United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/7-78-197a
October 1978

EPA

Water-related Environmental Effects in Fuel Conversion: Volume I. Summary

Interagency Energy/Environment R&D Program Report

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

EPA REVIEW NOTICE

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
RESEARCH TRIANGLE PARK
NORTH CAROLINA 27711

DATE: November 20, 1978

SUBJECT: Water-Related Environmental Effects in Fuel Conversion

FROM: William J. Rhodes
Program Manager, Synthetic Fuels
Fuel Process Branch
Energy Assessment and Control Div. (MD-61)

TO: Distribution

The attached multi-volume report presents results of water-related effects that can be expected from siting conversion plants in major U.S. coal and oil shale bearing regions. Ninety plant site combinations were studied from the Eastern, Central, and Western U.S.

The results include the water requirements, considerations in optimizing the use of water, costs and energy requirements for wastewater treatment, and ranges of residual solid wastes. All water requirements of this study are based on complete water reuse which is no direct water discharge to streams or rivers.

This report includes work performed for EPA and DOE. The work was integrated into one report to be more effective.

Attachment

Distribution

Ann Alford
Walt Barber
Del Barth
Thomas Belk
David Berg
K. E. Biesinger
Rudy Boksleitner
W. E. Bye
A. Corson
Stan Cuffe
Tom Duke
Al Ellison
J. E. Fitzgerald
Al Galli
Tom Hauser
Stan Hegre
Bill Horning
Joellen Huisingh
Nick Humber
B. M. Jarrett
J. W. Jordan
W. W. Kovalick
R. W. Kuchkuda
John Lehman
A. Levin
K. Mackenthun
W. N. McCarthy, Jr.
L. A. Miller
Don Mount
John Nader
Eric Preston
Gerry Rausa
Walt Sanders
Robert Schaffer
David Shaver
Jerry Stara
George Stevens
Bill Telliard
John Lum
W. G. Tucker
Jerry Walsh
Mike Waters
Eugene Wyszpolski
Morris Altschuler
Josh Bowen
P. P. Turner
A. B. Craig
Don Goodwin
R. P. Hangebrauck
T. K. Janes
Steve Jelinek
J. D. Kilgroe
A. Lefohn
G. D. McCutchen
E. L. Plyler
F. T. Princiotta
N. D. Smith
D. A. Schaller
R. M. Statnick

EPA-600/7-78-197a

October 1978

Water-related Environmental Effects in Fuel Conversion: Volume I. Summary

by

Harris Gold and David J. Goldstein

Water Purification Associates
238 Main Street
Cambridge, Massachusetts 02142

Contract No. 68-03-2207
Program Element No. EHE623A

EPA Project Officer: Chester A. Vogel

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

PREFACE

The work presented in this report was supported by the U.S. Environmental Protection Agency (EPA) under Contract No. 68-03-2207 and the U.S. Department of Energy (DOE) under Contract No. EX-76-C-01-2445. The site specific studies of the Western states were supported principally by EPA, while those of the Eastern and Central states were supported by DOE. In addition the results of the Western site studies were synthesized into the DOE program in order to generalize the results to the United States as a whole. It seemed appropriate to incorporate all of the results into one document in order to increase the usefulness of the report rather than to fragment the study into separate reports. The report consists of a summary volume and an appendix volume and will be issued separately by each of the sponsoring agencies to receive as wide a distribution as possible.

The authors gratefully acknowledge the help and support of Mr. John A. Nardella, Program Manager, and Mr. James C. Johnson of DOE and Mr. Chester A. Vogel, Program Manager, and Mr. T. Kelly Janes of EPA. We are grateful to D. Morazzi, C. Morazzi, P. Gallagher and P. Qamoos for carrying out the detailed process-site calculations. We wish also to acknowledge Resource Analysis, Inc. and Richard L. Laramie, John H. Gerstle and David H. Marks in particular for supplying information on water resources developed under several joint programs with Water Purification Associates.

CONTENTS

Contents (Cont.)

(*) All appendices are in Volume II.

FIGURES

Figures (Cont.)

Figures (Cont.)

TABLES

Number | Page

Number	Tables (Cont.)	Page

CONVERSION FACTORS

Conversion of American to International System (SI) Units

	Multiply	By	To Obtain
ACCELERATION	foot/second^2	3.048×10^{-1}	meter/second^2
	free fall, standard	9.807	meter/second^2
AREA	acre	4.047×10^{3}	meter^2
	feet^2	9.290×10^{-2}	meter^2
ENERGY	Btu (mean)	1.056×10^{3}	joule
	calorie (mean)	4.190	joule
	kilowatt-hours	3.60×10^{6}	joule
ENERGY/AREA-TIME	Btu/foot^2 hour	3.152×10^{-1}	watt/meter^2
	Btu/foot^2 minute	1.891×10^{2}	watt/meter^2
	Btu/foot^2 second	1.135×10^{4}	watt/meter^2
	calorie/cm^2 minute	6.973×10^{2}	watt/meter^2
FORCE	dyne	1.00×10^{-5}	newton
	kilogram force (Kg_f)	9.807	newton
	pound force (lb_f, avoirdupois)	4.448	newton
LENGTH	foot	3.048×10^{-1}	meter
	mile	1.609×10^{3}	meter
MASS	pound (avoirdupois)	4.536×10^{-1}	kilogram
	ton (metric)	1.00×10^{3}	kilogram
	ton (short, 2000 lb)	9.072×10^{2}	kilogram
MASS/TIME	pound/hour	1.260×10^{-4}	kilogram/second
	pound/minute	7.560×10^{-3}	kilogram/second
	ton (short)/hour	2.520×10^{-1}	kilogram/second
	ton (short)/day	1.050×10^{-2}	kilogram/second
MASS/VOLUME	gram/centimeter^3	1.00×10^{3}	kilogram/meter^3
	pound/foot^3	1.602×10^{1}	kilogram/meter^3
	pound/gallon (U.S. liquid)	1.198×10^{2}	kilogram/meter^3
MISCELLANEOUS	Btu/hr-ft^2-°F	5.674	joules/sec-m^2-°C
	Btu/kw-hr	2.929×10^{-1}	joules/kw-sec
	Btu/lb_m	2.324×10^{3}	joule/kg
	Btu/lb_m-°F	4.184×10^{3}	joule/kg-°C
	gal/10^6 Btu	3.585×10^{-12}	meter^3/joule
	kilocalorie/kilogram	4.184×10^{3}	joule/kg
POWER	Btu/hour	2.929×10^{-1}	watt
	Btu/minute	1.757×10^{1}	watt
	Btu/second	1.054×10^{3}	watt
	calorie/hour	1.162×10^{-3}	watt
	calorie/minute	6.973×10^{-2}	watt
	calorie/second	4.184	watt
	horsepower	7.457×10^{2}	watt
PRESSURE	atmosphere	1.013×10^{5}	pascal (= newton/m^2)
	foot of water (39.2°F)	2.989×10^{3}	pascal
	psi (lb_f/in^2)	6.895×10^{3}	pascal
	lb_f/foot^2	4.788×10^{1}	pascal
SPEED	foot/minute	5.08×10^{-3}	meter/second
	foot/second	3.048×10^{-1}	meter/second
	mile/hour	4.470×10^{-1}	meter/second
TEMPERATURE	°F	0.556 (°F + 459.7)	°K

(continued)

	Multiply	By	To Obtain
VOLUME	acre foot	1.590×10^{-1}	$meter^3$
	barrel (oil, 42 gal)	1.233×10^{3}	$meter^3$
	$foot^3$	2.832×10^{-2}	$meter^3$
	gallon (U.S. liquid)	3.785×10^{-3}	$meter^3$
VOLUME/TIME	ft^3/min	4.719×10^{-4}	$meter^3$/second
	ft^3/sec	2.832×10^{-2}	$meter^3$/second
	gal (U.S. liquid)/day	4.381×10^{-8}	$meter^3$/second
	gal (U.S. liquid)/min	6.309×10^{-5}	$meter^3$/second

Other Conversion Factors

The following table is based on a density of water of 62.3 pounds per cubic foot. This is the density of water at 68°F (20°C) and corresponds to 8.33 pounds of water per gallon.

acres	4.36×10^{4}	square feet
acres	1.56×10^{-3}	square miles
acre-feet	4.36×10^{4}	cubic feet
acre-feet	3.26×10^{5}	gallons
acre-feet/year	1.38×10^{-3}	cubic feet/second
acre-feet/year	3.91×10^{-5}	cubic meters/second
acre-feet/year	6.20×10^{-1}	gallons/minute
acre-feet/year	8.93×10^{-4}	million gallons/day
barrels, oil	4.2×10	gallons
Btu	2.52×10^{2}	calories
Btu	3.93×10^{-4}	horsepower-hours
cubic feet	2.30×10^{-5}	acre-feet
cubic feet	7.48	gallons
cubic feet of water	6.23×10^{1}	pounds of water
cubic feet/second	4.49×10^{2}	gallons/minute
cubic feet/second	6.46×10^{-1}	million gallons/day
gallons	3.07×10^{-6}	acre-feet
gallons	2.38×10^{-2}	barrels, oil
gallons	1.34×10^{-1}	cubic feet
gallons of water	8.33	pounds of water
gallons/minute	1.61	acre-feet/year
gallons/minute	2.23×10^{-3}	cubic feet/second
gallons/minute	1.44×10^{-3}	million gallons/day
gallons of water/minute	5.00×10^{-1}	thousand pounds of water/hr
horsepower	6.11×10^{4}	Btu/day
horsepower	2.55×10^{3}	Btu/hour
kilowatt-hours	3.41×10^{3}	Btu
milligrams/liter	1	parts/million
million gallons/day	1.12×10^{3}	acre-feet/year
million gallons/day	1.55	cubic feet/second
million gallons/day	6.94×10^{2}	gallons/minute
million gallons of water/day	3.47×10^{2}	thousand pounds of water/hr
pounds of water	1.20×10^{-1}	gallons of water
pounds of water	1.60×10^{-2}	cubic feet of water
pound moles of gas	3.80×10^{2}	standard cubic feet of gas
square feet	2.30×10^{-5}	acres
temperature, °C	1.8	32 °F
temperature, °F-32	5.56×10^{-1}	°C
thousand pounds/hour	1.2×10	tons/day
thousand pounds/hour	4.38×10^{3}	tons/year
thousand pounds of water/hour	2.00	gallons of water/minute
thousand pounds of water/hour	2.88×10^{-3}	millions gals of water/day
tons (short)	2×10^{3}	pounds
tons (short)	9.07×10^{-1}	metric tons
tons/day	8.33×10^{-2}	thousand pounds/hour
tons/year	2.28×10^{-4}	thousand pounds/hour
watts	3.41	Btu/hour

1. EXECUTIVE SUMMARY

1.1 Process and Site Selections

The synthetic fuel technologies examined include: coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low sulfur fuel oil; coal refining to produce a de-ashed, low sulfur solvent refined (clean) coal; and oil shale retorting to produce synthetic crude. A number of processes were chosen for each conversion. Detailed conceptual designs for integrated mine-plant complexes were made for each of the representative conversion processes in order to compare water requirements, types of water treatment plants, and the quantities of wet-solid residuals generated. The processes and products chosen for comparison are shown in Table 1-1. Except for the commercially available Lurgi process, the processes chosen are representative of those that have undergone extensive development and which are sufficiently described in the available literature so that detailed process calculations can be made. The products chosen are synthetic fuels; the production of chemicals from coal or shale, e.g., ammonia or methanol production via coal gasification, was not considered. Specific designs in the appendices are based on standard size plants with the given product output.

TABLE 1-1 PRODUCT FUEL OUTPUT OF STANDARD SIZE SYNTHETIC FUEL PLANTS

Technology and Conversion Process	Product	Output	Product Heating Value (10^{11} Btu/day)
Coal Gasification	Pipeline Gas	250×10^6 scf/day	2.4
Lurgi			
Synthane			
Hygas			
Bigas			
Coal Liquefaction	Fuel Oil	50,000 barrels/day	3.1
Synthoil			
Coal Refining	Solvent Refined Coal	10,000 tons/day	3.2
SRC			
Oil Shale	Synthetic Crude	50,000 barrels/day	2.9
Paraho Direct			
Paraho Indirect			
TOSCO II			

Many site and process criteria combinations were studied in order to obtain meaningful assessments on a regional and national level from detailed local results. Process criteria for the conversion of coal have been defined based upon the quality of the foul condensate recovered after gasification or liquefaction. Low temperature gasifiers (e.g., Lurgi and Synthane), produce a very dirty process condensate (typical values for bituminous coals: BOD $\sim$ 10,000 mg/l, phenol $\sim$ 3,000 mg/l and ammonia $\sim$ 7,000 mg/l). High temperature gasifiers (e.g., Koppers-Totzek and Bigas), produce a relatively clean condensate (typical values: ammonia $\sim$ 4,500 mg/l, BOD and phenol $\sim$ small). The intermediate temperature Hygas gasifier produces a process condensate of intermediate quality. Both the Solvent Refined Coal (SRC) and Synthoil processes have the foulest condensates. For oil shale conversion, the degree of water management depends on the type of retort used. For direct-heated retorting processes (e.g., Paraho Direct), most of the water is recovered; however, for indirect-heated processes (e.g., Paraho Indirect and TOSCO II), the water in the combustion products is generally lost up the furnace stack and not recovered.

As for site criteria, brackish ground water would have to be considered an important conjunctive supply to surface waters in the West, while surface waters are considered primarily in the East. Eastern and Central States have humid climates, while climates in the West are arid and semi-arid. Eastern and Central coals are both underground and surface mined, while Western coals are primarily surface mined. In the West, underground mining followed by surface retorting of oil shale has been investigated extensively. In-situ retorting was not considered in the present study because it is still under development and cannot yet be considered commercially, although it could drastically reduce the water consumption.

Site selection was based primarily on the availability of coal and oil shale, the rank of coal or oil shale, the type of mining (underground or surface) and the availability of surface and groundwater. Coal mining regions chosen were those where the largest and most easily mined deposits are located. In the West, these include the Powder River and Ft. Union regions in Montana, Wyoming, and North Dakota, and the Four Corners region in New Mexico. In the Central and Eastern regions, the Illinois and Appalachian coal basins were selected. Western coals are principally low sulfur subbituminous and lignite, while Eastern and Central coals are mainly high sulfur bituminous. The only oil shale considered was high grade shale from the Green River Formation. Specific design examples were restricted to shales with yields of about 30 to 35 gallons per ton, as might be found in Colorado or Utah.

Tables 1-2 and 1-3 list the plant-site combinations for the Eastern and Central States, and Western States, respectively. The number of plant-site combinations chosen are sufficient to enable generalized rules to be derived concerning the quantities of water consumed and wet-solid residuals generated as a function of conversion technology and coal or oil shale region. The locations of these sites with respect to the major energy reserves and the primary water resources characteristics are shown in Figures 1-1 and 1-2. The maps show more sites than the ones given in the tables. Primary sites correspond to the sites listed in Tables 1-2 and 1-3 and secondary sites were selected to provide a larger study area with respect to water availability.

1.2 Water Supply and Demand

A general assessment of the water resources data in the major U.S. coal and oil shale regions was made. Potential water supply sources for each site were evaluated on a site specific basis in terms of total available water supply, the needs and rights of other competing water users, and water quality. Factors which were considered were the extent and variability of nearby stream flows or ground-water aquifers, legal institutions regulating the use of these waters, environmental considerations, and the implications of competing users for limited supplies in certain areas. The institutional constraints include the legal doctrines governing the use of water. In the East this is generally the Riparian Doctrine, which defines surface water rights as ownership of land next to or traversing the natural stream. In the West the Appropriation Doctrine usually applies: first appropriation of water conveys priority, independently of the location of the land with respect to the water. Other constraints may involve competing claims, such as Indian water rights.

Principal among environmental considerations are the possibility of the disruption of natural underground aquifers from the mining operation, and

TABLE 1-2 PLANT-SITE COMBINATIONS FOR EASTERN AND CENTRAL STATES

State	County	Water Source		Mining [a]	Coal [b]	Coal Gasification				Coal Liquefaction and Coal Refining		Plant-Site Combinations	
						High Temp.Gasifier		Low Temp.Gasifier					
		Surface	Ground			Hygas	Bigas	Lurgi	Synthane	Synthoil	SRC	No.	Total State
Alabama	Jefferson	Alabama R.		U	B	X			X	X		3	
	Marengo	Tombigbee R.	X	S	L	X		X			X	6	9
Illinois	Bureau		X	U	B		X	X			X	3	
	Shelby	Ohio R.		U	B		X					1	
	St. Clair	Ohio R.		U	B			X				1	
	White	Ohio R.		U	B						X	1	
	Bureau	Illinois R.		S	B		X					1	
	Fulton		X	S	B			X			X	2	
	St. Clair	Ohio R.		S	B			X				1	
	Saline	Ohio R.		S	B						X	1	11
Indiana	Gibson	White R.		U	B	X			X	X		3	
	Vigo	White R.		U	B		X					1	
	Sullivan	Ohio R.		S	B				X			1	
	Warrick	Ohio R.		S	B	X				X		2	7
Kentucky	Floyd	Ohio R.		U	B				X			1	
	Harlan	Ohio R.		U	B					X		1	
	Muhlenberg	Green R.		S	B			X				1	
	Pike	Ohio R.		S	B					X		1	4
Ohio	Gallia	Ohio R.		U	B				X			1	
	Tuscarawas	Muskingum R.	X	U	B	X				X		4	
	Jefferson	Ohio R.		S	B	X			X	X		3	8
Pennsylvania	Armstrong	Allegheny R.		U	B	X			X			2	
	Somerset	Allegheny R.		U	B					X		1	3
West Virginia	Fayette	Kanawha R.		U	B	X						1	
	Kanawha	Kanawha R.		U	B				X			1	
	Monongalia	Allegheny R.		U	B	X						1	
	Preston	Kanawha R.		U	B				X			1	
	Mingo	Kanawha R.		S	B	X				X		2	6
												TOTAL	48

a U = Underground; S = Surface.

b B = Bituminous; L = Lignite

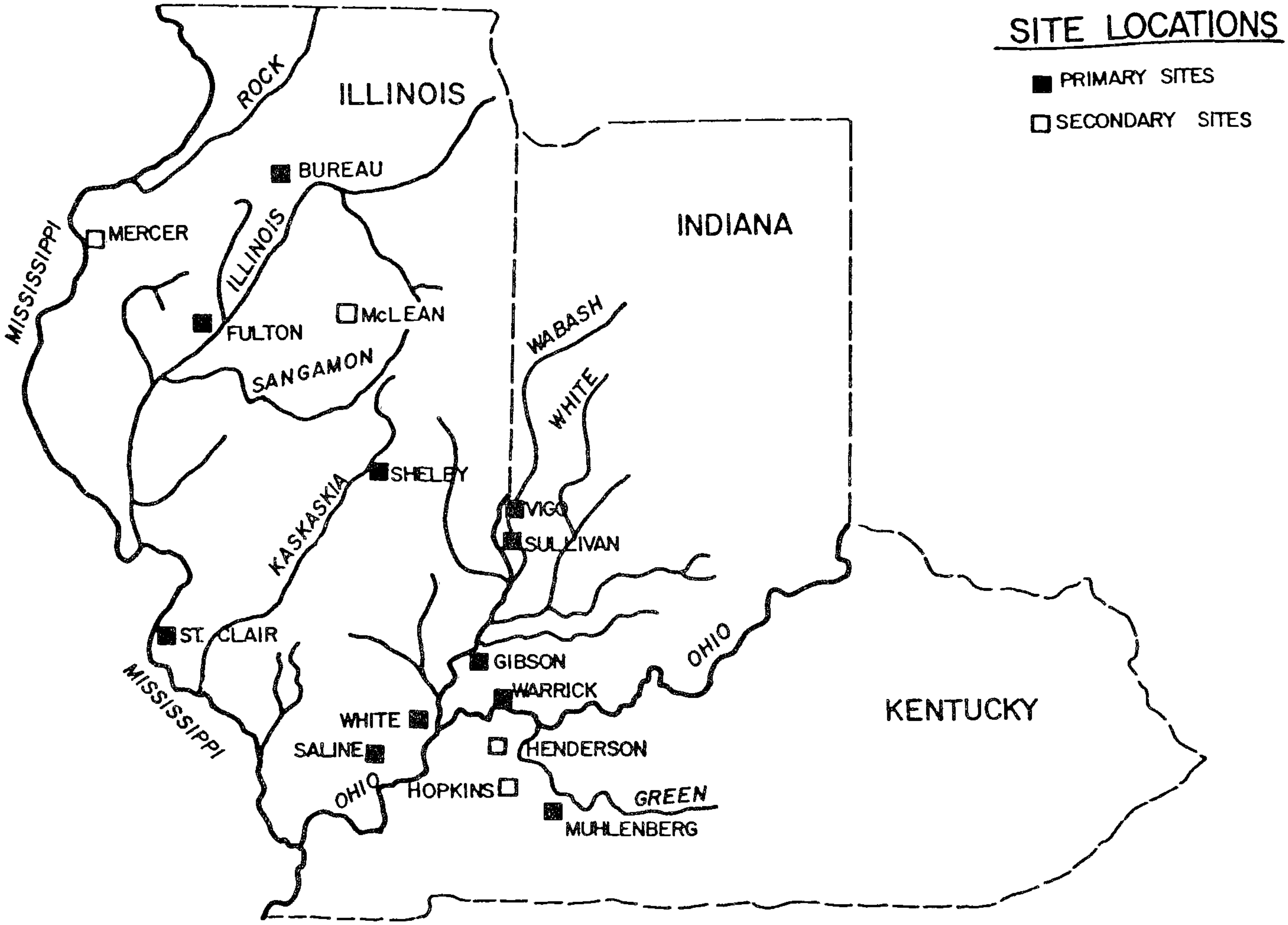
TABLE 1-3 COAL AND OIL SHALE CONVERSION PLANT-SITE COMBINATIONS FOR WESTERN STATES

State	Mine	Water Source Surface	Water Source Ground	Mining[a]	Coal[b]	Coal Gasification: High Temp. Gasifier Hygas	Coal Gasification: High Temp. Gasifier Bigas	Coal Gasification: Low Temp. Gasifier Lurgi	Coal Gasification: Low Temp. Gasifier Synthane	Coal Liquefaction and Coal Refining Synthoil	Coal Liquefaction and Coal Refining SRC	Plant-Site Combinations No.	Plant-Site Combinations Total State
Montana	Decker-Dietz		X	S	S	X		X				2	
	Foster Creek	Tongue R.		S	S			X				1	
	U.S. Steel Chupp Mine	Yellowstone R.		S	L		X					1	
	East Moorhead	Powder R.		S	L	X						1	
	Pumpkin Creek	Tongue R.		S	L						X	1	
	Otter Creek		X	S	L						X	1	
	Colstrip	Yellowstone R.		S	S	X			X		X	3	
	Coalridge	Missouri River		S	L						X	1	11
New Mexico	Gallup		X	S	S	X		X		X		3	
	El Paso	San Juan R.		S	S	X		X				2	
	Wesco	San Juan R.		S	S			X				1	6
North Dakota	Scranton	Grand R.		S	L		X					1	
	Bentley	Knife R.		S	L						X	1	
	Underwood	L. Sakakawea		S	L						X	1	
	Knife River	Knife R.		S	L			X				1	
	Center	Knife R.		S	L		X					1	
	Slope	Yellowstone R.		S	L		X					1	
	Dickinson	L. Sakakawea		S	L						X	1	
	Williston	Missouri R.		S	L			X				1	8
Wyoming	Belle Ayr	Crazy Woman Cr.		S	S	X						1	
	Gillette-Wyodak	Crazy Woman Cr.		S	S	X					X	2	
	Spotted Horse Strip	Powder R.		S	S				X			1	
	Hanna	Medicine Bow		S	S	X						1	
	Antelope Creek Mine	Beaver Cr.	X	S	S	X			X		X	3	
	Lake-de-Smet	Tongue R.		S	S					X		1	
	Kemmerer	Hams Fork		S	B		X	X				2	
	Jim Bridger	Green R.		S	S					X		2	
	Rainbow #8	Green R.		U	B						X	1	14
												TOTAL	39

State	Mine	Water Source Surface	Water Source Ground	Mining[a]	Shale[c]	Direct Retort Paraho Direct	Indirect Retort Paraho Indirect	Indirect Retort TOSCO II	Plant-Site Combinations No.	Plant-Site Combinations Total State
Colorado	Parachute Creek	Colorado R.		U	HG	X	X	X	3	3
									TOTAL	3

a U = Underground; S = Surface
b B = Bituminous; L = Lignite; S = Subbituminous
c HG = High grade shale

