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ENERGY AND WATER

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ABSTRACT

The geographic and temporal variability of freshwater supply in the U.S. constrains the choice and level of use of future energy sources.

Work performed under the auspices of the U. S. Department of Energy.

I. INTRODUCTION

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 U.S. may place on energy development.

Energy technologies use water resources in numerous ways. For example, cooling electric generating plants or coal gasification and liquefaction plants may consume freshwater. Coal and oil shale conversion processes require water as a chemical feed stock. 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 U.S., 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 constraints on the future level of development of many of this country's energy options.

One energy technology to which we will devote much attention in this article is the production of synthetic gaseous and liquid fuels. During the coming decades, the U.S. 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 water impacts of these three paths.

In the following section we set the background for a quantitative discussion of energy and water scarcity by delineating some aspects of water supply and demand and by developing a framework for evaluating the impacts of water consumption. In the third section we then estimate water requirements, on a per unit energy basis, for those energy options that are candidates for major expansion in the U.S. 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. In the fourth section, we 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. A summary and conclusion follows.

II. 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 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/y) from a river (2). This is the withdrawal rate. The conversion process uses the hydrogen in 10^5 m^3/y during the hydrogenation/methanation steps. Another 3×10^5 m^3/y 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/y evaporates, 0.5×10^5 m^3/y is disposed of as waste product and the rest (4.5×10^5 m^3/y) is treated and returned to the river five miles 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 leaves as a concentrate, or 5.5×10^5 m^3/y. 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 would be minimized to the rate at which water is used as chemical feedstock in the conversion process, or 10^5 m^3/y. 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), 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 future options for energy systems.

Aggregated Supply and Demand

In order to provide a quantitative basis for discussion of water consumption impacts, it is useful to describe the amount of freshwater potentially available to users in the U.S. Such a description should include information about average flows available and also statistical information about regional fluctuations in water supply.

First, consider the average, aggregated water supply situation in the 48 conterminous states. Precipitation averages about 5600 cubic kilometers/year (Km^3/y), about 70% of which either evaporates or is transpired by vegetation before it reaches the oceans (5). The remaining 30%, or 1700 Km^3/y, is called runoff or stream discharge (6). 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 (6) 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 U.S. is outlined in Table 1. At first glance, by comparing the averaged annual freshwater runoff of about 1700 Km^3/y with the annual consumption of 151 Km^3/y, 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 two years has averaged only about one-half normal. In addition, time-averaged local runoff is neither distributed uniformly over the U.S. 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 case of the Upper and Lower Mississippi regions) (9). They are shown in Figure 1. Regional mean annual runoff and 1975 consumption are shown in the first two columns of Table 2; also in the table is a regional breakdown of runoff per person and of consumption per unit runoff. Interestingly, it can be seen 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 U.S. are located in the Missouri, the Upper Colorado, the Upper Mississippi, the Ohio, and the Tennessee regions (see Figure 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 ${}_xQ_y$ (14). 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 (15). Two are in the West — the Yellowstone and the

Colorado — and there are three in the East: the Ohio, the Kenawha, and the Wabash. These particular rivers are chosen because they are located in coal-rich regions and, along with nearby and hydrologically similar rivers, are among the likely sources of water for coal-related activities in the U.S. Figure 2 shows representative values of ${}_xQ_y$ at specific USGS 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% of the mean annual flow. The ratio of seven-day, ten-year low runoff to mean runoff is also roughly in the same range for the 18 hydrological regions (16). 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 (17).

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 upon 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.

Secondly, 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 (18). The taxonomic diversity of river zooplankton (19) and the ability of benthic organisms to secure nest sites in river bottoms (18) 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 (20). Hynes (18) 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 (21).

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 Figure 2. Suppose that consumption were limited to 15% 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% 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 (18), suggests that limits to consumption be based on a percentage of some x-day, y-year low flow.

