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Water Supply and Demand in an Energy Supply Model

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December 1980

U.S. Department of Energy
Assistant Secretary for Environment
Office of Environmental Assessments

Under Contract Number AC04-EV10180

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December 1980

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Prepared for
U.S. Department of Energy
Assistant Secretary for Environment
Office of Environmental Assessments
Washington, D.C. 20585

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Preface

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

Environmental factors are frequently omitted from energy supply models. Water availability, when assessed, is usually considered separately and qualitatively. This report describes the incorporation and use of water supply and demand alternatives in a linear programming model of energy supply. Energy policy analyses made with the model explicitly take into account the effects of derived water availability on the spatial distribution, the mix and level of activity, and the cost of energy conversion.

Frank H. Osterhoudt
Regional Impacts Division

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ABSTRACT

This report describes a tool for water and energy-related policy analysis, the development of a water supply and demand sector in a linear programming model of energy supply in the United States. The model allows adjustments in the input mix and plant siting in response to water scarcity. Thus, on the demand side energy conversion facilities can substitute more costly dry cooling systems for conventional evaporative systems. On the supply side groundwater and water purchased from irrigators are available as more costly alternatives to unappropriated surface water. Water supply data is developed for 30 regions in 10 Western states. Preliminary results for a 1990 energy demand scenario suggest that, at this level of spatial analysis, water availability plays a minor role in plant siting. Future policy applications of the modeling system are discussed including the evaluation of alternative patterns of synthetic fuels development.

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CONTENTS

I.	INTRODUCTION AND PURPOSE	1
II.	A REVIEW OF REPRESENTATIVE LITERATURE	3
III.	A FRAMEWORK FOR WATER ALLOCATION	7
	Limitations of The Supply Scheme	13
IV.	THE MODEL AND THE DATA	15
	The Los Alamos Coal Use Modeling System (LACUMS)	15
	The Water Demand Sector	16
	Electricity Generation	16
	Synthetic Fuels	18
	Water Use and Technology Cost Coefficients	21
	The Water Supply Sector	21
	Arizona	23
	Colorado	25
	Idaho	29
	Montana	30
	Nevada	33
	New Mexico	36
	North Dakota	37
	South Dakota	37
	Utah	38
	Wyoming	40
	The Cost of Water Use	43
V.	SUMMARY AND APPLICATIONS	44
	Summary	44
	Preliminary Results	45
	Water-Related Policy Applications	48
	REFERENCES	49

I. INTRODUCTION AND PURPOSE

This report describes the method and data used to develop a water supply and demand sector for an existing large scale linear programming model of coal and electricity supply. This is a useful exercise for several reasons.

First, since the establishment of the Federal Energy Administration, the Federal Government has relied at least partly on energy/economic models to formulate energy policy. Public and private environmental groups have decried the lack of environmental considerations in these models. Thus, this inclusion of environmental considerations in the form of a water use sector is an attempt to construct a more complete context for analysis of energy/economic development.

Second, integration of a water use sector with the overall decision-making apparatus is preferable to "ex post" water impact analysis of a particular energy development scenario or energy future. This is because the integration affords producers the opportunity to respond to changes in water supply conditions as they do to changes in the costs and supplies of other inputs.

Third, the construction of a water use sector is a response to a host of studies, articles in the popular press, and public pronouncements that essentially speculate about the effects of water availability on the potential for energy and economic development. Not surprisingly, those who ignore the opportunities for input substitution or changes in facility location as adjustments to water scarcity are quite pessimistic about the prospects for development. A prototypical example of this viewpoint is the following quote from Ellis (1966):

In the western United States, water may be a limiting factor of production. Through this limitation, the amount of income which an area or region can generate may also be restricted. As a result, the growth potential of the region may be limited as to the number of people within the region and their standard of living. Most of the country has an ample physical quantity of water, but the West is running short in terms of future growth. As this occurs, one or both of two things must result: population growth must cease, or the standard of living must go down. Since the arid west is experiencing this phenomenon more severely than other regions, one would expect that population growth would slow down or even reverse itself before living standards would fall.

Water is certainly a limiting factor of production. But it is also one of the most abundant resources. In many regions its intense use, especially for irrigation and power plant cooling, yields a marginal value less than

\$5/acre-foot (a-ft).^{*} In water scarce regions, however, by substitution of capital and energy, there are tremendous opportunities for conservation or development of lower quality supplies. Some common examples of these substitutions are construction of storage reservoirs, canal lining, sprinkle and drip irrigation systems, closed cycle cooling, treatment of brackish water or municipal wastewater, and pumping of groundwater. Whether these activities are economic depends on the comparative advantage a firm or region has for production of other resources. Just as the Rocky Mountain/Northern Great Plains Region offsets the disadvantage of distance from markets with rich resources of low sulfur, strippable coal, so it may offset the disadvantage of water scarcity

Along this vein, Abbey (1979a) wrote:

Technologies are available to virtually eliminate water consumption for electric power generation. ... Even the most costly water conservation option, dry cooling, which reduces water requirements to one or two thousand acre-feet/year/1000 MW, adds less than 6 or 7 percent to the cost of generation. The increment is much smaller in terms of the retail price of electricity. Considering that in most cases far less costly water supplies are available as alternatives to dry cooling, water availability can be assumed to have an insignificant effect on the price or a demand for electricity.

The application of economic principles to water and energy-related issues was a contribution, but in a sense Abbey fell prey to the same dogmatism of the pessimist camp. Because freshwater conservation is technologically feasible and adds a small increment to energy product costs, Abbey correctly asserts that water scarcity will not frustrate the dominant energy policy objective of reduced dependence on foreign oil. But that type of qualitative reasoning, even substantiated by cost and quantity data, does not necessarily answer such questions as:

- How does water scarcity influence the location and mix of energy conversion activities?
- How much water will the energy sector use in future years?
- Where are the likely sources of water supplies?
- What is the effect of water demand in the energy sector on other water users and in-stream resources?

^{*}In 1975, irrigation and self-supplied thermal electric power use accounted for over three quarters of total withdrawals in the US (Murray and Reeves, 1977).

- How does or how should public policy influence water use for energy production?

The answers to these sorts of questions depend not only on local or regional water supply conditions and the opportunity costs of water use but on macroeconomic conditions and national energy, environmental and agricultural policies.

The purpose of this research, then, is to develop a tool for quantitative analysis of energy and water-related policy issues. We hope to replace the dead-end jargon of energy/environmental assessment ("constraints" and "impacts") with projections based on empirical data and system theory. Thus, Part II presents a representative review of the literature related to water allocation in large scale energy models. Part III discusses a framework or model of water allocation applicable to the appropriation states (generally those in the Western US). Part IV describes the application of this framework to the Los Alamos Coal Use Modeling System (a mathematical programming model of energy supply in the United States). Part V presents model results for a 1990 energy demand scenario and discusses policy applications of the modeling system.

II. A REPRESENTATIVE LITERATURE REVIEW*

Generally, one can identify three kinds of approaches to location of energy facilities. The first category entails informal evaluation and weighting of a number of factors (fuel, water, labor availability, and so forth) which bear on facility location. Utilities typically employ this type of analysis for preliminary site screening (see for example NUS Corp., 1974).

The second category is distinguished from the first by a much larger overall scale of analysis and by "ex post" impact analysis. One could say that this analysis is typically comprehensive but not typically integrated.** First, formal models of energy demand and supply are used to produce regionalized forecasts. Then these forecasts are further disaggregated to more localized levels (e.g., counties or BEA's) which become the spatial unit for location and impact analysis. Further regionalization might be based largely on qualitative impact assessment or quantitative analysis.

*For more extensive reviews see Buras (1979) and Cohen and Costello (1975.)

**Due to a lack of an overall integrating framework or objective function, these methods are in principle not capable of integration.

Examples of this approach abound in the numerous assessments of energy futures conducted by the Energy Research and Development Administration (ERDA) and the Department of Energy (DOE). The following quotation from the Executive Summary of the National Coal Utilization Assessment (US DOE, 1979) succinctly illustrates this characteristic approach to the analysis of water use.

Rates of water withdrawal and consumption for energy have been determined for each ASA using the load factors and unit water requirements shown in Table 8-1. Data for all other uses have been obtained from the Water Resources Council (WRC). Water availability for all uses, including instream flow, is based on the flow that will be exceeded 95% of the time in each critical month and adjusted to reflect the effects of surface water storage. Problem areas are identified wherever it is determined that the water demand for energy uses contributes significantly to total consumptive use in reducing these critical flow rates.

Reference to Table 8-1 indicates that there was some consideration given to alternative cooling technologies. But it is not clear if or how the availability of these technologies affected the conclusion that, "Energy development will face siting constraints and conflicts between users in numerous basins, but water supply problems will not dictate major modifications of the NEP (National Energy Plan)." (US DOE, 1979). For our purposes it is most important to note that the substitution possibilities for water use are not clearly specified and that streamflows are the only source of water supply.

A quantitative example in the same general class is the Oak Ridge National Laboratory Spatial Analysis Model called ORSAM (Honea, Hillsman, and Mader, 1979). This model employs a set of suitability criteria with numerical indices ranging from 1 to 10 for each criterion. A weighting scheme for each is then used to sum over the criteria and arrive at an overall suitability index for each potential plant site (county). A priori, many Western counties are excluded from consideration by the water availability criterion.

Multiobjective programming approaches employed by several authors are hybrids, having characteristics in common with both our second and third classes (see for example, Brill and others (1977), Church and Cohon (1976), Cohen and Marks (1975), and David and Duckstein (1976)). Accordingly we set these off in a category by themselves. The multiobjective approach has achieved a fairly high state of development and application largely in the water resource area.

The final category represents models with a formal mathematical structure driven by economic forces. One could say that this analysis is not typically comprehensive but is integrated.* For the most part these are spatial economic equilibrium models which minimize cost or maximize some form of quasi-welfare function. Buras (1979) distinguishes these models as regional and regionalized. These models have the same type of hierarchical structures as implied by the names, but only the regionalized models explicitly express this structure. Regional models are those which encompass a portion of a geographical entity, while regionalized models deal with the whole entity. Buras reviews a subset of these models (Battelle, ICF, Gulf-SRI, Bechtel Brookhaven, ETA-Macro and the Upper Colorado River Basin (UCRB) Model). Other models include those by Uri, Le Blanc, et. al., Muller, Schlottman, RFF/SEAS, and the Argonne Coal Model (ACM). The following more detailed review is restricted to examples of integrated (regionalized) models. The water use sector described below is structured for an integrated model.

The model by Le Blanc et. al. (1978) is a regionalized national model with 33 coal supply and 44 coal demand regions. Coal is classified by sulfur and Btu content for deep and surface reserves. The model is "quasi-dynamic" in that it allows for recursive solution through time. The purpose for integrating this somewhat unique feature was to permit the representation of a long-term contract coal market and a spot market in the same model. The Le Blanc model contains a point source sulfur emission constraint but does not contain water supply or demand components.

The Argonne Coal Model (Dux, et. al., 1978) employs a quadratic programming approach in order to accommodate differentiable coal supply functions. This was done to overcome alleged theoretical and computational shortcomings of the step function supply curve approach used by the National Coal Model and ICF. In other respects the ACM is similar to many energy-environment models in that the coal allocation system is represented as a network of supply and demand nodes. Coal supply regions are defined so that the coal in each region is reasonably homogeneous. Unlike some linear programming (LP) energy models, coal demand is determined exogenously and the model solves the allocation

*The economic equilibrium methods do not in principle lack comprehensiveness. As a practical matter, it is difficult to express some location considerations in the metric of the model.

problem. The model considers the air quality implications of a particular coal demand scenario but does not examine water supply and demand.