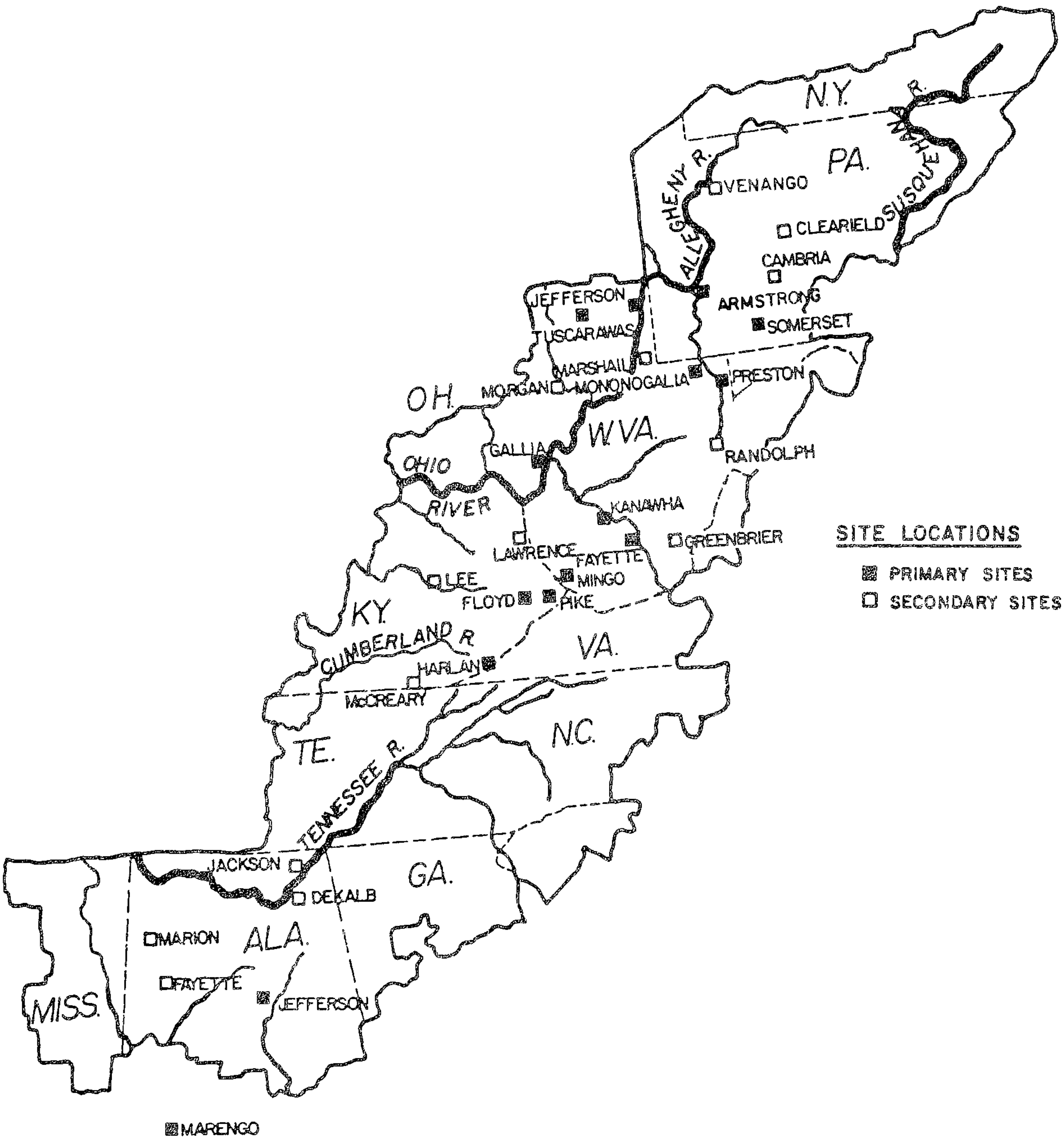
5



ILLINOIS COAL REGION

(continued)

Figure 1-1 Coal conversion site locations in Eastern and Central states.



APPALACHIAN COAL REGION

Figure 1-1 (concluded).

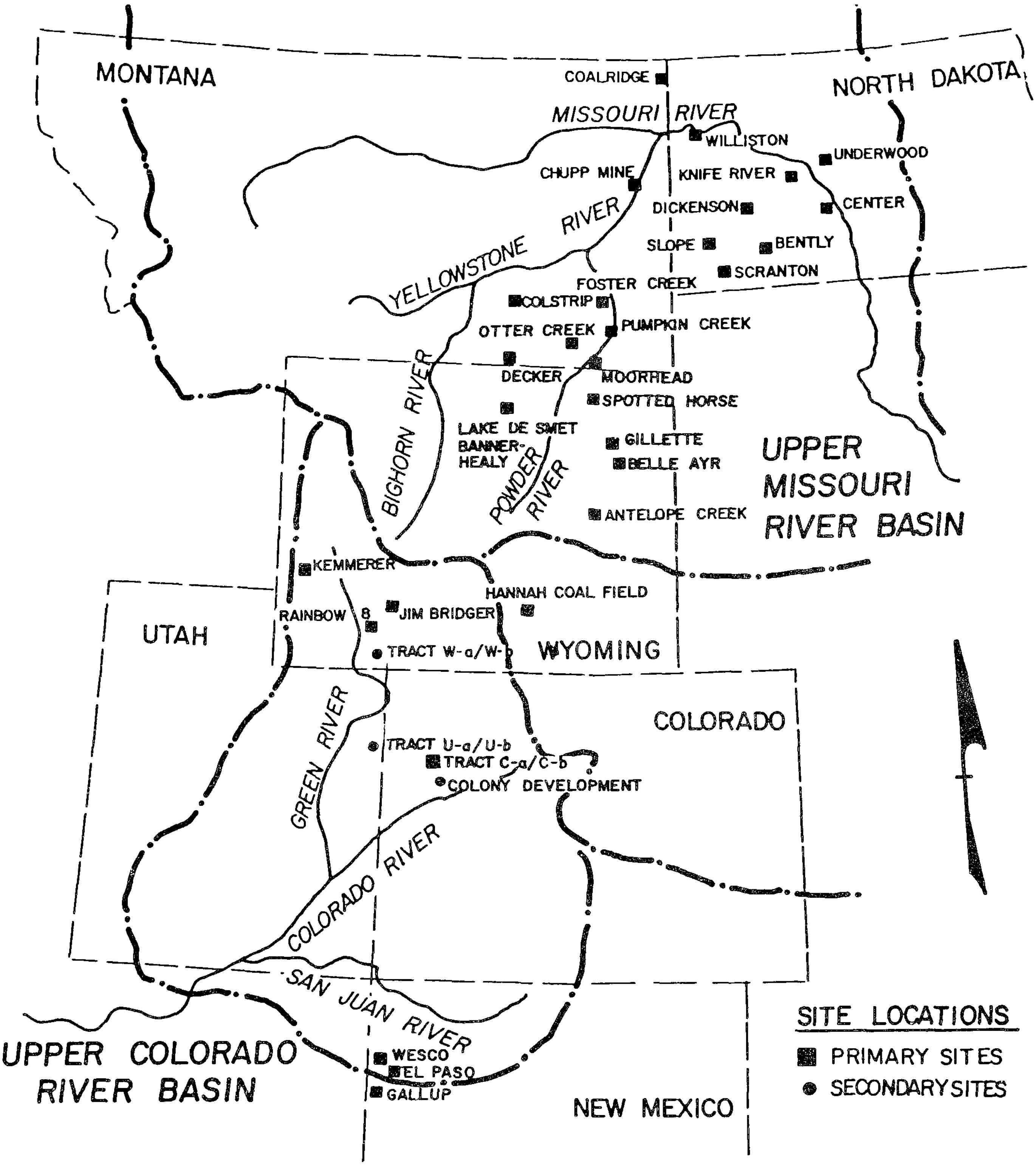


Figure 1-2 Coal and oil shale conversion site locations in Western states.

surface and groundwater contamination from the leaching of disposed wastes or from acid mine drainage; the latter particularly presents problems in the Appalachian coal region.

The adequacy of the water supply at each primary site having a stream as its water source was assessed through a comparison of a typical plant use with expected low flows in the stream. In the Appalachian coal region, where coal is available, there are a number of large rivers contiguous or adjacent to many of the sites that can provide a sufficient and reliable supply of water to support one or more large mine-plant coal conversion complexes. This applies to all plant sites in the vicinity of the Ohio, Allegheny, Tennessee, Tombigbee and Kanawha-New Rivers. In most of these instances present water use data and future demand projections indicate a significant surplus beyond expected use, even under low flow conditions.

The surface water supplies are much less reliable in the smaller streams, away from the major rivers. Regions generally found to have limited water supplies for energy development include: the upper reaches of the Cumberland and Kentucky Rivers in eastern Kentucky; the eastern Kentucky and adjacent West Virginia coal regions in the Big Sandy River Basin; and northern West Virginia and western Pennsylvania in the Monongahela River Basin, except those areas that can be supplied from the Allegheny, Ohio or Susquehanna Rivers. Under future conditions a minor surplus will exist for the Tuscarawas River in Ohio. In these water-limited areas extreme low flows are practically zero and a coal conversion complex could easily represent a significant portion of the seasonal low flow. In order for a plant to be sited here an alternative or supplemental supply must be assured. Figure 1-3 shows the availability of water in the Appalachian coal region.

Within the Illinois coal region, the Ohio and Mississippi Rivers have sufficient and reliable water supplies to support one or more large mine-plant coal conversion complexes. The lower section of the Kaskaskia, Illinois and Wabash Rivers in Illinois; the Wabash and White Rivers in Indiana; and the Green River in Kentucky also have reliable supplies. Under future conditions in the year 2000 deficit supplies are indicated for the Wabash River in Illinois Figure 1-4 shows the availability of water in the Illinois coal region.

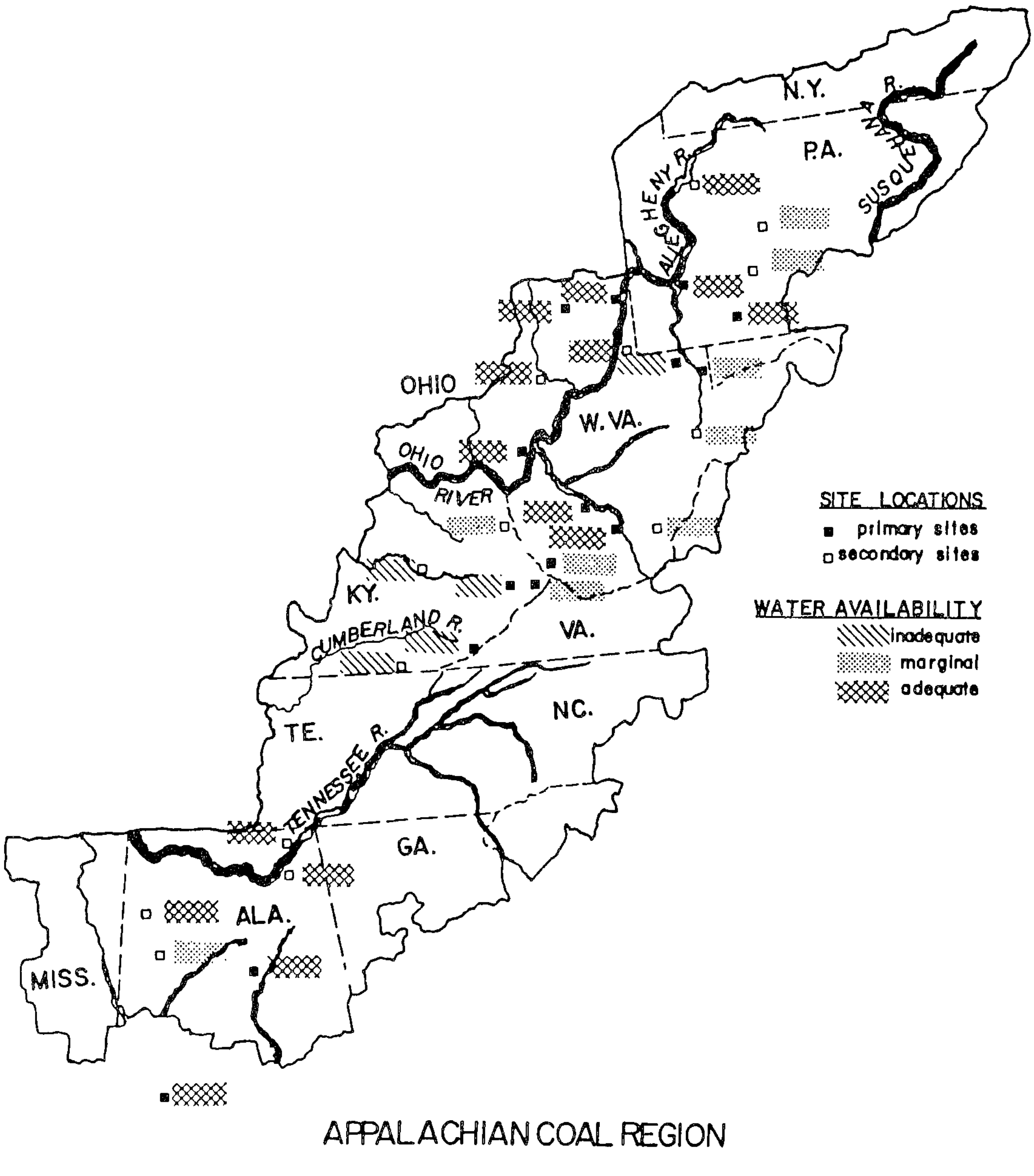


Figure 1-3 Water availability in the Appalachian coal region.

Figure 1-4. Water availability in the Illinois coal region.

Groundwater was also specified as a water source for some sites located in Illinois and Ohio. The Wabash and White subbasins probably have the highest potential of all Ohio River subbasins for additional groundwater development. Conditions appear to be most favorable for groundwater development in parts of Alabama.

The water resources in the major coal and oil shale bearing regions of the Western United States can be conveniently separated into two major water shed regions: the Upper Missouri River Basin and the Upper Colorado River Basin. Each one of the Basins was further divided into several hydrologic subregions of interest with respect to water availability for energy development. Estimates were made of water availability within each subregion for coal and oil shale production.

In the Powder River and Ft. Union coal regions shortages occur in parts of the Yellowstone River Basin during periods of low flow. Water can be obtained by appropriation and transferred by transbasin diversions. However, there are a number of serious institutional conflicts in the region, particularly in Montana and Wyoming, concerning the authority to allocate water. Competitive pressures from agricultural water users are very high and irrigation needs are large because of the semi-arid climate. Environmental problems associated with the disruption of natural underground reservoirs by mining may also be important.

The coal and oil shale regions of the Upper Colorado River Basin are situated in an arid area marked by an inadequate water supply of poor quality. The region is subjected to highly variable annual stream flows. It may be possible to utilize groundwater as a conjunctive supply, but this water is generally of a poor quality and often drawn from underground reservoirs which would eventually be depleted. However, we should note that for some proposed oil shale developments, the quantity of groundwater produced by mine dewatering would exceed the plant water requirements. Strong competition exists among agricultural, municipal and industrial users for the available supply, most of which is now either appropriated or over-appropriated. Serious institutional conflicts involving Indian water rights also exist in the area.

Because agriculture has long been an important part of the Western economy, numerous storage reservoirs have been built throughout both Basins to more evenly distribute spring runoff during the year, particularly the growing season.

Two limiting cases were examined with respect to water availability in the West: low water demand and high water demand. For low water demand, two standard size coal or oil shale conversion plants (without regard to type) were located in each of the hydrologic subregions. This corresponds to the production of from 0.5 to 1.0×10^6 barrels/day of synthetic crude, or its equivalent in other fuels. For high water demand, 1×10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 5.8×10^{12} Btu/day, were produced in each of the three principal coal bearing regions (Ft. Union, Powder River and Four Corners) and in the principal oil shale region (Green River Formation), for a total production of 4×10^6 barrels/day.

Low water demand can be accommodated by available supplies in most of the subregions. However, chronic water shortages do exist, especially in the northern Wyoming area of the Powder River coal region and the Tongue-Rosebud drainage area in the Ft. Union coal region. In the Four Corners-San Juan region in northwestern New Mexico and the Belle-Fourche-Cheyenne basin in northeast Wyoming, the water demands are greater than about twenty percent of the total water availability, which may be considered to be excessive. For high water demand, projected loads cannot be accommodated by available supplies in most subregions. Only in the Yellowstone, Upper Missouri, Lower Green and Upper Colorado mainstem basins does it appear that sufficient supplies are available for the expected loads of energy production. However, water availability in the Upper Colorado River Basin may be limited because all of the water rights to most of the free flowing water in the Basin are already allocated. These rights would have to be transferred to support additional energy development or water transferred by transbasin diversion.

Estimates have been made of the cost of transporting water to the point of use from major interstate rivers and riverways. Figure 1-5 shows the cost of transporting water to all sites for low water demand. The cost of water determines the degree to which wet cooling should be used. If water costs less than $0.25/1000 gals, a high degree of wet cooling should be used; if it costs greater than $1.50/ 1000 gals, a minimum degree of wet cooling should be used; in between these extremes, intermediate wet cooling should be used. Figure 1-5 shows that except for plants located near the mainstem of major rivers or near large reservoirs, intermediate or minimum practical wet cooling is desirable for most of the sites in the Western study area.

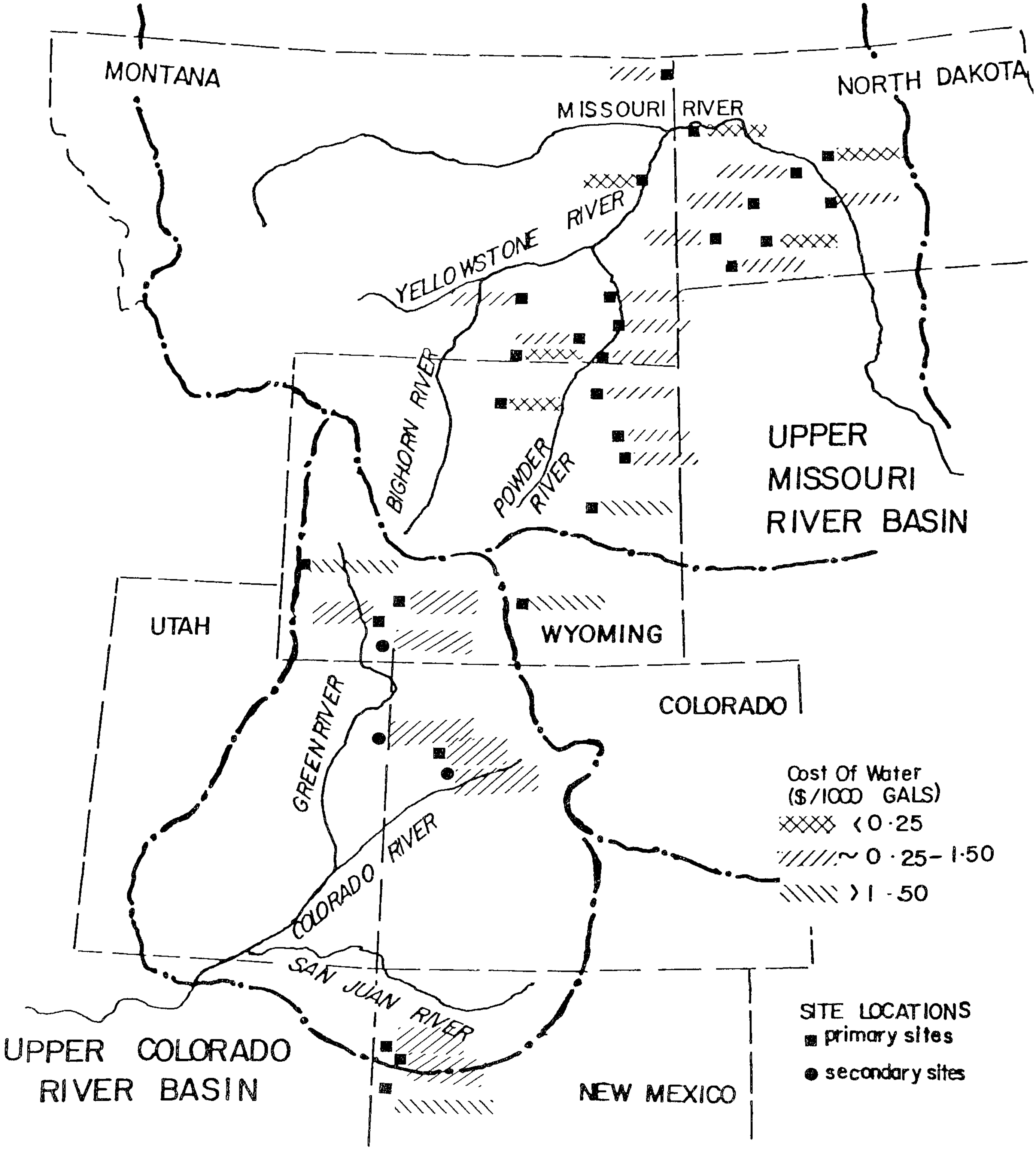


Figure 1-5 Cost of transporting water to specific site locations in the Western states.

For large scale synthetic fuel production, it is more economical to have a large single pipeline built to transport water to a large number of plants than to have a large number of individual pipelines supplying individual plants. Figure 1-6 shows the cost of transporting large quantities of water (high water demand) to some of the major coal producing areas and indicates that except for large scale development near the mainstem of major rivers, intermediate cooling is desirable for most of the study region.

1.3 Process-Site Results

The process-site results are summarized in Table 1-4. They are presented by conversion process with no distinction made between coal rank, except for the mining rates. Results have been normalized with respect to the heating value of the product. The difference in mining rates is due to the variation in the heating values of the different rank coals and the different conversion efficiencies of the processes considered.

Water Consumed

Estimates of water consumption are net; all major effluent streams are assumed to be recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated waters generated in the conversion process, which are unfit for disposal without treatment, and the highly saline water blown down from evaporative cooling systems. Water is only released to evaporation ponds as a method of salt disposal, when the usual inorganic concentration of released wastes is about 2 percent (for example, ion exchange regeneration wastes and cooling tower blowdown when more than 10 cycles of concentration are used and less than 10 percent of the intake water is released). However, we have generally assumed that these wastes are usually disposed of with the coal ash. The rest of the water consumed leaves the plant as vapor, as bonded hydrogen (after hydrogenation) in the product, or as occluded water in the solid residues. Dirty water is cleaned, but only for reuse and not for returning it to a receiving water.

In general the total quantity of net water consumed depends primarily on the quantity of water evaporated in cooling. The cost and availability of water determine the degree to which wet cooling should be used. Three cooling options were considered representing different kinds of wet evaporative cooling for turbine condensers and gas-compressor interstage coolers.

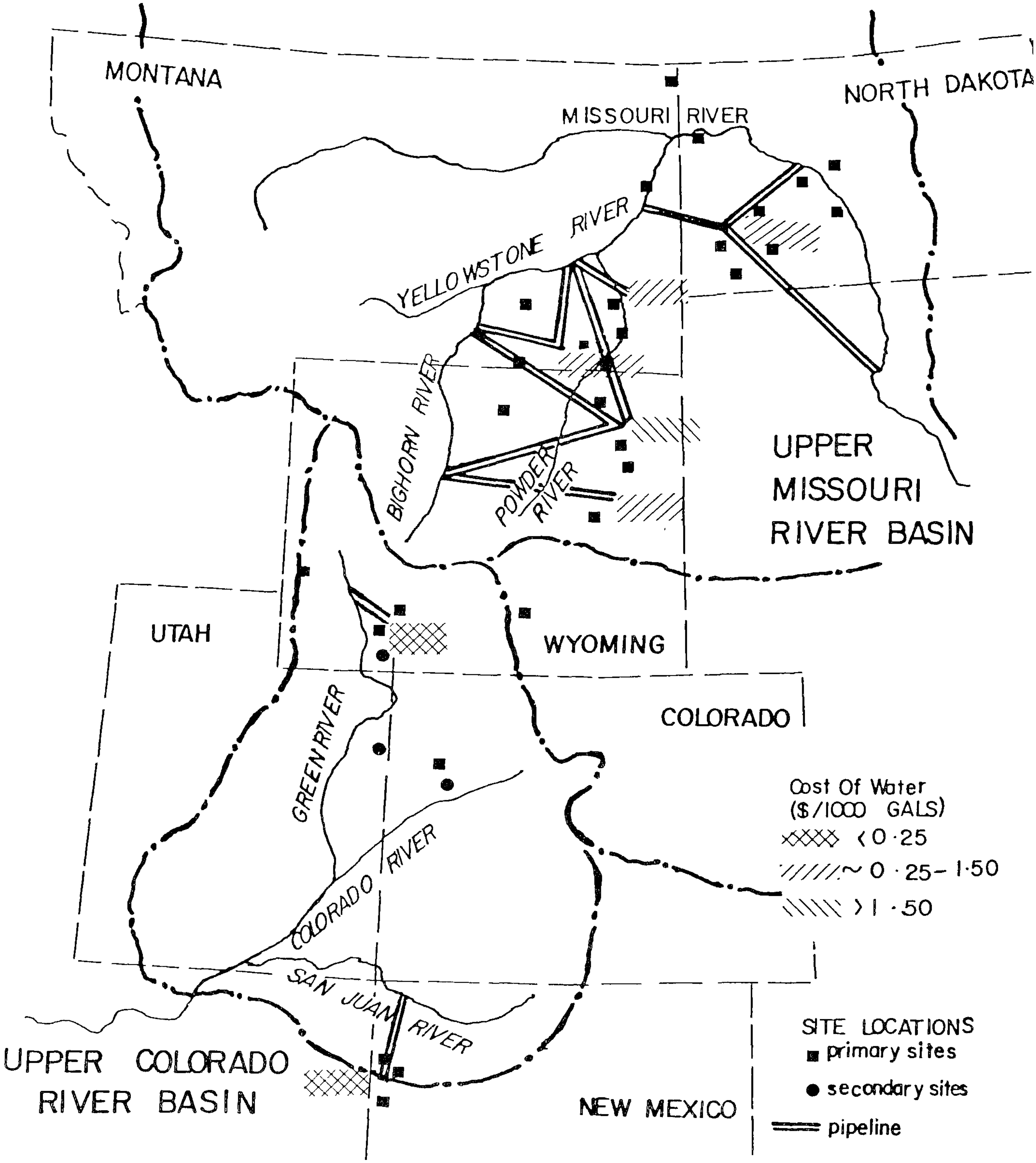


Figure 1-6 Cost of transporting water to coal regions in the Western states.