In a ground-breaking paper on water requirements and water consumption criteria for electric power plant cooling, Samuels (16) reviewed water flow data in the U.S. and proposed ecological criteria for permissable water use by nuclear power plants. From these criteria, Samuels then identified rivers in the U.S. where five or more 1200 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% of ${}_7Q_{10}$ and withdrawal of up to 15% of ${}_7Q_{10}$. Samuels' criterion for rivers with storage assumes that the storage is for seasonal variations only, and states that consumption not exceed 10% 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 insure that a shortfall in industrial water supply does not occur too frequently, then this is a reasonably way to determine a standard for rivers with storage. But the ecological effects of storage facilities on a river can vary greatly depending upon how the outflow from the reservoir is managed. For a given level of consumption, the presence of a storage facility does not necessarily insure 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 (18,20). 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. The choice of x to be 7 days is based on the considerable evidence that aquatic organisms often can tolerate several days of stress but not weeks or months (18). From Figure 2 it can be seen that the choice of y to be 10 years 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 percent 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 percent 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.

III. 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 U.S. 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 (J). Note that the commonly used unit of energy called the quad ($=10^{15}$ Btu) is approximately equal to 1.05×10^{18} J. Some energy quantities, pertinent to the following discussions, are listed in Table 3, expressed in units of 10^{18} J.

Coal and Oil Shale — Mining, Reclamation, and Conversion to Synthetic Fuels

Coal and oil shale are the major fossil fuel resources of the U.S. and potentially form the base for a large and long-lasting energy supply. Most of the coal and nearly all of the oil shale are found in five water resource regions (see Figure 1); about 50% of the total recoverable coal reserves and 30% 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 nearly all the oil shale reserves are found in sparsely populated, arid or semi-arid 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 (23). 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 (31). 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 the table in our judgment has a low probability of leading to genuine revegetation (24,31). We have not attempted to include in our estimates the additional 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 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 (13,24,32), 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 (33). 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 ground-water quality and flow are naturally maintained (34). 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, ground water 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. Over-allocation of water, low flow conditions, salinity, and erosion are well recognized (31-34). An oil shale industry, whether based on surface or deep mining, above ground or in-situ retorting, poses the risk of serious ecological impacts in its competition for water. The geographic confinement of 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 the uncertainties about aquifer disruption from oil shale activities must be considered along with the numbers in Table 4.

Cooling Requirements for Steam Electric Plants

The freshwater required for the major ways of cooling steam electric power plants is listed in Table 5, in units of Km^3 of water per 10^{18} joules of electric output (Je). 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%, 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 system 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 (4). In circumstances where additional storage is not required but water consumption is a problem (e.g., Western lakes), the once-through method may be preferable (36).

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 (35). 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% efficiency and employs wet-tower cooling, while the other operates at 36½% efficiency and is dry cooled. From the entries and footnotes to 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 - 0.0095 $Km^3/10^{18}$ Je at the mine site whereas the wet-tower cooled system would consume an additional 0.4 - 0.6 $Km^3/10^{18}$ Je 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, a LWR with a typical thermal conversion efficiency of 33% and a fossil-fuel plant operating at 38% efficiency (35). For the same power output this difference in efficiency results in the

the release of about 24% more waste heat by the LWR. Because a nuclear plant releases all but from 0 - 5% of its waste heat through its cooling condensers, while a coal-burning plant typically releases 15-20% of its waste heat directly into the atmosphere with flue gas (35), the LWR actually requires about 39-50% more cooling water than does the fossil plant. Together, these differences cause an additional consumptive loss of water by the LWR of 0.16 - 0.30 $Km^3/10^{18}$ Je 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 39-50% 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 (22). 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 (22). Should such ores be mined, their geographic location and depth will 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, how do coal and nuclear electric generation today compare with respect to water consumption? On the one hand, coal stripping and reclamation require an additional $0.004 - 0.09\ Km^3/10^{18}$ Je of water compared to uranium mining. On the other hand, nuclear plants which are wet-tower cooled require $0.16 - 0.30\ Km^3/10^{18}$ Je more water than a coal-fired plant. Thus the nuclear plants are more freshwater intensive. With dry cooling or sea-water 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 (37). 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

Among the solar energy options, there exists a large range of potential water impacts. Because solar radiation is most intense and most predictable in parts of the U.S. 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 consume would be during the manufacturing of materials and the installation and maintenance of operating facilities (38). 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% 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 (39).

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} J on about 8000 kM^2. On this basis, approximately 8½% of the land area of the 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 (40), about half of which would be consumed. From Table 1, we see that the water consumed in meeting the current U.S. annual energy demand of 80×10^{18} J by bioconversion would exceed *all* current water consumption in the U.S. by almost a factor of three. 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 U.S. 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, bioconversion systems designed to process agriculture 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. Below, we carry out a water consumption comparison of two ways of heating homes: using electricity produced from coal and 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 (41). 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%. 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.

