ohio, 67.2 km^3/year, 1933 to 1968 (*10*).

for rivers with storage. But the ecological effects of storage facilities on a river can vary greatly depending on how the outflow from the reservoir is managed. For a given level of consumption, the presence of a storage facility does not necessarily ensure that downstream flow will approximate the natural flow better than if there had been no storage. For example, if a reservoir is managed for hydroelectric power, the downstream flow will tend to be more uniform throughout the year than the natural flow, leading to increased flows during periods of normally low flow (usually late summer and fall). These increased flows can be destructive to bottom-living organisms that rely on low flow periods to secure their nest sites on bottom materials and can interfere with the incubation habits of certain fish species (*13, 15*). If the reservoir is managed for highly consumptive use at the storage site, then during prolonged dry periods, a self-interested manager might eliminate downstream flow entirely in order to prolong use of the water supply.

On the basis of these considerations, we will not attempt to develop different criteria for regions with differing levels of storage. In our scenario analysis, we simply compare total regional freshwater consumption (from total present use and possible future energy-related activities) in each region with the estimated ${}_7Q_{10}$ low flow in that region. Our decision that x should be 7 days was based on the considerable evidence that aquatic organisms often can tolerate several days of stress but not weeks or months (*13*). Figure 2 indicates that the choice of y is relatively insensitive to regional differences in that the ratios of the ${}_7Q_{10}$'s to the ${}_7Q_{20}$'s are fairly uniform from river to river. Rather than dignify any particular percentage of ${}_7Q_{10}$ as an acceptable level of consumption, we simply compare consumption with this low-flow quantity. Because we express our estimates of water consumption in our scenarios in absolute terms as well as in terms of percentages of ${}_7Q_{10}$ for each region, the interested reader can apply any desired criterion in order to assess the constraints of water supply on various levels and kinds of energy development.

Water Consumption Requirements of Energy Alternatives

In this section we estimate the water requirements for a variety of energy technologies that are candidates for major expansion in the United States. Based on these estimates, judgments are given about the relative impacts on water resources of some technologies which are competitive in the sense that they could provide similar benefits to society. We adopt as an energy reference the quantity, 10^{18} joules. Note that the commonly used unit of energy called the quad (10^{15} British thermal units, Btu) is approximately equal to 1.05×10^{18} joules. Some energy quantities, pertinent to the following discussions, are listed in Table 3.

Coal and oil shale: Mining, reclamation, and conversion to synthetic fuels. Coal and oil shale are the major fossil fuel resources of the United States and potentially form the base for a large and long-lasting energy supply. Most of the explored coal and oil shale deposits are found in five water resource regions (see Fig. 1); about 50 percent of the total recoverable coal reserves and 30 percent of the surface-mineable reserves are in the Ohio and Upper Mississippi regions, which are also close to major demand centers. The remaining coal resources (which happen to be more attractive commercially) and the principal oil shale reserves are found in sparsely populated, arid or semiarid areas of the West, with the oil shales confined to a far smaller region than the coal.

Estimates of water consumption for various shale- and coal-conversion pathways are given in Table 4 (*17*). Clearly the major part of the water consumption occurs at the conversion stage itself. Two other major categories of water consumption are reclamation of surface-mined land and coal transport via slurry pipelines. Unless the water used in a slurry pipeline is adequately treated and returned to its source, it must be considered to be consumed water in its region of origin.

Among the entries in Table 4, one with an especially large range of uncertainty is that for land reclamation in the West. This uncertainty is mostly due to a lack of understanding of environmental factors such as soil-binding properties and the conditions under which detrital and soil microorganism-based nutrient cycles can be reestablished in dry, disrupted terrain (*18*). The uncertainties include not only the unknown requirements for annual irrigation but also the unknown number of years for which irrigation would be necessary for reestablishing a viable ecosystem. Successful revegetation (though not necessarily restoration to original conditions) is likely to be necessary in order to reduce problems of erosion, mine drainage (with subsequent deterioration of downstream water quality), and possibly flooding. The lower value given in Table 4 in our judgment has a low probability of leading to genuine revegetation (*18, 19*). We have not attempted to include in our estimates the additonal water consumption resulting from secondary impacts of erosion, drainage, or flooding, should land reclamation be unsuccessful.

Table 4 shows the water consumption for converting shale to be smaller than the consumption for syncrude production from coal. However, the listed ranges of water consumption mean very different things in the two cases, and the actual situation could turn out to be more

Table 4. Water consumption for the production of synthetic fuels from coal and oil shale in the United States. Data are expressed as cubic kilometers per 10^{18} joules of synthetic fuel product. The data and the references were derived from (*19*). All calculations are based on coal energy content of 28, 22, and 14 million joules per kilogram of bituminous, subbituminous, and lignite coals (*36*) and on conversion efficiencies of 67 to 85, 55 to 67, and 41 to 75 percent for low- and high-Btu gasification and liquefaction, respectively (*37–39*).

	Category of use						
	Mining*	Reclamation†	Transport by slurry pipelines‡	Conversion§	Associated urban‖	Total with slurry pipelines	Total without slurry pipelines
			Low-Btu gas				
Eastern coal:							
Surface-mined	0.0028 to 0.0035	0.0 to 0.030	0.045 to 0.057	0.083 to 0.058	0.018	0.15 to 0.69	0.10 to 0.63
Deep-mined	0.0062 to 0.0078	0.0	0.045 to 0.057	0.083 to 0.058	0.018	0.15 to 0.66	0.11 to 0.61
Western coal:							
Surface-mined	0.0028 to 0.0070	0.0028 to 0.14	0.045 to 0.11	0.083 to 0.058	0.018	0.15 to 0.86	0.11 to 0.74
Deep-mined	0.0062 to 0.010	0.0	0.045 to 0.11	0.083 to 0.058	0.018	0.15 to 0.72	0.11 to 0.61
			High-Btu gas				
Eastern coal:							
Surface-mined	0.0035 to 0.0042	0.0 to 0.036	0.057 to 0.069	0.083 to 0.58	0.049	0.19 to 0.74	0.14 to 0.67
Deep-mined	0.0078 to 0.0095	0.0	0.057 to 0.069	0.083 to 0.58	0.049	0.20 to 0.71	0.14 to 0.64
Western coal:							
Surface-mined	0.0035 to 0.0085	0.0036 to 0.17	0.057 to 0.14	0.083 to 0.58	0.049	0.20 to 0.95	0.14 to 0.81
Deep-mined	0.0078 to 0.012	0.0	0.057 to 0.14	0.083 to 0.58	0.049	0.20 to 0.7	0.14 to 0.64
			Syncrude				
Eastern coal:							
Surface-mined	0.0031 to 0.057	0.0 to 0.048	0.051 to 0.093	0.11 to 0.74	0.029	0.19 to 0.92	0.14 to 0.82
Deep-mined	0.0070 to 0.013	0.0	0.051 to 0.093	0.11 to 0.74	0.029	0.20 to 0.88	0.15 to 0.78
Western coal:							
Surface-mined	0.0031 to 0.011	0.0032 to 0.23	0.051 to 0.19	0.11 to 0.74	0.029	0.20 to 1.2	0.14 to 1.0
Deep-mined	0.0070 to 0.017	0.0	0.051 to 0.19	0.11 to 0.74	0.029	0.20 to 0.98	0.14 to 0.79
			Oil from shale				
Surface technology							
Surface-mined	0.0040 to 0.0056	0.033 to 0.053	NA	0.030 to 0.044	0.0069 to 0.0092	NA	0.074 to 0.11
Deep-mined	0.0041 to 0.0056	0.032 to 0.056	NA	0.030 to 0.044	0.0082 to 0.011	NA	0.074 to 0.12
In situ technology:							
Modified in situ	0.0019 to 0.0026	0.014 to 0.030	NA	0.027 to 0.047	0.0087 to 0.010	NA	0.052 to 0.090
True in situ	NA	0.0 to 0.0077	NA	0.0 to 0.044	0.0088 to 0.010	NA	0.009 to 0.062