TABLE 1-4 SUMMARY OF RESULTS BY CONVERSION PROCESS

	Reactor Type	Mining Rates ($lb/10^6$ Btu) Lignite	Subbituminous	Bituminous	Net Water Consumption ($gal/10^6$ Btu) High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	Wet Solid Residuals ($lb/10^6$ Btu)	Water Treatment Cost (¢/10^6 Btu)	Water Treatment Energy (% Prod. Energy)
Coal Gasification										
Lurgi	Fixed Bed	250-360	160-220	140-160	18-30	9-22	7-21	59-126	5.4-14.0	2.3-8.3
Synthane	Fluid Bed	250[a]	180-220[a]	130-160	22-27	16-19	15-17	40-56	1.7-4.3	1.3-2.2
Hygas	Fluid Bed Hydrogasifier	200-240	120-180	110-140	21-26	16-19	15-19	32-64	2.3-4.1	1.0-4.0
Bigas	Entrained Flow	220-270	-	110-140	25-27	16-18	14-17	27-61	1.6-2.8	1.7-3.0
Coal Liquefaction										
Synthoil	Catalytic Fixed Bed	-	120-170	100-120	17-21	11-14	10-14	7-28	0.3-1.1	0.04-0.6
Coal Refining										
SRC	Dissolver	180-280	160-180	110[a]-140	13-21	8-13	7-11	12-40	0.7-1.6	0.1-1.0
Oil Shale		High Grade Shale								
Paraho Direct	Direct Retorting		630			18		520		
Paraho Ind.	Indirect Retort.		720			28		630		
TOSCO II	Indirect Retort.		510			29		470		

[a] Data from Ref. 3. Refers only to number and not to range.

Where water is plentiful and inexpensive to transport, high wet cooling should be used. The cooling loads on both the turbine condensers and interstage coolers are taken to be all wet cooled. For the Lurgi process a detailed thermal balance was not available: wet cooling was assumed to be used to dispose of 33 percent of the total unrecovered heat. The same value was one estimated for the Synthane process to facilitate comparison. This value falls within the range of Lurgi design data. The El Paso design[4] indicates that 36 percent of the unrecovered heat is dissipated by evaporative cooling, while the Wesco design[5] indicates 26 percent.

Where water is marginally available or moderately expensive to transport, intermediate cooling should be used. Intermediate cooling assumes that wet cooling handles 10 percent of the cooling load on the turbine condensers and all of the load on the interstage coolers. For the Lurgi process, 18 percent of the unrecovered heat is assumed to be dissipated by wet cooling. Again, this is based on Synthane process estimates. The oil shale processes are assumed to use an intermediate degree of wet cooling. For the Paraho Direct process, 28 percent of the unrecovered heat is dissipated by wet cooling. For both the Paraho Indirect and TOSCO II processes 18-19 percent is dissipated.

Where water is scarce or expensive to transport, minimum practical wet cooling should be used. Minimum practical wet cooling assumes that wet cooling dissipates 10 percent of the cooling load on the turbine condensers and 50 percent of the load on the interstage coolers. For this case the Lurgi process is assumed to dissipate 15 percent of the unrecovered heat by wet cooling; again it is based on the estimates for the Synthane process.

High wet cooling does not mean that all of the unrecovered heat is dissipated by wet cooling, since an appreciable fraction will be lost directly to the atmosphere. Minimum practical wet cooling does not mean that none of the unrecovered heat is dissipated by wet cooling, since this is not economical. For a given size conversion plant, the quantity of water consumed by cooling mainly depends on the overall conversion efficiency and the percent of unrecovered heat dissipated by wet cooling. All of the unrecovered heat not dissipated by wet cooling is lost directly to the atmosphere while the rest of the heat is transferred to the atmosphere by direct cooling.

For coal gasification and liquefaction the total net water consumption for a given process at a given site with intermediate wet cooling is about 72 percent of the total net water consumption for high wet cooling, and 66 percent with minimum practical wet cooling; the percentages for coal refining are 63 and 56 percent, respectively.

Besides cooling, the water consumption estimates include the process water requirements, the water required for the mining and preparation of the coal and shale, and for the disposal of ash or spent shale which is a function of location through the amount of material that must be mined or disposed. Sulfur removal also consumes water: the amount depends not only on the coal, but also on the conversion process. Water is also needed for a number of other purposes (e.g., land reclamation) that depend on climate. Generally any one requirement is not large and the needs can be met with lower quality water. Nevertheless, when the requirements are taken together, they are significant and cannot be neglected in any plant water balance, although general rules for the amount consumed are not easily stated. Differences in consumption in this category for a given coal conversion process, however, do not vary by more than 15 percent between regions, except for the Four Corners region. The difference is somewhat greater when this region is compared with others, since larger amounts of water are needed there for handling the high ash Navajo coal and for dust control and revegetation.

In general the net water requirements are largest for coal gasification, followed by coal liquefaction and coal refining. The difference between the latter two processes is relatively small. The differences in net water consumption as a function of coal rank are small, except for the Lurgi process for which the smallest requirement is for wet lignite coals. The Lurgi process accepts wet coal and the large quantities of dirty condensate produced are treated for reuse and are subtracted from the process requirement. For intermediate wet cooling the water requirements for the proposed Paraho Direct process designs are comparable with those for the Synthoil process, which produces roughly the same product. However, the proposed Paraho Indirect and TOSCO II process designs have the largest net water requirements due mainly to the larger requirements for spent shale disposal and revegetation.

The maximum difference in water consumption between high cooling and minimum practical wet cooling, across all the sites and gasification processes of this study, is about a factor of 4, pointing up the importance of the choice of process and cooling design in the amount of water consumed in synthetic fuel production. The maximum difference in water consumption between high wet cooling and minimum practical wet cooling at a given coal gasification site is approximately 10 gal/10^6 Btu. Minimum practical wet cooling will be used if water is relatively expensive, that is about $1.50/1000 gal or more. Even so, minimum practical cooling will cost about 1.5¢/10^6 Btu more than high wet cooling because of the higher annual capital investment costs of dry cooling systems.

Differences in water consumption are relatively small between the Illinois and Appalachian coal regions for bituminous coals, and the Powder River and Ft. Union coal regions for subbituminous coals for a given coal conversion process and cooling option: differences are no more than 15 percent, with the absolute difference no more than 2.5 gal/10^6 Btu. However, for lignite coals, the differences between the Eastern and Western regions are larger: the maximum is about 6 gal/10^6 Btu for the Lurgi process and 4 gal/10^6 Btu for the SRC process.

In a particular coal bearing region, differences in the water requirements between the four coal gasification processes that we have considered are due principally to the differences in the process water requirement and in the estimated overall plant efficiency resulting in different cooling water requirements.

For each process the average water consumed is relatively insensitive to the coal bearing region; variations for a given cooling option from site to site within the region are small for all of the processes except possibly for the Lurgi and SRC processes, for reasons which were discussed above. However, within a given region there might be large variations in water availability and water costs: different cooling options at different sites will produce large differences in cooling water consumption and plant water requirements (see Figures 1-3 to 1-6).

Figure 1-7 shows the total water consumed, normalized with respect to the heating value of the product fuel, for each cooling option: coal rank and regional difference are averaged out for each coal conversion technology.

Table 1-5 compares the results of the present study with those of two recently published studies in which regional and national fuel production was estimated based on water availability. Except for the oil shale results,

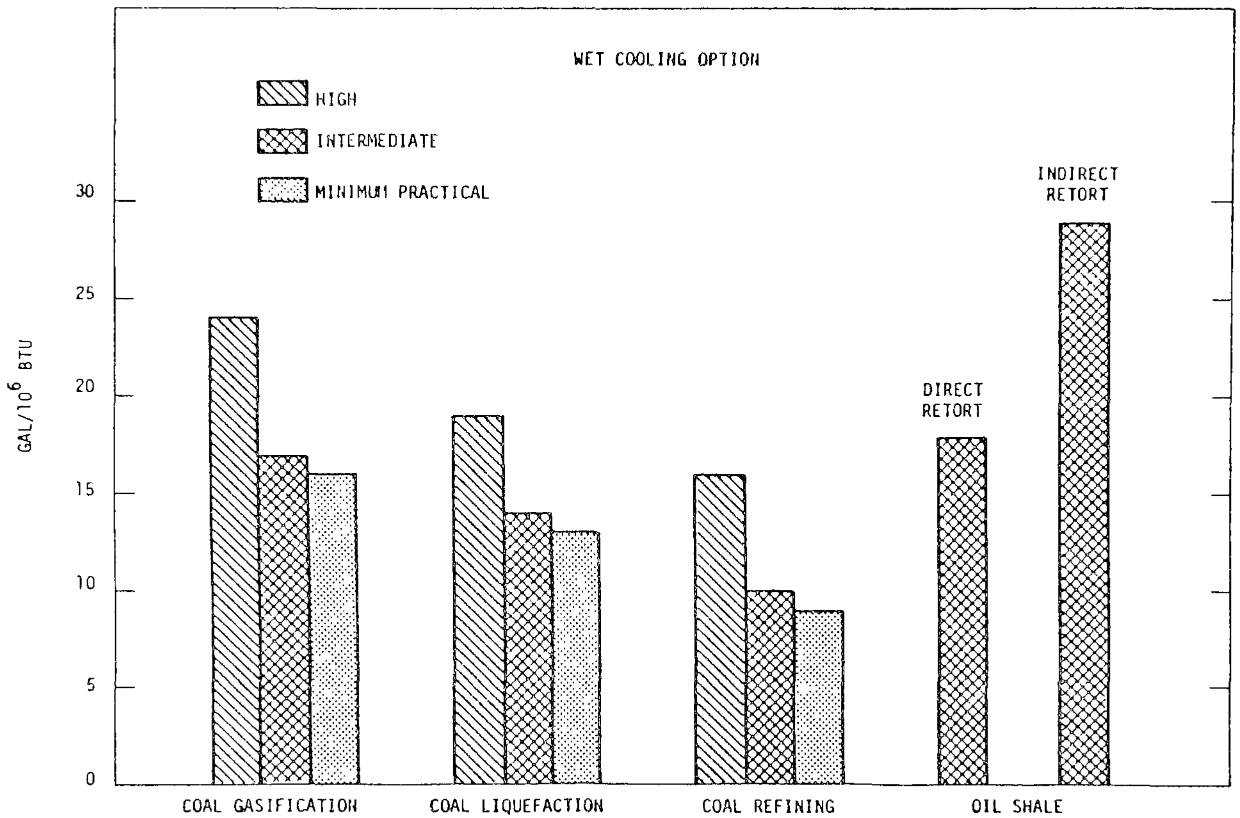


Figure 1-7 Average total water consumed normalized with respect to the heating value of the product fuel

TABLE 1-5 COMPARISON OF NET WATER CONSUMED (GAL/10^6 BTU)

	Ref. 1	Ref. 2	Present Study
Coal gasification (Pipeline gas)			
Eastern coals	25-173	66-69$^+$ 124-126*	7-28
Western coals	25-212	27-32$^+$ 56-60*	12-30
Coal liquefaction			
Eastern coals	25-221	100-114	12-21
Western coals	25-271	44-48	10-19
Coal refining			
Eastern coals		20-22	6-17
Western coals		10**	7-21
Oil Shale			
Surface mine	19-28	19-27	
Underground mine	18-30	19-31	18-29

$^+$Fixed bed gasifier
*Fluidized bed gasifier
**Includes moisture in raw coal

which are based on design data, the results of the present study for net water consumed are considerably lower than those of the other two studies. The Lurgi designs of El Paso[4] and Wesco[5] give a net water consumption of 37 and 30 gal/10^6 Btu, respectively, which are comparable to the high wet cooling estimates of the present study. Our high wet cooling estimates are comparable to the low values of Ref. 1.

Not enough detail was given in References 1 and 2 to explain the widely differing quantities. However, in a comparison of earlier assessments, Goldstein and Probstein[6] point out that the principal difference is in the method of estimating the cooling water makeup requirements. Another important difference, although not as important as the difference in the cooling water requirements, is the water consumed for mining, reclamation, evaporation, solids disposal and other uses, which is very much site specific. In any event some of the higher estimates of References 1 and 2 are unrealistic. For example, for a coal gasification plant designed to be extremely wasteful of water, the total net water consumption could be as high as 100 gal/10^6 Btu, which is about 3 times the Lurgi design values. and about one-half of the largest value shown in Table 2-4. The largest part is the water consumed for cooling, estimated to be 45 gal/ 10^6 Btu. This is based on a conversion efficiency of 65 percent with all of the unrecovered heat dissipated by wet cooling, a condition which is not realistic. In the Lurgi process, if all of the dirty process condensate were to be disposed of by evaporation and not reused in the cooling system, then the total process water consumed would be the total steam fed to the reactors, about 30 gal/10^6 Btu. Mining, flue gas desulfurization, reclamation and all other water requirements should not exceed 25 gal/10^6 Btu.

In a plant designed for a relatively high degree of water reuse and conservation, only about 33 percent of the unrecovered heat would be dissipated by wet cooling, so that 15 gal/10^6 Btu would be consumed by cooling, compared to 45 gal/10^6 Btu. All of the process water condensate would be reused and the mining, flue gas, and all other water requirements could be reduced by 75 percent from 25 gal/10^6 Btu to about 7 gal/ 10^6 Btu. The total water consumed for a plant not wasteful of water, but at the same time not designed for minimum water consumption, would be about 22 gal/10^6 Btu, as compared to 100 gal/10^6 Btu for a plant extremely wasteful of water. Coal liquefaction and coal refining processes are more efficient and do not produce as much dirty condensate so that the high estimates for these processes would be much lower.

Wet-Solid Residuals

Solid residues generated in coal and oil shale conversion plants are generally disposed of wet with occluded water. The principal residuals in coal conversion plants are coal ash and where flue gas scrubbing is used, flue gas desulfurization sludge. In oil shale plants, the principal residual is spent shale. Sludges from water treatment plants have also been considered. Between 3 and 15 x 10^3 tons/day of wet solids are disposed of for coal gasification plants, 1 and 4 x 10^3 tons/day for coal liquefaction plants, and 2 and 6 x 10^3 tons/day for solvent refined coal. Outstripping all of the coal conversion residuals by an order of magnitude are those from oil shale processing:

between 68 and 104 x 10^3 tons/day (62 and 97 x 10^3 metric tons/day) of wet solids are generated for the three oil shale conversion processes considered here. In-situ or modified in-situ processing have not been considered in this study. A summary of the wet-solid residuals generated by each conversion process, normalized with respect to the heating value of the product, is shown in Table 1-4.

The quantity of the residuals depends on: the ash content of coal, the salt content of the source water, and the sulfur content of coal when flue gas desulfurization is used on coal-burning plant boilers. The maximum residuals produced by each process depend on the site.

The largest quantities of residuals for the Lurgi, Hygas, and Synthoil processes occur in areas with the highest ash coals; i.e., in parts of Alabama and Four Corners, New Mexico. For the Synthane and SRC processes the largest residuals are generated at sites using brackish groundwater. For the Bigas process the quantities of both ash and flue gas desulfurization sludge determine the sites with the largest residuals.

Except for the Lurgi process, the wet-solids generated by the three other coal gasification processes are relatively insensitive to process. In general the Lurgi process generates more wet-solids because of the large quantity of boiler feed treatment wastewater required. The total wet residuals, normalized with respect to the heating value of the product, are comparable for the Synthoil and SRC processes; the SRC process has a slightly higher value. The larger quantities of wet residuals for coal gasification are attributed to flue gas desulfurization, which is not required for the liquefaction and coal refining processes.

Wastewater Treatment

In estimating consumptive water requirements and wet-solid residuals, it was assumed that no water streams leave the mine-plant boundaries and that all effluent streams are recycled or reused within the mine or plant after treatment. The water treatment plants are not designed to return flow to receiving waters. Returning water to a source is not economic when the water must be cleaned to a quality equal to or better than the source water in order to meet environmental regulations.

Cost and energy estimates for water treatment are much less well defined than the water and solid residual quantities. Although the water treatment technologies considered are achievable, experimental evidence for coal conversion process waters is not available to fully assess them. For this reason designs and costs must be regarded with a greater degree of uncertainty than the estimates of water quantity requirements. Because of the large number of plant-site combinations, all various water treatment options for each plant-site combination were not examined. Instead one or two water flow diagrams, each applicable to one or more processes, were used at many sites.

In any synthetic fuel plant, high quality water is required for the process, intermediate quality is required for cooling and low quality for disposal and mine uses. The two largest water treatment costs are for the treatment of the raw water to boiler water quality and for the treatment of the low quality process condensate to make it suitable for use in the cooling tower. The lowest cost is for treatment within the cooling tower. Figure 1-8 is a general water treatment scheme for a coal conversion plant generating dirty process water. The scheme is not unique, but does contain the main components of any water treatment plant: boiler feed water preparation, process water or condensate cleanup, and cooling water treatment. The three main streams are shown with heavy lines. Details of the water treatment block diagrams used for all of the processes are given in Appendix 11.

Boiler feed water preparation includes occasional lime soda softening, electrodialysis on all plants when the raw intake water is brackish, and ion exchange. Foul condensate treatment includes phenol extraction, ammonia separation, and biotreatment. Phenol extraction, involving solvent extraction of phenolic compounds in which phenol is recovered and sold to help defray treatment costs, is used only when the foul condensate is highly concentrated. The process was not used for Lurgi or Synthane processes fed by bituminous coal, nor was it used for the Hygas and Bigas processes. Ammonia separation, used for all process-site combinations, is a distillative extractive process, where the ammonia is assumed recovered as a 30 wt % solution and sold to help defray costs. Because of the lack of information on how much organic contamination is acceptable in cooling water, biotreatment is used on dirty condensate from all plants except Bigas. Cooling water treatment involves lime soda

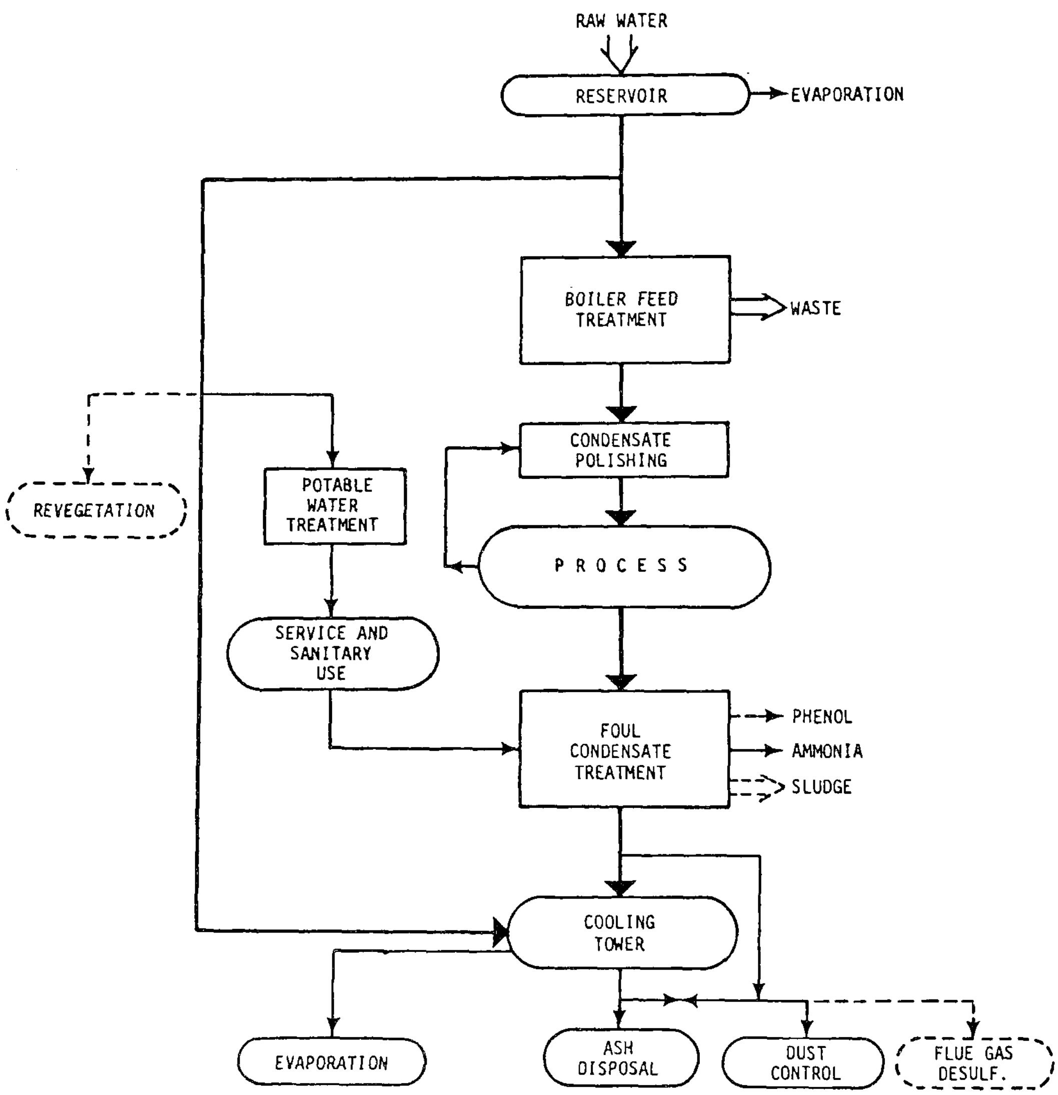


Figure 1-8 Water treatment flow diagram for coal conversion plant generating dirty process water (dashed boxes indicate the requirements are not necessary for every plant). (Reprinted from Ref. 3 with the permission of The MIT Press. Copyright 1978 by the Massachusetts Institute of Technology)

softening of the raw water for cooling tower makeup, filtration of the effluent water from biotreatment, acid treatment of all high alkalinity cooling water makeup streams, the addition of biocide anticorrosion chemicals and suspending agents, and lime soda softening of the cooling tower blowdown.

Table 1-4 also summarizes the costs of water treatment, not including the cost of residuals disposal. The costs of water treatment for oil shale were not calculated. For each process, except Bigas, the largest water treatment cost corresponds to the use of brackish water as a raw water source and reflects the high costs of boiler feed water treatment associated with demineralization. The highest cost is for the Lurgi process: the quantities of steam required and dirty condensate produced are greater than those for the coal liquefaction and coal refining processes. Although the process condensates for these last two processes have the poorest quality, the costs are determined primarily by the quantities of process condensate produced and boiler feed water required, which are quite low for the Synthoil and SRC processes. The cost of water treatment, after taking credit for byproduct ammonia, is not expected to exceed 7 percent of the sale price of the product fuel for any of the plants.

The energy required for the water treatment plants is controlled by the amount needed for ammonia separation, an amount directly proportional to the rate of foul condensate production. Referring to Table 1-4, the largest energy requirements for any conversion process are for the Lurgi process, followed by the three other gasification processes Again the liquefaction and clean coal processes have the lowest energy requirements. Large amounts of energy are also required if electrodialysis is required to demineralize brackish water for boiler feed water. The total energy requirements for the water treatment plants fall in the range of 0.04 to over 8 percent of the product energy, or about 0.03 to 6 percent of the energy in the feed coal.