The RFF/SEAS model (Ridker, Watson, and Shapanka, 1977) is used primarily to forecast energy use, residuals output, and abatement costs. The core of the SEAS model is an input-output model of 185 sectors making up the US economy. The RFF modifications to this basic structure include components with physical and monetary variables associated with energy, non-fuel minerals, transportation and the environment at both the regional and national levels. The model is non-autonomous in that it allows the sector coefficients to change over time in response to changes in technology, tastes, relative prices and supply constraints. Water supply and demand are not specifically addressed.

Uri (1975) has developed a spatial equilibrium model for electrical energy supply similar to other models of this general type. Regions (consuming sectors) are designated along with technologies for generating electrical energy. Demand for electricity is exogenously specified for each demand region. There are the usual material balance constraints which restrict the maximization of a net benefit function. One interesting twist introduced by Uri is the specification of net benefits as the maximand. To calculate gross benefits, Uri specifies regional demand prices as linear functions of regional consuming sector demand quantities. Uri concerns himself with strictly economic issues and has no environmental constraints in the model.

In contrast to Uri, Schlottman (1976) focuses mainly on air quality aspects in his model. The Schlottman model uses a linear programming format to examine the effects of air quality standards on the quantities of various types of coal which are produced and shipped. Schlottman examines the effects of flue gas desulfurization (FGD) by altering the objective function to include the added capital and operating cost of this activity. The model also contains a point source emission constraint for each region. Analysis of water supply and demand is not included.

This brief review has focused principally on regionalized models. There are several regional models which present significant contributions to the integration of water supply and demand into an LP framework.

The Brookhaven Energy Facility Siting model is a regional LP model employing a water availability constraint. The constraint is structured such

that water supply consists of consumptive use, reservoir releases, and the net of imports from and exports to other basins. The constraint also incorporates a cost penalty for dry cooling and a cost to be attached to new reservoir capacity. The work of Brookhaven as represented in the Energy Facility Siting Model, was apparently based on a version of the RELM model (a multi-objective, mixed integer LP).

By consideration of the models reviewed by Buras and herein, it appears that, while most models could incorporate water supply and demand sectors, no regionalized models extend the economic description of transportation and production to water resources allocation and use. Some of the water resources literature suggests that this is a significant oversight, especially with respect to the potential scale of energy development in the semi-arid Western states.

III. A FRAMEWORK FOR WATER ALLOCATION

In the United States there are two principal legal systems for the allocation of water resources, the appropriation and riparian systems. Under the riparian system one acquires the right to use water by acquiring land adjacent to streams. While there are vague restrictions concerning the reasonable use of water, all riparian landowners have coequal rights to use water in the stream. This legal system works as long as the supply exceeds the demand, that is, as long as water is a free good.

Under the appropriation system one obtains the right to use water by diverting it and applying it to a beneficial use. The date of the initial diversion establishes a priority of use during periods of shortages. One may change the point of diversion or the type of use or sell an appropriation right subject to a variety of restrictions, the most important being that the change or transfer will not impair the rights of third parties. In very broad terms the appropriation system establishes property rights to water resources and is conducive to market-oriented analyses. Happily, the energy-rich Western states allocate water resources predominantly by the appropriation doctrine.

The approach we take to modelling water allocation in the appropriation states is to focus on the supply and demand for water in the energy sector alone. As discussed in detail in Part IV, the demand for water in the energy sector is quite straightforward. The demand to use water depends on the

opportunity cost of water conservation. Under the reasonable assumption that energy conversion facilities in the semi-arid West are subject to a zero-discharge constraint (that is water withdrawal equals consumption), the principal avenue for water conservation is substitution of dry (air) cooling for evaporative (wet) cooling. One can easily construct a demand function based on discrete cooling options offering reduced water consumption at rising incremental costs.

The representation of water supply to the energy sector is potentially quite complex. The supply function should include a) quantities and development costs of unappropriated water resources and b) the quantity of water in existing uses and the opportunity cost of foregoing these uses and transferring water rights to the energy sector. Estimation of the supply or availability of unappropriated water should spring from a physical description of the water resource base. The hydrologic analysis requires information concerning a) the probabilistic distribution of flow along a stream as a function of time b) the quantity of water in storage in underground reservoirs (aquifers), and c) the rate of flow or transmissivity through the aquifers. One then derives engineering-based estimates of the cost of producing firm annual increments to water supply by construction of wellfields, dams, and storage reservoirs. Finally, one qualifies the hydrologic/economic analysis with reference to legal and institutional constraints to development such as compacts allocating streamflows among states, federal funding for storage projects, state statutes prohibiting groundwater mining, instream flow reservations, and so forth.

The task of estimating the supply and cost of water from existing users is no less formidable. There is some current market price data available (for transfers of water rights from irrigation to industrial use). But given the rudimentary nature of the market for water (especially legal restrictions and imperfect information), these prices do not necessarily reflect the true scarcity value of water. Moreover, present market conditions are likely to change with population growth, the demand for agricultural products, and so forth. In principle, then, it is necessary to derive the opportunity cost of water use in non-energy sectors from an equilibrium analysis that includes the water demands of other sectors and the physical supplies available.

Comprehensive hydrologic/economic analyses of water allocation have been conducted for some subbasins and basins in the West (see for example Bennett,

1979, Boris and Krutilla, 1980, and Morris, 1978). These studies do greater justice to hydrologic conditions at the expense of economic analysis, or vice versa. But to our knowledge, no one has performed such an analysis for the multi-basin region spanning the Rocky Mountains and the Northern Great Plains (or any other region of that size). By making a number of simplifying and conservative assumptions, however, one may actually derive a water supply function to the energy sector in this region.

A preliminary consideration is the level of spatial analysis. We develop water supply data for 30 regions in 10 states in the Rocky Mountain/Northern Great Plains Region. Generally, these 30 regions conform to the boundaries of surface water subbasins. While state borders define portions of the boundaries of these regions, this is acceptable because a) compacts often govern the allocation of interstate streams, and b) water supply data is available by state and subbasin. Given the zealous protection of local water supplies in the West, we preclude the possibility of interregional transfers.

To indicate the water development potential to the energy sector in each region, it is useful to distinguish between surface and groundwater resources. To estimate surface water supply, we simply identify discrete quantities of surface water that are earmarked to the energy sector. Generally these are either allocations to the municipal and industrial sector from US Water and Power Resources Service (formerly the Bureau of Reclamation) storage projects or conditional appropriations (permits) with a good priority date held by energy firms.

Our approach to groundwater supply is to exclude from consideration alluvial and shallow aquifers and other aquifers with a significant level of present use. This forces the energy sector to develop deep, consolidated rock aquifers at higher exploration, drilling, and pumping costs. This approach is reasonable because: most groundwater users, especially irrigators, cannot afford pumping costs at lifts much greater than 500 feet; by developing deep aquifers, energy firms avoid or lessen well interference with prior appropriators; and consolidated rock aquifers are far less permeable than alluvial aquifers, so pumping has a smaller effect on discharge from aquifers to streams.

To estimate the supply of water from existing users to the energy sector, for two reasons we focus exclusively on irrigated agriculture. First, as shown in Table 1, irrigation accounted for over 90% of freshwater consumption

TABLE 1
FRESHWATER CONSUMPTION IN TEN WESTERN STATES IN 1975
(10⁶ gal/d)

	<u>Irrigation</u>	<u>Public Supplies</u>	<u>Rural Use (Domestic and Livestock)</u>	<u>Self- Supplied Industrial</u>	<u>Thermo- Electric Power</u>
Arizona	5,400	200	66	210	41
Colorado	5,100	110	37	59	12
Idaho	4,700	34	27	160	2
Montana	2,700	49	55	12	nil
North Dakota	150	29	36	24	19
Nevada	1,500	52	14	71	22
New Mexico	1,400	83	56	85	33
South Dakota	180	14	100	6	3
Utah	2,200	130	14	51	8
Wyoming	<u>2,000</u>	<u>46</u>	<u>26</u>	<u>34</u>	<u>24</u>
	25,330	747	431	712	164
Percent of Total Use	92.5	2.7	1.6	2.6	0.6

Reference: C. Richard Murray and E. Bodette Reeves, 1977. "Estimated Water Use in the United States in 1975," Geological Survey Circular 765, USGS, Arlington, Va.

in 10 states in the Rocky Mountain/Northern Great Plains Region in 1975. Second, relative to many municipal and industrial uses water use in irrigation has a very small marginal value product. Using activity analysis models, a number of studies estimate the effect of reduced water allocation on farm income. Table 2, for example, shows the marginal value of water use in irrigation in the Estancia Closed Basin of New Mexico. Similar results were obtained for the Four Corners Region (Gisser and others, 1979) and the Green and Upper Yellowstone River Basins (Gollehon, 1980).

There has been much discussion of legal and institutional constraints on water reallocation. As extreme examples, South Dakota declares that irrigation water rights are appurtenant to the land and may not be severed

TABLE 2

MARGINAL VALUE OF WATER DIVERTED FROM IRRIGATION IN THE
ESTANCIA BASIN AT SELECTED LEVELS OF WATER REDUCTION

<u>Percent Reduction</u>	<u>Marginal Value of Diverted Water</u>	
	<u>(\$/a-ft)</u>	<u>(\$/1,000 gals.)</u>
15	0.53	0.002
20	17.43	0.053
25	27.81	0.085
30	28.79	0.088
35	43.93	0.135
40	57.89	0.178

Source: Adapted from Cummings, R. and M. Gisser, 1977. "Reduction of Water Allocations to Irrigated Agriculture in the Estancia Basin with Implications for New Mexico: Impacts and Technological Change," Univ. of New Mexico, Dept. of Resource Economics Working Paper No. 8, Albuquerque (January) p. 91.

unless irrigation becomes economically infeasible; North Dakota ranks industrial water use below agricultural use in priority and prohibits transfers from "superior" to "inferior" uses. In other states one finds statutes that attach an upper limit to the quantity of water that may be transferred to an industrial user (Montana), that require legislative approval of transfers to an electric utility (Arizona), that allow the State Engineer to reject transfers to utilities which export electricity (Nevada), and so forth. Even in states such as Utah or New Mexico, whose statutes facilitate the role of the market, uncertainty inhibits the reallocation of water resources. Irrigation water rights typically state a diversion point, a flow rate (ft^3/s), and a date. Often it is difficult to determine the quantity of water that is available for consumption upon changing the point of diversion and type of use.

These sorts of constraints increase the cost of water transfers to the energy sector, but they do not foreclose this water supply option. Table 3 presents evidence that transfers to the energy sector are a fact of life. Thus, except for North Dakota and South Dakota, we set the quantity of water available from irrigators at the level of annual consumption during the period 1970-1978. (The selection of the year depends on the availability of data.)