The results of the complete analysis are given in Table 6. Three cases are shown, labeled A, B, and C. In case A, which is our worst case from the viewpoint of water consumption, cooling is carried out by once-through 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 once-through 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 (41) 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 B (41); 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 consumptions, the use of active or passive solar space heating would be preferable to either of these coal paths.

IV. ANALYSIS OF ENERGY SCENARIOS

In this section we describe the demands on freshwater resources which are likely to arise as a consequence of an expansion of certain energy activities in the U.S. We specify future energy development in the U.S. by a series of scenarios. 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 twelve scenarios. Because we are interested in regional rather than nation-wide water impacts we disaggregate the energy scenarios, as described next.

The numerical specifications of the two sets of scenarios are found in Tables 7 and 8. Table 7 specifies the coal-activity scenarios, while Table 8 specifies the electric-generation scenarios. 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 Eastern coal activities will be drawn from three basins: the Upper Mississippi, the Ohio, and the Tennessee. From Table 2, it can be seen that these three Eastern regions yield over 30% of the mean runoff in the entire Eastern U.S. 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.

The electricity production scenarios are specified in Table 8. Only the water consumption required to meet *cooling* needs of electric power plants is considered here 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 sea-water cooling (three-fourths of the total) is assumed to be distributed among the regions in proportion to the amount of power presently produced in each region by freshwater cooling.

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 (43).

It can be seen that 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 water consumption plus the additional water consumption for coal activities would approach the ${}_7Q_{10}$ flow in the high coal-conversion scenarios, 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 U.S., 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 (44).

We have constructed the scenarios in such a way as to highlight some of the tradeoffs 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 approaches 8×10^{18} J/year (one-seventh of the present use of oil and gas in the U.S.). But even if maximum water conservation and water treatment efforts are made in coal conversion (including dry cooling), and if Western land reclamation is given minimal effort (leaving little likelihood of successful revegetation), nevertheless the quantities of water involved in the high coal-conversion scenarios are not inconsequential compared with ${}_7Q_{10}$ or with present day consumption. The table 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, e.g., scenarios 4 and 6 or 8 and 10). Finally, the table 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 effort at land reclamation) is large enough to be worrisome. Indeed, Western production of coal equal to 12×10^{18} J/year (Scenario 2) would require an amount of water that could be 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%. 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% of present day total regional consumption for all uses (see Table 2) the entry in Table 10 is underlined. 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 an asterisk when the upper limit for additional water for cooling exceeds 5% of the mean annual regional runoff (45). 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} Je/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} J/year of electricity may seem to be an absurdly high level to consider (it is a 5-fold 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.

V. SUMMARY AND 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 alternate 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 U.S. supplying as much as 8×10^{18} J/year of synthetic fuels will be constrained by a scarcity of freshwater. An annual production of 8×10^{18} J 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 (e.g., 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 is 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 the U.S., 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 presently 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 waste water; the economic feasibility of desalination; the results of further research on ground water 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 sea water 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.

Use Category	Withdrawal	Consumption
	(Km^3/year)	
Municipal use including domestic and commercial[a]	40.	9.2
Industrial Mining and manufacturing[a]	52.	5.8
Thermal electric power plant cooling[a]	180.	2.6
Irrigation, livestock and rural use[a]	200.	115.
Evaporation from man-made reservoirs[b]	18.	18.
TOTAL	490.	151.

Table 1. U.S. freshwater use in 1975.

[a]Data adapted from (7)

[b]Data adapted from (8)

Region	Mean annual runoff (Km^3/year)	1975 consumption (Km^3/year)	1975 per-capita runoff (10^3 m^3/person/year)	1975 consumption / mean annual runoff
New England	93.	0.61	7.9	0.0066
Mid Atlantic	120.	2.2	3.0	0.018
South Atlantic Gulf	270.	5.1	10.2	0.019
Great Lakes	100.	1.5	4.5	0.015
Ohio	170.	1.7	8.0	0.01
Tennessee	57.	0.39	17.	0.0068
Upper Miss.	90.	1.3	4.6	0.014
Lower Miss.	100.	7.6	17.	0.069
Souris-Red-Rainy	8.6	0.17	12.	0.016
Missouri	75.	24.	8.4	0.32
Arkansas	100.	16.	16.	0.16
Texas Gulf	44.	13.	4.2	0.30
Rio Grande	6.9	6.0	3.5	0.87
Upper Colo.	18.	3.4	40.	0.19
Lower Colo.	4.4	10.	1.7	2.3
Great Basin	10.	5.5	7.0	0.55
Pac. N.W.	290.	18.	44.	0.062
California	86.	34.	4.1	0.40
Alaska	800.	0.0077	2000.	9.6×10^{-6}
Hawaii	18.	0.77	22.	0.043
U.S.	2471.	151.	11.	0.060
U.S. excl. Alaska and Hawaii	1653.	150.	7.8	0.091