1.4 Recommendations

1. The water quantity estimates and estimating procedures given in this report are intended for use in determining the impact of a coal conversion plant on local water supplies. Some current estimates, as noted in this report, are considered excessive. Quantity estimates in large excess of those given here should be considered excessive; transference of quantity estimates from one site

to another is not usually accurate; transference of quantity estimates from one process to another is not usually accurate. The most reliable full-scale engineering designs published to date are within the ranges of water consumption given in this report.

2. The major use of water in coal conversion plants is water evaporated for cooling. Since much of the nation's coal is in areas where water is critically lacking, further study into the cost and methods of conserving cooling water is justified. Investigations of interstage coolers on hydrogen compressors, oxygen compressors and synthesis gas compressors will require only a small effort and give important guidance. In addition, condenser cooling on the acid gas absorber regenerator should also be investigated.

3. The quantity estimates made in this report are predicated on complete water reuse. It is extremely probable that technology exists to treat effluent waters adequately, and general cost and energy estimates have been made. Only reasonably standard technologies have been considered in this study, such as liquid-liquid extraction or biological oxidation. Advanced innovative technologies such as resin adsorption and the use of sequenced treatments instead of single unit treatments could be considered. A careful selection of innovative technologies could be undertaken to show the potential savings and to recommend the type of research or development work needed to validate the estimated saving.

4. The disposal of solid wastes should also be addressed.

5. This study refers to individual conversion plants at individual sites. No conclusions have been reached to determine whether certain conversion processes are most appropriate at certain sites. No conclusions should be reached until the study of waste solids disposal is complete. Upon completion of the study of waste solids disposal, the question of matching processes to sites, coals and water supplies can, and should, be addressed.

References - Section 1

1. Harte, J. and El-Gasseir, M., "Energy and Water", Science, 199, February 10, 1978.

2. Energy Research and Development Administration,"Alternative Fuels Demonstration Program. Final Environmental Impact Statement," ERDA-1547, Washington, D.C., September 1977.

3. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives, MIT Press, Cambridge, Mass. 1978.

4. Gibson, C.R., Hammons, G.A., and Cameron, D.S., "Environmental Aspects of El Paso's Burnham I Coal Gasification Complex," in Proceedings, Environmental Aspects of Fuel Conversion Technology (May 1974, St. Louis, Missouri), pp 91-100, Report No. EPA-650/2-74-118 (NTIS No. PB 238304), Environmental Protection Agency, Research Triangle Park, N.C., October 1974.

5. Berty, T.E. and Moe, J.M., "Environmental Aspects of the Wesco Coal Gasification Plant," in Proceedings, Environmental Aspects of Fuel Conversion Technology (May, 1974, St. Louis, Missouri) pp 101-106, Report No. EPA-650/2-74-118 (NTIS No. PB 238304), Environmental Protection Agency, Research Triangle Park, N.C., October 1974.

6. Goldstein, D.J. and Probstein, R.F., "Water Requirements for an Integrated SNG Plant and Mine Operation," in Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology II, pp 307-332, Report No. EPA-600/2-76-149 (NTIS No. PB 257 182), Environmental Protection Agency, Research Triangle Park, N.C., June 1976.

2. INTRODUCTION

Development of a synthetic fuel industry in the United States could be severely impaired because of local environmental problems associated with the large consumptive use of water required for coal and oil shale conversion processing and because of the large quantities of environmentally unacceptable solid wastes that leave these plants and for which a disposal site must be found. Moreover, water for synthetic fuel development in a given locale, where coal can be economically mined, may be in short supply, or there may be strong competition for the water among alternative uses including agricultural, power production, municipal, industrial, and recreational.

High water consumption has been a frequent reason cited for stifling the development of a synthetic fuel industry, particularly in the water-short Western States. These high water consumption estimates may be both excessive and misleading. They may be excessive because of the large quantity of water assumed to be evaporated for cooling, since cooling water is most often the prime determinant of total consumption. They may be misleading because the estimates, with few exceptions, have been regional, rather than derived from local site-, process-, and design-specific calculations.

The overall objective of the work presented in this paper was to determine: the feasibility of siting specific conversion plants at given locations in the major U.S. coal and oil shale bearing regions; and the extent of the environmental impacts that could be expected from local water-related site, process and plant design criteria. Of the 90 plant-site combinations studied, 48 were in the Central and Eastern coal bearing regions and 42 in the Western coal and oil shale bearing regions. The plants were sited taking into account the following broad categories of water-related site criteria: water supply and alternative demands, climate, coal rank or grade of oil shale, and mine type. Plant design considerations included the following broad categories of water-related process criteria: low temperature gasifiers, high temperature gasifiers, coal refining and liquefaction processes, and direct and indirect heated oil shale retorting. The plants were assumed to be designed so as not to waste water. Effluent process waters were assumed to be reused, and different cooling options were selected based on the availability and cost of water. Estimates were made of the total net water consumed, wet solid residuals generated, and the cost and energy required for water treatment for each plant-site combination and then generalized to each one of the major U.S.coal and oil shale bearing regions. The environmental impacts resulting from the consumptive use of water were evaluated. Other elements of an overall environmental assessment, such as population growth and waste disposal, were not considered.

A corollary objective was to generalize from the individual site-, process-, and design-specific results to arrive at guides for the expected extent of water-related local environmental impacts in their dependence on process and plant design, water supply, climate, and other site factors. From the generalizations, the following results were obtained:

(1) The range of consumptive water requirements was calculated and the conditions found for narrowing the range and optimizing the use of water.

(2) Ranges of residual solid wastes, their quantity and nature were estimated, and the conditions found for narrowing the ranges and minimizing disposal problems.

(3) Localities were selected where local water- related environmental impacts are large, moderate, or small.

(4) Localities were selected where certain processes are more suitable than others to minimize local water- related environmental impacts.

(5) Site and process criteria used in estimating local environmental impacts were ranked in order of their importance.

Calculations of water consumption and wet-solid residuals were made from block flow process diagrams at each site. Included in these calculations are estimates of the individual cooling loads for determining whether wet or dry cooling should be used and the quantity of water consumed by evaporation. Throughout the study the assumption was made that if wastewater was treated to a quality sufficient for return to the river, it was good enough for reuse in the plant. Non-wasteful consumption of water following the best common engineering practice was followed throughout. Results were found for specific processes at specific sites and then generalized to conversion technology and coal or oil shale bearing region. Specific conclusions for a particular process apply only to that process. However, general conclusions may be used more broadly.

The report has been divided into two volumes. The first volume is a summary of the entire study. The second volume contains 15 appendices which details all the process, cooling and water treatment calculations. In addition the second volume contains water supply and demand data for the Eastern, Central and Western coal regions and the water transportation cost calculations.

3. PROCESS AND SITE SELECTIONS

3.1 Introduction

The overall objective of this study is to determine the general environmental impacts that can be expected from local water-related site, process and plant design criteria. Site considerations include: water supply and alternative demands, climate and rank of coal and mine type. Plant design considerations include the following broad categories of water related process criteria: (i) low temperature gasifiers, (ii) high temperature gasifiers, and (iii) coal refining and liquefaction processes. The water requirements and water uses within the plant, the waters to be treated within the plant and the waste effluents are dependent on the site of the coal and shale oil conversion complex, as well as on the process itself. Furthermore, the water control technology and disposal of the waste solid residues are dependent on the quality of the supply water, which is also dependent on the site.

Many site and process criteria combinations were studied in order to obtain meaningful assessments on a regional and national level from detailed local results. Site and process criteria used to define a plant location, process, product and plant design have already been broadly categorized above. It is clear, however, that not every category of site and process criteria, with all of their subcategories, could be used in every possible combination, without arriving at an inordinately large number of configurations. Moreover, a great many of the configurations would be without meaning, since they could not be found in some of the coal and oil shale regions. We have therefore chosen to associate with each of the criteria the minimum number of principal characteristics associated with that criterion and will then define the physically meaningful number of site-plant combinations in terms of those characteristics. It is only with such an approach that generalized rules could be derived as to the feasibility of any given siting and its subsequent environmental impact resulting from the consumptive use of water at that site.

In Tables 3-1 and 3-2 we have listed the broad categories of site and plant criteria and next to each have set out the minimum number of important characteristics. We emphasize that this is a minimum number and does not include all of the details to be discussed in forthcoming sections. Rather these items are defined only to find the number of plant-site combinations it is necessary to examine in the Western, Central and Eastern coal bearing regions of the United States and in the Western oil shale bearing regions, in order to arrive at general results. The total number of important site characteristics were obtained by taking the product of each of the principal site characteristics. The number of process-site combinations were obtained by taking the product of the total number of process characteristics and the total number of site characteristics.

For the conversion of coal to either gas, oil or solvent refined coal, we have defined three process criteria relating to the quality of the foul process condensate recovered after gasification or liquefaction. The low temperature gasifiers, for example, Lurgi[1] and Synthane[2] produce a very dirty process condensate (typical values for bituminous coals: BOD $\sim$ 10,000 mg/l, phenol $\sim$ 3,000 mg/l and ammonia $\sim$ 7,000 mg/l). The high temperature gasifiers, for example, Koppers-Totzek[3], Winkler and Bigas produce a relatively clean process condensate (typical values: ammonia $\sim$ 4,500 mg/l, BOD and phenol $\sim$ small). The intermediate temperature Hygas gasifier[4] produces a process condensate of intermediate quality. The process condensate from the liquefaction sections of the Solvent Refined Coal[4] process is dirtier than the process condensate from the low temperature gasifier sections. The Synthoil[35] foul process condensate from the liquefaction section is comparable in contamination to the SRC process (typical values: BOD $\sim$ 30,000 mg/l, phenol $\sim$ 5,000 mg/l and ammonia $\sim$ 8,000 mg/l). As for site criteria, brackish groundwater would have to be considered as an important conjunctive supply in the West, while surface waters are considered primarily in the East and Central States. Eastern and Central climates have humid climates, while the climates in the West are arid and semi-arid. Eastern and Central coals are both underground and surface mined, while Western coals are primarily surface mined.

TABLE 3-1 SITE AND PROCESS CRITERIA AND PRINCIPAL CHARACTERISTICS

FOR CENTRAL, EASTERN AND WESTERN COAL BEARING REGIONS

Criteria	Central and Eastern Regions: Principal Characteristics	Central and Eastern Regions: Number	Western Region: Principal Characteristics	Western Region: Number	
Process					
Low temperature gasifiers	As defined		As defined		
High temperature gasifiers	As defined	3	As defined	3	
Coal refining & liquefaction	As defined		As defined		
Total		3		3	
Site					
Water supply and alternative demands	Surface water Ground water	2	Surface water Brackish ground-water	2	2
Climate	Humid-temperate	1	Arid	1[+]	
			Semi-arid		1[++]
Rank of coal	Bituminous-Subbituminous	1	Lignite		2[++]
			Subbituminous-bituminous	1[+]	
Mine type	Surface Underground	2	Surface	1	1
Total		4		2	4
Process-site combinations:		12		18	

[+]Subbituminous coal is primarily mined in the arid region of New Mexico.

[++]Both lignite and subbituminous coals are mined in the semi-arid regions of Wyoming, Montana and North Dakota.

TABLE 3-2 SITE AND PROCESS CRITERIA AND PRINCIPAL CHARACTERISTICS FOR WESTERN OIL SHALE BEARING REGIONS

Criteria	Principal Characteristics	Number
Process		
Oil shale retorting	As defined	2
Total		2
Site		
Water supply and alternate demands	Surface Water and Brackish Groundwater	2
Climate	Semi-arid	1
Rank of shale	High grade	1
Mining	Surface-underground	1
Total		2
Process-site combinations:		4

Twelve plant-site combinations are required to cover the characteristics denoted for the Central and Eastern coal bearing regions and 18 plant-site combinations are required for the Western region.

The pyrolysis or destructure distillation of shale to produce crude shale oil is termed retorting. Two retorting options have been investigated extensively: mining followed by surface retorting and in situ retorting[5,6] in which the shale oil is released by underground heating and pumping the shale to the surface. The primary advantage of in situ retorting is that the disposal of spent shale is simplified considerably and the water required for this purpose is drastically reduced. However, in situ processes are under development and cannot yet be considered suitable for commercial operation. In this study we will only consider underground mining followed by surface retorting. Oil shale retorts are classified into two basic types, those that are direct heated, such as the Paraho Direct[5,6] process, and those that are indirect heated, such as the TOSCO II[7] and Paraho Indirect[5,6] processes. From the point of view of water management, the type of retort is quite important. When the retort is direct heated, most of the water is recovered, while with indirect heated retorts, the water in the combustion products is generally lost up the furnace stack and not recovered. Furthermore, for direct heated retorts, no intermediate medium is used to transfer heat from the pyrolysis and the thermal efficiency is high, resulting in reduced cooling loads, as compared to the indirect heated retorts. Finally, large amounts of water are required for the disposal and revegetation of the spent shale piles. Different procedures with considerably different water needs have been proposed for the disposal of the TOSCO and Paraho spent shales. Thus, two different types of surface retorting methods are sufficient to characterize the process criteria. We have only considered shale oil deposits in the West, since most of the high grade oil shale is found in areas in Colorado, Utah and Wyoming underlain by what is called the Green River Formation and where the greatest promise for commercial production lies. Large amounts of lower grade shale are found in many areas of the United States, but particularly in the same regions as the coal basins o the East and Central states. However, the economics of converting the lower grade material is considerably less promising and will not be considered. About four plant-site combinations will suffice for shale oil conversion.

Therefore, a minimum of 34 plant-site combinations should be studied in order to arrive at general results. Another 10 plant-site combinations should account for any additional unusual site characteristics.

3.2 Process and Plant Selection

The synthetic fuel technologies examined include the conversion of coal to clean gaseous, liquid and solid fuels, and the conversion of oil shale to clean liquid fuels. The conversion is basically one of hydrogenation in which the weight ratio of carbon to hydrogen is higher in the raw material than for the gaseous or liquid synthetic fuel. In the conversion, sulfur and nitrogen are reduced to produce a cleaner fuel; and ash, oxygen, and nitrogen are reduced to produce a synthetic fuel with a higher heating value.

We have compared several fuel technologies in this study:

1. Coal gasification to convert coal to pipeline or high-Btu gas, which has a heating value of about 920 to 1000 Btu/scf and is normally composed of more than 90 percent methane. Because of its high heating value, high-Btu gas is a substitute for natural gas and can be transported economically by pipeline We have not considered low-Btu gas (termed producer or power gas) which will probably have its greatest utility in gas-steam combined power cycle for steam-electric power generation, nor have we considered medium-Btu gas, which may be used as a source of hydrogen for the production of methanol and other liquid fuels, or as a fuel for the production of high-Btu gas.

2. Coal liquefaction to convert coal to low sulfur fuel oil.

3. Coal refining to produce a de-ashed, low sulfur solvent refined (clean) coal, and

4. Oil shale retorting to produce synthetic crude.

For each of the technologies we have examined a standard size mine-plant complex. The size of the plants have been selected so that the product heating values are approximately equal, although the products are different. The products chosen are synthetic fuels; the production of chemicals from coal or shale, e.g., ammonia or methanol via coal gasification, was not considered. Table 3-3 lists the technologies and the processes chosen to illustrate them, together with a summary of the product fuel output and heating value for the

TABLE 3-3 PRODUCT FUEL OUTPUT OF STANDARD SIZE SYNTHETIC FUEL PLANTS

Technology and Conversion Process	Product	Output	Product Heating Value (10^{11} Btu/day)
Coal Gasification	Pipeline Gas	250×10^6 scf/day	2.4
Lurgi Synthane Hygas Bigas			
Coal Liquefaction	Fuel Oil	50,000 barrels/day	3.1
Synthoil			
Coal Refining SRC	Solvent Refined Coal	10,000 tons/day	3.2
Oil Shale	Synthetic Crude	50,000 barrels/day	2.9
Paraho Direct Paraho Indirect TOSCO II			

standard size plants examined.

Except for the commercially available Lurgi process, the processes that we have chosen are representative of those that have undergone extensive development and which are sufficiently described in the available literature so that detailed process calculations can be made. The gasification and liquefaction sections of the processes are characteristic of the three coal conversion technologies; the three oil shale conversion processes are representative of the different surface retorting techniques.

Figure 3-1 (adapted from Refs. 8 and 9) show the different methods of producing clean synthetic gaseous, liquid and solid fuels. Synthetic gases can be produced from coal by indirect hydrogenation in which the gasification takes place by reacting steam with the coal, or by direct hydrogenation or hydrogasification, in which hydrogen is contacted with the coal. Clean liquid fuels can be produced in a number of different ways. For example, direct hydrogenation as for a synthetic gaseous fuel. Coal can be gasified first and then the liquid fuel synthesized from the gas. Another process is pyrolysis in

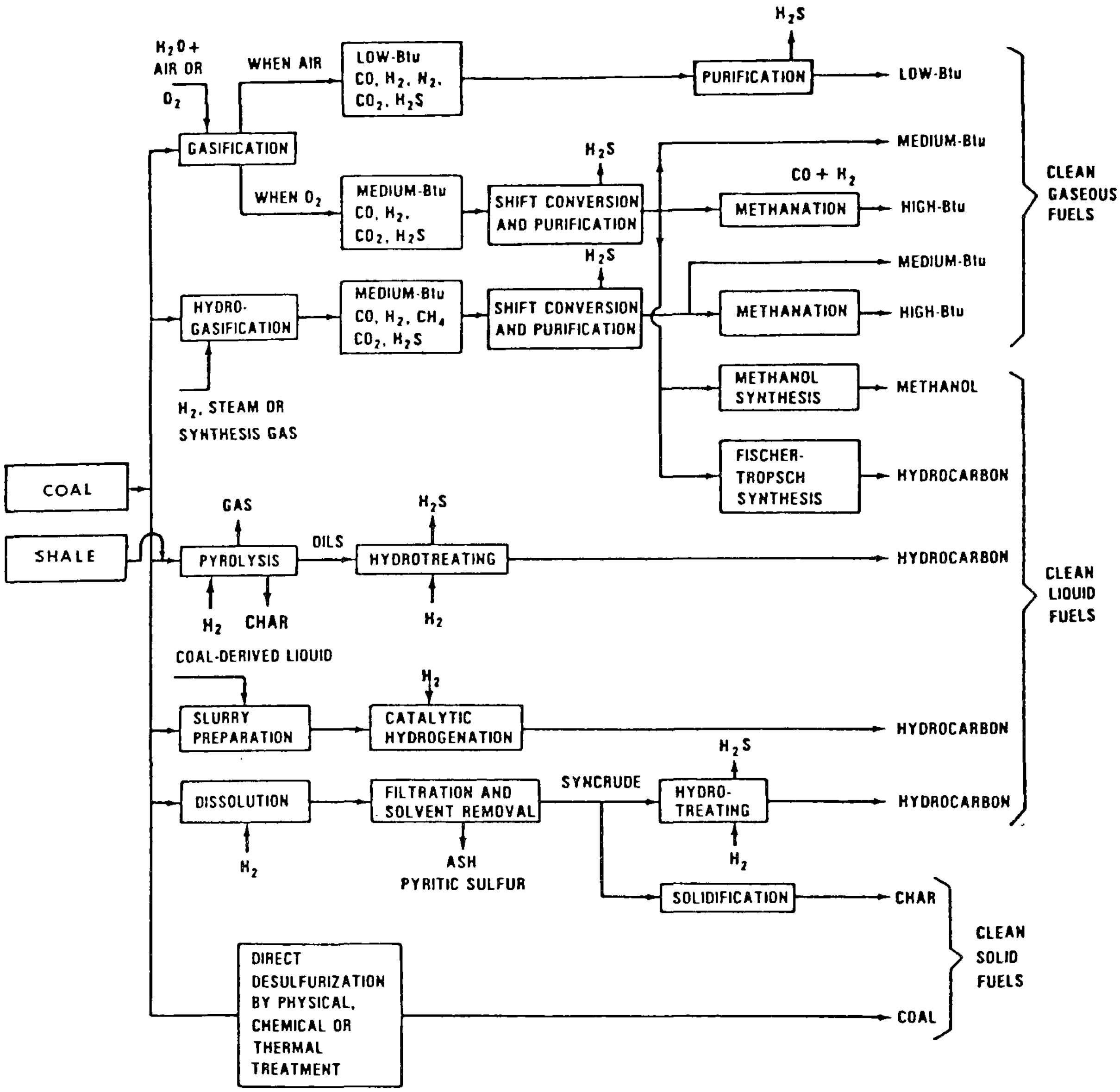


Figure 3-1 Methods of producing clean synthetic gaseous, liquid and solid fuels

which natural oil is distilled out of the coal or shale. The last procedure involves dissolving coal in a hyrogen donor solvent, removing sulfur, filtering out the ash and recovering the solvent, cleaning the resultant heavy synthetic crude, and upgrading it to the desired liquid fuels. Solvent refined coal is obtained by cooling down the synthetic crude instead of hydrotreating it. Physical, chemical or thermal treatment to desulfurize the coal also results in a cleaner solid fuel.

Table 3-4 summarizes the coal technologies, the methods of producing synthetic fuels from coal and shale, the reactor types, and the specific conversion processes considered in the site studies. Detailed descriptions and characteristics of the gasifier systems are found in Refs. 10, 11, and 12; the Synthoil process are found in Refs. 13 and 14; the SRC process are found in Refs. 4 and 15; and the Paraho and TOSCO II processes are found in Refs. 5, 6 and 7. In addition process details are given in the Appendices to this report.

The selection of the representative conversion processes was partially based on the availability of pilot plant data and integrated plant designs. Table 3-5 briefly summarizes the reference data used in our integrated plant designs. The table also shows the type of coal and oil shale on which the reference data is based. Table 3-6 shows the matrix of coal type and coal conversion process combinations used in our site studies and those coal/process combinations where design data were available in the literature. All other combinations required our own plant designs. All plant designs are given in Appendices 1 through 6.

3.3 Site Selection

Site selection was based on the availability of coal and oil shale, the type of coal (bituminous, anthracite or lignite) or oil shale (high grade or low grade), the type of mining (underground or surface) and the availability of surface and groundwater. Only mine-mouth plant complexes are considered.

The coal fields of the conterminous United States and the rank of the coal found in these fields are shown in Figure 3-2. Coal rank refers to the percentage of carbon and heat content of the coal. The coal of lowest rank is lignite, followed in increasing rank by subbituminous coal, bituminous coal and anthracite. The fraction of carbon in the coal increases from lignite to anthracite, and the moisture fraction decreases. The fact that

TABLE 3-4 SUMMARY OF CONVERSION PROCESSES AND REACTOR TYPES USED IN SITE STUDIES

Technology	Conversion Process	Reactor Type	Process	Product
Coal Gasification	Indirect Hydrogenation	Fixed Bed Gasifier	Lurgi	Pipeline Gas
	-Partial Oxidation	Fluid Bed Gasifier	Synthane	
		Entrained Flow Gasifier	Bigas	
	-Hydrogasification	Fluid Bed Hydrogasifier	Hygas	
Coal Liquefaction	Direct Hydrogenation -Hydroliquefaction	Catalytic Fixed Bed	Synthoil	Fuel Oil
Coal Refining	Indirect Hydrogenation -Solvent Extraction	Dissolver	SRC	Solvent Refined Coal
Oil Shale	Pyrolysis	Direct Retorting	Paraho Direct	Synthetic Crude
		Indirect Retorting	Paraho Indirect	
		Indirect Retorting	TOSCO II	

TABLE 3-5 REFERENCE DATA FOR THE DESIGN OF INTEGRATED CONVERSION PLANTS UTILIZING SPECIFIC COALS AND OIL SHALE

	Plant Design	Refs.	Pilot Plant Data	Refs.
Coal Gasification				
Hygas	W.Va. Bit.	16	Illinois #6 Bit.	4
	Wyoming Sub.	16,4	Montana Lig.	4
	No.Dakota Lig.	4		
Bigas	Montana Sub.	17		
	Kentucky Bit.	17		
Lurgi	Bit.	18	Montana Sub.	1
	Navajo Sub.	19		
Synthane	Wyoming Sub.	20,4	Illinois #6 Bit.	2
	Pittsburg Bit.	20	No. Dakota Lig.	2
			W. Kentucky Bit.	2
			Pittsburgh Bit.	2
			Wyoming Sub.	2
Coal Liquefaction				
Synthoil	Wyoming Sub.	21		
	New Mexico Sub.	4		
Coal Refining				
SRC	Wyoming Sub.	4	Pittsburgh Bit.	22,23
	New Mexico Sub.	4	Illinois Bit.	22,23
	No. Dakota Lig.	4	Kentucky Bit.	22
			No. Dakota Lig.	24
			Wyoming Sub.	24
Oil Shale				
Paraho Direct		5	Anvil Points	5
Paraho Indirect		6	Anvil Points	27,6
TOSCO II		7		7

TABLE 3-6 MATRIX OF COAL TYPE/COAL CONVERSION PROCESS COMBINATIONS USED IN SITE STUDIES

		Coal Gasification				Coal Liquefaction	Coal Refining
		High Temp. Gasifier		Low Temp. Gasifier			
Site Locations	Coal Type	Hygas	Bigas	Lurgi	Synthane	Synthoil	SRC
West	Lignite		X	X			X*
	Subbituminous	X*		X*	X*	X*	X*
	Bituminous		X	X			X
East-Central	Lignite	X		X	X		X
	Bituminous	X*	X*	X*	X*	X	X*

*Based on pilot plant data and plant designs available in literature.