With respect to the cost of water acquisition for these supply categories, we set unappropriated surface water at \$20/a-ft, ($\$0.07/10^3$ gal), a standard water service cost to industrial users from storage reservoirs

TABLE 3

**TRANSFERS OF WATER RIGHTS TO ENERGY FIRMS
IN THE INTERMOUNTAIN WEST**

<u>To</u>	<u>From</u>	<u>Quantity (for consump- tive use) (a-ft/yr)</u>
<u>Colorado River Basin</u>		
Utah Power and Light Company (for Hunt- ington and Emery Plants, Emery County, Utah)	Cottonwood Creek Consolidated Irrigated Company	5,000
	Ferron Creek Irrigation Co.	7,000
	Emery County Water Conserva- tion District (under con- tract from the Bureau of Reclamation)	6,000
San Diego Gas & Electric (Sundesert Plant, Blythe, California)	Metropolitan Water District	17,000
	Water rights obtained from purchase of 7,700 acres ranchland in Palo Verde Irrigation District	33,000
Nevada Power Company (for Reid Cardner, Moapa, Nevada)	Purchase of a ranch and leasing winter agricultural water	3,500
Nevada Power Company ^a (500 MW Warner Valley Plant, St. George, Utah)	Washington County Conservancy District	10,000
Nevada Power Co. (2000 MW at Las Vegas)	Las Vegas and Clark County Sanitary Districts	43,764 (Sewage treat- ment plant effluent)
Arizona Electric Power Cooperative (350 MW at Benson, Arizona)	Purchase of 1500 acres of farm- land in Sulfur Springs Valley	7,000 (from wells)
Arizona Public Service Co. (4000 MW Nuclear plant at Wintersburg, Az.)	City of Phoenix	64,000 (Sewage treatment plant effluent)
<u>Great Basin</u>		
Intermountain Power Project (3,000 MW at Lyndyll, Utah)	Shares in the Delta, Melville, Abraham, and Deseret Irrigation Cos. and the Central Utah Canal Co.	45,000
<u>Arkansas Basin</u>		
Public Service Co. of ^b Colorado (1000 MW near Las Animas, Co.)	Las Animas Consolidated and Consolidated Extension Canal Cos.	8,000- 10,000
Platte River Power Authority (230 MW near Ft. Collins)	City of Ft. Collins and Water Supply and Storage Co. (a mutual ditch company)	4,200
<u>Platte River Basin</u>		
Missouri Basin Power Project (1500 MW at Wheatlands, Wyo.)	Boughton Ditch, irrigated land in undated by reservoir, and groundwater from Johnson Ranch	6,000
Panhandle Eastern Pipe- line Co. (for coal gas plant near Douglas, Wyo.)	Douglas Reservoir Water Users Association (by financing repairs on a dam on La Prele Creek)	5,000

^aIn negotiation.^bOption agreement.

of the US Water and Power Resources Service. Conservatively, we estimate the price of acquiring irrigation water rights at \$1,750/a-ft.* This is the highest price (that we are aware of) paid by an energy firm to an irrigator. We convert the cost of this property right to an annual or unit cost using a fixed charge rate of 11%. This unit cost, \$192.50/a-ft ($\$0.59/10^3$ gal), is substantially greater than the marginal value of water irrigators. Well or pumping costs vary greatly. Drilling costs, for example, depend not only on the depth to water, but the type of rock above the aquifer. To achieve a given production rate, the number of wells necessary depends on the yield of each well. Well yield depends on the hydraulic gradient, the transmissivity, and storage capacity of the rock. We arbitrarily set well head costs at 10 percent greater than the cost of water purchased from irrigators.

In addition to water acquisition costs, water use costs include transportation, storage, treatment, and disposal costs. The costs of water treatment and disposal, which depend on the quality of intake water, may be substantial. An engineering economic analysis of the use of irrigation return flows for power plant cooling, for example, estimated treatment costs of $\$0.34/10^3$ gal ($\$110/a-ft$) in 1976 dollars assuming treatment of 11.5 million gal/day and average total dissolved solids concentrations of 4,319 mg/m³ (the State of California and others, 1978). However, we do not differentiate water supplies by water quality and cannot account for cost differentials attributable to variations in water quality.

Transportation costs may be even greater than treatment costs. Transportation costs depend on a number of factors--pipeline distance, pipeline diameter, flow rate, static head (lift), and so forth. Table 4 illustrates the range of variation in conveyance cost estimates for individual plant sites. Though these costs would decline dramatically for pumping at greater flow rates, again the important point is that a full accounting of conveyance cost differentials practically requires site specific analyses. We set the sum of these water use costs at \$250/a-ft ($\$0.77/10^3$ gal).

Limitations

The principal limitations of the water supply scheme relate to the cost specifications. First, since we distinguish water use costs solely by the

*This price reflects the industrial consumption right, not the irrigation diversion right.

TABLE 4

WATER CONVEYANCE COST ESTIMATES FOR PLANT
SITES IN THE WEST
(for flow rates of 2.4-7.0 million gal/d)

<u>Plant Location</u>	<u>Water Source</u>	<u>Distance (miles)</u>	<u>Static Head (feet)</u>	<u>\$/10³ gal</u>	<u>\$/a-ft</u>
Decker Cr., Mt.	North State Line Reservoir	1	50	0.03	8
Lake-de-Smet, Wyo.	Lake-de-Smet	5	200	0.12	39
Williston, ND	Lake Sakakawea	8	250	0.16	53
Hanna, Wyo.	Seminole Reservoir	20	100	0.43	140
Wesco, NM	San Juan River	30	400	0.66	213
Dickinson, ND	Mott Reservoir	50	100	1.29	420

Reference: Harris Gold and David Goldstein, 1978. "Water Related Environmental Effects in Fuel Conversion," prepared for US Dept. of Energy, Wash., DC, Appendix Volume II, pp. 648-649.

acquisition cost of water, the energy sector will first exhaust all the surface water available, then purchase all the water consumed in irrigation, and, only then, tap groundwater resources. Thus, the model results are likely to underestimate the use of water supply alternatives and water conservation with dry cooling technologies. Second, rather than casting water acquisition costs in an economic equilibrium framework, we employ a "ceteris paribus" assumption and rely on current, observed market prices. These deficiencies are correctable by much more intensive collection of hydrologic and economic data and perhaps by revision of the water allocation framework. Whether such efforts are useful depends on the degree to which water supplies are a binding constraint on energy plant siting and the sensitivity of model results to water cost variations.

Some may argue that the level of spatial aggregation is an additional limitation of the water supply framework. That depends on the questions at hand. We intend the Los Alamos Coal Use Modeling System to aid the formulation of national energy and environmental policies—for example, the choice of alternative synthetic fuel research and development strategies or

the regulation of thermal discharges from electric plants. From a national policy perspective it doesn't matter whether a facility is built near Vernal or Bonanza, Utah. Of course, it may matter a great deal to the residents of Vernal and Bonanza, to endangered species such as the Colorado squawfish, and to state and local officials. But then in the latter cases an entirely different method of analysis is probably appropriate.

IV. THE MODEL AND THE DATA

The Los Alamos Coal Use Modeling System (LACUMS)

LACUMS is a spatially disaggregated, partial competitive equilibrium model of the transshipment type for the coal supply, electricity generation, and synthetic fuel production sectors. Given exogenous demand for electricity and non-utility coal, the model determines the competitive equilibrium locations and levels of coal production, electricity generation, and transmission/shipment of electricity/coal. The scope of the model is national but three types of regions comprise the core of the model. In 49 states there are 30 coal supply regions, 65 coal demand (electricity supply) regions, and 39 electricity demand regions.

The model contains upward sloping coal supply curves for each of 40 different coal categories. Heating value and sulfur content define these categories. Coal demand regions are fairly aggregate with the exception of the Rocky Mountain/Northern Great Plains Region where states are disaggregated by consideration of air sheds and stream basins (see Fig. 1, p. 22). Coal use translates into vectors of water use and SO_2 emissions by coal demand region. A linear transfer function converts SO_2 emissions into a vector of ambient SO_2 concentrations based on a series of assumptions regarding regional meteorological conditions as well as other assumptions. Thus, environmental considerations (water and air) are a principal focus of LACUMS. Given 1990 electricity demand computed econometrically by a state-level model and 1990 non-utility coal consumption computed by extrapolating 1975 consumption at the rate of 2 percent per year, the model optimizes the location of energy processing activities.

In the remainder of this report we discuss the form of the water supply and demand sectors in the model and the derivation of the water use data. For descriptions of the modeling system refer to Kolstad (1980), Kolstad and others (1979), and Bivins and others (1979).

The Water Demand Sector

In LACUMS water consumption is embedded in the conversion technology mix by fuel type and by cooling technology. We include water consumption data for coal and nuclear electricity generation, coal liquefaction by the Synthoil process, coal gasification by the Lurgi process, and shale oil production by the TOSCO II process.

The principal avenues for water conservation at energy conversion plants are a) substitution of dry for wet cooling, b) process water recirculation, and c) treatment and reuse of wastewater. Extensive, if not exhaustive, process water recirculation and wastewater treatment are standard practice for energy plants in the West. This is because (1) the Clean Water Act effectively mandates containment of liquid effluent in semi-arid regions, and (2) the costs of recirculation and reuse generally compare favorably with the cost of land disposal (wastewater evaporation) and other water use costs (acquisition costs, transportation and treatment costs) (Abbey, and Lucero, forthcoming). Thus, one may estimate water consumption by examining water use for cooling (waste heat rejection). Other water uses such as flue gas desulfurization (FGD), solid waste disposal, boiler makeup and process water (as a source of hydrogen for synthetic fuels) are taken as insensitive to the cost and availability of water.*

Electricity Generation. The engineering economics of electric plant cooling systems have been described in detail (see for example Tokarz and others, 1978, and Hu and Engleson, 1977). The standard description of cooling alternatives is in terms of water consumption of a dry or wet/dry cooling system relative to an all-wet or evaporative cooling system. Thus, a 40% wet cooling system is a configuration of wet and dry cooling towers or cells designed to use, on an annual average, 40% of the water used for an all-wet cooling system. Evaluation of cooling alternatives is necessarily site-specific; water consumption and cooling costs are greater in hotter, dryer regions. However, the variation is less than 10-15% (Hu, Pavlenko, and

*This is not to say that water consumption for these other uses is fixed; rather that such parameters as fuel quality, intake water quality, and process type are more important determinants of water use than the cost of water. In any case, water consumption for these other uses is small compared to cooling water consumption.

Engleson, 1978). Accordingly, we generalize cost and quantity data from a site-specific estimate.

Table 5 presents estimates of total water use for three cooling alternatives at a coal-fired and a nuclear electric plant. Although possible combinations of wet/dry cooling vary continuously, these three discrete options illustrate the range of substitution possibilities. Coefficients for 2% wet and all-dry cooling are not reported because of the substantial cost

Table 5

WATER CONSUMPTION AND INCREMENTAL COSTS
FOR 1000 MW COAL-FIRED AND NUCLEAR ELECTRIC PLANTS:
THREE COOLING ALTERNATIVES

	<u>100% wet</u>	<u>40% wet/60% dry</u>	<u>10% wet/90% dry</u>
Coal Electric (65% Capacity Factor)			
a-ft/yr ^a	9,750	5,000	2,500
mills/Kwh	--	+0.85	+1.2
\$/Kw	--	+14	+22
Nuclear Electric (57% Capacity Factor)			
a-ft/yr ^b	10,700	4,300	1,100
mills/Kwh	--	+1.28	1.5
\$/Kw	--	+21	+33

^aEstimate for Farmington, NM assumes flue gas desulfurization, use of reverse osmosis and brine concentration units to evaporate and recover wastewater, and excludes reservoir losses.

^bAssumes waste heat load to steam condensers 50% greater than at coal electric plant.