*In the East, surface and deep mining consume 2.3 and 5.2 $m^3/10^{12}$ joules of coal mined. In the West, consumption is 2.3 to 4.7 and 5.2 to 6.8 m^3 per 10^{12} joules mined, respectively (*40*). †In the East, land disturbance is 22 to 65 m^2 per 10^2 joules of coal mined (*37*) and annual water consumption is 0 to 0.015 m^3/m^2 over a 1- to 2-year period (*19*). In the West, the corresponding figures are 3.9 to 31 m^2 per 10^{12} joules of coal mined (*37*) and 0.30 to 0.61 m^3/m^2 over 2 to 5 years (*19*). The shale estimates include consumption for revegetation as well as processed shale disposal (*41*). ‡Slurry pipelines consume 38 and 37 to 76 m^3 per 10^{12} joules of coal mined in the East and the West, respectively (*42*). §For coal conversion see (*42, 43*); for shale extraction see (*41*). ‖For coal conversion see (*38*); for shale see (*41*).

complicated than these numbers indicate. The effects of coal mining have long been recognized. Mine drainage, soil erosion, and alteration of runoff characteristics are among the important ones. These effects are also expected from shale mining. However, mining of oil shale results in a volume of processed shale that is about 1.2 times greater than the raw shale. The resulting difficulty of storing the wastes in the excavated areas has led to proposals to use natural canyons as storage space for spent shale. Such action would lead not only to permanent loss of many canyon lands but also to the destruction of natural habitats, many of which are homes for a number of rare and endangered species (*19, 20*), and to an alteration of the hydrologic regime of the region. Furthermore, the stability of the spent shale when subjected to precipitation and snowmelt is questionable (*21*).

These, and also economic, considerations have directed attention toward in situ technology for extracting oil from shale. One water-related problem with in situ processes is particularly worrisome. The significant shale deposits of the Piceance Basin in Colorado are in themselves an integral part of the mechanism by which groundwater quality and flow are naturally maintained (*22*). A disruption of this system could affect the flow and quality of the White River and ultimately the Green and Colorado rivers by causing the release of artesian, saline groundwater into freshwater systems. Our listed range of uncertainty in Table 4 does not cover the case of aquifer disruption leading to alteration of the White, Green, and Colorado rivers; it includes only the more narrow range of water requirements associated with the range of technological options.

Problems affecting water availability and quality in the Upper and Lower Colorado regions are already serious. Overallocation of water, low-flow conditions, salinity, and erosion are well recognized (*18, 20–22*). An oil shale industry, whether based on surface or deep mining, aboveground or in situ retorting, poses the risk of serious ecological impacts in its competition for water. The geographic confinement of commercially attractive and explored oil shales to this region is in contrast to coal, which is found in significant quantities across a spectrum of meteorological, topographical, hydrological, and ecological conditions. In choosing between coal and oil shale, the greater flexibility of coal mining sites and uncertainties about aquifer disruption from oil shale activities must be considered along with the numbers in Table 4.

Table 5. Water requirements for electric power-plant cooling. Data are expressed as cubic kilometers of water per 10^{18} joules of electric output. It is assumed that the thermal efficiency is 38 percent and that 17 percent of the waste heat is dissipated directly to the atmosphere in the form of hot stack gases (*23*).

Cooling mode	Withdrawal	Consumption
Once-through (no storage)	28.0 to 40.0	0.2 to 0.4
Once-through (storage*)	28.5 to 41.5	0.5 to 1.5
Wet cooling tower†	0.6 to 0.8	0.4 to 0.6

*Reservoir capacity is assumed to meet backup storage requirements of 1000 MWe-sized plants for 90 days; lake surface evaporative loss is assumed to be in the range .75 to 1.5 meters per year. For further assumptions, see King (*23*). †Wet tower consumption is the sum of evaporative loss plus drift; withdrawal is equal to consumption plus blowdown.

Cooling requirements for steam electric plants. The freshwater required for the major ways of cooling steam electric power plants is listed in Table 5. The listed range of requirements reflects variation in regional evaporation rates, differences in the temperature to which the cooling water is heated, and some uncertainties arising from the complex mechanisms by which open water dissipates heat. The thermal efficiency of the electric generating system is assumed to be 38 percent, typical of a modern coal-burning plant.

Table 5 shows that the use of wet cooling towers is not necessarily preferable to once-through cooling. Wet tower cooling reduces the withdrawal requirements, while once-through cooling reduces consumption requirements, provided that additional water storage is not needed to meet withdrawal needs of a once-through system. In areas where water is scarce and river flow is variable, the large withdrawal needs of a once-through system may not be met without providing for additional storage. If storage must be added with a once-through cooling system, then wet cooling is preferable. In this circumstance, wet tower cooling not only reduces water consumption but also avoids problems of thermal pollution in aquatic habitats, as well as the many ecological hazards associated with damming free-flowing rivers (*5*). In circumstances where additional storage is not required but water consumption is a problem (for example, western lakes), the once-through method may be preferable (*23*).

Lest it appear that dry cooling is an unqualified blessing because of savings in water, we note that a coal-burning, dry-cooled, electric generating plant is likely to have a thermal efficiency of about 1½ percentage points lower than a plant with a once-through or wet tower cooling (*24*). Thus more fuel will be required for a given electric output, and extra water will be consumed for mining and land reclamation. Consider, for example, two electric power plants producing the same electric output from western surface-mined coal. Assume that one operates at 38 percent efficiency and employs wet tower cooling, while the other operates at 36½ percent efficiency and is dry-cooled. From Tables 4 and 5 it can be calculated that the dry-cooled plant indeed leads to less total water consumption than the water-cooled plant. The dry-cooled plant would consume an additional 0.0005 to 0.0095 $km^3/10^{18}$ joule electric at the mine site whereas the wet tower cooled system would consume an additional 0.4 to 0.6 $km^3/10^{18}$ joule electric at the power plant. However, one must consider that the additional water use at the mine may be environmentally more critical in terms of a possible shortage in local water supply.

Coal and uranium for electricity. Coal and uranium are often viewed as alternative sources of energy for future electric generation. Although these are not the only candidates for meeting future demand for electricity, it is nevertheless interesting to look at the coal-nuclear issue from the perspective of water resources.