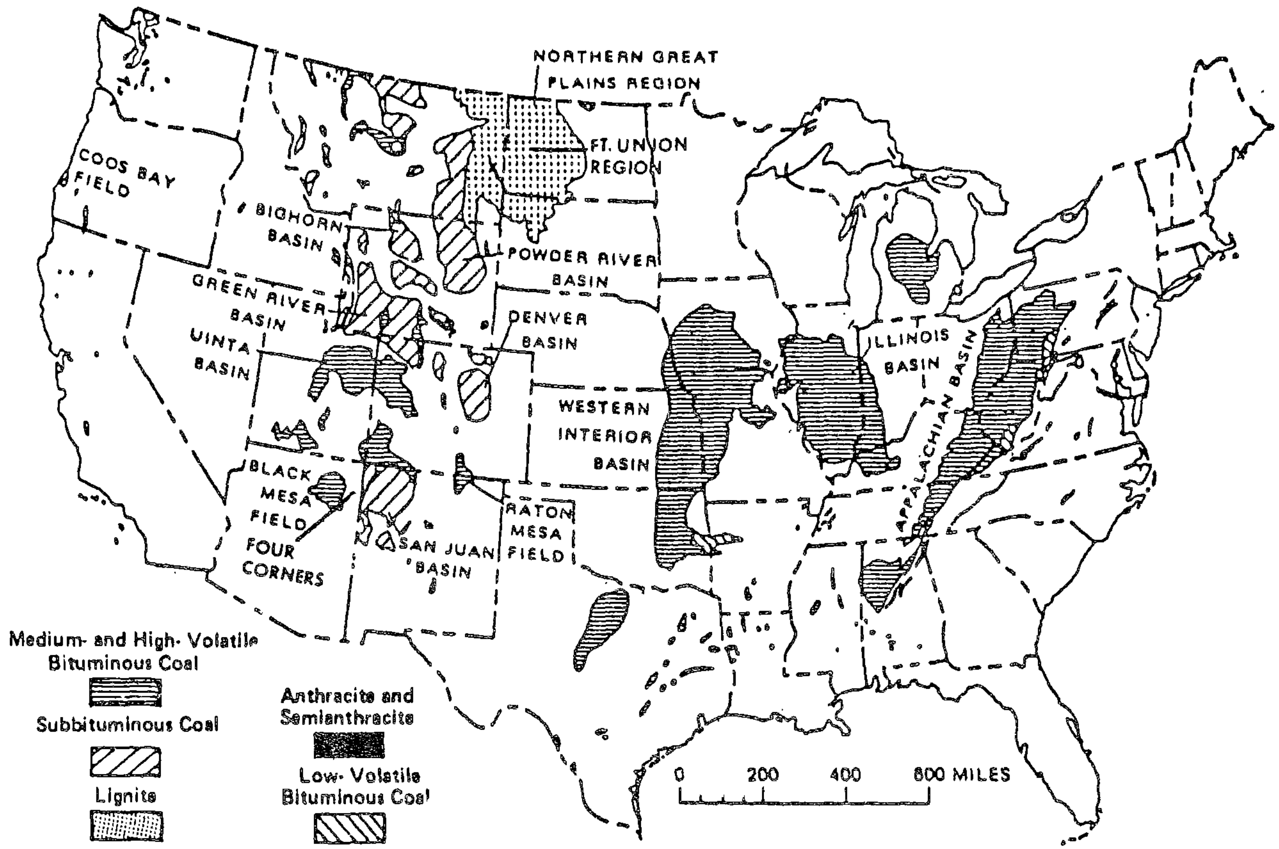


Figure 3-2 Coal fields of the conterminous United States

The fact that the coal moisture varies considerably with the type of coal can affect the process water requirements in a synthetic fuel plant. The heating value increases from lignite to low-volatile bituminous coal. For a given synthetic fuel output, the heating value of the coal determines the actual quantity of coal required. We have not considered anthracite coal since it is not suitable for conversion.

The demonstrated coal reserve has been tabulated according to region as shown in Table 3-7, compiled from the data of Averitt[25]. This reserve refers to identified resources suitable for mining by present methods, where at least 50 percent is recoverable and the coal lies less than 1000 feet below the surface. Table 3-7 shows the potential methods by which the coal can be mined. In the Northern Great Plains and Rocky Mountains region, where almost half of the Nation's coal is to be found, more than 40 percent of the coal can be surface mined. Surface, or strip mining can be done more economically than underground mining and in most cases with a much higher percentage of the coal recovered.

TABLE 3-7 DEMONSTRATED COAL RESERVE BASE OF THE UNITED STATES IN BILLIONS OF TONS BY REGION AND POTENTIAL METHOD OF MINING

Region	Underground	Surface	Total	Percent of Grand Total
Northern Great Plains and Rocky Mountain	113	86	199	46
Appalachian Basin	97	16	113	26
Illinois Basin	71	18	89	20
Other	16	17	33	8
Grand Total	297	137	434	100

Oil shale can be classified according to its organic content and yield. High grade oil shale is shale with an organic content greater than 14 percent yielding 25 gallons or more of oil per ton of shale and is found in beds at least 10 feet thick. Large amounts of lower grade shale are found in many areas of the United States, particularly in the same regions as the coal basins of the East and Central states. However, the greatest promise for commercial production lies in the mining of high grade shale, which is the only shale considered in this study. High grade shale is found in areas in Colorado, Utah and Wyoming underlain by what is called the Green River Formation (Figure 3-3)[26]. The identified high grade shales with yields between 25 and 65 gallons per ton have an oil equivalence of about 570 to 620 billion barrels. About 80 percent of the high grade material is located in Colorado in the Piceance Creek Basin[27].

The U.S. Bureau of Mines lists the quantity of coal available by county and state, in millions of short tons, in underground and strippable reserves[28,29]. The amount of coal needed for coal conversion at any plant site will vary with the capacity and type of plant and the nature of the coal. For a given conversion efficiency and a fixed plant size (determined by the heating value of the product) the rate of coal mined is set by its heating value.

For the three major coal ranks the following average heating values are used: bituminous, 13,000 Btu/lb; subbituminous, 9,800 Btu/lb; and lignite, 6,800 Btu/lb.[30]. Table 3-8 shows the quantities of different rank coals that must be mined daily for a Synthane plant producing 250 million standard cubic feet per day of pipeline gas. Also shown are the total recoverable reserves required and the total coal reserves required for both underground and surface mining. The recoverable reserve is the amount of coal actually mined or recovered as distinguished from the amount of coal present in the ground, or coal reserve. The total recoverable coal reserve is about 50 percent of the total coal reserve for underground mining and about 80 percent for surface mining[25,30]. The total coal reserves required to produce clean fuel oil and solvent refined coal by the specific processes and in the standard size plants previously noted do not exceed approximately 110 percent of those listed in Table 3-8.

Site selection in the Central and Eastern regions of the United States was limited to those states having the largest coal reserves. These states are Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. Table 3-9 lists the counties by state in which the criteria shown in Table 3-8

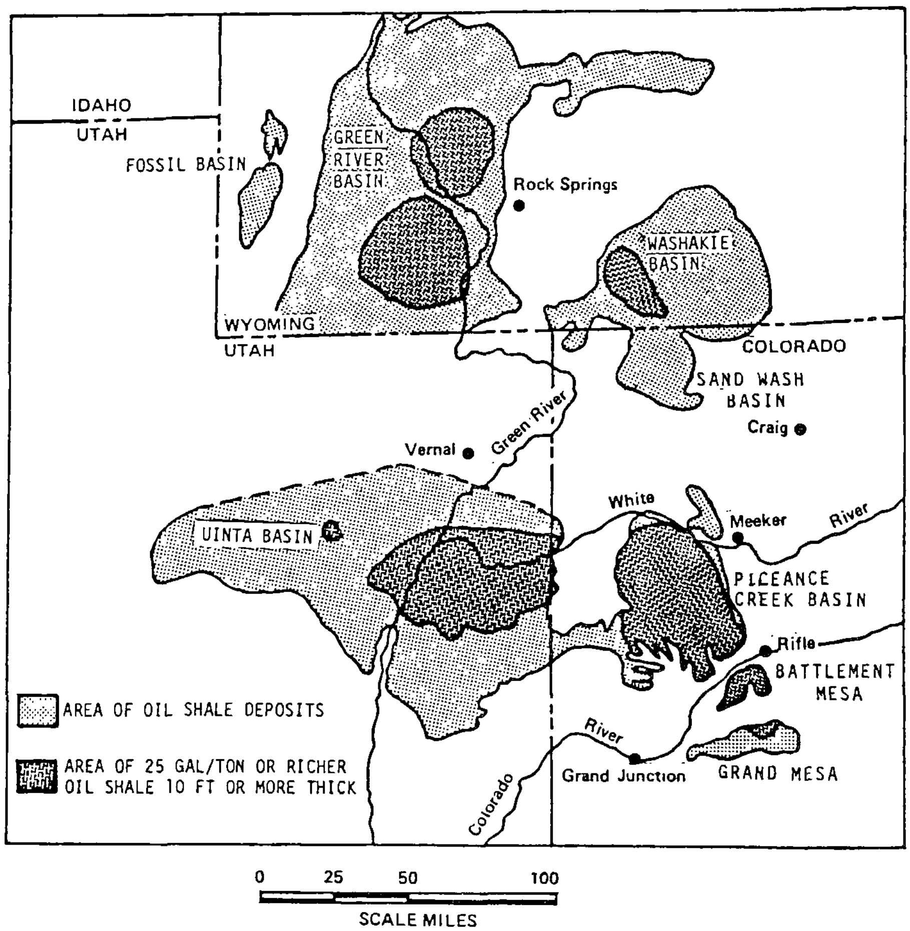


Figure 3-3 Oil shale areas of the Green River Formation in Colorado, Utah and Wyoming

TABLE 3-8 COAL MINING RATES AND RESERVES REQUIRED FOR A SYNTHANE PLANT PRODUCING 250 MILLION STANDARD CUBIC FEET PER DAY OF PIPELINE GAS

Coal Rank (Heating Value)	Daily Production Rate (tons/day)	Total Recoverable Reserve Required* (10^6 tons)	Total Coal Reserve Required** (10^6 tons)	
			Underground Mining	Surface Mining
Bituminous (13,000 Btu/lb)	15,800	154	308 (300) +	193 (200)
Subbituminous (9,800 Btu/lb)	20,900	204	408 (400)	255 (250)
Lignite (6,800 Btu/lb)	30,100	294	588 (600)	368 (350)

*Based on 325 day/year production and a 30 year mine life.
**Numbers in parenthesis are rounded off and used as criteria for the reserve requirements.

TABLE 3-9 COUNTIES OF PRINCIPAL COAL RESERVES IN CENTRAL AND EASTERN STATES

STATE	COUNTY	MINING[1]	COAL[2]	RESERVES (million short tons)
Alabama	Jefferson	U	B	758
	Walker	U	B	630
	Marengo	S	L	500
Illinois	Bond	U	B	1831
	Bureau	U	B	1029
	Christian	U	B	3347
	Clinton	U	B	1322
	Crawford	U	B	442
	Douglas	U	B	412
	Edgar	U	B	1750
	Fayette	U	B	1173
	Franklin	U	B	3038
	Gallatin	U	B	1761
	Hamilton	U	B	2440
	Jefferson	U	B	1800
	LaSalle	U	B	1083
	Lawrence	U	B	893
	Livington	U	B	586
	Logan	U	B	813
	Macon	U	B	439
	Macoupin	U	B	3421
	Madison	U	B	1366
	Marion	U	B	421
	Marshall	U	B	358
	McLean	U	B	420
	Menard	U	B	1460
	Montgomery	U	B	3906
	Perry	U	B	1201
	Putnam	U	B	588
	St. Clair	U	B	951
	Saline	U	B	2553
	Sangamon	U	B	3540
	Shelby	U	B	712
	Vermilion	U	B	1544
	Washington	U	B	1555
	White	U	B	992
	Williamson	U	B	1573
(Illinois, continued)	Bureau	S	B	221
	Fulton	S	B	1810
	Greene	S	B	423
	Grundy	S	B	381
	Henry	S	B	381
	Jackson	S	B	299
	Knox	S	B	605
	Madison	S	B	509
	Peoria	S	B	355
	Perry	S	B	973
	Randolph	S	B	417
	St. Clair	S	B	1162
	Saline	S	B	431
	Vermilion	S	B	353
	Williamson	S	B	529
Indiana	Gibson	U	B	1301
	Knox	U	B	1453
	Posey	U	B	720
	Sullivan	U	B	1922
	Vanderburgh	U	B	451
	Vermilion	U	B	497
	Vigo	U	B	1212
	Warrick	U	B	532
	Sullivan	S	B	316
	Warrick	S	B	313
Kentucky	Breathitt	U	B	410
	Fletcher	U	B	730
	Floyd	U	B	952
	Harlan	U	B	1408
	Henderson	U	B	1503
	Hopkins	U	B	1805
	Knott	U	B	1248
	Leslie	U	B	619
	McLean	U	B	723
	Muhlenberg	U	B	898
	Perry	U	B	560
	Pike	U	B	2170
	Union	U	B	1926
	Webster	U	B	1436
	Harlan	S	B	363
	Henderson	S	B	504
	Hopkins	S	B	769
	Muhlenberg	S	B	1091
	Ohio	S	B	593
	Perry	S	B	454
	Pike	S	B	504

(continued)

[1]U = underground mining; S = surface mining.

[2]B = bituminous; L = lignite.

TABLE 3-9 (continued)

STATE	COUNTY	MINING	COAL	RESERVES (million short tons)
Ohio	Athens	U	B	1326
	Belmont	U	B	3927
	Carroll	U	E	758
	Columbiana	U	E	748
	Gallia	U	B	340
	Guernsey	U	B	1184
	Harrison	U	E	1523
	Jefferson	U	B	1356
	Lawrence	U	B	477
	Mahoning	U	B	308
	Meigs	U	B	396
	Monroe	U	B	468
	Morgan	U	B	453
	Muskingum	U	B	720
	Noble	U	B	570
	Perry	U	B	644
	Stark	U	B	376
	Tuscarawas	U	B	841
	Vinton	U	B	301
	Jefferson	S	B	338
	Noble	S	B	343
Pennsylvania	Allegheny	U	B	881
	Armstrong	U	B	1092
	Beaver	U	B	435
	Butler	U	B	863
	Cambria	U	B	1454
	Clarion	U	B	640
	Clearfield	U	B	1102
	Fayette	U	B	1023
	Greene	U	B	6515
	Indiana	U	B	1716
	Jefferson	U	B	456
	Somerset	U	B	1240
	Washington	U	B	3604
	Westmoreland	U	B	747
West Virginia	Barbour	U	B	948
	Boone	U	B	1868
	Braxton	U	B	467
	Clay	U	B	695
	Fayette	U	B	796
	Grant	U	B	313
	Harrison	U	B	380
	Kanawha	U	B	1120
(West Virginia, continued)	Lewis	U	B	730
	Lincoln	U	B	360
	Logan	U	B	3760
	Marion	U	B	2599
	Marshall	U	B	3043
	McDowell	U	B	912
	Mingo	U	B	1887
	Monongolia	U	B	3008
	Nicholas	U	E	1433
	Ohio	U	E	379
	Preston	U	B	837
	Randolph	U	B	757
	Rayleigh	U	B	1656
	Taylor	U	B	388
	Upshur	U	B	876
	Wayne	U	B	403
	Webster	U	B	1098
	Wetzel	U	B	846
	Wyoming	U	B	1642
	Boone	S	B	579
	Fayette	S	B	275
	Kanawha	S	B	563
	Logan	S	B	557
	McDowell	S	B	324
	Mingo	S	B	444
	Rayleigh	S	B	339

(in parenthesis) have been met, together with the total reserves found in the each county[28]. Not all of the coal reserve is available for mining. For example, the amount of coal found under towns, roads, railroads, etc. must be subtracted from the total reserve. However, the total coal reserve is still a good measure of the coal available for mining. Furthermore, we have assumed that if a plant is located in one of the counties listed in Table 3-9, the mine will have a large enough coal reserve to meet the criteria shown in Table 3-8. This may not be the case and we have not subdivided the county to determine where the required coal reserve may be found.

From the list of total reserves, 26 sites were selected in the Central and Eastern states (Table 3-10 and Figure 3-4). In Alabama sufficient bituminous coal is found in the central portion of the state and sufficient lignite is found in one county in the south central region. Most of the surface mining sites are found in Illinois. In Indiana there are a few counties in the southwest with sufficient coal beds. Kentucky has concentrations of coal reserves in the eastern and western parts of the state, while Ohio's coal reserves are located principally in two counties in the southeastern region. Bituminous coal is found in Pennsylvania in the western part of the state, while the largest coal reserves in West Virginia are located in four counties in the southwest. The sites were distributed geographically in each of the states. Table 3-10 also lists the water sources for each of the sites. The selection is based upon a sufficient and reliable water supply (Section 4.1 and Appendix 13) and available water quality data (Section 3.6).

In a similar manner, we have listed in Table 3-11 the counties by state in the Western states that meet the criteria for total reserves. Site selection was limited to the states of Montana, New Mexico, North Dakota and Wyoming. A total of 28 coal conversion sites were selected in the Western states. These sites are listed in Table 3-12 and shown on Figure 3-5.

In the Western states the areal extent of a county is much larger than those found in the Central and Eastern states. As a result the plant sites were identified with either a particular existing mine, a town, or a quadrangle on a U.S. Geological Survey topographical map. Table 3-12 also lists the water source for each of the sites. As noted above the water sources were selected on the basis of a sufficient and reliable water supply (Section 4.2

TABLE 3-10 COAL CONVERSION PLANT SITES FOR CENTRAL AND EASTERN STATES

STATE	COUNTY	MINING[1]	COAL[2]	WATER SOURCE
Alabama	Jefferson	U	B	Alabama River
	Marengo	S	L	Tombigbee River and Well Water
Illinois	Bureau	U	B	Well Water
	Shelby	U	B	Ohio River
	St. Clair	U	B	Ohio River
	White	U	B	Ohio River
	Bureau	S	B	Illinois River
	Fulton	S	B	Well Water
	St. Clair	S	B	Ohio River
	Saline	S	B	Ohio River
Indiana	Gibson	U	B	White River
	Vigo	U	B	White River
	Sullivan	S	B	Ohio River
	Warrick	S	B	Ohio River
Kentucky	Floyd	U	B	Ohio River
	Harlan	U	B	Ohio River
	Muhlenberg	S	B	Green River
	Pike	S	B	Ohio River
Ohio	Gallia	U	B	Ohio River
	Tuscarawas	U	B	Muskingum River
	Tuscarawas	U	B	Well Water
	Jefferson	S	B	Ohio River
Pennsylvania	Somerset	U	B (MV, LV)	Allegheny River
	Armstrong	U	B	Allegheny River
West Virginia	Fayette	U	B	Kanawha River
	Kanawha	U	B (HV)	Kanawha River
	Monongalia	U	B (HV)	Allegheny River
	Preston	U	B (HV, MV, LV)	Kanawha River
	Mingo	S	B (HV)	Kanawha River

1. U = Underground mining; S = Surface mining
2. B = Bituminous; HV = High volatile, MV = Medium volatile; LV = Low volatile.

TABLE 3-11 COUNTIES OF PRINCIPAL COAL RESERVES IN WESTERN STATES

STATE	COUNTY	MINING[1]	COAL[2]	RESERVES (million short tons)
Montana	Big Horn	S	S	10621
	Custer	S	S	1150
	Custer	S	L	1168
	Dawson	S	L	1101
	McCone	S	L	464
	McCone	S	S	707
	Powder River	S	S	15217
	Powder River	S	L	1252
	Roosevelt	S	L	431
	Rosebud	S	S	7313
	Sheridan	S	L	454
	Treasure	S	S	327
	Wibaux	S	L	1000
New Mexico	Colfax	U	B	1381
	McKinley	S	S	250
	San Juan	S	S	2008
	San Juan	U	S	442
North Dakota	Billings	S	L	1078
	Bowman	S	L	785
	Dunn	S	L	2000
	Hettinger	S	L	980
	McClean	S	L	1009
	McKenzie	S	L	825
	Mercer	S	L	1986
	Morton	S	L	342
	Oliver	S	L	629
	Slope	S	L	2326
	Stark	S	L	1275
	Ward	S	L	501
	Williams	S	L	1130
Wyoming	Campbell	S	S	19591
	Carbon	S	S	464
	Converse	S	S	565
	Johnson	S	S	1013
	Lincoln	S	S	1000
	Sweetwater	S	S	1115

1. U = Underground mining; S = Surface mining
2. B = Bituminous; L = Lignite; S = Subbituminous

Figure 3-4 Coal conversion site locations in Eastern and Central states.

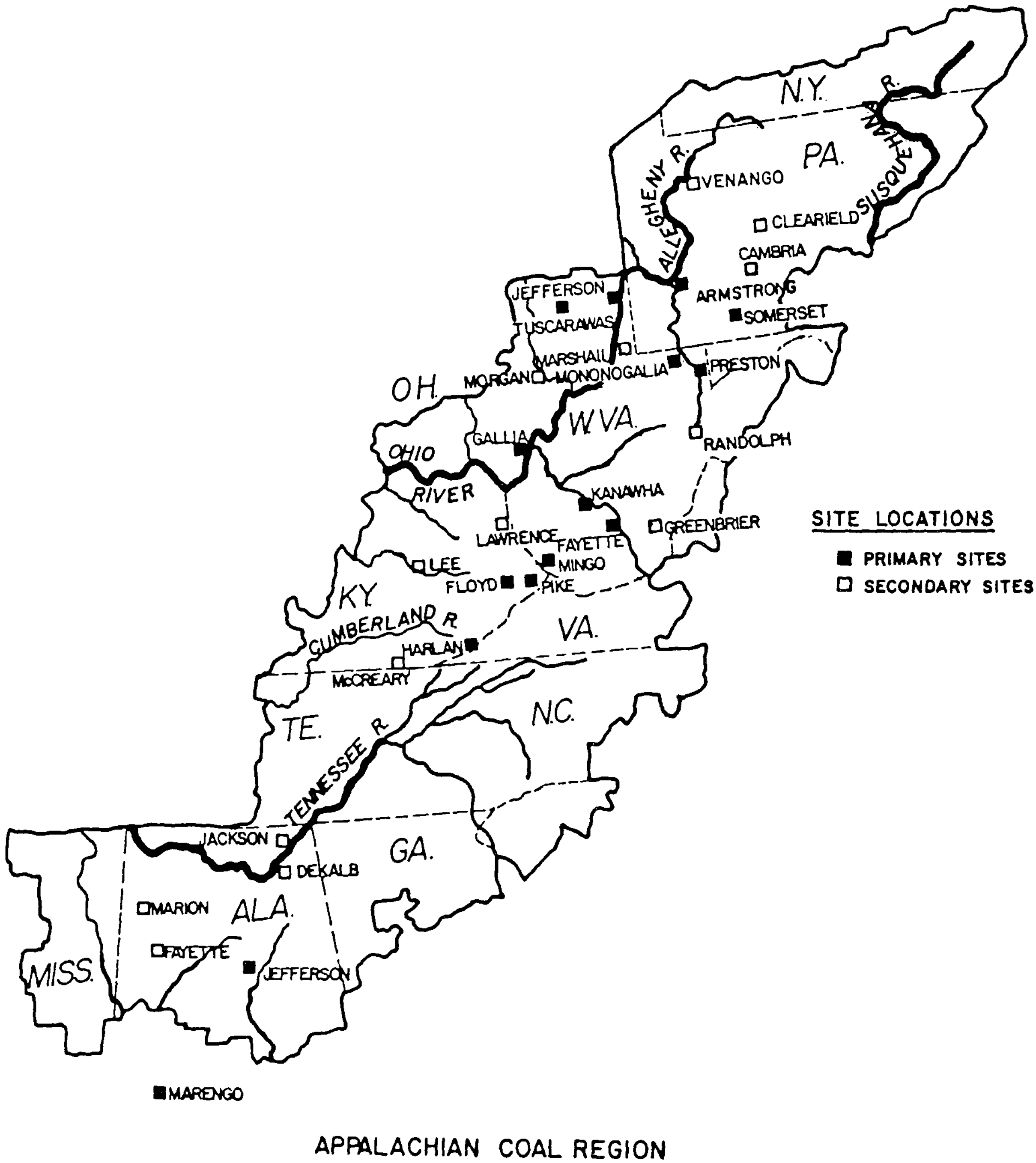


Figure 3-4 (concluded).