Table 2. Regional runoff, 1975 consumption, per-capita runoff, and consumption per unit runoff. Data adapted from (7).

Energy Category	Energy (10^{18} J/year)
Total U.S. energy consumption in 1975	72.7
U.S. liquid fuels consumption in 1975	34.5
U.S. natural gas consumption in 1975	21.3
U.S. coal consumption in 1975	14.1
U.S. steam-generated electricity output in 1975	6.1
Energy yield from 1 km^2 average Western surface-mined coal	0.1-0.2
Annual average sunlight in U.S. on 1 km^2	0.0056

Table 3. Some useful energy quantities. Data adapted from (22).

Table 4. Water consumption for the production of synthetic fuels from Coal and Oil Shale[a] ($Km^3/10^{18}$ J of synthetic fuel product)

Product Fuel and Resource	Category of Use						
	Mining[b]	Reclamation[c]	Transport by slurry pipelines[d]	Conversion[e]	Associated urban[f]	Total with slurry pipelines	Total without slurry pipelines
Low-Btu Gas:							
Eastern Coal:							
Surface-mined	.0028-.0035	0. -.030	.045-.057	.083-.58	.018	.15- .69	.10- .63
Deep-mined	.0062-.0078	0.	"	"	"	.15- .66	.11- .61
Western Coal:							
Surface-mined	.0028-.0070	.0028-.14	.045-.11	"	"	.15- .86	.11- .74
Deep-mined	.0062-.010	0.	"	"	"	.15- .72	.11- .61
High-Btu Gas							
Eastern Coal:							
Surface-mined	.0035-.0042	0. -.036	.057 .069	.083-.58	.049	.19- .74	.14- .67
Deep-mined	.0078-.0095	0.	"	"	"	.20- .71	.14- .64
Western Coal:							
Surface-mined	.0035-.0085	.0036-.17	.057-.14	"	"	.20- .95	.14- .81
Deep-mined	.0078-.012	0.	"	"	"	.20- .7[illegible]	.14- .64
Syncrude							
Eastern Coal:							
Surface-mined	.0031-.057	0. -.048	.051-.093	.11 -.74	.029	.19- .92	.14- .82
Deepmined	.0070-.013	0.	"	"	"	.20- .88	.15- .78
Western Coal:							
Surface-mined	.0031 .011	.0032-.23	.051-.19	"	"	.20-1.2	.14 -1.0
Deep-mined	.0070-.017	0.	"	"	"	.20-.98	.14- .79
Shale:							
Surface Technology							
Surface-mined	.0040-.0056	.033 -.053	n.a.	.030-.044	.0069-.0092	n.a.	.074- .11
Deep-mined	.0041-.0056	.032 -.056	n.a.	.030-.044	.0082-.011	n.a.	.074- .12
In-situ Technology:							
Modified in-situ	.0019-.0026	.014 -.030	n.a.	.027-.047	.0087-.010	n.a.	.052- .090
True in-situ	n.a.	0. -.0077	n.a.	0. -.044	.0088-.010	n.a.	.009- .062

(n.a. = not applicable)

Table 4. Water Consumption for the Production of Synthetic Fuels from Coal and Oil Shale (continued)

[a]The data presented in this table and the references have been derived from reference (24). All calculations are based on coal energy-content of 28, 22, and 14 million J/Kg of bituminous, subbituminous, and lignite coals (25), and on conversion efficiencies of 67-85, 55-67, and 41-75% for low- and high-Btu gasification, and liquefaction, respectively (12,13,26).

[b]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 2.3-4.7 and 5.2-6.8 $m^3/10^{12}$ Joules mined, respectively (27).