The cooling required for a light-water reactor (LWR) is considerably greater than that for a modern coal- or petroleum-fueled plant producing the same electric power. Consider, for example, an LWR with a typical thermal conversion efficiency of 33 percent and a fossil-fuel plant operating at 38 percent efficiency (*24*). For the same power output this difference in efficiency results in the release of about 24 percent more waste heat by the LWR. Because a nuclear plant releases all but from 0 to 5 percent of its waste heat through its cooling condensers, whereas a coal-burning plant typically releases 15 to 20 percent of its waste heat directly into the atmosphere with flue gas (*24*), the LWR actually requires about 39 to 50 percent more cooling water than does the fossil plant. Together, these differences cause an additional consumptive loss of water by the LWR of 0.16 to 0.30 $km^3/10^{18}$ joule electric as compared to the fossil fuel plant, if both employ wet tower cooling. Moreover, with once-through river water cooling, the need for storage reservoirs for the LWR will be greatly increased because of the 39 to 50 percent increased water withdrawal requirement.

The future water needs for uranium mining, even on a per-unit-energy basis, are difficult to predict because of uncertainty over available reserves of high-grade uranium ore. Today, uranium fuel can be obtained from ores containing 50 times the energy content of coal per unit weight (*25*). As long as such rich sources of uranium fuel are available, the water required for uranium mining and reclamation will be considerably less than they are for surface mining of coal. But as these rich supplies dwindle, nuclear reactors will require the use of low-grade ores. One possible ore, the Chattanooga shale, has an energy content per unit weight roughly twice that of coal (*25*). Should such ores be mined, their geographic location and depth would be decisive factors in comparing impacts of water requirements of coal and uranium mining.

One worrisome possibility is that the last remaining rich supplies of uranium ores might happen to lie either in areas of special ecological value or in regions of especially scarce water. Economic pressure to exploit these supplies might be difficult to resist. In contrast, coal, being more widespread geographically, would then offer a wider choice of mining sites. These issues and the actual water impacts of uranium mining will become clearer when the amount and distribution of uranium fuel reserves become better known.

Taking into account the entire fuel cycle, we may question how coal and nuclear electric generation today compare with respect to water consumption. On the one hand, coal stripping and reclamation require an additional 0.004 to 0.09 $km^3/10^{18}$ joule electric of water compared to uranium mining. On the other hand, nuclear plants which are wet tower-cooled required 0.16 to 0.30 $km^3/10^{18}$ joule electric more water than a coal-fired plant. Thus the nuclear plants are more freshwater-intensive. With dry cooling or seawater cooling, the situation is, of course, reversed.

Future efficiencies of power plants are quite uncertain. Pollution control equipment on fossil-fuel plants could reduce their efficiency, but fluidized-bed combustion could eventually provide ways for controlling emissions at efficiencies higher than today's coal-burning plants (*26*). The breeder reactor is likely to have a higher efficiency than the LWR. And finally, cogeneration of process steam and electricity, combined-cycle, fossil-fuel plants, and development of uses for waste heat will make the water bookkeeping more complicated than presented here.

The solar options. The various solar energy technologies differ greatly with respect to water consumption. Because solar radiation is most intense and most predictable in parts of the United States where runoff is lowest and least predictable, water impacts of solar energy technologies must be thoroughly examined.

Several solar options for electricity generation are attractive on this score because the only water they would consume would be that used during the manufacturing of materials and the installation and maintenance of operating facilities (*27*). Wind energy is an example, because wind-generated electricity requires no cooling water. Certain methods of photovoltaic conversion provide other examples. Among the solar thermal conversion systems that have been suggested, either open-cycle Brayton generation (gas turbine) or Rankine-cycle conversion with dry cooling towers would require minimal amounts of water. Although thermal generation of electricity by solar energy is likely to be less than 20 percent efficient, the steam cycle should operate at about the same efficiency as a fossil-fuel plant and therefore water consumption for wet tower or once-through cooling will be approximately the same as for coal-fired plants (*28*).

Bioconversion is a possible means of producing gaseous and liquid fuels. One of the most efficient crops for energy plantations is sugar beets, which could have an annual yield of 10^{18} joules on about 8000 km^2. On this basis, approximately 8½ percent of the land area of the conterminous 48 states would be required to meet all current U.S. energy needs, provided that this land were sufficiently irrigated and fertilized and had high insolation and warm temperatures. Irrigation requirements alone for such a crop are estimated to be 10 $km^3/10^{18}$ joules of biomass (*29*), about half of which would be consumed. Table 1 indicates that the water consumed in meet-

Table 6. Water and energy consumption for home heating by synthetic gas and electricity derived from coal. Case A denotes little or no conservation of energy or water. Case C represents the other extreme, while case B is intermediate.

Region	End-use energy consumption (10^9 joule/house/year)*		Coal consumption (10^9 joule/house/year)		Water consumption (m^3/house/year)			
					Gas§		Electricity‖	
	Gas	Electricity	Gas†	Electricity‡	Surface mining	Deep mining	Surface mining	Deep mining
				Case A				
East	220	79	390	230	150 to 160	152	88 to 100	89 to 100
West	120	52	210	150	83 to 100	83	58 to 77	58 to 63
				Case B				
East	160	72	280	210	66 to 72	67	25 to 40	26 to 36
West	86	47	150	140	36 to 50	36	16 to 34	16 to 21
				Case C				
East	60	26	97	78	8.8 to 11	9.1	0.77 to 6.2	0.99 to 4.9
West	60	26	97	78	9.0 to 18	9.1 to 9.2	0.64 to 11	0.68 to 3.4

*These are estimates of the energy to be delivered to a single-family, one-story detached house for the purpose of space heating. Cases A and B are based on synthesized (model) demand (*30*). In case A, the demand reflects 1970 conditions. Case B is based on projected reductions of, respectively, 28 and 9 percent in gas and electricity consumption per home (relative to 1970). In case C, the house is designed according to NEMA standards (single thermostat) with net heating requirements amounting to 52×10^9 joules/year and 60×10^9 joules/year for the electric- and gas-heated home, respectively (*30*). The homes are equipped with a gas or an electric heat pump of equal coefficients of performance (COP =2). The gas heat pump has a mechanical efficiency of 33 percent, but half of the heat not converted is recovered. In cases A and B, East denotes a Michigan house dependent on eastern coal, while West refers to a New Mexico location fueled with western coal. East and West in case C denote only the source of coal. †Based on regional distribution and pipeline transport (1600 km average) losses of 0.7 and 7 percent, respectively (*44*). In cases A and B, efficiency of conversion (to high-Btu gas) is assumed to be 61 percent. In C, the efficiency is 67 percent (*19*). ‡A transmission loss of 8.6 percent is assumed (250 km) (*44*). Power-plant thermal efficiency is 38 percent of cases A and B and 36.5 percent for case C (dry tower cooling) (*24*). §Slurry piplines are not included. In case A, conversion water consumption is 0.58 m^3 per 10^9 joules of gas (at the plant). In case C, it is 0.083 $m^3/10^9$ joules. Case B assumes the mean of these two values. Other assumptions are the same as in Table 4 (high-Btu gasification). ‖Cooling by once-through in cases A and B (A uses storage, B does not) and by dry tower in case C. Water consumption estimates include mining and reclamation (see Table 4), cooling (1.0, 0.3, and 0.0097 m^3 per 10^9 joules electric for cases A, B, and C, respectively) [Table 5 and (*24*)], coal cleaning (0.012 to 0.062 m^3 per 10^9 joules electric) in the East and none in the West (*35*), and air pollution control (0 to 0.10 m^3 per 10^9 joules electric) (*24*) (all joules electric refer to the power plant).