References: M. C. Hu, et al., 1978. "Water Consumption and Costs for Various Steam Electric Power Plant Cooling Systems, EPA-600/7-78-157, pp. 29, 48, 50, 51; David Abbey, 1979. "Water Supply/Demand Alternatives for Electric Generation in the Colorado Basin," Los Alamos Scientific Laboratory, LA-7662-MS, p. 4. \$1978 deflated to \$1975 using Table 62S, Statistical Year Book, Edison Electric Institute.

penalty for small water savings. For example, the marginal cost of water conservation for all-dry cooling (when compared to 2% wet cooling) is about \$5,000/a-ft.

A number of assumptions apply to the estimates shown in Table 5. The coal plant data apply to conditions at Farmington, New Mexico and assume use of a lime or limestone wet scrubber for FGD and the best available intake water and wastewater treatment technology. The nuclear plant data assume a condenser heat rate (Btu to the condenser/net Kwh output) 50% greater than that for the coal plant. This is because nuclear plants have a lower thermal efficiency and reject almost the entire waste heat load to the condenser. (At a coal-fired electric plant about 15% of the waste heat dissipates to the atmosphere in the flue gas.) We also assume that cooling is the only consumptive water use at a nuclear plant. Hence, quantity and incremental cost data are calculated as a proportion of cooling water consumption and incremental cost for the coal plant. Capacity factors for the electricity generating technologies are an exogenous input to the model. The water consumption rates are calculated for these capacity factors. The incremental costs of water conservation for wet/dry cooling represent the sum of operating and maintenance costs (including an energy penalty) and annualized capital costs (including a penalty charge for backup electricity generating capacity).

Synthetic Fuels. As with electricity generation, there is considerable information concerning the engineering economics of water use for synthetic fuels production (see especially Probststein and Gold, 1978 and Gold and Goldstein, 1978). Water consumption and especially cost estimates however, exhibit a greater range of uncertainty due to a) the host of process and product alternatives, and b) limited operating experience.

Nevertheless, on a Btu basis, water use for synthetic fuels production is likely to be less than for conventional electricity generation. This is for two reasons, both related to waste heat rejection. First, synthetic fuel conversion efficiencies are in the range of 55-80% versus 30-35% for electric plants. Thus, the waste heat load is much smaller. Second, the waste heat occurs at a variety of temperatures higher and lower than that typical of steam turbine condensers at electric plants (100-130° F). Since the capital and energy cost penalties of dry cooling vary inversely with temperature, dry cooling is economic for some high temperature waste heat loads, even where

abundant, inexpensive water supplies are available. Process water requirements do not offset these advantages.*

In Table 6 we present water quantity and incremental cost estimates for high-Btu coal gasification by the Lurgi process and coal liquifaction by the Synthoil process. The Lurgi process is unusual among most coal gasification

TABLE 6
WATER USE FOR COAL GASIFICATION AND LIQUEFACTION

Coal Gasification, Lurgi Process: 125×10^6 ft³/avg. day, 10^3 Btu/ft³ (137.5 MMcfd plant at 91% cf) (applicable only on non-caking, primarily Western, coals).

	<u>36% wet^a</u>	<u>18% wet</u>	<u>15% wet</u>
Lignite (a-ft/yr)	2,950	1,700	1,400
Subbituminous (a-ft/yr)	3,700	2,600	2,450
Bituminous	3,800	2,800	2,600
Incremental product cost (percent)	—	+0.5	+1.0

Coal Liquifaction, Synthoil Process: 50,000 bbl/d, 17,600 Btu/lb., 350 lbs./bbl; 3.1×10^{11} Btu/d.

	<u>49% wet</u>	<u>30% wet</u>	<u>27% wet</u>
a-ft/yr	6,600	4,850	4,500
Incremental product cost (percent) ^b	—	+0.5	+1.0

^aRefers to percent of unrecovered heat load dissipated to wet coolers. At least 25% of the unrecovered heat dissipates directly to the atmosphere (in hot ash, flue gas, etc.). At least another 25% of the unrecovered heat load is at relatively high temperatures (>140°F) for which dry cooling is economical. Assumes extensive wastewater treatment and recirculation.

^bNo data was available to the authors concerning incremental costs of water conservation for coal liquefaction. We simply applied the same incremental costs for gasification to liquefaction.

Reference: Gold and Goldstein, 1978. "Water Related Environmental Effects in Fuel Conversion," prepared for U.S. Department of Energy, Washington, DC, project officer, John Nardella, Vol. 1, pp. 188, 218-221.

*Water is a feedstock, a source of hydrogen for fuel conversion. In Western coal, for example, the ratio of carbon to hydrogen is about 4:3 compared to 1:4 in methane or high-Btu gas.

processes in that it accepts a raw (as opposed to a dry) coal feed. The moisture in the coal vaporizes in the gasifier and, while produced as a foul effluent, reduces net process water consumption (assuming extensive wastewater treatment). Thus, Table 6 differentiates water consumption for the Lurgi process by coal rank with rank serving as a proxy for variation in moisture content. Despite the advantage of Lurgi with respect to process water consumption, second generation coal gasification processes use slightly less water because of their higher energy conversion efficiencies (hence, lower solid waste and heat disposal requirements). Very generally, water use for the Synthoil process can be taken as representative of other coal liquefaction alternatives except for the Fischer-Tropsch process. Fischer-Tropsch has a significantly greater process water (hydrogen) requirement and cooling load (because of its relatively low thermal efficiency).

The principal limitation of the data in Table 6 is the assumption that foul effluents are treated for reuse and the exclusion of water treatment costs from the analysis of cooling alternatives. Water treatment for the Lurgi process, for example, adds up to 5% to energy product cost. Cooling tower evaporation might substitute for wastewater treatment for the concentration and disposal of process effluent and provide a credit against water treatment costs. The fact that two Lurgi coal gasification plants in North Dakota propose to use all-wet cooling supports this reasoning (Abbey, 1979b). (Recall that Table 6 indicates that a minimum level of dry cooling is economic). If cooling and water treatment economics are evaluated jointly, the upper bound of water consumption might increase by 2,000-3,000 a-ft/yr. The incremental costs of water conservation would also rise.

The rate of water use for shale oil production varies over a wide range depending on the type of conversion technology. An upper bound is about 8,000 a-ft/yr per 50,000 b/d plant using the Tosco II process* (Denver Research Institute, 1979). An intermediate estimate is about 2,550 a-ft/yr per 50,000 bbl/d plant using the Paraho Direct process. The Denver Research Institute estimates that a modified in-situ plant might produce 8,500 a-ft/yr per 50,000 b/d plant though that estimate includes over 11,000 a-ft/yr of minewater. Not only does the minewater production rate depend on site-specific geohydrologic

*50,000 bbl/average day. Equilavent to 55,555 bbl/day at 90% annual capacity factor.

conditions, but minewater production might be more properly attributed to plant consumption.

Evaluation of the effect of technological change on water use is beyond the scope of this report. Its importance, however, should not be underemphasized (see Bower, 1966). Advanced dry cooling concepts, for example, using ammonia as the heat exchange fluid may provide cost savings up to 40% over conventional dry cooling systems (Johnson, 1979).

Water Use and Technology Cost Coefficients. Given the above discussion concerning water use for electricity generation and synthetic fuel production, we now specify the technology options formally. The index defines combinations of air pollution control technology and cooling technology for coal-fired electric power plants and synthetic fuel production plants. For each we define water use coefficients as follows:

UR_ℓ -- water use rate for coal-fired electricity generating technology in units of 10^3 acre-ft/ 10^9 Kwh;

σ_ℓ -- water use rate for coal liquefaction in units of a-ft/ 10^{12} Btu output;

ϕ_ℓ -- water use rate for coal gasification in units of a-ft/ 10^{12} Btu;

θ_ℓ -- water use for shale oil production, a-ft/ 10^{12} Btu;

and WR_n -- water use for non-coal technology n where n indicates the cooling option at nuclear plants, 10^3 a-ft/ 10^9 Kwh.

The incremental costs of the water conserving cooling technologies are added to the base production costs. Thus, the coefficient CO_{jlmk} becomes the cost of operating ℓ -type plants in region j in mode m using k type coal. The units of this coefficient are mills per kilowatt-hour (mills/Kwh) including the cost of installing and operating the referenced cooling technology. Likewise, the coefficient COP_{jnm} is the cost of operating n -type plants in region j in mode m , which for appropriate values of n (nuclear plants) includes the cost of installing and operating the referenced cooling towers.

We derive the water use and cooling cost coefficients from Tables 5 and 6 and the estimate for the Tosco II shale oil process reported above.

The Water Supply Sector

Fig. 1 shows the coal demand regions in LACUMS. For the shaded coal demand regions, j , we specify constraints, or upper bounds, for three water

Fig. 1.
Coal Demand Regions in the Los Alamos Coal Use Modeling System*

*Water supply curves are developed for the shaded regions.

supply categories: stream flows (S_j); water consumed for irrigation which may be transferred to the energy sector (T_j); and groundwater (G_j).^{*} The units are 10^3 a-ft/yr. Table 7 presents these estimates by coal demand region. Below, we discuss the assumptions underlying these data and describe the water supply conditions for the energy sector in 10 Western states.

Arizona. The boundaries of the principal surface water subbasins of Arizona, the Little Colorado, the Lower Colorado Mainstem, and the Gila, do not conform to the boundaries of the LACUMS coal demand regions. However, the US Geological Survey (USGS) designates 67 water supply regions which are more easily apportioned to the LACUMS regions. Water supply and use data are available for most of these subbasins in the Arizona State Water Plan (Arizona Water Comm., 1975).

Law**. Surface water transfers for use at electric plants require state legislative approval.

Currently, groundwater is appurtenant to the land; its use is governed by the rule of "reasonable use." Several state Supreme Court decisions and a 1977 legislative action developed an interpretation that this prohibits groundwater use off-site if pumping damages the water supplies of adjacent landowners. One may, however, retire groundwater used for irrigation and use the water off-site. The 1977 legislation also authorized a special commission to propose a new groundwater code by December 31, 1979. This code becomes law in the absence of legislative modification by September, 1981.

Streamflows. The US Water and Power Resources Service's (WPRS) Central Arizona Project (CAP) is scheduled to deliver 1.1 million a-ft/yr to the Phoenix/Tucson area from the Colorado River by 1987. As the states of the Upper Basin develop their full entitlements, Arizona will have to curtail use of CAP water to about 700,000 a-ft/yr. Provisionally, 100,000 a-ft/yr are allocated for power production, though the Secretary of the Interior has yet to sign an allocation agreement (Carr, 1979).

*In several instances constraints were set for pairs rather than for individual coal demand regions.

**As the principal reference on state water law, we relied on a report by George Gould (1979), law professor at the University of Wyoming. Gould reviews water law in thirteen Western states to determine the legal climate for industrial water use. Emphasis is placed on the potential for "free" acquisition and reallocation of water rights.