TABLE 3-12 COAL CONVERSION PLANT SITES FOR WESTERN STATES

State	County	Mine, Seam or Coal Region (location)	Mining[1]	Coal or Shale[2]	Water Source
Coal Conversion					
Montana	Big Horn	Decker-Dietz (Quad)*	S	S	Well Water
	Custer	Foster Creek (S.W.Custer)	S	S	Tongue River
	Dawson	U.S. Steel Chupp Mine (Intake N.W. Quad)	S	L	Yellowstone River
	Powder River	East Moorhead (Moorhead)	S	L	Powder River
	Powder R.-Custer	Pumpkin Creek (Elk Ridge Quad)	S	L	Tongue River
	Powder R.-Rosebud	Otter Creek (Otter)	S	L	Underground water
	Rosebud	Colstrip (Colstrip)	S	S	Yellowstone River
	Sheridan	Coalridge (Coalridge)	S	L	Missouri River
New Mexico	McKinley	Gallup (Gallup)	S	S	Brackish groundwater
	San Juan	El Paso (Bisti Trading Post Quad)	S	S	San Juan River
	San Juan	Wesco (Newcombe Quad)	S	S	San Juan River
North Dakota	Bowman	Scranton (Quad)	S	L	Grand River
	Hettinger	Bentley (Quad)	S	L	Knife River
	McLean	Underwood (Quad)	S	L	Lake Sakakawea
	Mercer	Knife River (Beulah-Zap)	S	L	Knife River
	Oliver	Center (Center)	S	L	Knife River
	Slope	Slope (Amidon)	S	L	Yellowstone River
	Stark	Dickinson (Dickinson)	S	L	Lake Sakakawea
	Williams	Williston (Quad)	S	L	Missouri River

*Quad = U.S. Geological Survey Quadrangle on topographical map.
1 - U = Underground mining; S = surface mining.
2 - B = Bituminous coal; L = lignite coal; SB = subbituminous coal, HG = high grade shale.

TABLE 3-12 (concluded)

State	County	Mine, Seam or Coal Region (location)	Mining[1]	Coal or Shale[2]	Water Source
Wyoming	Campbell	Belle Ayre Mine (Caballa)	S	S	Crazy Woman Creek
	Campbell	Gillette-Wyodak (Gillette)	S	S	Crazy Woman Creek
	Campbell	Spotted Horse Strip (Spotted Horse)	S	S	Powder River
	Carbon	Hanna (Hanna)	S	S	Medicine Bow Reservoir
	Converse	Antelope Creek Mine (Verse)	S	S	Brackish Groundwater
	Johnson	Lake-de-Smet (Quad)	S	S	Tongue River
	Lincoln	Kemmerer (Quad)	S	B	Hams Fork
	Sweetwater	Jim Bridger (Superior Quad)	S	S	Green River
	Sweetwater	Rainbow #8 (Rock Springs Quad)	U	B	Green River
Shale Oil Conversion					
Colorado	Garfield	Parachute Creek (Forked Gulch Qd)	U	HG	Colorado River

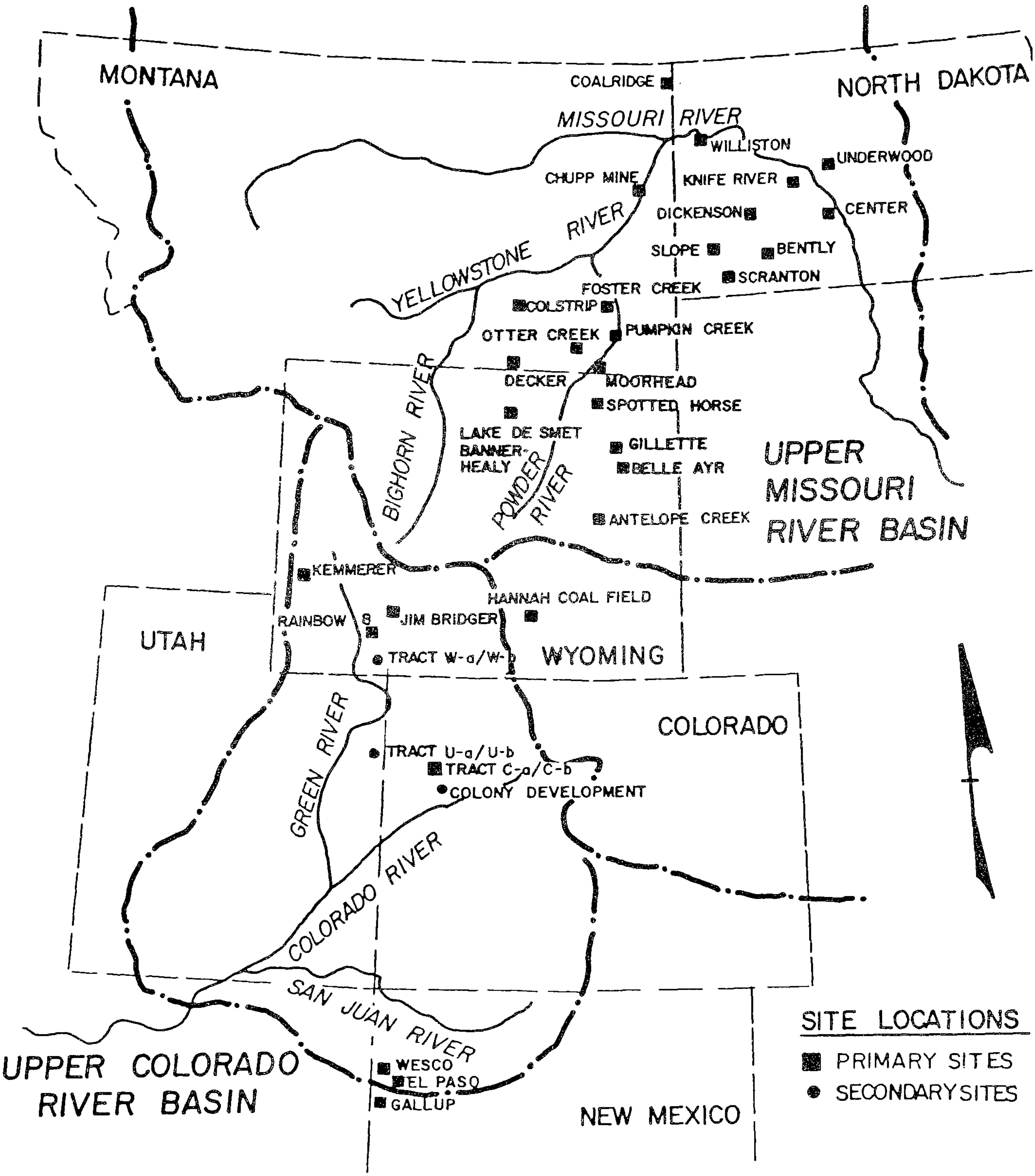


Figure 3-5 Coal and oil shale conversion site locations in Western states.

and Appendix 14) and/or available water quality data (Section 3.6).

Most of the coal found in the Northern Great Plains, which includes the states of Wyoming, North Dakota, Montana, South Dakota and Nebraska, is either lignite or subbituminous. Nine sites were chosen in Wyoming where most of the coal is subbituminous. Subbituminous coal is found in southeastern Montana andlignite is found in Eastern Montana. Eight sites were selected in Montana. All eight sites in North Dakota have lignite and all three sites in New Mexico have subbituminous coal.

The location of some active strip mines were found on a U.S. Geological Survey map of the stripping coal deposits of the Northern Great Plains[32]. Most of these mines are located in the areas of the largest coal reserves. For example, in Campbell County, Wyoming, seven strip mines are shown, all of which are located in the coal deposits running from Spotted Horse in the northwestern part of the county down through the Gillette deposit to the southern tip. These deposits have 19,591 million short tons of subbituminous coal of which 17,000 million short tons are found in strippable reserves. In New Mexico two of the sites selected were those proposed for coal gasification.

Depending on the shale grade and the particular process, approximately 75,000 to 100,000 tons of high grade shale must be mined daily from an underground shale mine integrated with a shale oil plant to produce 60,000 to 75,000 barrels/day of shale oil. This is the range of shale oil needed to produce 50,000 barrels/day of synthetic crude in a self-sufficient integrated plant. For one plant this means a total recoverable reserve of from 600×10^6 to 730×10^6 barrels of shale oil is needed, assuming 325 days/year production and a 30 year mine life. About 30 percent of the shale remains underground with conventional room-and-pillar mining techniques[6], so that a total reserve of from 860×10^6 to $1{,}040 \times 10^6$ barrels of shale oil is required for a plant producing 50,000 barrels/day of synthetic crude. This may be compared to identified reserves of about 370×10^9 to 620×10^9 barrels from high grade shale in the Green River Formation[26].

One oil shale site has been selected in Colorado in Garfield County near the Colorado River (Table 3-12). This is near Anvils Point in the Piceance Creek Basin where a number of Bureau of Mines shale oil test facilities are located.

3.4 Plant-Site Combinations

Tables 3-13 and 3-14 list the plant-site combinations for the Eastern and Central states and the Western states, respectively. Table 3-15 lists the plant-site combinations by conversion process. In the East and Central states, 48 plant-site combinations for coal conversion were chosen; in the West 39 plant-site combinations for coal conversion and 3 plant-site combinations for shale oil conversion were chosen.

Tables 3-16 and 3-17 show a breakdown by the major process and site characteristics of the process-site combinations selected for the study. The tables also show a comparison of the selected combinations with the minimum number of process-site combinations given in Tables 3-1 and 3-2. Two combinations involving groundwater were not considered due to an oversight: one in the Eastern states for a high temperature gasifier using surface mined bituminous coal; and one in the Western states for a high temperature gasifier using surface mined lignite coal. In a recently completed study[33], two combinations involving surface water in the Western States were considered: a low temperature gasifier using surface mined lignite coal, and liquefaction-coal refining using surface mined subbituminous coal. The results of the study will be included in the present study. For oil shale conversion the groundwater combinations were eliminated in favor of another indirect retorting process.

3.5 Coal Analyses

Both proximate and ultimate coal analyses for each of the sites are shown in Table 3-18 and 3-19; the proximate analysis are given in the top block, while the ultimate analysis is given in the bottom block. The analyses are typical of those found in the vicinity of each of the sites. They were obtained from Refs. 30 and 34 and from data published by the U.S. Geological Survey, U.S. Bureau of Mines, and various state geological surveys.

The heating value of the coal determines the actual quantity of coal required and the quantity of ash to be disposed of while the moisture can affect the process water requirements. The carbon associated with the volatile content of the coal is highly reactive at temperatures of about 1400°F to 2000°F while the fixed carbon is less reactive and requires temperatures of about 2000°F for conversion. Sulfur in coal is found principally in the form of either pyritic or organic sulfur and must be removed. In the Western low

TABLE 3-13 PLANT-SITE COMBINATIONS FOR EASTERN AND CENTRAL STATES

State	County	Water Source				Coal Gasification				Coal Liquefaction and Coal Refining		Plant-Site Combinations	
						High Temp. Gasifier		Low Temp. Gasifier					
		Surface	Ground	Mining[a]	Coal[b]	Hygas	Bigas	Lurgi	Synthane	Synthoil	SRC	No.	Total State
Alabama	Jefferson	Alabama R.		U	B	X			X	X		3	
	Marengo	Tombigbee R.	X	S	L	X		X			X	6	9
Illinois	Bureau		X	U	B		X	X			X	3	
	Shelby	Ohio R.		U	B		X					1	
	St. Clair	Ohio R.		U	B			X				1	
	White	Ohio R.		U	B						X	1	
	Bureau	Illinois R.		S	B		X					1	
	Fulton		X	S	B			X			X	2	
	St. Clair	Ohio R.		S	B			X				1	
	Saline	Ohio R.		S	B						X	1	11
Indiana	Gibson	White R.		U	B	X			X	X		3	
	Vigo	White R.		U	B		X					1	
	Sullivan	Ohio R.		S	B				X			1	
	Warrick	Ohio R.		S	B	X				X		2	7
Kentucky	Floyd	Ohio R.		U	B				X			1	
	Harlan	Ohio R.		U	B					X		1	
	Muhlenberg	Green R.		S	B			X				1	
	Pike	Ohio R.		S	B					X		1	4
Ohio	Gallia	Ohio R.		U	B				X			1	
	Tuscarawas	Muskingum R.	X	U	B	X				X		4	
	Jefferson	Ohio R.		S	B	X			X	X		3	8
Pennsylvania	Armstrong	Allegheny R.		U	B	X			X			2	
	Somerset	Allegheny R.		U	B					X		1	3
West Virginia	Fayette	Kanawha R.		U	B	X						1	
	Kanawha	Kanawha R.		U	B				X			1	
	Monongalia	Allegheny R.		U	B	X						1	
	Preston	Kanawha R.		U	B				X			1	
	Mingo	Kanawha R.		S	B	X				X		2	6
												TOTAL	48

a U = Underground; S = Surface.

b B = Bituminous; L = Lignite

TABLE 3-14 COAL AND OIL SHALE CONVERSION PLANT-SITE COMBINATIONS FOR WESTERN STATES

State	Mine	Water Source Surface	Ground	Mining[a]	Coal[b]	Coal Gasification: High Temp. Gasifier Hygas	Bigas	Low Temp. Gasifier Lurgi	Synthane	Coal Liquefaction and Coal Refining Synthoil	SRC	Plant-Site Combinations No.	Total State
Montana	Decker-Dietz		X	S	S	X		X				2	
	Foster Creek	Tongue R.		S	S			X				1	
	U.S. Steel Chupp Mine	Yellowstone R.		S	L		X					1	
	East Moorhead	Powder R.		S	L	X						1	
	Pumpkin Creek	Tongue R.		S	L						X	1	
	Otter Creek		X	S	L						X	1	
	Colstrip	Yellowstone R.		S	S	X			X		X	3	
	Coalridge	Missouri River		S	L						X	1	11
New Mexico	Gallup		X	S	S	X		X		X		3	
	El Paso	San Juan R.		S	S	X		X				2	
	Wesco	San Juan R.		S	S			X				1	6
North Dakota	Scranton	Grand R.		S	L		X					1	
	Bentley	Knife R.		S	L						X	1	
	Underwood	L. Sakakawea		S	L						X	1	
	Knife River	Knife R.		S	L			X				1	
	Center	Knife R.		S	L		X					1	
	Slope	Yellowstone R.		S	L		X					1	
	Dickinson	L. Sakakawea		S	L						X	1	
	Williston	Missouri R.		S	L			X				1	8
Wyoming	Belle Ayr	Crazy Woman Cr.		S	S	X						1	
	Gillette-Wyodak	Crazy Woman Cr.		S	S	X					X	2	
	Spotted Horse Strip	Powder R.		S	S				X			1	
	Hanna	Medicine Bow		S	S	X						1	
	Antelope Creek Mine	Beaver Cr.	X	S	S	X			X		X	3	
	Lake-de-Smet	Tongue R.		S	S					X		1	
	Kemmerer	Hams Fork		S	B		X	X				2	
	Jim Bridger	Green R.		S	S					X		2	
	Rainbow #8	Green R.		U	B						X	1	14
												TOTAL	39

State	Mine	Water Source Surface	Ground	Mining[a]	Shale[c]	Direct Retort Paraho Direct	Indirect Retort Paraho Indirect	TOSCO II		Plant-Site Combinations No.	Total State
Colorado	Parachute Creek	Colorado R.		U	HG	X	X	X		3	3
										TOTAL	3

a U = Underground; S = Surface
b B = Bituminous; L = Lignite; S = Subbituminous
c HG = High grade shale

TABLE 3-15 PLANT-SITE COMBINATIONS LISTED BY CONVERSION PROCESS

Site	Raw-water Source	Coal Rank[1]	Mine[2]
Coal Conversion			
Process: Hygas			
East: Jefferson, Alabama	Alabama R. at Selma, Alabama	B	U
Marengo, Alabama	Tombigbee R. at Jackson, Ala.	L	S
Marengo, Alabama	Well-water, Marengo, Alabama	L	S
Gibson, Indiana	White R. at Hazleton, Indiana	B	U
Warrick, Indiana	Ohio R. at Cannelton Dam, Ky.	B	S
Tuscarawas, Ohio	Muskingum R. at McConnelsville, O.	B	U
Tuscarawas, Ohio	Well-water from alluvial ground in Tuscarawas, Ohio	B	U
Jefferson, Ohio	Ohio R. at Cannelton Dam, Ky.	B	S
Armstrong, Pa.	Allegheny R. at Oakmont, Pa.	B	U
Fayette, W. Virginia	Kanawha R. at Kanawha Falls. W.Va.	B	U
Monongalia, W. Va.	Allegheny R. at Oakmont, Pa.	B	U
Mingo, W. Virginia	Kanawha R. at Kanawha Falls, W.Va.	B	S
West: Gillette, Wyoming	Crazy Woman Creek nr. Arvada, Wy.	S	S
Antelope Cr. Mine, Wy.	Brackish Water at Beaver Creek near Newcastle, Wy.	S	S
Belle Ayr Mine, Wy.	Crazy Woman Creek nr. Arvada, Wy.	S	S
Hanna Coal Field, Wy.	Medicine Bow R. above Seminoe Reservoir, Wy.	S	S
Decker, Montana	Well-water nr. Decker, Montana	S	S
E.Moorhead Coal Field, Montana	Powder R. at Arvada, Wyoming	L	S
Colstrip, Montana	Yellowstone R., Montana	S	S
El Paso, New Mexico	San Juan R., New Mexico	S	S
Gallup, New Mexico	Brackish Groundwater, New Mex.	S	S
Process: Bigas			
East: Bureau, Illinois	Illinois R. at Marseilles, Ill.	B	S
Bureau, Illinois	Well-water from alluvial ground at Bureau, Ill.	B	U
Shelby, Illinois	Ohio R. at Grand Chain, Ill.	B	U
Vigo, Indiana	White R. at Hazleton, Indiana	B	U
West: Kemmerer, Wyoming	Hams Fork near Granger, Wy.	B	S
Slope, N. Dakota	Yellowstone R. at Terry, Mont.	L	S
Center, N. Dakota	Knife River at Hazen, N. Dakota	L	S
Scranton, N. Dakota	Grand River at Shadehill, S. D.	L	S
U.S. Steel, Chupp Mine, Montana	Yellowstone River, Montana	L	S
Process: Lurgi			
East: Marengo, Alabama	Tombigbee R. at Jackson, Alabama	L	S
Marengo, Alabama	Well-water, Marengo, Alabama	L	S
Bureau, Illinois	Well-water from alluvial ground at Bureau, Illinois	B	U
St. Clair, Illinois	Ohio R. at Grand Chain, Illinois	B	S
St. Clair, Illinois	Ohio R. at Grand Chain, Illinois	B	U
Fulton, Illinois	Groundwater nr. Fulton, Illinois	B	S
Muhlenberg, Kentucky	Green R. at Beech Grove, Ky.	B	S
West: Jim Bridger Mine, Wy.	Green R. below Green R., Wyoming	S	S
Kemmerer, Wyoming	Hams Fork, near Granger, Wyoming	B	S
Knife River, N.Dakota	Knife R. at Hazen, N. Dakota	L	S
Williston, N. Dakota	Missouri R. nr. Williston, N. D.	L	S
Decker, Montana	Well-water nr. Decker, Montana	S	S
Foster Creek, Montana	Tongue R., Montana	S	S
El Paso, New Mexico	San Juan R., New Mexico	S	S
Wesco, New Mexico	San Juan R., New Mexico	S	S
Gallup, New Mexico	Brackish groundwater, New Mexico	S	S
Process: Synthane			
East: Jefferson, Alabama	Alabama R. at Selma, Alabama	B	U
Gibson, Indiana	White R. at Hazleton, Ind.	B	U
Sullivan, Indiana	White R. at Hazleton, Ind.	B	S
Floyd, Kentucky	Ohio R. at Cannelton Dam, Ky.	B	U
Gallia, Ohio	Ohio R. at Cannelton Dam, Ky.	B	U
Jefferson, Ohio	Ohio R. at Cannelton Dam, Ky.	B	S
Armstrong, Pa.	Allegheny R. at Oakmont, Pa.	B	U
Kanawha, West Virginia	Kanawha R. at Kanawha Falls, W.Va.	B	U
Preston, West Virginia	Kanawha R. at Kanawha Falls, W.Va.	B	U
West: Antelope Cr. Mine, Wy.	Brackish water at Beaver Creek near Newcastle, Wy.	S	S
Spotted Horse, Wyoming	Powder River at Arvada, Wy.	S	S
Colstrip, Montana	Yellowstone River, Montana	S	S

1. B = Bituminous coal, L = lignite coal, S = subbituminous coal, HG = high grade shale.
2. S = Surface, U = Underground.

TABLE 3-15 (continued)

Site	Raw-water Source	Coal Rank[1]	Mine[2]
Process: Synthoil			
East: Jefferson, Alabama	Alabama R. at Selma, Alabama	B	U
Gibson, Indiana	White R. at Hazleton, Indiana	B	U
Warrick, Indiana	Ohio R. at Cannelton Dam, Ky.	B	S
Harlan, Kentucky	Ohio R. at Cannelton Dam, Ky.	B	U
Pike, Kentucky	Ohio R. at Cannelton Dam, Ky.	B	S
Tuscarawas, Ohio	Muskingum R. at McConnelsville, O.	B	U
Tuscarawas, Ohio	Well-water from alluvial ground in Tuscarawas, Ohio	B	U
Jefferson, Ohio	Ohio R. at Cannelton Dam, Ky.	B	S
Somerset, Pa.	Allegheny R. at Oakmont, Pa.	B	U
Mingo, W. Virginia	Kanawha R. at Kanawha Falls, W.Va.	B	S
West: Lake-de-Smet, Wyoming	Tongue R. at Goose Creek below Sheridan, Wy.	S	S
Jim Bridger Mine, Wy.	Green R. below Green River, Wy.	S	S
Gallup, New Mexico	Brackish Groundwater, New Mexico	S	S
Process: SRC			
East: Marengo, Alabama	Tombigbee R. at Jackson, Alabama	L	S
Marengo, Alabama	Well-water, Marengo, Alabama	L	S
Bureau, Illinois	Well-water from alluvial ground at Bureau, Illinois	B	U
White, Illinois	Ohio R. at Grand Chain, Illinois	B	U
Fulton, Illinois	Groundwater nr. Fulton, Illinois	B	S
Saline, Illinois	Ohio R. at Grand Chain, Illinois	B	S
West: Gillette, Wyoming	Crazy Woman Creek nr. Arvada, Wy.	S	S
Antelope Cr. Mine, Wy.	Brackish water at Beaver Creek near Newcastle, Wy.	S	S
Rainbox, Wyoming	Green R. below Green River, Wy.	B	U
Dickinson, N. Dakota	Lake Sakakawea, N. Dakota	L	S
Bentley, N. Dakota	Knife R. at Hazen, N. Dakota	L	S
Underwood, N. Dakota	Lake Sakakawea, N. Dakota	L	S
Otter Creek, Montana		L	S
Pumpkin Creek, Montana	Tongue R., Montana	L	S
Coalridge, Montana	Missouri R. at Culbertson, Mont.	L	S
Colstrip, Montana	Yellowstone R., Montana	S	S

Site	Raw-water Source	Shale[1]	Mine[2]
Oil Shale Conversion			
Process: Paraho Direct			
West: Parachute Creek, Colorado	Colorado R. nr. Glenwood Springs, Colorado	HG	S
Process: Paraho Indirect			
West: Parachute Creek, Colorado	Colorado R. nr. Glenwood Springs, Colorado	HG	S
Process: TOSCO II			
West: Parachute Creek, Colorado	Colorado R. nr. Glenwood Springs, Colorado	HG	S

TABLE 3-16 BREAKDOWN OF PROCESS-SITE COMBINATIONS FOR EASTERN AND CENTRAL STATES

Site/Process Criteria	High Temperature Gasifiers	Low Temperature Gasifiers	Liquefaction and Coal Refining
Surface Water (Humid-temperature climate)			
Underground mining-bituminous coal	8 (1)*	8 (1)	6 (1)
Surface mining-bituminous coal	4 (1)	4 (1)	5 (1)
Surface mining-lignite coal	1 (0)	1 (0)	1 (0)
TOTAL	13 (2)	13 (2)	12 (2)
Groundwater (Humid-temperature climate)			
Underground mining-bituminous coal	2 (1)	1 (1)	2 (1)
Surface mining-bituminous coal	0 (1)	1 (1)	1 (1)
Surface mining-lignite coal	1 (0)	1 (0)	1 (0)
TOTAL	3 (2)	3 (2)	4 (2)
Process-site Combinations - TOTAL	16 (4)	16 (4)	16 (4)

*Numbers in parenthesis are the minimum number of process-site combinations given in Table 3-1.