Table 7. Scenarios for future energy development in the United States based on the use of coal.

Scenario	Total annual U.S. coal consumption (10^{18} joule/year)	Coal mining distribution*	Slurry pipeline† (10^{18} joules/year)	Total annual coal conversion to synfuels‡ (10^{18} joule synfuel/year)	Conversion distribution§
1	16	E	0	0	NA‖
2	16	W	0	0	NA
3	32	E	0	4	B
4	32	W	0	8	A
5	32	W	4	8	B
6	32	E	0	8	B
7	32	W	0	16	A
8	48	W	0	16	A
9	48	W	4	16	B
10	48	E	0	16	B
11	48	W	0	0	NA
12	64	W	8	32	B

*All coal is divided into two classes, eastern and western, where Illinois and other midwestern coals are included under eastern. Coal mining distribution plan W assumes 75 percent of the coal is western and 25 percent is eastern. Plan E assumes 25 percent is western and 75 percent is eastern. All the western coal is surface-mined, while eastern coal is assumed to be half surface-mined and half deep-mined. †Slurry pipeline refers to the use of western water to transport coal away from western mine sites. ‡Total coal conversion produces 50 percent high-Btu gas by energy content and 50 percent liquid syncrude. §In conversion distribution plan A, 50 percent of the conversion is in the East and 50 percent in the West; in plan B, 75 percent is in the East and 25 percent is in the West. ‖Not applicable.

ing the current U.S. annual energy demand of 80×10^{18} joules by bioconversion would exceed *all* current water consumption in the United States by almost a factor of 3. If such bioconversion plantations were located in the Southwest, as would be favored by factors such as climate and land availability, their annual water withdrawal requirements would exceed the mean annual runoff of all rivers in the conterminous United States west of the Mississippi. Evidently, such plantations could be maintained only by a massive system of water imports. Bioconversion schemes using artificial ponds for freshwater algal culture would result in comparable water consumption on a per-unit-energy basis unless evaporation-preventing protective covers were used.

On a smaller scale, however, biconversion systems designed to process agricultural or feedlot wastes or designed in tandem with sewage treatment facilities could actually have a net beneficial effect on water resources, and could make small but useful contributions to U.S. energy needs.

Solar rooftop panels and passive systems for domestic and commercial heating appear quite favorable from the viewpoint of water conservation. Indiscriminate cutting down of trees in the vicinity of houses could lead to greater household water consumption for maintenance of lawns and low shrubs, but coordinated efforts of landscape architects and solar engineers should avoid such problems.

How should coal be used to heat homes? Coal can be used to heat homes directly or by conversion to synthetic fuels or electricity. Direct heating is not environmentally acceptable. Establishment of a major synthetic fuel industry is likely to require massive amounts of natural resources, and it is therefore imperative that a careful assessment of the consequences of such an industry be made. An assessment procedure that avoids some pitfalls of cost-benefit analysis is to estimate and compare the environmental impacts and the consumption of natural resources which will accompany the provision of a given measure of a particular end use via alternative technologies. Here, we compare the amounts of water consumed for two home-heating methods, one using electricity produced from coal and the other using synthetic high-Btu gas produced from coal.

Electricity production is less efficient than synfuel production. However, there is also a considerable gap between the number of joules of electricity and of gas required for space heating at the point of use. This is illustrated in the first two columns of Table 6 which show the energy requirements, at the point of use, for electrically heated and gas-heated model unit houses in two locations, as developed by the Federal Energy Administration (FEA) (*30*). The difference between the number of joules of electricity and gas is attributed to the lower system-efficiency of gas-heated homes. First, at the point of conversion to heat, the gas furnaces of today are less efficient than electric heaters, the difference being about 20 percent. Second, and more important, is the higher heat loss rates in gas-heated homes today, arising from duct and ventilation losses. Electricity also allows for individual zonal or room thermostat settings, in contrast to most gas-heated homes. It is quite difficult to predict improvements in the efficiency of coal-conversion plants or electric generating plants, and also of home-heating systems. In principle, one can build homes so that human warmth and electric lighting suffice for space heating. Concern over indoor air pollution may influence progress toward this ideal by gas-heated homes.

Table 8. Scenarios for future energy development based on electricity production.

Scenario	Total steam-generated electricity (10^{18} joule /year)	Cooling mode*
1	12	A
2	12	B
3	30	A
4	30	B

*Cooling mode A refers to the following mix of cooling methods: once-through cooling (no storage), 25 percent; once-through cooling (storage), 25 percent; wet cooling towers, 25 percent; seawater cooling, 25 percent. In cooling mode B we assume: once-through cooling (no storage), 15 percent; once-through cooling (storage), 10 percent; dry cooling towers, 50 percent; seawater cooling, 25 percent. Included in the range of uncertainty for power-plant cooling requirements will be a range of thermal efficiencies varying from 33 to 38 percent. We further assume that the fraction of waste heat released directly to the atmosphere ranges from 0 to 20 percent.

We show our results for three cases in Table 6. In case A, which is our worst case from the viewpoint of water consumption, cooling is carried out by the once-through method with storage; minimal water conservation and treatment is assumed in the production of synfuels (see Table 4); and home insulation and heating appliances are typical of those in use today. In case B, cooling is carried out by the once-through method without storage; water consumption in synfuel production is assumed to be midway between the worst and best cases (see Table 4); and home insulation and home-heating appliances are taken from FEA estimates (*30*) of improved 1990 homes. In case C, dry cooling is employed; maximal water treatment and conservation is assumed in the production of synfuels; home insulation is superior to case B (*30*); and home heating is carried out with heat pumps, with one-half of the waste heat from the gas-fired heat pump captured and used in the home.

In case C, which minimizes water consumption, both coal and water needs for home heating are sufficiently low that resource considerations would probably not be an important factor in deciding between the electric and the synfuels path. Where they could be an important factor, in either of the first two cases, the electric path appears to be superior to the synfuels path. From the perspective of water consumption, the use of active or passive solar space heating would be preferable to either of these coal paths.

Analysis of Energy Scenarios

Here we describe the demands on freshwater resources which are likely to arise as a consequence of an expansion of certain energy activities in the United States. We specify future energy development in this country by a series of scenarios prepared on a regional basis. These scenarios are intended to portray possibilities, not projections or predictions. Moreover, they do not specify all aspects of future energy development, but only those pertaining to electric generation cooling requirements, in one set of four scenarios, and coal mining, land reclamation, slurry pipeline, and conversion of coal to synthetic fuels, in another set of 12 scenarios.