[c]In the East land disturbance is 22-65 $m^2/10^{12}$ Joules of coal mined (12) and water consumption is 0-.15 m^3/m^2 over 1-2 years period (24). In the West the corresponding figures are 3.9-31 $m^2/10^{12}$ Joules of coal mined (12) and .30-.61 m^3/m^2 over 2-5 years (24). The shale estimates include consumption for revegetation as well as processed shale disposal (28).

[d]Slurry pipelines consume 38 and 37-76 $m^3/10^{12}$ Joules of coal mined in the East and the West respectively (29).

[e]For coal conversion see references (29,30). For shale extraction see reference (28).

[f]For coal conversion see reference (13). For shale see reference (28).

Cooling mode	Withdrawal	Consumption
	($Km^3/10^{18}$ Je)[c]	
Once-through (no storage)	28.0 - 40.0	0.2 - 0.4
Once-through (storage[a])	28.5 - 41.5	0.5 - 1.5
Wet Cooling tower[b]	0.6 - 0.8	0.4 - 0.6

Table 5. Water requirements for electric power plant cooling. It is assumed that the thermal efficiency is 38% and that 17% of the waste heat is dissipated directly to the atmosphere in the form of hot stack gases (35).

[a]Reservoir capacity is assumed to meet back-up storage requirements of 1000 MWe-sized plants for 90 days; lake surface evaporative loss is assumed to be in the range .75 - 1.5 m/year. For further assumptions, see King (36).

[b]Wet tower consumption is the sum of evaporative loss plus drift; withdrawal is equal to consumption plus blowdown

[c]Je refers to joules of electric output

Table 6. Water and energy consumption for home heating by synthetic gas and electricity derived from coal.

Case[a]		End Use Energy Consumption (10^9 J/house/year)[b]		Coal Consumption (10^9 J/house/year)		Water Consumption (m^3/house/year)			
						Gas[e]		Electricity[f]	
		Gas	Electricity	Gas[c]	Eletricity[d]	Surface Mining	Deep Mining	Surface Mining	Deep Mining
A	East	220	79	390	230	150-160	152	88-100	89-100
	West	120	52	210	150	83-100	83	58-77	58-63
B	East	160	72	280	210	66-72	67	25-40	26-36
	West	86	47	150	140	36-50	36	16-34	16-21
C	East	60	26	97	78	8.8-11	9.1	0.77-6.2	0.99-4.9
	West	60	26	97	78	9.0-18	9.1-9.2	0.64-11	0.68-3.4

Table 6. Water and energy consumption for home heating by synthetic gas and electricity derived from coal. (continued)

[a]Case A denotes little or no effort for conserving energy or water. Case C represents the other extreme while B is intermediate.

[b]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 upon synthesized (model) demand (41). In A, the demand reflects 1970 conditions. B is based upon projected reductions of 28% and 9% in gas and electricity consumption/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 J/year and 60×10^9 J/year for the electric and gas-heated home respectively (41). 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%, but ½ the heat not converted is recovered. In A and B, East denotes a Michigan location 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.

[c]Based on regional distribution and pipeline-transport (1,000 miles average) losses of 0.7% and 7% respectively (42). In Cases A and B efficiency of conversion (to high-Btu gas) is assumed to be 61%. In C, the efficiency is 67% (24).

[d]A transmission loss of 8.6% is assumed (150 miles) (42). Power plant thermal efficiency is 38% for Cases A and B and 36.5% for Case C (dry-tower cooling) (35).

[e]Slurry pipelines are not included. In Case A, conversion water-consumption is $0.56\ m^3/10^9$ J of gas (at the plant). In C, it is $0.083\ m^3/10^9$ J. Case B assumes the mean of these two values. Other assumptions are the same as in Table 4 (high-Btu gasification).

[f]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 (Footnotes a and b of Table 4), cooling (1.0, 0.3, and $0.0097\ m^3/10^9$ Je for A, B, and C respectively) (Table 5 and Ref. 35), coal cleaning (0.012-$.062\ m^3/10^9$ Je in the East and none in the West (35), and air pollution control (0-$0.10\ m^3/10^9$ Je) (35) (all Je are electric joules at the power plant).