TABLE 7

**WATER SUPPLY ESTIMATES BY COAL DEMAND
REGION AND WATER SUPPLY CATEGORY**

State/Coal Demand Region	(103 a-ft/yr)		Groundwater(G)
	Streamflows(S)	Transfers(T)	
<u>Arizona</u>			
29	240	1,091	-
30	- ^a	8	50
31	-	4	48
32	-	876	180
33	-	123	103
<u>Colorado</u>			
34	-	8,000	-
38	-	-	-
35	98	113	17
36	88	969	NAB
37	-	812	NA
<u>Idaho</u>			
39	4,500	7,000	-
40	No Constraint		-
<u>Montana</u>			
41	No Constraint		-
42	300	3,160	NA
61	355	1,650	40
62			
<u>Nevada</u>			
43	-	560	70
44	-	275	335
45	44	-	-
<u>New Mexico</u>			
46	80	80	?
47	40	135	380
48	70	1500	400
<u>North Dakota</u>			
58	233	-	40
59	No Constraint		-
<u>South Dakota</u>			
60	233	-	40
<u>Utah</u>			
49	-	413	-
50	10	1,902	85
51	135	560	30
52			
<u>Wyoming</u>			
53	-	580	-
54	217	151	40
63	325	1,029	NA
64			
65	25	242	NA

^aNil.^bNot Available.

^cFor several regions surface water supplies are taken as infinite. These regions lack coal resources, are predominately rugged in terrain, and/or are traversed by mighty streams.

Depletions for Irrigation (Transfers). Table 8 shows surface water depletions for irrigation in 1970 by LACUMS coal demand region and USGS water supply region. This understates the quantity of irrigation water that might be transferred to industrial or municipal use as it excludes groundwater used for irrigation (which is perhaps more easily transferrable than surface water).

Municipal wastewater in the Phoenix area is also a source of supply that might be transferred to industrial use. Arizona Public Service Company and the Salt River Project have an option to purchase 140,000 a-ft/yr from the City of Phoenix and other owners of a sewage treatment plant for the Palo Verde nuclear plant near Wintersburg. (This water is included in the surface water coefficient for Coal Demand Region 29.) While the acquisition cost is only \$30/a-ft, the estimated cost of transportation and treatment is about \$570/a-ft (the sum of annualized capital and O&M costs) (Hulse, 1979).

Groundwater. The NUS Corporation (1974) in a siting analysis for Arizona Public Service Company identified 24 basins with sufficient groundwater in storage to supply at least 1.4 million a-ft/yr for a 40-year period. Table 9 presents estimates of the total quantity in storage for these basins by USGS water supply region and LACUMS coal demand region. To determine groundwater supply coefficients for Arizona, we assume that 0.1 percent of the quantity of water in storage is available on an annual basis. This is analagous to the situation in the Willcox Basin where the Arizona Electric Power Cooperative purchased and retired irrigated land for a wellfield to supply a 200 MW electric plant. Their use only slightly hastens the time period at which groundwater pumping for irrigation becomes uneconomic (generally when the water table drops 500 feet below the surface).

No groundwater supply data was available to the authors for the Little Colorado region (Coal Demand Region 30). However, this basin overlies the productive Navajo and Coconino sandstone aquifers, the source of water supply to several existing or proposed coal-fired electric plants in northeastern Arizona. The supply coefficient is arbitrarily taken as 50,000 a-ft/yr.

Colorado. The correlation between stream basins and coal demand regions is as follows:

TABLE 8

SURFACE WATER DEPLETIONS FOR IRRIGATION IN ARIZONA IN 1970

<u>Coal Demand Region</u>	<u>USGS Water Supply Region</u>	<u>10³ a-ft/yr^a</u>
29	Lower Santa Cruz Valley	197
	Salt River Valley	894
30	St. Johns	8
31	Little Chino Valley	4
32	Colorado R. - Hoover Dam	
	to Imperial Dam	265
	Yuma	326
	Gila Bend Area	8
33	Duncan Valley	10
	Safford Valley	113

^aAssumed to be the lesser number of either surface water or irrigation depletions.

SOURCE: Arizona Water Commission, 1975. "Arizona State Water Plan, Inventory of Resources and Uses," pp. 22-24 (July).

TABLE 9

GROUNDWATER IN STORAGE AND OVERDRAFTS FOR SELECTED BASINS IN ARIZONA

<u>Coal Demand Region</u>	<u>Designated Basin</u>	<u>Storage (10³ a-ft/yr)</u>	<u>Overdraft (10³ a-ft/yr)</u>
30	Little Colorado	- ^b	-
31	Big Sandy	21,500	-
	Sacramento	0	-
	Hualapui	3,500	-
	Big Chino	12,500	5
	Little Chino	10,100	7
	Williamson	-	-
		<u>47,600</u>	<u>12</u>
32	Yuma	34,600	-
	Altor	15,000	-
	Hassayampa	-	-
	Rainbow	-	-
	Gila Bend	60,000	102
	Marquahala Plains	26,000	95
	McMullen	14,000	77
	Palomas	-	-
	Ranegrass Plains	<u>31,000</u>	<u>12</u>
		180,600	286
33	Duncan	18,800	-
	Safford	15,000	-
	San Simon	15,300	49
	Aravaipa	-	-
	Willcox	54,000	182
	San Pedro	-	-
		<u>103,100</u>	<u>231</u>

^aOverdraft is the rate of withdrawals in excess of annual recharge.

^bData not available.

Reference: Arizona Water Comm., 1975. "Arizona State Water Plan, Inventory of Resource and Uses," (July) pp. 24 and 25.

Coal Demand RegionRiver Basin (Subbasin)

34	}	Platte/Arkansas
38		
35		Green (Yampa/White)
36		Upper Colorado Mainstem
37		San Juan/Rio Grande

Law. Gould (1979) reports that, "Unlike many Western states, Colorado water rights are freely transferred to new types of uses or new places of use subject only to the limitation that the transfer may not injure other appropriators." The Colorado Department of Natural Resources (1978) corroborates that, "the present Colorado water rights system constitutes a private market approach to the allocation of a scarce resource with government having very little formal authority over the use of water."

Colorado law distinguishes between tributary and nontributary groundwater. Tributary ground water is that water hydraulically connected to a stream, the use of which modifies flow. It is essentially managed as surface water and requires an appropriation permit from the State Engineer. Nontributary groundwater is managed only in designated groundwater basins by a groundwater commission.

An important consideration for the energy sector is that no groundwater basins are designated in the Upper Colorado Basin (repository of coal and oil shale resources). Thus, groundwater developers in that region must compensate surface water users for any reduction in streamflow.

Streamflows. The Laramie River, Arkansas River, and the Rio Grande are fully appropriated (Colo. DNR, 1979). Of the 200,000 a-ft/yr remaining on the South Platte, the WPRS' Narrows project will use about 100,000 a-ft/yr for irrigation. Storage/firm annual yield ratios of as much as 10:1 might be necessary to develop the rest of the water resource. On the North Platte an upper limit on water use for irrigation is set by the Supreme Court decree in Nebraska v. Wyoming. We interpret the silence of that decree with respect to industrial uses as a disincentive to development.

The Colorado River represents an alternative source of water for the Eastern slope. Municipalities have plans to develop and import almost 300,000

a-ft/yr, of which some might find its way to the energy industry. The Platte River Power Authority, for example, bought Ft. Collins' 16,000 a-ft/yr (one-third) share of the Windy Gap Project for its Rawhide plant (250 MW). Windy Gap, however, is encountering opposition from both environmentalists and Western Slope water users. In summary, we take the availability of surface water on the Eastern Slope as nil.

Even by conservative reckoning of average annual flows and interpretation of interstate compacts, at least 700,000 a-ft/yr are available for development in the Colorado River Basin (the Western Slope). Two existing WPRS storage projects, Ruedi on the Fryingpan River and Blue Mesa on the Gunnison River, have 40,000 and 30,000-50,000 a-ft/yr, respectively, available for leasing to municipal and industrial (M&I) users (Colo. DNR, 1978). Two other WPRS projects, Animas-La Plata and West Divide, if constructed, could supply 76,200 and 77,500 a-ft/yr respectively to M&I users. Over 150,000 a-ft/yr are allocated to irrigation from other authorized projects.

Conditional private water rights in the Colorado River Basin would probably require a pre-1930 priority date to provide sufficient reliability to industrial users (Colo. DNR, 1979). A planning document of the old Bureau of Reclamation (1977) projects use of 20,000 a-ft/yr on the Yampa River for the Hayden and Craig steam electric plants and 78,000 a-ft/yr for prototype oil shale development on the C-a/C-b tracts in the White River Basin.

Depletions for Irrigation. Table 10 shows depletions for irrigation in Colorado at the 1970 level of development.

For years municipalities and industrial developers in the fast growing Front Range region have been buying irrigation and other water rights. Public Service Company of Colorado (PSC) has rights to about 28,000 a-ft along the South Platte that they now lease but eventually expect to convert to industrial use (including 7,000 a-ft/yr for the 500 MW Pawnee plant near Ft. Morgan, Colorado) (Green, 1979). The PSC also has an option to purchase about 25,000 a-ft/yr of Arkansas River diversion rights from two ditch companies serving irrigator/members near Las Animas (Easton, 1979). The PSC expects to develop 8,000-10,000 a-ft/yr of consumptive use rights for a coal-fired electric plant at a cost of \$1,300/a-ft (subject to escalation).^{*} About 6,500 acres would be lost from agricultural production.

^{*}The Southeastern project was recently cancelled because of a reduction in projected growth of electricity demand.

TABLE 10

1970 DEPLETIONS FOR IRRIGATION IN COLORADO

<u>Basin</u>	<u>10³ a-ft/yr</u>
Green	113
Upper Colorado Mainstem	967
San Juan	195
Platte	1,357
Arkansas	704
Rio Grande	617

SOURCE: Bureau of Reclamation, 1974. "Water for Tomorrow: Colorado State Water Plan, Appraisal Report," prepared in cooperation with the State of Colorado (February) p. 3.3.

Groundwater. Groundwater use is extensive on the Eastern Slope. There are about 1,000 large-capacity wells along the South Platte River and 3,000 along the Arkansas River (Bureau of Reclamation, 1974). The Ogallala formation provides water for irrigation on the High Plains, but is likely to be depleted within 25 years. Certainly there is a potential for conjunctive management of surface and ground water to enhance supply, but it is not possible to make any quantitative estimate of this potential.

In the Colorado Basin, only the Piceance Basin in oil shale country has been studied in detail. A USGS study provided an estimate of 2.5 to 25 million a-ft in storage in the Lancy and Tipton shales of the Green River formation (Weeks et al., 1974). A hypothetical mine dewatering plan for the C-a/C-b tracts projected depletion of 500,000 a-ft over a 30-year project life--5 to 20 percent of the volume in storage--and a decline in surface discharge of 8 ft³/s (6,000 a-ft/yr) at the end of the period.

Little data is available for other promising aquifers, notably the Dakota Sandstone and the Morrison formation.

Idaho.

<u>Coal Demand Region</u>	<u>Basin</u>
39	Central and Upper Snake
40	{ Salmon
	{ Clarks Fork
	{ Lower Snake

Law. Idaho recently added a "public interest" statute to its water code. Thus, industrial water users may receive closer scrutiny in the future. Reservoirs in excess of 10,000 a-ft storage capacity require approval of the Idaho Water Resources Board.

The lack of statutory authority for water right transfers is a minor source of uncertainty.

Groundwater mining is prohibited in rechargeable aquifers.

Water Supply. We estimated water supply constraints only for the central and upper Snake River subbasin after considering the topography of Idaho and the probable location of energy conversion facilities.

About 7 million a-ft/yr are available for development (Idaho Water Resources Board, 1976). About 4.5 million a-ft/yr are used for irrigation.

Montana.