The numerical specifications of the two sets of scenarios are given in Tables 7 and 8. We assume that the water for mining, land reclamation, slurry pipeline, and coal gasification and liquefaction that take place in the West will be drawn from two hydrologic basins: the Missouri (which includes the Powder River Basin) and the Upper Colorado region. We further assume that water for the coal activities in the East will be drawn from three basins: the Upper Mississippi, the Ohio, and the Tennessee. Table 2 indicates that these three eastern regions yield over 30 percent of the mean runoff in the entire eastern United States. Within the two western regions, and separately within the three eastern regions, we assume optimum geographic matching of water supply and demand in the way that would occur if interregional planning lumped the three eastern regions together and the two western regions together.

In Table 8 we estimate only the water consumption required to meet cooling needs of electric power plants because we do not wish to specify the mix of fuel sources used to produce the electricity, and because the water required for other phases of a fuel cycle generally will be obtained outside the region in which the electricity is produced. While some of the cooling required for future electric power plants is assumed to be met with seawater, not all regions have access to oceans. Therefore, the electric power specified in the scenarios as not produced with seawater cooling (three-fourths of the total) is assumed to be distributed among the regions in proportion to the amount of power now produced in each region by freshwater cooling.

Table 9. Water consumption in coal scenarios. For meaning of East and West, see text. In 1975, total water consumption for all users in the areas of the United States we have denoted East and West was 3.4 km^3 and 27.4 km^3, respectively; $_7Q_{10}$ in East and West is 22 km^3/year and 14 km^3/year, respectively; and mean annual runoff is 317 km^3/year and 93 km^3/year, respectively.

Scenario	Coal-related water consumption (km^3/year)		1975 consumption plus additional coal-related consumption as percentage of $_7Q_{10}$*	
	East	West	East	West
1	0.046 to 0.18	0.091 to 0.38	16	196
2	0.015 to 0.056	0.056 to 1.12	16	196 to 203
3	0.48 to 2.4	0.17 to 1.45	18 to 26	197 to 206
4	0.55 to 2.9	0.63 to 5.0	18 to 29	200 to 231
5	0.81 to 4.3	0.52 to 3.9	19 to 35	199 to 223
6	0.87 to 4.5	0.30 to 2.1	19 to 36	198 to 211
7	1.1 to 4.7	1.2 to 7.8	10 to 41	204 to 251
8	1.1 to 5.8	1.2 to 9.0	20 to 42	204 to 260
9	1.6 to 8.5	0.85 to 6.4	23 to 54	202 to 241
10	1.7 to 8.8	0.49 to 3.9	23 to 55	200 to 223
11	0.046 to 0.17	0.17 to 3.4	16	197 to 220
12	3.2 to 17	1.6 to 10	30 to 93	207 to 267

*For 1975.

Table 9 shows the estimated water consumption for the coal scenarios, as listed separately for the eastern and western regions. This consumption is expressed in two ways: (i) as the absolute amount consumed and (ii) as the ratio of the sum of present-day water consumption plus anticipated coal-related water consumption to the low-flow parameter, $_7Q_{10}$, for the eastern and the western regions (*31*).

The water problems arising from future coal activities are of a somewhat different nature in the East and West. In the East, water consumption for a major coal-conversion industry becomes a large fraction of total present-day consumption (3.4 km^3/year, in 1975). The large relative increase in water consumption for the East would pose problems for water allocation management and could have major economic repercussions. Moreover, in the East the sum of present-day consumption plus the additional water consumption for coal activities would approach the $_7Q_{10}$ flow in the scenarios for intensive coal use, and thus the eastern regions will become vulnerable to drought. Before setting forth on a course of massive development of a coal-conversion industry in the United States, it would be important to explore further the implications of this finding for freshwater and estuarine ecosystems and for present and future human activities that depend on reliable freshwater supplies.

In the West, present-day consumption of water is already a large fraction of $_7Q_{10}$, and even of total runoff. Because the West is already vulnerable to drought, the additional water consumption for scenarios with intensive coal use would greatly exacerbate the existing problem of competition for water rather than create, as in the East, new kinds of problems. It is possible that water for future coal-related activities in the West will be diverted from present consumers of freshwater, in particular from crop and livestock growers (*32*).

We have constructed the scenarios in such a way as to highlight some of the trade-offs that are possible in the production of coal. Table 9 shows that if consumption were at the upper end of the range of uncertainty, major water consumption problems would arise in the East, or the West, or in both, as total synfuel production approached 8×10^{18} joule/year (one-seventh of the present use of oil and gas in the United States). But even if maximum water conservation and water treatment efforts were made in coal conversion (including dry cooling), and if western land reclamation were given minimal effort (leaving little likelihood of successful revegetation), the quantities of water involved in the high coal-conversion scenarios would not be inconsequential compared with $_7Q_{10}$ or with present-day consumption. Table 9 also shows that, while the scarcity of water today is far more critical in the West than in the East, attempts to put more of the water burden on the East by giving it a larger role in mining and converting coal would simply transfer the problem of water supply (compare, for example, scenarios 4 and 6 or 8 and 10). Finally Table 9 indicates that coal mining is far less a water consumption problem than coal conversion, although even without a synthetic fuel industry, water consumption at the upper limit of possible use (reflecting a serious

Table 10. Freshwater consumption for electric power-plant cooling in four scenarios (see Table 8 for scenario specification).

Region	1975 freshwater consumption for electric power generation (km^3)	Future freshwater consumption for electric power generation (km^3/year)			
		1	2	3	4
New England	0.13	0.096 to 0.32	0.029 to 0.11	0.24 to 0.80*	0.072 to 0.28
Mid-Atlantic	0.19	0.34 to 1.2	0.10 to 0.38	0.85 to 2.0*	0.25 to 0.95
South Atlantic Gulf	0.29	0.44 to 1.5	0.13 to 0.49	1.1 to 3.8*	0.33 to 1.2
Great Lakes	0.072	0.58 to 2.0*	0.17 to 0.66	1.5 to 5.1*†	0.43 to 1.6*
Ohio	0.39	0.98 to 3.4*	0.29 to 1.1	2.5 to 8.3*	0.75 to 2.8*
Tennessee	0.081	0.20 to 0.68*	0.062 to 0.23	0.50 to 1.7*	0.16 to 0.58*
Upper Mississippi	0.13	0.42 to 1.4*	0.13 to 0.49	1.1 to 3.6*	0.33 to 1.2*
Lower Mississippi	0.40	0.20 to 0.68	0.062 to 0.23	0.50 to 1.7	0.16 to 0.58
Souris-Red-Rainy	0.0017	0.0058 to 0.020	0.0017 to 0.0065	0.015 to .049	0.0043 to 0.016
Missouri	0.094	0.19 to 0.66	0.056 to 0.22	0.48 to 1.7	0.14 to 0.55
Arkansas	0.13	0.24 to 0.80	0.070 to 0.27	0.60 to 2.0	0.18 to 0.68
Texas Gulf	0.52	0.40 to 1.4	0.12 to 0.46	1.9 to 3.9†	0.30 to 1.2
Rio Grande	0.028	0.042 to 0.14	0.013 to 0.048	0.11 to 0.36†	0.033 to 0.12
Upper Colorado	0.082	0.062 to 0.20	0.018 to 0.070	0.15 to 0.50	0.045 to 0.18
Lower Colorado	0.065	0.054 to 0.18	0.016 to 0.060	0.14 to 0.46†	0.040 to 0.15
Great Basin	0.0079	0.022 to 0.072	0.0064 to 0.024	0.055 to 0.18	0.016 to 0.060
Pacific Northwest	0.012	0.024 to 0.080	0.0070 to 0.027	0.60 to 0.20	0.018 to 0.068
California	0.044	0.0096 to 0.032	0.0029 to 0.011	0.024 to 0.080	0.0073 to 0.028
United States (excluding Hawaii and Alaska)	2.6	4.5 to 15	1.3 to 4.9	11.0 to 37.	3.3 to 12