Scenario	Total annual U.S. coal consumption (10^{18} J/year)	Coal mining distribution[a]	Slurry pipeline[b] (10^{18} J/year)	Total annual U.S. coal conversion to synfuels[c] (10^{18} J synfuel/year)	Conversion distribution[d]
1	16	E	0	0	n.a.[e]
2	16	W	0	0	n.a.
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	n.a.
12	64	W	8	32	B

Table 7. Coal scenarios

[a]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% of the coal is Western and 25% is Eastern. Plan E assumes 25% is Western and 75% is Eastern. All the Western coal is surface mined, while Eastern coal is assumed to be half surface- and half deep-mined.

[b]"Slurry pipeline" refers to the use of Western water to transport coal away from Western mine sites.

[c]Total coal conversion produces 50% high Btu gas by energy content, and 50% liquid syncrude.

[d]In conversion distribution plan A, 50% of the conversion is in the East and 50% in the West. In plan B, 75% is in the East and 25% is in the West.

[e]not applicable

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

Table 8. Electric power plant cooling scenarios

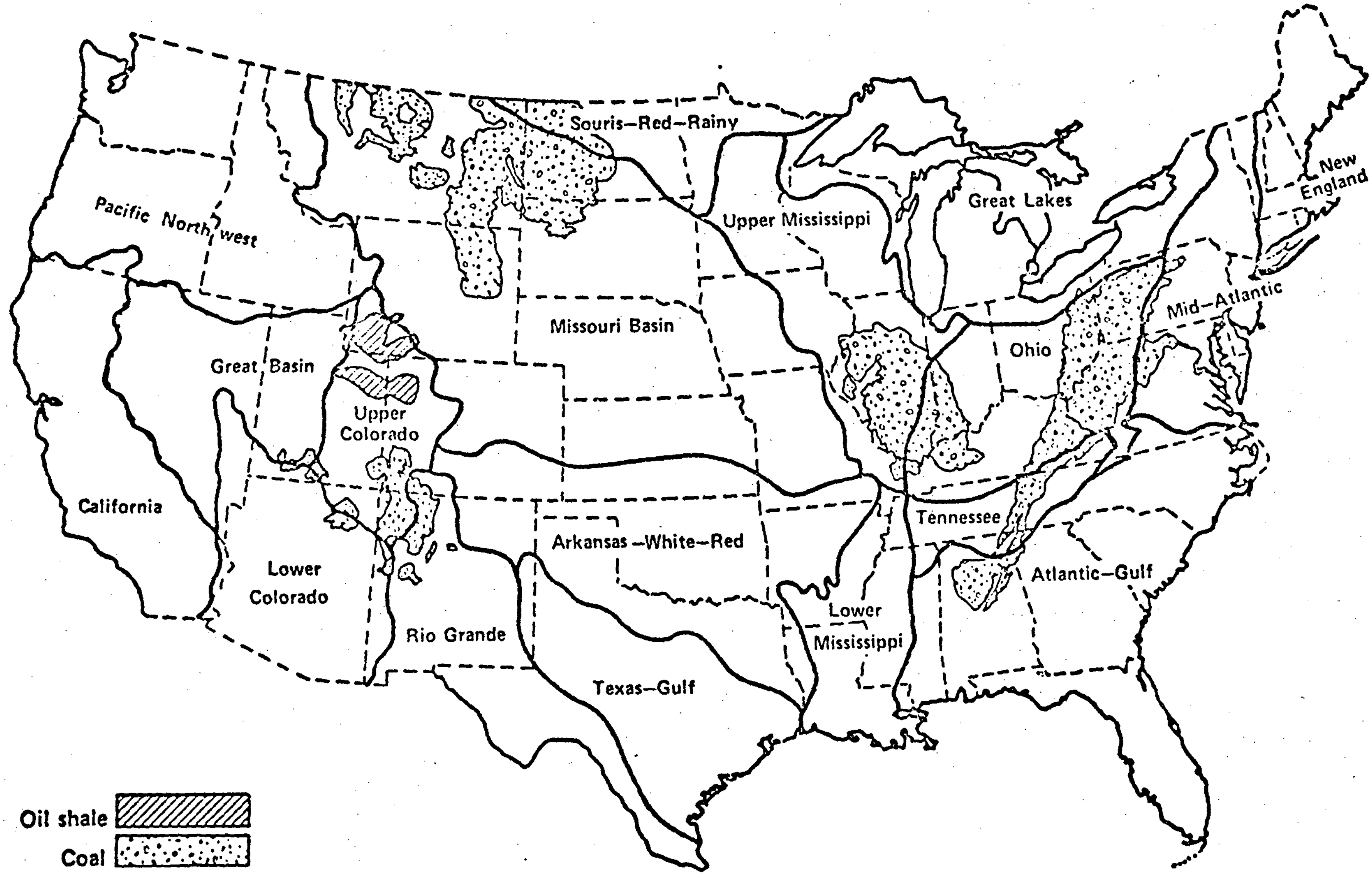
[a]Cooling mode A refers to the following mix of cooling methods: once-through cooling (no storage) - 25%; once-through cooling (storage) - 25%; wet cooling towers - 25%; seawater cooling - 25%, while in cooling mode B we assume: once-through cooling (no storage) - 15%; once-through cooling (storage)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