TABLE 3-17 BREAKDOWN OF PROCESS-SITE COMBINATIONS FOR WESTERN STATES

Site/Coal Conversion Process Criteria	High Temperature Gasifiers	Low Temperature Gasifiers	Liquefaction and Coal Refining
Surface Water (Semi-arid)			
Surface mining-lignite	3 (1)*	0 (1)	5 (1)
Surface mining-bituminous coal	7 (1)	5 (1)	4 (1)
Underground mining-bituminous coal	0 (0)	0 (0)	1 (0)
TOTAL	10 (2)	5 (2)	10 (2)
Groundwater (Semi-arid)			
Surface mining-lignite	0 (1)	2 (1)	1 (1)
Surface mining-subbituminous-bituminous coal	2 (1)	2 (1)	1 (1)
TOTAL	2 (2)	4 (2)	2 (2)
Surface Water (Arid)			
Surface mining-subbituminous coal	1 (1)	2 (1)	0 (1)
TOTAL	1 (1)	2 (1)	0 (1)
Groundwater (Arid)			
Surface mining-subbituminous coal	1 (1)	1 (1)	1 (1)
TOTAL	1 (1)	1 (1)	1 (1)
Process-site Combinations - TOTAL	14 (6)	12 (6)	13 (6)

*Numbers in parenthesis are the minimum number of process-site combinations given in Table 3-1.

(continued)

TABLE 3-17 (concluded)

Site/Oil Shale Conversion Process Criteria	Indirect Retorting	Direct Retorting
Surface Water	2 (1)	1 (1)
Underground Water	0 (1)	0 (1)
Process-site Combinations - TOTAL	2 (2)	1 (2)

TABLE 3-18 COAL ANALYSES BY COUNTY FOR EASTERN AND CENTRAL COALS IN WT. PERCENT

	ALABAMA		ILLINOIS						INDIANA				KENTUCKY			
	Jefferson	Marengo	Bureau	Shelby	St. Clair	White	Fulton	Saline	Gibson	Vigo	Sullivan	Warrick	Floyd	Harlan	Muhlenberg	Pike
Moisture	2.3	48.7	16.1	13.9	11.3	8.5	15.6	6.8	10.0	16.2	13.5	9.3	3.4	3.6	11.0	3.0
Volatile matter	26.0	23.1	38.5	32.7	37.7	35.4	34.1	34.0	36.7	32.1	37.3	40.0	36.4	38.3	34.5	33.2
Fixed carbon	55.6	23.4	38.0	38.9	39.9	47.1	40.3	49.7	46.9	45.2	41.8	42.4	57.3	54.3	47.3	59.0
Ash	16.1	4.8	7.4	14.5	11.1	9.0	10.0	9.5	6.4	6.5	7.4	8.3	2.9	3.8	7.2	4.8
	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Moisture	2.3	48.7	16.1	13.9	11.3	8.5	15.6	6.8	10.0	16.2	13.5	9.3	3.4	3.6	11.0	3.0
C	71.0	32.1	60.1	56.0	61.1	66.6	58.8	67.9	68.2	62.8	63.9	64.8	79.8	77.8	64.8	79.6
H	4.4	2.2	4.1	4.0	4.2	4.6	4.1	4.5	4.6	4.4	4.5	4.6	5.2	5.1	4.7	5.1
O	3.8	9.8	8.3	7.2	7.4	7.1	7.3	6.8	7.6	8.1	7.1	9.4	6.5	7.6	8.3	5.3
N	1.5	0.6	1.1	1.3	1.2	1.4	1.1	1.4	1.1	1.4	1.4	1.2	1.6	1.5	1.4	1.5
S	0.9	1.8	2.9	3.1	3.7	2.8	3.1	3.1	2.1	0.6	2.2	2.4	0.6	0.6	2.6	0.7
Ash	16.1	4.8	7.4	14.5	11.1	9.0	10.0	9.5	6.4	6.5	7.4	8.3	2.9	3.8	7.2	4.8
	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
HHV*	12,790	5,340	10,760	10,190	11,070	12,100	10,650	12,260	12,200	11,260	11,600	11,650	14,300	13,900	11,800	14,300

*Btu/lb, calculated by Dulong formula (and differing less than 2% from the reported value).

(continued)

TABLE 3-18 (continued)

	OHIO			PENNSYLVANIA		WEST VIRGINIA				
	Gallia	Tuscarawas	Jefferson	Armstrong	Somerset	Fayette	Kanawha	Monongalia	Preston	Mingo
Moisture	7.4	6.3	2.4	2.3	1.8	3.0	1.9	3.1	2.5	2.2
Volatile matter	39.7	40.3	38.1	36.2	19.9	23.6	34.5	29.1	29.5	36.1
Fixed carbon	43.1	47.8	49.4	51.8	64.7	65.4	54.3	61.4	57.3	56.8
Ash	9.8	5.6	10.1	9.7	13.6	8.0	9.3	6.4	10.7	4.9
	100	100	100	100	100	100	100	100	100	100
Moisture	7.4	6.3	2.4	2.3	1.8	3.0	1.9	3.1	2.5	2.2
C	64.8	71.2	71.1	73.6	74.0	78.5	75.1	78.8	74.6	79.5
H	4.6	4.9	4.9	4.9	4.0	4.6	4.9	4.9	4.7	5.2
O	9.1	8.1	5.3	5.3	3.1	3.7	6.7	4.2	3.3	5.9
N	1.1	1.4	1.2	1.4	1.4	1.4	1.4	1.5	1.5	1.4
S	3.2	2.5	5.0	2.8	2.1	0.8	0.7	1.1	2.7	0.9
Ash	9.8	5.6	10.1	9.7	13.6	8.0	9.3	6.4	10.7	4.9
	100	100	100	100	100	100	100	100	100	100
HHV*	11,700	12,900	13,100	13,400	13,080	14,000	13,400	14,200	13,600	14,300

TABLE 3-19 COAL ANALYSES FOR WESTERN COALS IN WT. PERCENT

	WYOMING									NORTH DAKOTA							
	Gillette (Wyodak)	Lake de Smet-Banner-Healy	Antelope Creek Mine	Spotted Horse Strip-Felix Bed	Jim Bridger Mine	Belle Ayr Mine	Hanna Coal Field (Rosebud 4&5)	Kemmerer	Rainbow #8 Mine	Slope (Harmon)	Knife River	Dickenson	Williston	Center	Bently	Underwood	Scranton
Moisture	30.4	23.6	26.2	28.0	21.2	21.7	11.8	2.8	10.4	44.4	35.0	41.2	40.0	36.2	36.4	35.4	40.2
Volatile matter	30.1	31.9	31.9	31.7	31.4	34.5	40.1	37.4	38.1	25.2	26.8	25.4	26.0	26.2	27.4	28.3	24.5
Fixed carbon	31.7	34.8	37.4	32.5	39.2	38.3	40.0	50.6	46.1	23.7	32.1	26.9	28.4	29.0	30.4	30.7	27.8
Ash	7.8	9.7	4.5	7.8	8.2	5.5	8.1	9.2	5.4	6.7	6.1	6.5	5.6	8.6	5.8	5.6	7.5
	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Moisture	30.4	23.6	26.2	28.0	21.2	21.7	11.8	2.8	10.4	44.4	35.0	41.2	40.0	36.2	36.4	35.4	40.2
C	45.8	48.3	52.6	46.8	51.9	54.3	60.5	71.8	66.1	32.9	42.5	37.6	39.1	39.9	41.6	42.7	38.0
H	3.4	3.5	3.6	3.5	3.2	3.9	4.5	5.0	4.6	2.6	2.8	2.7	2.8	2.8	3.1	3.0	2.6
O	11.3	13.2	12.0	12.3	13.9	13.2	12.5	9.0	11.0	11.0	12.3	11.0	11.2	11.0	11.3	12.2	9.8
N	0.6	0.7	0.6	0.7	1.1	0.9	1.5	1.2	1.6	0.6	0.6	0.5	0.7	0.6	0.6	0.6	0.6
S	0.7	1.0	0.5	0.9	0.5	0.5	1.1	1.0	0.9	1.8	0.7	0.5	0.6	0.9	1.2	0.5	1.3
Ash	7.8	9.7	4.5	7.8	8.2	5.5	8.1	9.2	5.4	6.7	6.1	6.5	5.6	8.6	5.8	5.6	7.5
	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
HHV*	7,920	8,200	9,000	8,060	8,500	9,310	10,660	12,880	11,650	5,620	7,000	6,310	6,580	6,720	7,140	7,140	6,430

*Btu/lb, calculated by Dulong formula (and differing less than 2% from reported value).

(continued)

TABLE 3-19 (continued)

	MONTANA								NEW MEXICO		
	Decker (Dietz)	Otter Creek (Knobloch)	East Moorhead Coal Field	Foster Creek	Pumpkin Creek	Coalridge	U.S. Steel, Chupp Mine	Colstrip	El Paso	Wesco	Gallup
Moisture	23.9	29.4	36.1	30.7	30.7	40.4	38.3	24.4	16.3	12.4	15.1
Volatile matter	31.3	29.2	27.0	27.2	28.5	24.5	24.4	28.0	64.5	28.2	34.2
Fixed carbon	41.1	36.4	30.7	34.4	32.9	27.6	30.0	40.7		33.8	45.6
Ash	3.7	5.0	6.2	7.7	7.9	7.5	7.3	6.9	19.2	25.6	5.1
	100	100	100	100	100	100	100	100	100	100	100
Moisture	23.9	29.4	36.1	30.7	30.7	40.4	38.3	24.4	16.3	12.4	15.1
C	57.2	50.3	42.4	45.7	44.6	35.2	40.4	52.4	49.2	47.5	63.2
H	3.2	2.9	2.8	2.9	3.1	2.4	2.5	3.5	3.6	3.6	4.7
O	10.9	11.2	11.4	11.8	12.5	13.5	10.6	11.6	10.2	9.3	10.4
N	0.6	0.6	0.7	0.7	0.7	0.6	0.6	0.8	0.8	0.9	1.1
S	0.5	0.6	0.6	0.5	0.5	0.4	0.3	0.4	0.7	0.7	0.4
Ash	3.7	5.0	6.2	7.7	7.9	7.5	7.3	6.9	19.2	25.6	5.1
	100	100	100	100	100	100	100	100	100	100	100
HHV*	9,480	8,270	7,040	7,550	7,460	5,600	6,600	8,910	8,620	8,440	11,300

sulfur coals, the sulfur is in the organic form; in the high sulfur Eastern coals, most sulfur is in the pyritic form. High volatile coals agglomerate at high temperatures and pressures causing blockages in the reactor.

3.6 Water Analyses

The water analysis for each water source is shown in Tables 3-20 and 3-21. The surface water data were obtained from published U.S. Geological Survey water supply-water quality reports, while most of the groundwater data came from STORET computer printouts. The water source for each process-site combination is given in Tables 3-15 and A11-3 (Appendix 11).

TABLE 3-20 RAW SOURCE WATER QUALITY FOR CENTRAL AND EASTERN STATES (CONCENTRATION IN MG/LITER)

	Tombigbee River @ Jackson, Alabama	Alabama River @ Selma, Alabama	Well Water @ Marengo, Alabama	Illinois River @ Marseilles, Illinois	Well Water @ Bureau, Illinois	Ohio River @ Grand Chain, Illinois	Groundwater @ Fulton, Illinois	White River @ Hazleton, Indiana	Ohio River @ Cannelton Dam, Kentucky	Green River @ Beech Grove, Kentucky	Muskingum River @ McConnelsville, Ohio	Allegheny River @ Oakmon, Pa.	Kanawha River @ Kanawha Falls, W. Va.	Well Water @ Tuscarawas, Ohio
Ca^{+}	15	12	2.4	69	60	36	90	51	38	39	83	34	21	75
Mg^{++}	3.1	3.2	0.4	24	18	9	50	16	10	9	17	10	5	20
HCO_3^-	53	53	600	247	200	106	250	166	97	115	132	17	62	217
$SO_4^=$	18	92	17	102	90	60	1000	110	69	54	145	108	29	60
TDS	91	76	880	466	360	209	2000	269	216	191	582	215	134	363
SiO_2	9.1	7	9	7	7.5	6.5	9.0	5.7	4.6	5.9	6.3	7	7.3	7
pH (units)	6.9	7.3	8.3	7.5	7.4	7.4	7.7	7.7	7.1	6.9	7.2	6.2	7.1	7.5

TABLE 3-21 RAW SOURCE WATER QUALITY FOR WESTERN STATES (CONCENTRATION IN MG/LITER)

	Tongue River below Sheridan, Wyoming	Medicine Bow River nr. Hanna, Wyoming	Hams Fork nr. Granger, Wyoming	Green River nr. Green River, Wyoming	Beaver Creek nr. Newcastle, Wyoming	Groundwater nr. Otter Creek, Montana	Yellowstone River nr. Terry, Montana	Knife River @ Hazen, N. Dakota	Lake Sakakawea, N. Dakota	Missouri River nr. Williston, N. Dakota	Grand River @ Shadehill, S. Dakota	San Juan River nr. Farmington, N. Mexico	Yellowstone River @ Forsyth, Montana	Powder River @ Arvada, Wyoming	Tongue River, between Decker & Miles City, Montana	Missouri River @ Culbertson, Montana	Yellowstone R., between Sidney & Terry, Montana	Crazy Woman Creek @ Arvada, Wyoming	Well Water nr. Decker, Montana	Groundwater nr. Gallop, New Mexico	Colorado River nr. Glenwood Springs, Col.
Ca^{++}	59	109	65	55	446	70	54	69	49	62	39	55	40	138	52	63	55	133	13	12	61
Mg^{++}	36	60	30	21	156	100	21	39	19	21	21	9	14	69	36	21	21	66	6	13	20
HCO_3^-	245	189	211	175	183	600	173	511	181	191	363	143	138	247	222	197	183	216	1700	408	137
$SO_4^=$	137	537	171	164	1802	1200	187	419	170	176	412	114	109	769	167	168	197	620	13	509	98
TDS	451	945	429	394	4667	2200	424	1037	428	436	931	300	284	1580	328	427	439	1046	2400	2655	589
SiO_2	8.3	7.4	4.2	5.7	6.8	12	9.6	11	7	9.3	5.6	12	10	9.5	8	6.3	10	-	7	5.6	14

References - Section 3

1. Woodall-Duckham Ltd., "Trials of American Coals in a Lurgi Gasifier at Westfield, Scotland," Report No. 105 (NTIS Catalog No. FE-105), Energy Res. & Develop. Admin., Washington, D.C., Nov 1974.

2. Forney, A.J., Haynes, W.P., Gasior, S.J., Johnson, G.E. and Strakey, J.P., Jr., "Analysis of Tars, Chars, Gases and Waters Found in Effluents from the Synthane Process," Technical Progress Report No. 76, Bureau of Mines, Dept. of the Interior, Pittsburg Energy Research Center, Pittsburgh, Penn., Jan 1974.

3. Farnsworth, J.F., Mitsak, D.M. and Kamody, J.F., "Clean Environment with Koppers-Totzek Process," Symp. Proc., Environmental Aspects of Fuel Conversion Technology, pp. 115-130, Report No. EPA-650/2-74-118, Environmental Protection Agency, Research Triangle Park, N.C., Jan 1974.

4. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion Processes", Report No. EPA-600/7-77-065, Environmental Protection Agency, Research Triangle Park, N.C., June 1977.

5. Jones, J.B., Jr., "Paraho Oil Shale Retort," Quarterly Colorado School of Mines, 71, (4), 39-48, Oct 1976.

6. McKee, J.M. and Kunchal, S.K., "Energy and Water Requirements for an Oil Shale Plant Based on Paraho Processes," Quarterly Colorado School of Mines, 71, 49-64, Oct 1976.

7. Colony Development Operation, "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Part I-Plant Complex and Service Corridor," Atlantic Richfield Co., Denver, Colorado, 1974.

8. Bodle, W.W., Vyas, K.C. and Talwalkar, "Clean Fuels from Coal, Technical-Historical Background and Principles of Modern Technology," Clean Fuels from Coal Symposium II, pp. 53-84, Institute of Gas Technology, Chicago, Ill., 1975.

9. Tetra Tech, Inc., "Energy from Coal - A State-of-the-Art Review," ERDA Report No. 76-7, U.S. Government Printing Office, Washington, D.C., 1976.

10. Dravo Corp., "Handbook of Gasifiers and Gas Treatment Systems," Report No. FE-1772-11, Energy Res. & Develop. Admin., Washington, D. C., Feb 1976.

11. Hendrickson, T.A., Synthetic Fuels Data Handbook, Cameron Engineers, Inc., Denver, Colo., 1975.

12. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives. The MIT Press, Cambridge, Mass., 1978.

13. Freedman, S., Yavorsky, P.M. and Akhtar, S., "The Synthoil Process," Clean Fuels from Coal Symposium II, pp 481-494, Institute of Gas Technology, Chicago, Ill., 1975.

14. Yavorsky, P.M., Akhtar, S., Lacey, J.J., Weintraub, M., and Reznik, A.A., "The Synthoil Process," Chemical Engineering Progress, 71, (4), 79-80, April, 1975.

15. Schmid, B.K., "The Solvent Refined Coal Process," Symp. on Coal Gasification and Liquefaction, Univ. of Pittsburgh, Pittsburgh, Pa., Aug 1974.

16. Institute of Gas Technology, Private communications, July 1976 and June 1977.

17. Bureau of Mines, "Preliminary Economic Analysis of BCR Bi-gas Plant Producing 250 million SCFD High-Btu Gas from Two Coal Seams: Montana and Western Kentucky," Report ERDA 76-48, FE-2083-2, UC-90-C, March 1976.

18. Fluor Engineers and Constructors, Inc.,"Economics of Current and Advanced Gasification Processes for Fuel Gas Production," p. 85, Report EPRI-AF-244, Electric Power Research Institute, Palo Alto, Calif., 1976.

19. El Paso Natural Gas Company, "Second Supplement to Application of El Paso Natural Gas Company for a Certificate of Public Convenience and Necessity", Federal Power Commission Docket CP73-131, 1973.

20. Bureau of Mines, "Preliminary Economic Analysis of Synthane Plant Producing 250 million SCFD High-Btu Gas from Two Coal Seams: Wyodak and Pittsburgh," ERDA-76-59, March 1976.

21. U.S. Dept. of the Interior, "Synthoil Process Liquid Fuel from Coal Plant, 50,000 Barrels per Stream Day. An Economic Evaluation," Report No. ERDA 76-35, Bureau of Mines, Morgantown, W. Va., 1975; summarized in Katell, S. and While, L.G., "Economic Comparison of Synthetic Fuels Gasification and Liquefaction," presented at ACS National Meeting, Division of I&EC, New York, April 1976.

22. Catalytic, Inc. for Southern Services, Inc., "SRC Technical Report No. 5, Analysis of Runs 19 through 40, 20 January to 8 August 1974", Wilsonville, Alabama, unpublished report.

23. Hydrocarbon Research, Inc., "Solvent Refining Illinois No. 6 and Pittsburg No. 8 Coals," Electric Power Research Institute, Palo Alto, California, Report EPRI 389, June 1975.

24. Wright, C.H., et al, "Development of Process for Producing an Ashless Low-Sulfur Fuel from Coal, Vol. II, Laboratory Studies, Part 2; Continuous Reactor Studies using Anthracane Oil Solvent," ERDA Research and Development Report No. 53, Interim Report No. 7, September 1975 (NTIS Cat. No. FE-496-T4)

25. Averitt, P., "Coal Resources of the United States, January 1, 1974.", Geological Survey Bulletin No. 1412, U.S. Gov't Printing Office, Washington, D.C., 1973.

26. U.S. Department of the Interior, "Final Environmental Statement for the Prototype Oil Shale Leasing Program," Vol. I, U.S. Gov't Printing Office, Washington, D.C., 1973.

27. Keighin, D. W., "Resource Appraisal of Oil Shale in the Green River Formation, Piceance Creek Basin, Colorado," Quart. Colorado School of Mines, 70 (3), 57-68 (1975).

28. Thomson, R.D. and York, H.F., "The Reserve Base of U.S. Coals by Sulfur Content (in Two Parts). Part 1: The Eastern States," U.S. Bureau of Mines Information Circular 8680, 1975.

29. Hamilton, P.A., White, D.H. and Matson, T.K., "The Reserve Base of U.S. Coals by Sulfur Content (in Two Parts). Part 2: The Western States," U.S. Bureau of Mines Information Circular 8693, 1975.

30. Fluor Utah, Inc., "Economic System Analyses of Coal Preconversion Technology, Vol. 2, Characterization of Coal Deposits for Large Scale Surface Mining," Report No. FE-1520-2, Energy Research and Develop. Admin., Washington, D.C., July 1975.

31. National Academy of Science, Rehabilitation Potential of Western Coal Lands, Ballinger Publishing, Cambridge, Mass., 1974.

32. U.S. Geological Survey, "Stripping Coal Deposits of the Northern Great Plains, Montana, Wyoming, North Dakota and South Dakota," U.S. G.S. Map, 1974

33. Gold, H. et al, "Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," EPA Report No. 400/7-77-037, U.S. Environ. Prot. Agency, Washington, D.C., February 1977.

34. Fieldner, A.C., Rice, W.E. and Moran, H.E., "Typical Analysis of Coals of the United States," U.S. Bureau of Mines Bulletin 446, 1942.

35. Akhtar, S., Mazzocco, N.J. and Yavorsky, P.M., "Aqueous Effluents from the Synthoil Process," presented at 175th ACS National Meeting, Division of Fuel Chemistry, Paper No. 58, Anaheim, California, March, 1978.

4. WATER SUPPLY AND DEMAND

4.1 Introduction

A general assessment of the water resources data in the major coal and oil shale bearing regions of the United States is presented in this section. Water resources data have been collected and used as a basis for determining the availability of surface and groundwater resources at each specific conversion plant site selected in Section 3 in terms of other competing users. This work was performed under subcontract by Resources Analysis, Inc. The two reports submitted as part of their study have been included in their entirety as Appendix 13 Water Availability and Demand in Eastern and Central Regions and Appendix 14 Water Availability and Demand in Western Region and summarized in this section.

Sufficient and reliable water supplies are essential to the siting and operation of coal and oil shale conversion plants. Significant quantities of water are consumed as a raw material, particularly when a high degree of wet cooling is used. The supply of water must be available on a continuous 24-hour basis. The economics of shutdowns due to water supply shortages are such that the reliability of water supplies are a major consideration in establishing the overall feasibility of siting at a particular location, or the feasibility of siting a large number of plants within a given region.

Potential water supply sources for each site were evaluated on a site specific basis in terms of total available water supply, required plant use, needs and rights of other competing water users, and the quality of the alternative water supplies. Factors considered were the extent and variability of nearby stream flows or groundwater aquifiers, legal institutions regulating the use of these waters and the implications of competing users for limited supplies in certain areas.

In assessing the water resources situations at each designated site, no attempt has been made to generate new field data. All data used in the investigation was previously collected by various Federal and State governmental agencies, local State water boards and universities and private concerns. This study serves primarily to compile the existing data into a form most useful for establishing the water related aspects of synthetic fuel plant siting and complements more extensive studies that have recently been completed, for example, the DOE Alternative Fuels Demonstration Program[1] (formerly called ERDA Synthetic Fuels Commercialization Program) and the National Academy of Science's CONAES report, referred to and partially summarized in Ref. 2, and some studies for particular river basins[3-8].

In most of the Appalachian and Illinois coal bearing regions the legal doctrine governing the use of water is the Riparian Doctrine which defines surface water rights as ownership of land next to or traversing the natural stream. The cost of transporting water in these regions is very low because of the close proximity of the coal conversion plant to the water source. In the Western coal and oil shale bearing regions the Appropriation Doctrine usually applies. The first appropriation of the water conveys priority independently of the location of the land with respect to the water so that the source water may not be in close proximity to the conversion plant. Furthermore, chronic water shortages exist in many of the river basins. Large reservoirs may have to be built on the main stems of the principal rivers and water transported over large distances to the water-short regions. The cost of transporting water to a particular site is an important consideration in determining the total water consumed at that site.