<u>Coal Demand Region</u>	<u>Basin</u>
41	Columbia (no constraint)
42	Upper Missouri
61	Yellowstone
62	

Law. Montana places a number of obstacles before large or industrial appropriators. For example, in 1973 the legislature placed a moratorium on industrial appropriations in the Yellowstone Basin (encompassing the vast coal reserves of the Ft. Union formation) pending action of the Board of Natural Resources and Conservation (BNRC) on streamflow reservation requests. Large appropriators are probably required to prepare an environmental statement evaluating water use alternatives under the Montana Energy Policy Act. The Montana Major Facility Siting Act subjects energy projects to a "public interest" review for certification by the Department of Natural Resources and Conservation. Under the Yellowstone River Compact, diversion of water outside the Basin requires consent of the legislatures of the other states in the basin (Wyoming and North Dakota).

It is not commonly recognized that Montana allows the transfer of water rights to industrial users. No single transfer may exceed 15 ft³/s (11,500 a-ft/yr), but that is enough for most energy projects.

Groundwater withdrawal is probably limited to the annual rate of recharge.

Streamflows. The principal sources of new surface supplies for industrial users along the Upper Missouri Mainstem are the five storage reservoirs of the WPRS (Ft. Peck in Montana, Sakakawea in North Dakota, and Oahe, Francis Case, and Sharpe in South Dakota). Based on projections of water use for land reclamation, the Bureau of Reclamation (1977b) conservatively projected at least a 1 million a-ft/yr surplus or residual available for contracting to industrial users from these reservoirs at a standard price of \$20/a-ft. The WPRS has a contract with Montana to subcontract up to 300,000 a-ft of this water (Rawlings, 1979). (In other states of the Basin, industrial users will contract directly with the WPRS.) We take 300,000 a-ft/yr as the surface water supply constraint for Montana's Upper Missouri Basin.

In Table 11 we present estimates of the mean flow of the Yellowstone at the 1975 level of development and projected uses and reservations in an approximate ordering of priority. On comparison, it might seem that enough water is available to supply the proposed Tongue River reservoir, the WPRS off-stream storage reservoirs, and even pending industrial applications. But this conclusion ignores a host of legal and institutional complications.

First, the Wind River, Crow, and Northern Cheyenne Tribes claim reserved rights to as much as 1.2 million a-ft/yr for irrigation. Second, the Yellowstone River Compact allocates portions of the Clark's Fork, Big Horn, Tongue, and Powder Rivers to Wyoming, which estimates its share of the Yellowstone at almost 2.5 million a-ft/yr, much of which is not being used (Missouri River Basin Commission, 1978). Third, Utah International Co. initiated a suit challenging the state's authority to suspend industrial permit applications (Gordon, 1979). Fourth, both Utah International and Intake Water Co., an arm of Tenneco, Inc., have countersuits challenging the priority dates assigned to permit applications for their two mutually exclusive development projects on the Powder River. Fifth, Intake is challenging the provision of the Yellowstone River Compact that requires consent of the state legislatures to divert water outside the basin. Sixth, contracting water from Yellowtail Reservoir requires preparation of programmatic and contract-specific environmental impact statements. Surely, the list goes on.

For a surface water constraint for the Yellowstone Basin, we summed the projected uses that precede the BNRC reservations in priority. Considering

TABLE 11

1975 MEAN FLOW AND PROJECTED USES BY APPROXIMATE
PRIORITY DATE IN THE MONTANA/YELLOWSTONE BASIN
(10³ a-ft/yr)

Avg. Flow at Sidney, Mt. (1975 level of development)	8,345 325 ^a
Yellowtail Reservoir	
Tenneco appropriation	80 ^b
Board of Nat. Res. & Conserv. (BNRC)	61 ^c
Reservations for Municipalities	
BNRC Reserv. for Irrigation	655 ^c
BNRC Reserv. for Stream flows at Sidney, Mt.	5,500-6,100 ^d
Reservation for pumping to WPRS off-stream storage (3 sites)	726
BNRC Reserv. for Tongue River Reservoir	58-70
Utah International	40 ^f
Intake Water Co. (Tenneco);	124 ^g
Gulf	90
	<hr/> 7,965

^ataken as one-half of firm annual yield of Yellowtail.

^b30,000 a-ft diversion proposed for energy development, the balance proposed for land reclamation.

^crate of diversion.

^d80% of mean flow less reservations for off-stream use.

^efirm annual yield developed by expansion of Tongue River Reservoir to 450,000 a-ft capacity.

^ffirm annual yield developed by diversion from Powder River to off-stream reservoir.

^gfirm annual yield developed by diversion to Moorhead Reservoir (400,000 a-ft capacity).

References: Missouri River Basin Comm., 1978. "Report on the Yellowstone Basin and Adjacent Coal Area Level B Study," Omaha, Neb., p. II-28; letter from Gary Fritz, Chief, Water Planning Bureau, DNRC (no date-summary statement of DNRC reservations); Montana Dept. of Nat. Res. and Conserv., 1979. "Water Development in the Tongue and Powder River Basins," Helena (January) pp. 41-44.

both uncertainty and complexity, this estimate is neither liberal nor conservative.

Depletions for Irrigation. Depletions for irrigation in 1970 in the Upper Missouri Mainstem and Yellowstone Basins were 3.16 and 1.65 million a-ft/yr, respectively (Montana DNRC, 1975). As a consequence of the BNRC reservations and other restrictions or uncertainties affecting new appropriators, one may begin to witness the purchase of existing water rights by industrial developers, especially in the Yellowstone River Basin.

Groundwater. Several sandstone formations in central and eastern Montana yield water to wells at rates up to 200 gal/min (Taylor, 1978). The Tensleep Sandstone in the Powder River Basin yields up to 1200 gal/min. However little data is available concerning the quantity of water in storage or recharge rates for these sandstone aquifers. The Madison Formation, an extensive limestone aquifer in the Northern Plains, is the subject of an extensive hydrologic modeling and well drilling program of the US Geological Survey (1975). One test well near Billings reached water at 4400 feet below land surface, had a potentiometric head 1000 feet above land surface, and an average yield of 1000 gal/min. Another test well in Custer County, however, was abandoned, dry, at 9,400 feet below land surface (at a cost of about \$2 million). A preliminary hydraulic digital simulation model estimated annual recharge to the Madison of 200 ft³/s (Konikow, 1976). We very arbitrarily assign one quarter of this rate to each of Montana, North Dakota, and South Dakota, the states in the Northern Plains that limit groundwater withdrawals to the rate of annual recharge.

Nevada.

Coal Demand Region

Subbasin

43

Humboldt and Tonapah region of the Great Basin, including the Humboldt River Basin.

44

Central Lahontan region of the Great Basin, including the Truckee, Carson, and Walker River Basins.

45

Lower Colorado River Basin.

Law. While Nevada law does not guarantee static well levels for existing groundwater users, it is the policy of the State Engineer to limit withdrawals to average annual recharge or perennial yield.

There are no special restrictions on the transfer of water rights.

Streamflows. The only surface water available for development in Nevada is Colorado River water. The WPRS' Southern Nevada Water Project will eventually deliver 167,000 a-ft/yr from Lake Meade to the Las Vegas area. Current use is about 75,000-80,000 a-ft/yr; the balance is contracted to 5 municipal agencies. Nevada Power Company has a contract with the Las Vegas and Clark County Sanitary Districts for 43,764 a-ft/yr. of municipal sewage treatment plant effluent.*

Depletions for Irrigation. Apparently, no one in Nevada estimates water use for irrigation. (We inquired at the State Engineer's Office, the Water Resources Agency, and the Agricultural Economics Department at the University of Nevada, Reno).

We estimate surface water depletion arbitrarily as one-half of virgin mean annual flow (see Table 12). This is reasonable, because on the Humboldt virtually all water use is attributed to irrigated agriculture (Danner, 1979), and because diversions to the Newlands Irrigation project are about 400,000 a-ft/yr, half from the Truckee and half from the Carson.

Indian reserved water rights, however, cast a pall over non-Indian water use in the Truckee/Carson Basin (see Mahannah, Guitjens, and York, 1975). The Paiutes claim 400,000 a-ft/yr to maintain the water level in Pyramid Lake, a claim that would antedate the rights of virtually all existing users.

There is little water use for irrigation in the Las Vegas area. However, Nevada Power Company has purchased water rights from irrigators along Muddy Creek, a tributary of the Virgin River.

Groundwater. We estimated groundwater supply constraints by summing average annual recharge for selected regions (see Table 13). These are regions with recharge in excess of 25,000 a-ft/yr and without evidence of legal constraints to development (that is, little present groundwater use and limited hydraulic connection between aquifers and streams).

*Technically, the sanitary districts have permits to divert their effluent from Las Vegas Wash; Nevada Power Company has a secondary permit to use the water (Reynolds, 1979).

TABLE 12

SUMMARY OF RENEWABLE SUPPLY IN GREAT BASIN
REGION OF NEVADA

<u>Subregions</u>	<u>Principle Streams</u>	<u>Virgin Mean Flows (10 a-ft/yr)</u>	<u>Natural Groundwater^a Discharge (10 a-ft/yr)</u>	<u>Average Well Yield (gal/min)</u>
Humboldt	Humboldt R.	554	480	1,700
Tonapah	None	None	680	1,200
Central Lanhontan	Truckee/ Carson/Walker	1,200	104	1,500

^aGenerally excluding ground water flows to streams.

Reference: Eakin, Price, and Harrill, 1976, p. G-8.

TABLE 13

ANNUAL RECHARGE FROM PRECIPITATION BY
SELECTED GROUNDWATER BASINS
(10³ a-ft/yr)

Central Lanhontan

Black Rock Desert	25
Amargosa Desert	<u>45</u>
	70

Tonapah

Big Smoky (Northern Part)	65
Railroad Valley	52
Ruby Valley	68
Steptoe Valley	85
Spring Valley	<u>75</u>
	335

SOURCE: Eakin, Price, and Harrill, 1976.

New Mexico.

<u>Coal Demand Region</u>	<u>Basin</u>
46	San Juan
47	Upper Rio Grande/Gila
48	Canadian/Pecos/Middle and Lower Rio Grande

Law. The principal restrictions on water transfers are the usual ones that protect the rights of other appropriators.

Groundwater mining is generally permitted. In a key case, Mathers v. Texaco, the court upheld a decision of the State Engineer that permitted depletion of one-third of the quantity in storage over a 40-year period. Careful attention, however, will be paid to the effects of pumping on the economic interests of existing surface and groundwater users. For example, the State Engineer recently allowed Phillips Uranium Co. to appropriate 32,250 a-ft/yr of water pumped from a uranium mine near Crownpoint. They must, however, assign 164 a-ft/yr to the State Engineer to compensate for loss of flows in the Rio Grande and San Juan River systems (Ward, 1979).

Surface Water. There are about 520,000, 40,000, and 70,000 a-ft/yr available for development (not necessarily unappropriated) in the San Juan, Gila/San Francisco, and Canadian River Basins, respectively (US BuRec, 1976). The water supply situation in the San Juan Basin is the one most crucial to industrial developers. The WPRS controls most of the water available and has allocated most of it to the Navajo Indian Irrigation Project and several small municipal uses. Still, between private water rights held by Utah International and WPRS contracts with energy companies, it appears that about 80,000 a-ft/yr of San Juan River water is available for industrial development (US Bureau of Reclamation, 1977a).

Depletions for Irrigation. As in Arizona, New Mexico irrigators, especially in the Lower Rio Grande and Pecos Valleys, make extensive use of groundwater. The transfer constraints shown in Table 7 reflect both surface and groundwater depletions for irrigation (Lansford, et. al., 1973).