*See text. †See text.

effort at land reclamation) is large enough to be worrisome. Indeed, western production of coal equal to 12×10^{18} joule/year (scenario 2) would require an amount of water that could be considered unacceptable.

The total annual water consumption, by region, for each of the electricity scenarios is given in Table 10, expressed in absolute amounts of water used for cooling. The range in consumption assigned to the various scenarios represents the range of values from Table 5 plus a range of thermal efficiencies ranging from 33 to 38 percent. It is instructive to compare the water consumption projected by these scenarios with total present-day regional consumption for all uses. For those regions and scenarios in which the upper limit for the additional water required for cooling of power plants (upper limit of regional entry in scenario minus present-day regional cooling-water consumption) exceeds 50 percent of present-day total regional consumption for all uses (see Table 2) the entry in Table 10 is marked with an asterisk. Note that all these regions are in the East. An interesting fact is that such regions are generally not the ones with a high ratio of present-day consumption to mean annual runoff (see Table 2). Although the additional water consumed for cooling represents a major increase in water consumption in these regions, the environmental impacts created by such consumption are likely to be of a different nature than those arising in the West. To emphasize this distinction, entries in Table 10 are marked with a dagger when the upper limit for additional water for cooling exceeds 5 percent of the mean annual regional runoff (*33*). Except for the Great Lakes region (which is a special case in the sense that much of its water comes from Canada and is not indicated in Table 2), no overlap is found between regions having a relatively deficient annual flow and regions where the projected demand would substantially exceed present consumption.

Although broad conclusions drawn from the electricity scenarios can be regarded as either vague or indefensible, we venture to conclude (neglecting all facets of the electricity supply problem other than cooling water) that 30×10^{18} joules of electric output per year would be tolerable with cooling mode B (dry cooling dominant) but would pose major unacceptable regional problems with mode A (evaporative cooling dominant). While 30×10^{18} joule/year of electricity may seem to be an absurdly high level to consider (it is a fivefold increase over present levels), we included this level in our scenarios because of our concern with the general problem of finding ultimate replacements for natural gaseous and liquid fuels.

Conclusions

We have examined constraints of freshwater on the expansion rate of particular energy options and have answered specific questions which were posed in terms of rather narrow sets of choices among alternative technological means to common objectives. From technology comparisons and scenario analyses the availability of freshwater is clearly a paramount factor to be considered in setting energy policy. Our conclusions are based solely on the factor of water consumption; numerous other factors, including land use, air and water pollution, economics, and occupational hazards, must be included in any overall planning effort.

Our analysis suggests several conclusions. One is that a coal-conversion industry in the United States supplying as much as 8×10^{18} joule/year of synthetic fuels will be constrained by a scarcity of freshwater. An annual production of 8×10^{18} joules of synthetic fuels is not even enough to replace the present consumption of natural gaseous and liquid fuels in only those end uses for which direct burning of coal is inappropriate (for example, transportation and home heating). This deficiency, coupled with the low likelihood that bioconversion can meet these present needs in an environmentally acceptable fashion, suggests the importance of directing greater R & D effort toward ultimate end-use modification which would permit the use of electricity in place of natural gaseous and liquid fuels. It also emphasizes the acute need for more stringent energy conservation in transportation and home heating.

A second finding is that production of steam-generated electricity as a substitute for natural gaseous and liquid fuels would cause conflicts in the use of freshwater unless dry cooling were extensively used. Technologies for electricity production that do not depend on water, such as wind and photovoltaics, as well as solar active or passive home heating look especially desirable in this light.

Combining these two observations we conclude that limited availability of freshwater is likely to be a severely constraining factor in future energy development. Even if no overall growth in energy consumption were to take place in this country, the need for substitutes for natural gaseous and liquid fuels could pose staggering problems for water resource management and for natural ecosystems that depend on relatively free flowing freshwater. Overall growth in U.S. energy consumption would, of course, exacerbate these problems.

The degree of dependence of energy development on freshwater hinges on a number of unknown factors: the extent to which water conservation practices, including water pollution treatment, are carried out in coal-conversion plants and mining operations; the economic feasibility of dry cooling or cooling with agricultural wastewater; the economic feasibility of desalination; the results of further research on groundwater and its management as a renewable resource rather than as a commodity to be mined and lost; the results of further experience with land reclamation, especially in areas hard to reclaim such as the northern Great Plains; and the feasibility of piping seawater inland for use in cooling power plants. The consequences to society of use of freshwater for energy will depend also on what the future demand will be in competing sectors of the water economy such as agriculture, municipal use, and industry. Moreover, decisions on acceptable limits of water use for energy will require greater understanding of rivers, lakes, and estuaries and greater knowledge of climatic variability.

Resolving these uncertainties will not be easy. Information on biological and climatic constraints is likely to be especially elusive. Yet planning must proceed, even in the face of uncertainty. Water constraints on energy development are sufficiently great to warrant far more attention. Two broad and urgent needs are identified. First is the need to develop adequate criteria for acceptable water consumption based on considerations of ecosystem balance, human well-being, nonuniform distribution of water, and the vicissitudes of its abundance under a capricious climate. Second is the need to set energy policy and water management on a course compatible with the criteria that are chosen. That course is certain to be characterized by a vital and enormous role for energy and water conservation.