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

Table 9. Water consumption in coal scenarios. For meaning of East and West, see text. In 1975, total water consumption for all uses in the areas of the U.S. we have denoted by 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.

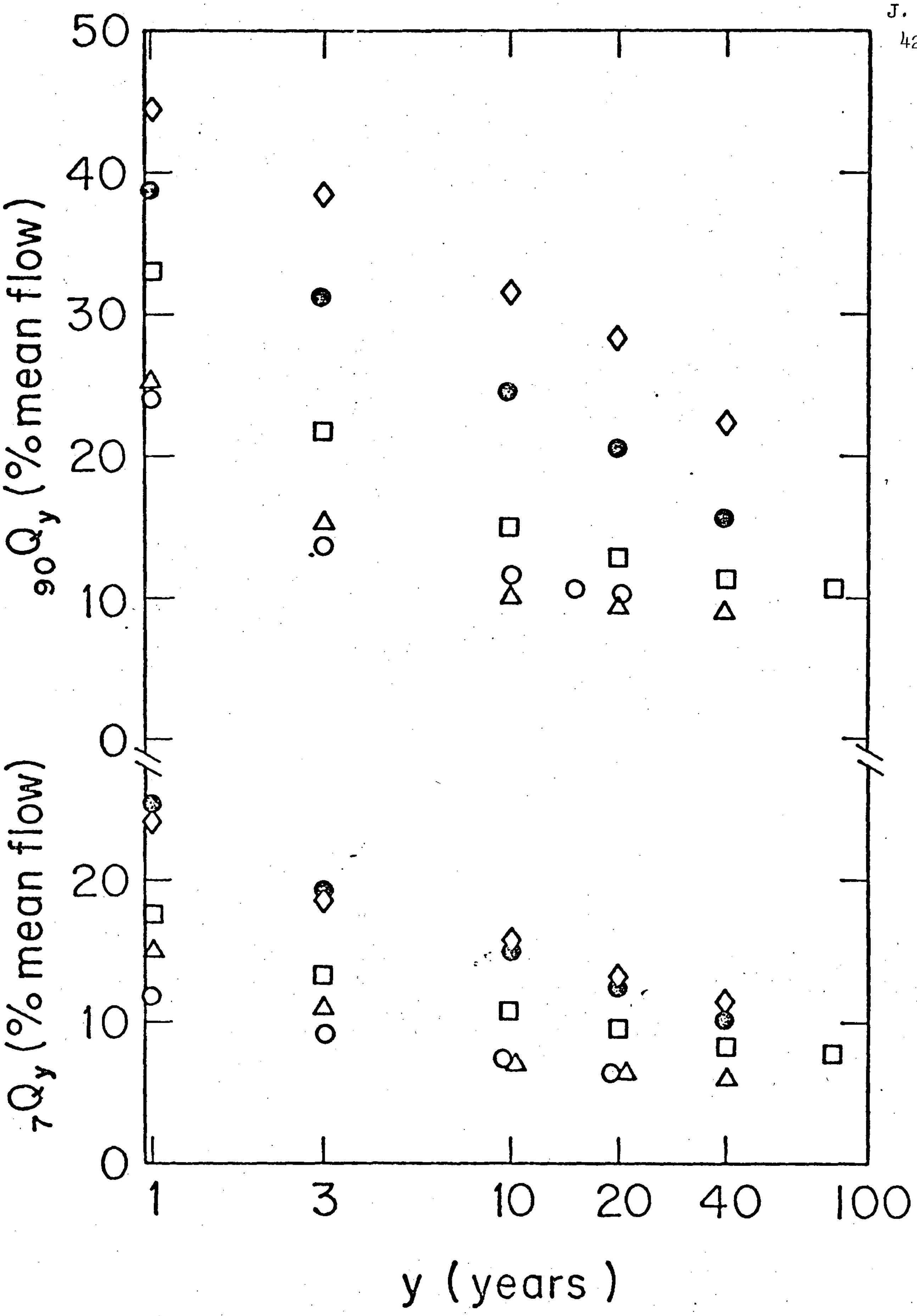
Region	1975 Freshwater consumption for electric power generation (Km^3)	Future freshwater consumption for electric power generation (Km^3/year) Scenario 1	2	3	4
New England	0.13	0.096 -0.32	0.029 -0.11	0.24 -0.80	0.072 -0.28
Mid Atlantic	0.19	0.34 -1.2	0.10 -0.38	0.85 -2.0	0.25 -0.95
South Atlantic Gulf	0.29	0.44 -1.5	0.13 -0.49	1.1 -3.8	0.33 -1.2
Great Lakes	0.072	0.58 -2.0	0.17 -0.66	1.5 -5.1*	0.43 -1.6
Ohio	0.39	0.98 -3.4	0.29 -1.1	2.5 -8.3	0.75 -2.8
Tennessee	0.081	C.20 - .68	0.062 -0.23	0.50 -1.7	0.16 -0.58
Upper Miss.	0.13	0.42 -1.4	0.13 -0.49	1.1 -3.6	0.33 -1.2
Lower Miss.	0.40	0.20 -0.68	0.062 -0.23	0.50 -1.7	0.16 -0.58
Souris-Red-Rainy	0.0017	0.0058-0.020	0.0017-0.0065	0.015- .049	0.0043-0.016
Missouri	0.094	0.19 -0.66	0.056 -0.22	0.48 -1.7	0.14 -0.55
Arkansas	0.13	0.24 -0.80	0.070 -0.27	0.60 -2.0	0.18 -0.68
Texas Gulf	0.52	0.40 -1.4	0.12 -0.46	1.9 -3.9*	0.30 -1.2
Rio Grande	0.028	0.042 -0.14	0.013 -0.048	0.11 -0.36*	0.033 -0.12
Upper Colo.	0.082	0.062 -0.20	0.018 -0.070	0.15 -0.50	0.045 -0.18
Lower Colo.	0.065	0.054 -0.18	0.016 -0.060	0.14 -0.46*	0.040 -0.15
Great Basin	0.0079	0.022 -0.072	0.0064-0.024	0.055-0.18	0.016 -0.060
Pac. N.W.	0.012	0.024 -0.080	0.0070-0.027	0.60 -0.20	0.018 -0.068
California	0.044	0.0096-0.032	0.0029-0.011	0.024-0.080	0.0073-0.028
U.S. (excl. Hawaii and Alaska)	2.6	4.5 -15	1.3 -4.9	11 -37	3.3 -12