Groundwater. New Mexico has vast quantities of fresh and saline groundwater in storage. There is no data available to the authors, however, that distinguishes between groundwater in alluvial aquifers and groundwater in consolidated or bedrock aquifers with relatively little hydraulic connection to the surface. As with Arizona, we arbitrarily take groundwater supply

constraints as 0.1 percent of the total volume in storage (disaggregated by coal demand region) (US Bureau of Reclamation, 1976).

Another potential source of supply which we do not distinguish from groundwater is the water pumped from uranium mines in the San Juan Structural Basin, a quantity that may reach 60,000 gal/min or about 100,000 a-ft/yr within a decade (Perkins, 1978). Public Service Company of New Mexico hopes to acquire some of this water for a coal-fired electric plant near Bisti.

North Dakota.

Coal Demand Region

58

59

Basin

Upper Missouri

Souris/Red (no constraint)

Law. The North Dakota Water Conservation Commission must approve appropriations in excess of 5,000 a-ft/yr. Water rights may be transferred only to superior uses. Industrial water use is ranked fifth (favored only to fish and wildlife). Pressure levels of groundwater users are not protected against new uses. Mining, however, is not necessarily permitted.

Streamflows. The status of water development on the tributaries of the Missouri in western North Dakota (the lignite-bearing region) is uncertain (Krenz, 1979). There is a moratorium on new storage projects on the Cannonball River. The Heart Butte project on the Heart River is allocated for irrigation, but local farmers have been unable to agree on a repayment contract. Transfer to industrial use, however, would acquire approval of the State Engineer. The Knife River may provide the best potential for tributary development. But we assume that the principal source of supply will be the WPRS' Lake Sakakawea Project.

Groundwater. We assume that the principal source of supply is the Madison formation and that pumping is restricted to the rate of annual recharge (see Montana section).

South Dakota. Though the entire state is in Coal Demand Region 60, we limit the water supply analysis to the Upper Missouri region, thus excluding the Big Sioux and the James Rivers in the eastern third of the state.

Law. South Dakota statutes are relatively restrictive towards industrial water users. The State Water Commission, of which five of the eight members represent agriculture, must approve all new appropriations. In addition, the state legislature must approve appropriations in excess of

10,000 a-ft. Water rights for irrigation are appurtenant to the land and probably not transferable. Groundwater pumping is specifically limited to rate of annual recharge.

Water Supply. The South Dakota Water Plan (1977) states, "Most streams, except for the Mainstem and some at higher levels in the Black Hills, have had periods of zero flow." Hence, we again take WPRS storage water as the principle source of surface water to industrial users. (South Dakota, Wyoming, and the Old West Commission authorized a feasibility study of a 170,000 a-ft/yr, 300 mile pipeline from Lake Oahe to Gillette, Wyoming to supply water for energy projects and municipalities in western South Dakota and northeastern Wyoming (CH2M Hill, 1978). Projected transportation costs, however, range as high as \$1,850/a-ft.) As in Montana and North Dakota, we estimate groundwater supply at one-quarter of the estimated annual recharge for the Madison formation.

Utah.

Coal Demand Region

River Basins

49

Weber/Jordan

50

Bear/Great Basin/
Virgin (Lower Colorado)

51

Green/Upper Colorado

52

Mainstem/San Juan

Law. Gould (1979) states that, "Utah is free from artificial restrictions on the transfer of water rights," and allows "a reasonable reduction in groundwater levels to promote maximum development." This generally reflects the Beehive State's Mormon tradition and free market orientation.

Streamflows. Interbasin transfers from the Bear and Green subbasins will eventually supply the Salt Lake City metropolitan region (Coal Demand Region 49). The most advanced project, the WPRS' Bonneville Unit of the Central Utah Project, would divert 80,000 a-ft/yr from the Duchesne River to the Provo River, principally for municipal and industrial uses. Water delivery, however, is at least 15 to 20 years in the future (Talbot, 1979).

Coal Demand Region 50 spans western Utah. The perennial streams of the Great Basin--the Sevier, the Cedar, and Beaver--are virtually depleted, mostly for irrigation. Storage projects could develop additional water on the Virgin

River in the Lower Colorado River Basin. One proposed project, an alliance of Nevada Power Company and other utilities with the city of St. George and the Washington County Conservancy district, would develop water for municipal, irrigation, and industrial use, including 10,000 a-ft/yr for the Warner Valley electric plant. But the bitter controversy between these developers and the US Fish and Wildlife Service concerning stream flow regimes recommended to protect the endangered roundfin minnow suggests a limit on further depletions on the Virgin (US Senate, 1978). Over 500,000 a-ft/yr are available for development on the Bear River, which drains the Wasatch Mountains (Saunders, 1979). We do not account for this in order to reflect the arid conditions of the Great Basin Region.

Coal Demand Regions 51 and 52 encompass the Utah portion of the Upper Colorado River Basin. A Bureau of Reclamation planning document indicates that almost 500,000 a-ft/yr are available for development. Projected uses for energy development are about 135,000 a-ft/yr (for the Emery, Huntington Canyon, Intermountain Power Project, and Kaiparowits electric plants and for oil shale development on the U-a/U-b tract) (US BuRec, 1977a). The State of Utah and the WPRS hold water rights for these or alternative projects.

Depletions for Irrigation. Table 14 indicates 1975 consumption for irrigation by county. The counties are apportioned to coal demand regions.

Utah Power and Light Co. purchased about 20,000 a-ft/yr of water rights from irrigators for electric plants in Emery County. In 1979 the Intermountain Power Project (IPP) purchased 40,000 a-ft/yr at \$1,750/a-ft from five ditch companies along the Sevier River for a 3,000 MW electric plant near Lyndyll.

Groundwater. In the Great Basin at least two valleys appear suitable for industrial groundwater development, the Skull and the Snake Valleys (see criteria in Nevada groundwater section) (Eakin, Price, and Harrill, 1976). Annual recharge, from precipitation to these two basins is about 85,000 a-ft/yr (although this figure is not necessarily relevant as Utah does not prohibit groundwater mining).

Between 50 and 115 million a-ft of water are in storage in the upper 100 feet of saturated rock in the Upper Colorado region (Price and Arnou, 1974). (No delineation by state is available.) Annual recharge or perennial yield, is about 4 million a-ft/yr. Most of the water, however, is in deep, sedimentary rock which yields water to wells relatively slowly (50 gal/min).

TABLE 14

<u>Coal Demand Region</u>	<u>County</u>	<u>10³ a-ft/yr</u>
49	Weber, Davis, Morgan Salt Lake and Tooele	413
50	Cache, Box Elder, Rich, Summit, Utah, Wasatch, Millard, Juab, Sanpete, Sevier, Piute, Wayne, Beaver, Iron, Garfield, Kane and Washington	1,902
51/52	Carbon, Emery, Grand, San Juan, Daggett, Uinta, and Duchesne	560

Reference: Utah Div. of Water Resources, 1978. "The State of Utah Water, 1978," Utah Dept. of Nat. Res., Salt Lake City (December), p. 19.

Nevertheless, over two dozen areas in Utah are indicated as having aquifers with sufficient potential for large-scale development. At one area, Hanksville, the State of Utah approved the Intermountain Power Project's plan to withdraw 20-25 ft³/s (about 30,000 a-ft/yr) from the Navajo sandstone (an extensive aquifer in the Colorado Plateau). Projections of flow reductions to the Colorado River, however, ranged from 5-16 ft³/s (Hood, 1979). Utah would probably be reluctant to approve further development of this aquifer without more accurate hydrologic data.

Wyoming.

<u>Coal Demand Region</u>	<u>Subbasin</u>
53	Platte/Niobrara
54	Cheyenne/Belle Fourche/ Little Missouri/Powder/Tongue
63 64	Yellowstone/Clark's Fk. of the Yellowstone/Big Horn
65	Green

Law. Water may be transferred from irrigators to industrial users. Groundwater mining is probably permissible in aquifers with a low rate of recharge.

Streamflows. Interstate compacts allocating waters of the Platte among Colorado, Nebraska, and Wyoming limit water use for irrigation and new

mainstem storage projects. Physically, some water is available for development, but the sorry experience of the Missouri Basin Power Project (MBPP) will probably discourage development for industrial uses.*

In northeastern Wyoming the State Water Plan reports that about 217,000 a-ft/yr are available by interstate compact on the Powder and Tongue Rivers. Minor amounts are available on the Cheyenne, Belle Fourche and Little Missouri Rivers. Existing uses from Texaco's Lake-de-Smet Reservoir on the Powder River are only 10,000 a-ft/yr of the firm annual yield of 60,000 a-ft/yr. A number of other energy companies, including Carter Oil Company (Exxon), Pacific Power and Light, and Sun Oil Company, have permit applications and proposals to build other storage projects on the Powder and the Tongue Rivers (many of which are mutually exclusive).

The Clark's Fork of the Yellowstone and the Big Horn River have relatively large water supplies and little industrial demand (compared to the Powder River Basin). We take one-half of the firm annual yield of the WPRS' Boysen Reservoir (Yellowtail Dam) as the streamflow supply for Coal Demand Regions 63 and 64.

Almost 400,000 a-ft/yr, or one-half of Wyoming's share of Colorado River water, are available for development. Most of this water is tied up with the WPRS' Seedskaadee project--direct flow rights of 1,140 ft³/s for irrigation and 125 ft³/s for municipal and industrial users (Allen, 1979). Based on the M&I flow right, the State of Wyoming contracted 35,000 a-ft/yr to Pacific Power and Light Co. for its Jim Bridger electric plant and optioned 25,000 a-ft/yr to Sun Oil Company (an option that expired in 1978). At present, it seems unlikely that the irrigation component will be developed, so eventually this water might be reallocated to industrial use. But there are at least two problems: a) determining a firm annual yield from the direct flow right for irrigation, and b) determining the quantity available for consumptive use, because in Wyoming transfers are based on the historical quantity of use (which is zero). Conservatively, then, we estimate streamflow supply for the Green River Basin solely on the basis of the 25,000 a-ft/yr originally optioned to Sun Oil Company.

*Environmental and other interests forced the temporary rescindment of a critical dredge and fill permit. A district judge cited especially the potential for adverse modification of "critical habitat" for the whooping crane along the Platte in Nebraska. MBPP eventually settled out-of-court by paying \$7 million to a whooper habitat trust fund (among other things) (see Harrington, 1980).

TABLE 15
DEPLETIONS FOR IRRIGATION IN WYOMING BY
ROCKY COAL DEMAND REGION

<u>Coal Demand Region</u>	<u>10³ a-ft/yr</u>
53	580
54	151
63	1,029
64	
65	242

Reference: Wyoming State Engineer's Office, 1973. "The Wyoming Framework Water Plan," (May) pp. 35,64,129, 186, and 199.

Depletions for Irrigation. Table 15 shows depletions for irrigation by coal demand region and subbasin in 1970. In several cases in Wyoming, irrigation water rights have been transferred to industrial users, but the transfers aroused considerable opposition and resulted in a smaller industrial consumptive use right than had been anticipated (Humm and Selig, 1978).

Groundwater. In the Platte River Basin, the semiconsolidated Arikaree sandstone has a large quantity of water in storage. However, present use is about 100,000 a-ft/yr. Furthermore, a USGS study of a depletion schedule for a hypothetical industrial development in Platte County suggested that at the end of a 40-year pumping period reduction in aquifer discharge and streamflows would approach or even exceed pumping rates (Hoxie, 1977). Groundwater development for large industrial uses does not appear promising in this region.