References and Notes

1. For an overview of water use taxonomy, see F. W. Sinden, in *Boundaries of Analysis: An Inquiry into the Tocks Island Dam Controversy*, H. A. Feiveson, F. W. Sinden, R. H. Socolow, Eds. (Ballinger, Cambridge, Mass., 1976), pp. 163–215.
2. One cubic meter is approximately 264 gallons; one acre-foot is approximately 1.23×10^3 m^3.
3. J. F. Storr, in *Thermal Ecology* (U.S. Atomic Energy Commission, U.S. Government Printing Office, Washington, D.C., 1973), pp. 291–295.
4. A. Jassby, in (*5*), pp. A1-A26.
5. J. Harte, Ed., *Energy and the Fate of Ecosystems*, report of the Ecosystem Impacts Resource Group of the Risk/Impact Panel of the Committee on Nuclear and Alternative Energy Systems (National Academy of Sciences–National Research Council, Washington, D.C., in press).
6. B. Skinner, *Earth Resources* (Prentice-Hall, Englewood Cliffs, N.J., 1969).
7. Environmental impact assessment that only estimates the stresses on natural systems caused by human activities and the consequences of those stresses to the health of natural systems are incomplete. They stop short of assessing the social costs resulting from environmental degradation. For a survey and evaluation of the ways in which environmental degradation from energy activities can reduce the quality of human life, both materially and intangibly, see J. Harte, in (*5*, pp. 6–103). See also W. E. Westman, *Science* **197**, 960 (1977).
8. An ambiguity in the assignment of runoff to a region arises when one region is downstream from another. This ambiguity is resolved by the U.S. Water Resources Council by assigning the flow entering a downstream region to the region in which the flow originated. Thus, runoff assigned to the Lower Colorado region does not include the flow entering that region from the Upper Colorado. Because most of the coal deposits in the West and Midwest are located in "upstream" rather than "downstream" regions, the water resources that appear to be potentially available for coal-related activities may be exaggerated, at least from the downstream user's point of view.
9. See, for example, C. W. Fetter, *Water Resour. Bull.* **13**, 309 (1977).
10. Stream flow data have been obtained from the U.S. Geological Survey computerized data bank with the help of L. Jorgensen and others at the Survey office in Menlo Park, Calif. We are grateful for their cooperation.
11. G. Samuels, *Assessment of Water Resources for Nuclear Energy Centers* (ORNL-5097 UC-80, Oak Ridge National Laboratory, Oak Ridge, Tenn., September 1976).
12. R. K. Linsley, M. A. Kohler, J. L. H. Paulhus, *Hydrology for Engineers* (McGraw-Hill, New York, 1975), pp. 338–373.
13. H. B. N. Hynes, *The Ecology of Running Waters* (Liverpool Univ. Press, Liverpool, 1970), pp. 196–235 and 326–332.
14. J. Cairns, in *The Structure and Function of Fresh-water Microbial Communities*, J. Cairns, Ed. (American Microscopial Society Symposium, Virginia Polytechnic Institute and State University, Blacksburg, 1970), pp. 219–247.
15. C. Hazel, *The Effects of Altered Streamflows on Fish and Wildlife in California* (U.S. Department of Commerce, National Technical Information Service, PB-263 245, Springfield, Va., 1976); M. Brusven and C. MacPhee, *The Effect of River Fluctuation from Hydroelectric Peaking on Selected Aquatic Invertebrates and Fish* (Idaho Water Resources Research Institute, University of Idaho, September 1976).
16. G. Lauff, Ed., *Estuaries* (AAAS, Washington, D.C., 1967). See especially L. E. Cronin, in *ibid.*, pp. 667–689; K. F. Bowden, in *ibid.*, pp. 15–36; J. Hedgpeth, in *ibid.*, pp. 408–419; M. Carriker, in *ibid.*, pp. 442–487. See also B. Ketchum, *Sewage Ind. Wastes* **23** (No. 2), 198 (1951); *J. Mar. Res.* **10**, 18 (1951); G. Gunter, *Limnol. Oceanogr.* **6**, 182 (1961); J. Hedgpeth, in (*5*), pp. G1-G53).
17. A detailed discussion of the environmental impacts associated with the water requirements for coal conversion, including effects on aquatic life which could result from untreated effluent water, are discussed in (*19*).
18. R. Curry, in *Practices and Problems of Land Reclamation in Western North America*, M. K. Wali, Ed. (Univ. of North Dakota Press, Grand Forks, 1976).
19. M. El-Gassier, in (*5*), pp. EI1-EIX.52.
20. A. McDonald, *Shale Oil, an Environmental Critique* (CSPI Oil Ser. 3, Center for Science in the Public Interest, Washington, D.C., 1974).
21. F. M. Pfeffer, *Pollutional Problems and Research Needs for an Oil Shale Industry* (U.S. Environmental Protection Agency, EPA-660/2-74-067, Washington, D.C., June 1974).
22. G. D. Weaver, *Oil Shale Technology*, Hearings before the Subcommittee on Energy, U.S. House of Representatives, 93rd Congress, 2nd Session, 1974; J. B. Weeks, G. H. Leavesly, F. A. Welder, G. J. Saulnier, Jr., *U.S. Geol. Surv. Prof. Pap. 908* (1974).
23. L. King, in (*5*), pp. K1-K74.
24. T. H. Pigford *et al.*, *Fuel Cycles for Electrical Power Generation*, parts I and II, *Towards Comprehensive Standards: The Electric Power Case* (Teknekron, Inc., Berkeley, Calif., 1974).
25. P. Ehrlich, A. Ehrlich, J. Holdren, *Ecoscience: Population, Resources, Environment* (Freeman, San Francisco, 1977).
26. J. M. Beer, *The Fluidised Combustion of Coal, Sixteenth Symposium (International) on Combustion* (Combustion Institute, Pittsburgh, Pa., 1976), p. 439.
27. A rough estimate of water consumed in the provision of materials for a solar central-receiver system can be worked out from data provided by Davidson and Grether (*28*). Most of the water consumption will result from the cement requirements for the heliostat. Averaged over an assumed 30-year plant lifetime, this water consumption will be about 0.002 km^3/joules of electric output. We thank B. Wolfson for information on this subject.
28. M. Davidson and D. Grether, *The Central Receiver Power Plant: an Environmental, Ecological, and Socioeconomic Analysis* (LBL-6329, UC-62, Lawrence Berkeley Laboratory, Berkeley, Calif., 1977).
29. C. Calef, *Environment* **18**, 17 (1976).
30. For cases A and B, see Federal Energy Administration, Project Independence Blueprint—Final Task Force Report, *Project Independence—Residential and Commercial Energy Use Patterns 1970–1990* (Government Printing Office, Washington, D.C., November 1974), vol. 1, pp. 78–81. For case C see Energy Utilization Systems, Inc., *Energy Consumption and Life-Cycle Costs of Space Conditioning Systems*, sponsored by Electric Environmental Equipment Section (National Electrical Manufacturers Association, New York, 1976).
31. The value of ${}_7Q_{10}$ in the two western regions and in the three eastern regions is estimated by multiplying mean annual runoff by the ratio of ${}_7Q_{10}$ river flow to mean annual river flow. This we have done for the East and the West, using the Colorado and Yellowstone rivers in the West and the Wabash, the Ohio, and the Kanawha in the East (see Fig. 2). This procedure is reasonable if the river flow is a significant fraction of runoff. In fact, the combined mean annual flow of the three eastern rivers at the chosen U.S. Geological Survey stations accounts for 35 percent of the combined mean annual runoff of the Ohio, the Upper Mississippi, and the Tennessee regions, while in the West, the combined annual flow of the Colorado and Yellowstone at the chosen stations is 20 percent of the combined mean annual runoff of the Missouri and Upper Colorado regions.
32. The fact that an energy producer (or housing developer) can afford to pay more for land and water than a farmer or rancher generates a strong force toward what may be a serious future misallocation of resources. See, for example, J. J. Jacobsen, *A Dynamic Analysis of the Environmental and Social Impacts of Coal Development in the Eastern Powder River Basin of Wyoming, 1960–2010* (Systems Dynamics Group, Thayer School of Engineering, Dartmouth College, May 1975), pp. 31–32. See also W. D. Gertsch, J. Sathay, R. Ritschard, S. Parker, *Water Requirements for Future Energy Development in the West: State Perspectives* (LA-6688-MS, Los Alamos Scientific Laboratory, Los Alamos, N.M., August 1977).
33. Comparison is made with mean annual runoff rather than ${}_7Q_{10}$ because the latter quantity is not well estimated in many of the hydrological regions. When consumption is 5 percent of mean annual runoff, it is very roughly 50 percent of ${}_7Q_{10}$ and thus will generate significant effect on river flow during times of drought.
34. U.S. Water Resources Council, *1975 National Assessment*, preliminary draft.
35. C. R. Murray and E. B. Reeves, *U.S. Geol. Surv. Circ. 765* (1977).
36. V. E. Swanson, J. H. Medlin, J. R. Hatch, S. L. Coleman, G. H. Wood, S. D. Woodruff, R. T. Hilderbrand, *Collection, Chemical Analysis, and Evaluation of Coal Samples in 1975* (U.S. Geological Survey Open-file Report 76-468, 1976).
37. E. M. Dickson *et al.*, *Impacts of Synthetic Liq-*