Table 10. Freshwater consumption for electric powerplant cooling in several scenarios (see Table 8 for scenario specification). For explanation of asterisks and underlining, see text.



XBL 7710- 2072

Figure 1



XBL 7710-2073

Figure 2

Figure Captions

Figure 1. Map of the conterminous United States showing Water Resources Council regions and major coal and oil shale deposits, adapted from (10, 11, 12, 13).

Figure 2. Values of ${}_7Q_y$ and ${}_{90}Q_y$ for five rivers in the U.S. The rivers and the U.S.G.S. measuring station at which were taken the data from which these flows were calculated are: the Yellowstone River (◇) at Miles City, Montana; the Colorado (●), near Cisco, Utah; the Kanawha (□) at Kanawha Falls, W. Va.; the Wabash (△) at Mt. Carmel Ill.; and the Ohio (○) at Huntington W. Va. 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, 1930-1977; Colorado, 6.9 Km^3/year, 1924-1976; Kanawha, 11.2 Km^3/year, 1878-1976; Wabash, 24.1 Km^3/year, 1929-1976; and Ohio, 67.2 Km^3/year, 1933-1968 (15).

1. For an excellent 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, and R.H. Socolow, eds. (Ballinger, Cambridge, Mass., 1976) pp.163-215.

2. One m^3 is approximately 264 gallons; one acre-foot is approximately $1.23 \times 10^3\ m^3$.

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for supplying information on this subject.

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45. 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% of mean annual runoff, it is very roughly 50% of ${}_7Q_{10}$, and thus will generate significant effect on river flow during times of drought.

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