The Madison formation underlies much of northeastern Wyoming. In 1974 pumping levels from the Madison in Wyoming were about 25,000 a-ft/yr, mostly for secondary oil recovery (Swenson and others, 1976). Well yields have been reported as great as 4,000 gal/min, and well depths have been over 10,000 ft below sea level. Since Wyoming apparently does not restrict pumping to the rate of annual recharge, the Madison would appear to provide a great potential resource for the energy industry in the Powder River Basin.

Elsewhere in Wyoming there is insufficient hydrologic data to determine the potential for groundwater development.

The Cost of Water Use

In Part III we discussed water use costs for the three water supply categories. Thus, we specify

cs_j - the cost of surface water use in region j ($\$10^6/10^3$ a-ft);

ct_j - the cost of using water purchased from irrigators in region j ($\$10^6/10^3$ a-ft);

and cg_j - the cost of using groundwater in region j ($\$10^6/10^3$ a-ft).

In addition, we define

$W1_j$ - the amount of surface water used in Region j (10^3 a-ft/yr)

$W2_j$ - the amount of water purchased from irrigators in Region j (10^3 a-ft/yr)

and $W3_j$ - the amount of groundwater used in Region j (10^3 a-ft/yr).

These variables are bounded as follows:

$$W1_j \leq S_j$$

$$W2_j \leq T_j$$

$$W3_j \leq G_j$$

The cost phrase for water supply in the objective function is

$$\sum_j cs_j W1_j + ct_j W2_j + cg_j W3_j .$$

Thus, the model minimizes the cost of heat rejection by selecting the appropriate combination of water supply sources and cooling technology, subject to the constraints.

V. SUMMARY AND APPLICATIONS

Summary

There are two fundamental water- and energy-related issues:

- How does the availability of water resources influence the energy sector - the spatial distribution of activity, the mix of conversion technologies, the level of activity, and the cost of energy products?
- How does water use in the energy sector affect other water users? Some primary concerns are: the effect of flow reduction on instream resources (aesthetics, recreation, water quality, and fisheries); the effect of residuals discharges (heat, salts, and toxics) on surface and groundwater quality; the effect of groundwater pumping on water levels and discharge rates from aquifers; and the effect on output, employment and income in other sectors (especially agricultural and municipal water use).

In this report we describe a tool for water- and energy-related policy analysis, the development of a water supply and demand sector in the Los Alamos Coal Use Modeling System (LACUMS), a linear programming model of energy supply in the United States. Generally, LACUMS models the decentralized decision making of energy firms seeking to minimize production cost. Water is treated in the same manner as other economic goods necessary in the production process. Thus the model allows adjustments in the input mix and the location of activity in response to water scarcity. Electric utilities, for example, can reduce water consumption by substitution of 40 percent and 10 percent wet cooling systems for all evaporative (100 percent wet) cooling. The wet/dry cooling systems achieve roughly 50 percent and 75 percent reductions in water consumption at coal-fired electric plants for approximately a 9 percent and 12 percent increase in cost, respectively. On the water supply side, groundwater and water purchased from irrigators are available as more costly alternatives to unappropriated surface water. We determine the availability of water in these three supply categories from water basin information for 30 regions in 10 Western states (Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Montana, North Dakota, and South Dakota). Since the cost of both water use and cooling are components of total system cost, the solution algorithm examines all possible combinations of location, water supply, and cooling technology to select the least cost pattern of production. This simulates the behavior of firms in the presence of competitive water markets.

Returning then to the original dichotomy of water and energy issues, LACUMS provides quantitative data related to the first issue: that is, how do alternative energy-, and to a lesser degree water-related, policies influence

the spatial distribution, the mix and level of activity, and the cost of energy conversion? LACUMS is also useful, although to a lesser extent, in evaluating the economic and environmental impacts of alternative policies and scenarios. Because LACUMS provides quantitative estimates of groundwater use and water bid from other users, one can use the model output to set priorities for more localized impact assessments.

In summary, the distinguishing feature of LACUMS is that the pattern of water use in the energy sector (quantities and sources of supply) is determined endogenously. Most energy- and water-related modeling schemes employ a requirements approach based on the use of evaporative cooling and assume that unappropriated surface water is the only source of supply.

Preliminary Results

We made two runs of LACUMS for a 1990 energy demand scenario of a) 4.8 percent annual growth in electricity consumption from 1975 (disaggregated to the state level by an econometric model), b) production of 420,000 barrels shale oil/day, and c) production of 280,000 barrels of coal-derived liquids/day. One run employed the water supply curves in the 10 Western states in their fully active mode; the other run allowed infinite water supplies at zero cost which is the same as not having water constraints in the model.

In Table 16 comparison of the "limited" and "unlimited" water supply columns indicates that the extent of change in regional distribution of plant capacity is minor; only one region, Salt Lake City, experiences any change in capacity. The net effect of active water constraints is to shift the location of 210 MW of coal-fired electricity generation capacity from the Rocky Mountain and Northern Great Plains states to California and the Northeastern Great Plains.

There was no change in the type of cooling technology employed between the limited and unlimited water supply cases.

Table 17 presents water use by supply category and coal demand region. No groundwater consumption occurred in either the limited or unlimited water supply cases, though this is a consequence of the cost specification (10 percent greater than purchased water). In the limited water supply case, in those regions in which we estimate that surface supplies are nil-- Denver/Colorado Springs, Durango, Reno/Carson City, Salt Lake City, and North Platte, Wyoming--purchased water was used. The total purchased water constitutes 18 percent of total water consumption. Thus, a significant

TABLE 16

**RESULTS OF LACUMS MODEL RUNS: REGIONAL DISTRIBUTION OF
NEW ENERGY CONVERSION CAPACITY IN TEN WESTERN STATES^a**

Region Number	State/Region Name	New Coal Electric Capacity (MW)		Coal Liquefaction (10 ³ bbl/day)		Oil Shale (10 ³ bbl/day)	
		Limited Water Supply	Unlimited Water Supply	Limited Water Supply	Unlimited Water Supply	Limited Water Supply	Unlimited Water Supply
29	Arizona - Phoenix/Tucson	8 230	8 230				
34	Colorado - Denver/Colo. Springs	4 490	4 490				
35	- Routt					384	384
39	Idaho - Boise/Idaho Falls	3 290	3 290				
42	Montana - Upper Missouri	2 590	2 590				
61	- Yellowstone	8 830	8 830	400	400		
44	Nevada - Reno/Carson City	3 690	3 690				
47	New Mexico - Rio Grande	2 580	2 580				
49	Utah - Salt Lake City	110	320				
51	- Uintah					216	216
53	Wyoming - North Platte	1 420	1 420				
65	- Green River						
59	North Dakota - Northeast						
	TOTALS	35 230	35 440	400	400	600	600

^aWe assume coal electric plants and synthetic fuel plants operate at 65% and 70% annual capacity factors, respectively.

TABLE 17

RESULTS OF LACUMS MODEL RUNS:
1990 WATER CONSUMPTION FOR ENERGY CONVERSION
IN TEN WESTERN STATES
(10³ a-ft/yr)

Region Number	State/Region Name	Surface Water		Purchased	
		Limited	Unlimited	Limited	Unlimited
29	Arizona - Phoenix/Tucson	82.0	82.0	-	-
30	- Navajo	-	-	-	-
31	- Yavapai	-	-	-	-
34	Colorado - Denver/Colo. Springs	-	44.0	44.0	-
35	- Routt	75.0	75.0	-	-
36	- Grand Junction	1.0	1.0	-	-
37	- Durango	-	1.0	1.0	-
38	- Great Plains	-	-	-	-
39	Idaho -	32.0	32.0	-	-
42	Montana - Upper	25.0	25.0	-	-
61	- Yellowstone	139.0	139.0	-	-
44	Nevada - Reno/Carson City	-	36.0	36.0	-
46	New Mexico - San Juan	2.0	2.0	-	-
47	- Rio Grande	27.0	27.0	-	-
48	- Little Texas	2.0	2.0	-	-
49	Utah - Salt Lake City	-	3.0	1.0	-
51	- Uintah	42.0	42.0	-	-
53	Wyoming - North Platte	-	14.0	13.9	-
65	- Green River	-	-	-	-
TOTALS		427.0	525.0	95.9	-

quantity of water which might be used at energy facilities could be supplied by the agricultural sector. Although we do not trace the ramifications of this reduction for economic activity in that sector, we note that 95,900 a-ft/yr represents about one-third of one percent of 1975 freshwater consumption for irrigation in the ten Western states (see Table I).

The sensitivity of the results of the LACUMS runs should be tested by variation of a) the quantity of water available in each supply category, b) water use costs, c) water consumption coefficients, and d) incremental costs of water conservation by substitution of wet/dry cooling. Nevertheless, we offer the tentative conclusion that in the short to intermediate term and at the level of spatial disaggregation in LACUMS, water availability plays a minor role in energy facility siting. Certainly, there are legal and institutional impediments to the procurement of large industrial water

supplies. But, as represented by the structure and data inputs of the model, there are a variety of water use alternatives available to energy firms when any one option is foreclosed.

Water-Related Policy Applications of LACUMS

A recent Bechtel study projected costs of coal-derived liquid and gas in the range of \$7-10/10⁶ Btu output and shale oil in the range of \$3-4/10⁶ Btu output (\$1979) (Synthetic Fuels, 1980). This radical cost differential suggests the rationale for Exxon's startling projection that, "the output of a cost-effective 15 million bbl/day [synthetic fuel industry by the year 2000] would include eight million bbl/day of shale oil from high-yielding deposits in the Piceance and Uinta Basins in Colorado and Utah." (Exxon, Corp., 1980).

The response to the Exxon scenario from Colorado politicians was rapid and vehement. They complained about the lack of consultation, they noted air quality, reclamation, and boom town problems; most important, they said the water was not available. One might use the Los Alamos Coal Use Modeling System to project the water demands of such a large scale industry, to comment on the feasibility of this level of production, and most important, to examine tradeoffs between apparently less costly shale oil production and production of more costly coal-derived liquids dispersed throughout the coal producing regions of the United States.

Another possible policy application relates to the policies of the US Environmental Protection Agency towards waste heat rejection from steam turbine condensers. In the 1970s, to avoid thermal pollution of streams and adverse effects on aquatic organisms, the EPA forced most inland utilities to employ closed-cycle cooling systems that cost more and that consume more water than once-through cooling systems. In the last several years there has been growing interest in even more costly dry and wet/dry cooling systems as part of a water conservation policy. Reynolds (1980) suggests that renewed consideration be given to the environmental and economic tradeoffs of cooling alternatives. With proper management and design the risk of damage to aquatic ecosystems from once-through cooling may be minimal. Closed-cycle cooling not only increases energy product costs but reduces the flow and assimilative capacity of streams and causes other irreversible environmental damages (from drift and disposal of salts and water treatment chemicals). One might use the Los Alamos Coal Use Modeling System to quantify the reduction in water

consumption and energy costs available by a relaxation of EPA standards for power plant thermal discharges.

For these and other policy applications, it is certainly important to supplement the LACUMS modeling activities with other kinds of analyses. But the Los Alamos Coal Use Modeling System has the distinct advantage of casting the problem of water allocation to the energy sector in an economic and quantitative framework.

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