uid Fuel Development—Automotive Market, Environmental Protection Agency, Interagency Energy-Environment Research and Development Program Report (EPA-600/7-76-0046, Government Printing Office, Washington, D.C., July 1976), vol. 2.
38. U.S. Department of the Interior, Energy Research and Development Administration, *Synthetic Fuel Commercialization Program*, Draft Environmental Statement (ERDA-1547, Government Printing Office, Washington, D.C., December 1975), vol. 4.
39. U.S. Department of the Interior, Bureau of Mines Process Evaluation Group, Morgantown, W. Va. Prepared for the Energy Research and Development Administration, ERDA 76-47, 76-48, 76-49, 76-52, 76-57, 76-58, 76-59, March, 1976 (National Technical Information Service, U.S. Department of Commerce, Springfield, Va., 1976).
40. Committee on Interior and Insular Affairs, U.S. Senate, *Factors Affecting Coal Substitution for other Fossil Fuels in Electric Power Production and Industrial Uses* (The National Fuels and Energy Policy Study, Serial No. 94-17, Government Printing Office, Washington, D.C., 1975).
41. Federal Energy Administration, *Project Independence Blueprint Final Task Force Report*, Project Independence-Interagency Task Force on Oil Shale (Government Printing Office, Washington, D.C., November 1974).
42. Western States Water Resources Council, *Western States Water Requirements for Energy Development to 1990* (Western States Water Resources Council, Salt Lake City, Utah, November 1974).
43. W. H. Smith and J. B. Stall, *Coal and Water Resources for Coal Conversion in Illinois*, State Water Survey State Geological Survey Cooperative Report 4, 1975; Water Resources Council, *Project Independence-Water Requirements, Availabilities, Constraints, and Recommended Federal Actions*, Federal Energy Administration Project Independence Blueprint Final Task Force Report (Government Printing Office, Washington, D.C., November 1974), p. 22.
44. Colorado Energy Research Institute, *Net Energy Analysis: An Energy Balance Study of Fossil Fuel Resources* (Denver, Colorado, April 1976).
45. U.S. Water Resources Council, *The Nation's Water Resources* (Government Printing Office, Washington, D.C., 1968); Federal Energy Administration Project Independence Blueprint Final Task Force Report, *Project Independence—Coal*, November 1974.
46. We thank the Energy Research and Development Administration for their support. We are also grateful for the numerous discussions we have held with many members of the National Academy of Sciences' Nuclear and Alternative Energy Systems Study. L. King, a participant in that study, has especially contributed to our thinking. P. Benenson, P. Fox, J. Holdren, L. King, D. Levy, and especially H. Malde, suggested numerous improvements in both substance and style in an earlier draft of this article.

Photovoltaic Power Systems: A Tour Through the Alternatives

A family of new technologies, rich in ideas, may provide the basis for many useful energy systems.

Henry Kelly

We probably know only slightly more about generating energy from photovoltaic devices than James Watt knew about producing mechanical energy from steam. Like Watt, we know that the technology works, we know something about the principles which govern it, and we can dare to speculate about a promising future. Indeed, it is very likely that photovoltaic arrays will be a common sight in less-well-developed nations and in remote parts of the developed world during the coming decade. With only a little more courage, we can envision photovoltaic-generating equipment becoming a major part of new U.S. generating capacity by the turn of the century. These promises, however, are clouded by a host of distressingly relevant questions.

In particular, we have only recently begun to think seriously about designing practical photovoltaic systems and about how these systems can best be integrated into national patterns of energy supply and demand. The number of alternative approaches turns out to be enormous, and the analytical basis for choosing between them surprisingly primitive. We do not know, for example, what the optimum size for such systems will be, we do not know whether we should emphasize the development of low-cost devices (which could perhaps eventually be used as integral parts of buildings) or the development of tracking apparatus or both, and we do not know whether cogeneration or total energy systems should be attempted.

It will be difficult to improve the present photovoltaic development program without answers to these questions. Criteria for components, for example, cannot be established without a clear understanding of the ways in which these components can contribute to integrated systems meeting real loads in real operating environments. Taking advantage of the opportunities presented by the torrents of emerging ideas will require a great deal of imagination and flexibility.

The most immediate barrier for all photovoltaic systems, of course, is the present high cost of the devices. In its latest procurement, the federal government was able to purchase flat plate arrays in quantities of tens of kilowatts for about \$11 per peak watt of output (*1*); electricity from systems using such cells costs \$1 to \$2 per kilowatt-hour.

Developmental work to reduce the cost of photovoltaic energy can be divided into three general categories: (i) reducing the cost of manufacturing the single crystal silicon cells that are now on the market; (ii) developing techniques for mass producing and increasing the performance of cells made from thin films of materials such as CdS/Cu_2S or amorphous silicon, and (iii) developing high-efficiency cells which can be installed at the focus of magnifying optical systems.

There is little doubt that it is technically possible to use any of these approaches to reduce costs to \$1 to \$2 per peak watt (electricity costing \$0.10 to \$0.40 per kilowatt-hour) during the next 3 to 5 years. Further cost reductions are almost certainly possible without any fundamental innovations, but costs below \$1 to \$2 per watt will, at a minimum, require a considerable amount of engineering development. Progress in any of a number of current research programs would give us greater confidence about meeting the lower cost goals.

A set of goals for reducing the cost of silicon photovoltaic devices was established somewhat arbitrarily during the crash "Project Independence" studies conducted in 1973. Officials in the Department of Energy believe that, with some relatively minor adjustments, these goals are achievable and are using them for planning purposes. The present goals for flat plate arrays (with 20-year+ life expectancies) are \$2 per watt by 1982, \$0.50 per watt by 1986, and \$0.10 to \$0.30 per watt in the 1990's (*2*).

The author is technical assistant to the director, Office of Technology Assessment, U.S. Congress, Washington, D.C. 20510.