4.2 Eastern and Central Regions

The major coal regions in the Eastern and Central states are located in the Appalachian and the Illinois coal regions. The Appalachian coal region extends from eastern Pennsylvania through eastern Ohio, eastern Kentucky, West Virginia and into northern Alabama. The Illinois region includes the deposits in Illinois, southern Indiana and western Kentucky. The Appalachian region is characterized by highly variable terrain resulting from extensive geologic folding and faulting, while the Illinois region is underlain by a smoother, much more consistent geologic framework.

The majority of the study sites shown in Table 3-10 are located within the limits of the Ohio River Basin. A few others are located in the Upper Mississippi Basin in northern central Illinois and the Mobile River Basin in central Alabama. Annual precipitation and runoff exceeds the national average (30 in/yr) throughout the region and water supplies are generally plentiful. Monthly and season variability in precipitation is greatest in the northwest portion of the region and least in the southern part. The major water use is municipal and industrial.

The water supplies of the major rivers of the Appalachian region, shown in Figure 3-4, are generally plentiful with total average stream flow of more than 150 billion gallons daily[1]. Surface water reservoirs within the region can store about 25 percent of the total average stream flow. Groundwater is generally abundant but its availability varies throughout the region. These water supplies are supported by ample rainfall and runoff. In the northern part of the basin, the precipitation averages about 35 in/yr with more precipitation occurring in the late spring and summer[9]. The southern region receives an average of 55 in/yr of precipitation with most of the precipitation during winter and early spring. Surface water runoff averages 20 in/yr throughout the region with some areas in the south averaging 30 to 40 in/yr. The evaporation from open water surface ranges from 28 in/yr in Pennsylvania to 42 in/yr in Alabama[9].

The situation in the Illinois coal region (Figure 3-4) is similar to that in the Appalachian region with respect to water supply. Both surface water and groundwater are abundant and are supported by ample rainfall and surface runoff[4]. The average precipitation ranges from 35 to 40 in/yr in central Illinois to about 48 in/yr in western Kentucky. In the northern part of the region most of the precipitation occurs in the spring, while in the southern part the highest precipitation occurs in midwinter and early spring. The average annual surface runoff ranges from 8 in/yr in the northern region to 18 in/yr in the southern region, with the highest runoff occurring at the same time as the highest precipitation. The annual average evaporation from an open water surface is 33 in/yr in Illinois to 36 in/yr in western Kentucky.

In the Eastern and Central regions the use of surface flows is usually subject to the Riparian Doctrine, which defines surface water rights as ownership of land next to or traversing the natural stream. The owner of riparian land has the right to make use of the surface water in connection with the use of the riparian land as long as such use is reasonable with respect to others having a similar right. The Riparian Doctrine establishes an order of preference among various categories of users for determining a reasonable share; domestic users have the highest priority and industrial users a relatively low ranking.

Surface Water Availability

The adequacy of the water supply at each primary site having a river or stream as its water source was assessed through a comparison of a typical plant use with expected low-flows in the stream. As we discussed previously, the Riparian Doctrine governing water use in the Eastern and Central states requires each use be reasonable in relation to other riparian uses. For preliminary screening purposes plant use at each site was compared to the low-flow in the associated water source to establish whether the use would probably be reasonable, possibly be reasonable, or probably be unreasonable. The criteria used in judging the situation at each site were the following:

Favorable: Site use is less than 5 percent of the estimated seven-day, twenty-year low-flow.

Quesionable: Site use is about 10 percent of the estimated seven-day, twenty-year low-flow.

Unreliable: Site use is more than 20 percent of the estimated seven-day, twenty-year low-flow.

The seven-day, twenty-year low-flow used in the comparison is defined to be the minimum average flow over seven consecutive days that is expected to occur with an average frequency of once in twenty years. This is an appropriate criteria for sites having a useful life of about twenty years and holding ponds with a reserve capacity of about a seven-day water supply. Low-flow values were determined from stream-flow data reports for each state, from various state or regional agencies, or were estimated from historical low-flow at nearby gauging stations. Low-flows from major streams where flow is regulated are very difficult to establish accurately. In many of these instances, however, flows are relatively high and a normal result of regulation is to achieve higher low-flow.

In Section 5 we summarize the net water consumed by region for the standard size synthetic fuel plants shown in Table 3-3. For the Central and Eastern states the water consumed ranged from a low of 1.7×10^6 gpd to a high of 6.8×10^6 gpd, with the low value corresponding to a high degree of dry cooling and the high value corresponding to a low degree of dry cooling (high wet cooling). We have assumed a typical plant use of 6.5×10^6 gpd (about 10 c.f.s. or 7000 acre-ft/yr) for the water availability analysis; it should be remembered that this is a high water use.

For the purpose of a detailed feasibility analysis of water availability, the choice of a water source for each of the sites selected in Section 3 was based upon the source being contiguous or in close proximity to the site. The list of coal conversion plant sites and the water sources chosen on that basis are shown in Table 4-1. A number of secondary sites shown in Table 4-2 were also considered in order to provide a larger study area with respect to water availability in the coal regions as a whole, but were not considered in the detailed analysis of specific sites. The water sources shown in Table 4-1 differ from those shown in Table 3-10 since they were chosen on a different basis. For each water source, representative water quality data for that source was required for determining the costs and energy of water treatment within the coal conversion plant. We were not able to find water quality data for many of the sources listed in Table 4-1. The water sources shown in Table 3-10 are those for which we were able to obtain water quality data (Appendix 11). In this section we will be primarily concerned with the water sources shown in Table 4-1.

Table 4-3 lists the runoff characteristics of each primary supply source and the results of the assessment based on local low-flows. The analysis shows that surface supplies are most favorable for those sites having the main stream of a major regulated river near by.

Surface water supplies are shown to be much less reliable for many of the smaller streams away from the major rivers. In many of these streams low-flows may in fact be less than the typical coal conversion plant requirement. In other cases a plant water requirement would represent a large portion of the flow and such a use would probably interfere with other small existing users.

The analysis described above clearly suggests that there are sites having

TABLE 4-1 LIST OF PRIMARY COAL CONVERSION PLANT SITES FOR CENTRAL AND EASTERN STUDY

State	County	Water Source
Alabama	Jefferson	Coosa River
	Marengo	Tombigbee River or Groundwater
Illinois	Bureau	Groundwater
	Shelby	Kaskaskia River
	St. Clair	Mississippi River
	White	Wabash River
	Bureau	Illinois River
	Fulton	Groundwater
	St. Clair	Mississippi River
	Saline	Saline River
Indiana	Gibson	White River
	Vigo	Wabash River
	Sullivan	Wabash River
	Warrick	Ohio River
Kentucky	Floyd	Big Sandy River
	Harlan	Cumberland River
	Muhlenberg	Green River
	Pike	Levisa Fork
Ohio	Gallia	Ohio River
	Jefferson	Ohio River
	Tuscarawas	Tuscarawas River
	Tuscarawas	Groundwater
Pennsylvania	Armstrong	Allegheny River
	Somerset	Allegheny River
West Virginia	Fayette	New River
	Kanawha	Kanawha River
	Mingo	Big Sandy River
	Monongalia	Monongahelia River
	Preston	Cheat River

TABLE 4-2 LIST OF SECONDARY COAL CONVERSION PLANT SITES

State	County	Water Source
Alabama	DeKalb	Tennessee River
	Fayette	Warrior River
	Jackson	Tennessee River
	Marion	Tennessee River
Illinois	Mercer	Mississippi River
	McLean	Illinois River
Kentucky	Henderson	Ohio River
	Hopkins	Green River
	Lee	Kentucky River
	Lawrence	Big Sandy River
	McCreary	Cumberland River
Ohio	Morgan	Muskingum River
Pennsylvania	Venango	Allegheny River
	Clearfield	West Branch River
	Cambria	Conemaugh River
West Virginia	Greenbrier	Greenbrier River
	Marshall	Ohio River
	Randolph	Tygart River

TABLE 4-3 ASSESSMENT OF POTENTIAL SURFACE WATER SOURCES

State	County	Source	Drainage Area (SM)	USGS Gauge No.	Mean Flow (CFS)	Historical Low-Flow (CFS)	7 day - 20 Yr. Low-Flow (CFS)	Situation (1)	Possible Alternate Source
Alabama	Jefferson	Coosa	8,390	4070	13,790	370	---	F	---
	Marengo	Tombigbee	5,900	4450	8,631	165	---	F	---
Illinois	Bureau	Groundwater	---	---	---	---	---	See Table 4.1	---
	Bureau	Illinois	12,040	---	12,500(E)	1,800(E)	800(2)	F	---
	Fulton	Groundwater	---	---	---	---	---	See Table 4.1	---
	St. Clair	Mississippi(R)	700,000	0100	177,000	18,000	10,000	F	---
	Saline,	Saline	---	None	---	10(E)	(NA)	U	Ohio or Prop. Res.
	Shelby	Kaskaskia(R)	1,054	5920	788	0	(NA)	U	Lake Shelbyville
	White	Wabash	28,635	3775	27,030	1,650	800(2)	F	---
Indiana	Gibson	White(R)	11,125	3740	11,540	573	610(4)	F	---
	Sullivan	Wabash(R)	13,161	3420	11,600	858	350(2)	F	---
	Vigo	Wabash(R)	12,265	3415	10,660	701	300(2)	F	---
	Warrick	Ohio(R)	107,000	3220	113,700	NA	2,000(2) (13,000(5))	F	---
Kentucky	Floyd	Levisa Fork	1,701	2098	2,104	20	(NA)	U	Dewey Lake
	Harlan	Cumberland(R)	374	4010	689	3	(NA)	U	Surface Storage
	Henderson	Ohio(R)	107,000	3220	133,900	NA	15,400(5)	F	---
	Muhlenburg	Green Pond(R)	6,182	3165	9,201	250	(NA)	Q	Groundwater
	Pike	Levisa Fork	1,237	2015	1,458	2	(NA)	U	Fishtrap Lake or Groundwater
Ohio	Galia	Ohio(R)	---	---	77,600	---	8,600(5)	F	---
	Jefferson	Ohio(R)	---	---	40,900	---	5,600(5)	F	---
	Tuscarawas	Tuscarawas(R)	2,443	1290	2,453	170	215(7)	Q	Groundwater
	Tuscarawas	Groundwater	---	---	---	---	---	See Table 4.1	---
Pennsylvania	Armstrong	Allegheny(R)	12,500	---	19,500(E)	900(E)	(NA)	F	---
	Somerset	Casselman	382	0790	655	10	12(4)	U	Quemahoning Res.
West Virginia	Fayette	New(R)	9,000	1930	10,500	950(3)	1,184	F	---
	Kanawha	Kanawha(R)	10,419	1980	14,480	2,360	1,750	F	---
	Marshall	Ohio(R)	---	---	40,900	---	5,600(5)	F	---
	Mingo	Tug Ford(R)	850	2140	1,351	17(3)	30	U	Groundwater
	Monongalia	Monongahela(R)	4,407	0725	8,137	20	248	Q	Surface Storage
	Preston	Cheat	972	0700	2,239	10	95	U	Lake Lynn or Groundwater

(1) Situation assessment: F=Favorable, Q=Questionable, U=Unreliable

(2) Low-flow (1 day, 50 year) data from Illinois State Water Survey (1975)

(3) Estimated from nearby gauges

(4) Estimated using regression equations in Streamflow Data Program Reports (USGS, 1970)

(5) Low flow (7 day, 10 year) from ORBC Table of Instream Flows

(6) Pennsylvania Department of Forests and Waters, Bulletin No. 1 (1966)

(7) Ohio Department of Natural Resources Bulletin 40 (1965)

(E) Estimated from best available information

(R) River substantially regulated at source location

(NA) Data not available at present, or nonapplicable abundant supplies at hand where meeting the water requirements of one or more conversion plants would be no problem. There are others where supplies are such that the designated supply source could not be relied on during very dry periods and where alternative or supplemental sources should be developed. The supplies available at several other sources are in between the extremes. The adequacy of these sources depends in large part on the extent of other competing uses or the likelihood that competing demands will develop the future.

As noted earlier, in addition to the primary specific sites, additional sites in several other regions were considered to complete the assessment of overall water availability throughout the coal regions. Using the same analytical criteria as described earlier, these additional sites are listed in Table 4-4 with their associated water source and a general assessment of the water supply availability at each site.

In summary, within the Appalachian Basin, where coal is available, there are a number of large rivers contiguous or adjacent to many of the sites that can provide a sufficient and reliable supply of water to support one or more large mine-plant coal conversion complexes. This applies to all plant sites in the vicinity of the Ohio, Allegheny, Tennessee, Tombigbee and Kanawha-New Rivers. In most of these instances present water use data and future demand projections indicate a significant surplus streamflow beyond expected use, even under low-flow conditions. For the few cases where data on other demands is not readily available, the coal conversion plant demand is generally in the order of less than one percent of the seven-day, twenty-year low flow. Uses of this magnitude would appear to safely satisfy the common law requirement of being reasonable relative to the users. The surface water supplies are much less reliable in the smaller streams, away from the major rivers. Regions generally found to have limited water supplies for energy development include the upper reaches of the Cumberland and Kentucky rivers in eastern Kentucky, the eastern Kentucky and adjacent West Virginia coal regions in the Big Sandy River Basin, and northern West Virginia and western Pennsylvania in the Monongahela River Basin, except those areas that can be supplied from the Allegheny, Ohio or Susquehanna Rivers. In these areas extreme low flows are practically zero, and a coal conversion complex could easily represent a significant portion of the seasonal low-flow in many of these areas. In order for a plant to be sited in these regions, an alternative or supplemental supply to stream flows must be assured.

TABLE 4-4 ASSESSMENT OF ADDITIONAL SURFACE WATER SOURCES

State	County	Source	Drainage Area (SM)	USGS Gauge No.	Mean Flow (CFS)	Historical Low Flow (CFS)	7 day, 20 Yr. Low Flow (CFS)	Situation (1)	Possible Alternate Source
Alabama	Fayette	Warrior(R)	4828	4650	7822	37	N.A.	Q	Groundwater
	Marion	Tennessee(R)	30810	5895	51610	105	N.A.	F	---
	Jackson	Tennessee(R)	25610	5755	43760	400	N.A.	F	---
	De Kalb	Tennessee(R)	25610	5755	43760	400	N.A.	F	---
Illinois	Mercer	Mississippi(R)	119000	4745	62570	5000	6500(2)	F	---
	McLean	Illinois(R)	15819	5685	14529	1810	N.A.	F	---
Kentucky	Hopkins	Green(R)	7564	3200	10960	280	N.A.	F	---
	McCreary	Cumberland	1977	4045	3199	4	12(3)	U	Lake Cumberland
	Lee	Kentucky	2657	2820	3638	4	8.6(3)	U	Unknown
	Lawrence	Big Sandy(R)	2143	2150	2480	8.4	74(3)	Q	Ohio River
Ohio	Morgan	Muskingum	7422	1500	7247	218	565(5)	F	---
Pennsylvania	Venango	Allegheny(R)	5982	02550	10330	334	N.A.	F	---
	Clearfield	West Branch	1462	5425	2467	100	115(4)	Q	Unknown
	Cambria	Conemaugh	715	04150	1269	105	155(4)	Q	Unknown
W. Virginia	Randolph	Tygart	408	0510	800	0.1	0.4(3)	U	Tygart Lake
	Greenbrier	Greenbrier	1835	1835	1980	24	43(3)	Q	Bluestone Res.

(1) Situation assessment: F=Favorable; Q=Questionable; U=Unreliable

(2) Low-Flow (1 day, 50 year) from Illinois State Water Survey Report No. 4 (1975)

(3) Estimated using regression equations in USGS Streamflow Data Program Reports (1970)

(4) Pennsylvania Department of Forests and Waters Bulletin No. 1 (1966)

(5) Ohio Department of Natural Resources Bulletin 40 (1965)

(R) River substantially regulated from source location

(NA) Data not available at present or non-applicable

Within the Illinois Basin, the Ohio and Mississippi Rivers have sufficient and reliable water supplies to support one or more large mine-plant coal conversion complexes. The lower sections of the Kaskaskia, Illinois and Wabash Rivers in Illinois; the Wabash and White Rivers in Indiana; and the Green River in Kentucky also have reliable supplies.

Surface Water Doctrines

The general aspects of water use regulations were reviewed primarily as applicable to the surface water supply assessments described previously. As stated above, the reasonable use interpretation of the Riparian Doctrine is now widely accepted. Each owner of riparian land (i.e. traversed by or adjoining a natural stream) has the right to make any use of the water in connection with the use of the riparian land as long as such use is reasonable with respect to others' having a similar right. This suggests three important considerations related to the use of water for energy development.

1) Reasonable use. This is a rather vague requirement primarily determined by the impact of the use in question on other valid users. This is a relative matter and is generally dependent more on the magnitude of the proposed use than the nature of it. The basic requirement is that some degree of sharing of available supplies must take place among the various demands.

2) Riparian land use limitation. This important aspect of the Doctrine requires that water use be restricted to the riparian land upon which the right is derived. The basic requirement for land to be riparian is physical contact with the water source. This can be a significant limitation on the availability of an otherwise adequate water supply source when coal reserves are located some distance away from the water. Certain state regulations allow use on non-riparian land where supplies are sufficient, so that no riparian user is injured by such a use. Thus, non-riparian use is generally dependent on the existence of surplus water after all riparian use has been satisfied--a very restrictive condition. Only the major rivers of the region such as the Kanawha, Allegheny, Ohio and Mississippi can satisfy this condition reliably enough to justify the large capital investments involved in the construction of coal conversion plants.

3) Variability over time. An important limitation in the Doctrine to significant users requiring dependable, long-term availability such as synthetic fuel plants is that a reasonable use at one point in time may become unreasonable at some unknown future time. Other riparian owners do not lose their

right through disuse. Also, riparian water rights generally are not quantified and recorded, but simply must remain reasonable with respect to all other users.

In addition to the above, the Riparian Doctrine establishes an order of preference among various categories of users for determining a reasonable share with domestic users having the highest priority and industrial users a relatively low ranking. It is possible, however, that should the national energy situation continue on its present course, energy development users in the future may have a high social priority.

Several Eastern states have recently adopted statutory modifications to the Common Law Doctrine that allow some degree of water appropriation by permit. These states are Kentucky, Indiana, Iowa and North Carolina. These statutory modifications are generally aimed at allowing potential users, including in some instances non-riparian users, to obtain the legal right to use a specified quantity of water. At the same time they attempt to insure that no existing user would be harmed and all riparian rights are preserved. The effect of such legislation would be to encourage high investment type industries requiring firm and reliable sources of water to locate in other areas than they could presently. Historically the vague requirements of the Riparian Doctrine have forced signficiant water using industries to locate primarily on the major rivers of the region that have surplus flows.

Competing Water Use

In the previous section we have made an assessment of surface water sources in terms of the relative amount of streamflow at low-flow conditions that would be required for a coal conversion plant. This approach provides a good basis for identifying sites where the water requirements of a typical coal conversion plant would be a reasonably small fraction of the total surface water flow under drought conditions and therefore could be reliably maintained. It also clearly points out sites where the plant requirements probably or might not always be maintained since another provision of the law is that users must also share in cutting back their use when supplies are low.

Although this approach gives a valid indication of the relative reasonableness of a typical conversion plant use, another factor that might be considered in plant siting is the amount of competing use in a particular location from such other water demands as municipal, industrial, power production, etc. The difference between the low-flow in a stream or river and the total present or projected water use is the surplus flow available for coal conversion, or a deficit indicating that supplies are insufficient even for other uses. This information would be of particular importance where coal resources are located some distance away from a water source and a non-riparian use of the water is being considered. Such a use might be feasible if a significant surplus supply exists at the source and therefore no other user would be harmed by the withdrawal.

Although data on other competing uses is not available for all sites, data compiled by the Ohio River Basin Commision[10] gives estimated consumptive water use for 1975 and 2000 for the Ohio River main stem and its larger tributaries. This data was used to compute surplus (or deficit) water supplies available under critical low-flow conditions for many of the specific sites being studied. Water use quantities for the tributary basins were given for the entire basin. For sites located some distance into these basins, water use quantities were estimated as being proportional to the ratio of drainage areas. The estimated present and future consumptive water use for other uses, and the results of the supply surplus calculations for a number of sites are presented in Table 4-5.

It is apparent from these results that significant water surpluses exist even at low-flow conditions all along the Ohio main stem both now (year 1975) and in the future (year 2000). In fact at least some surplus under present use conditions exists at all sites listed. Under future (2000) conditions deficit supplies are indicated for the Monongahelia River at Monongalia County, W. Virginia and the Wabash River at White County, Illinois, and only a relatively minor surplus will exist for the Tuscarawas River at Tuscarawas County, Ohio. Most of the other sites, too far removed from the Ohio main stem for meaningful use estimates, would also be expected to show supply deficits under these conditions. However, the Wabash and White Basins, and some others, have excellent supplies of groundwater, as is described below.

Thus far we have considered the availability of water for single mine-plant complexes without considering the development of a large scale synthetic fuel industry. For example, if a synthetic fuel industry is to produce $1x10^6$ barrels/day of synthetic crude, or its equivalent in other fuels of

TABLE 4-5 ESTIMATED CONSUMPTIVE WATER USE

AND SURPLUS SUPPLIES IN THE OHIO RIVER BASIN FOR 1975 AND 2000

Location	Mean Annual(4) Flow (cfs)	Low Flow 7 Day, 20 Yr Except as Noted (cfs)	Estimated Present 1975 Use (5) (cfs)	Available Quantity With Present Use at Low Flow Conditions (cfs)	Estimated Future 2000 Use (5) (cfs)	Available Quantity With Future Use At Low Flow Conditions (cfs)
Allegheny R. (Allegheny Co. Pa.)	19,500	1,000 (1)	280	720	350	650
Monongahela R. (Monongalia Co. W. Va.)	8,137	248	110	138	310	-62
Ohio R. (Jefferson Co. Ohio)	40,900	5,600 (2)	695	4,905	1,129	4,471
Ohio R. (Marshall Co. W. Va.)	40,900	5,600 (2)	700	4,900	1,306	4,294
Muskingum (Tuscarawas) R. (Tuscarawas Co. Ohio)	2,453	215	45	170	85	130
Kanawha R. (Kanawha Co. W. Va.)	14,480	1,750	130	1,620	240	1,510
Ohio R. (Gallia Co. Ohio)	77,600	8,600 (2)	1,010	7,590	1,980	6,620
Ohio R. (Warrick Co. Ohio)	113,700	13,000 (2)	1,420	11,580	3,220	9,780
Green R. (Muhlenburg Co. Ky.)	9,201	500 (1)	55	445	60	440
Ohio R. (Henderson Co. Ky.)	133,900	15,400 (2)	1,500	13,900	3,310	12,090
Wabash R. (White Co. Ill.)	11,540	610 (3)	330	280	1,120	-510

NOTES:
(1) Estimated from available information
(2) Ohio River Basin Commission (1977) estimates
(3) Low-flow (1 day, 50 year) from Illinois State Water Survey Report No. 4 (1975)
(4) Mean flow from U.S.G.S. Data
(5) Estimated uses are accumulated consumptive use for the Ohio Main Stem, or on its tributaries, use at the named location determined from the total tributary basin use from the ratio of drainage areas (ORBC 1977)

5.8×10^{12} Btu/day in the Appalachian coal region and an equal amount in the Illinois coal region, then approximately 18 standard size clean coal plants each producing 10,000 tons/day of solvent refined coal to 24 standard size coal gasification plants, each producing 250×10^{6} scf/day of pipeline gas would be required in each region. The maximum quantity of water that would be required in each region would be approximately 160×10^{6} gpd (or about 240 cfs or 170,000 acre-ft/yr). Table 4-5 shows there should be sufficient water available to support this level of synthetic fuel development in each of the two basins all along the main rivers even at low flow conditions.

Groundwater Supply

Groundwater was specified as a primary supply for certain sites located in Illinois and Ohio. In several other regions, conditions appear to be favorable for the development of groundwater as an alternative source to unreliable surface supplies or as a supplemental source. Groundwater sources may also have institutional advantages in some instances even though they would generally be more expensive to develop than surface supplies.

Groundwater in the East/Central coal region states is a large and important water resource that may have a significant role in the development of the coal resources. In the Ohio River Basin, which encompasses much of the study area, present groundwater development plans do not nearly utilize the full potential of the resource. It has been estimated[11] that the average annual groundwater recharge of the region is about 35 billion gallons per day. Annual groundwater use in 1960 by municipal and rural users was estimated to be about one billion gallons per day or only about 3 percent of recharge. Although not all of the groundwater is recoverable or located so as to be of value in energy development, much of it is.

Figure 4-1 shows the general locations of high-yield sources of groundwater in the region. Primary groundwater sources and all surface sources classified as unreliable in the assessment of surface supplies were considered in an initial review of groundwater availability. A screening process similar to that used for surface sources was utilized to establish whether or not it would be feasible to develop groundwater as sources of supply. The following criteria were used in assessing the situation at each site:

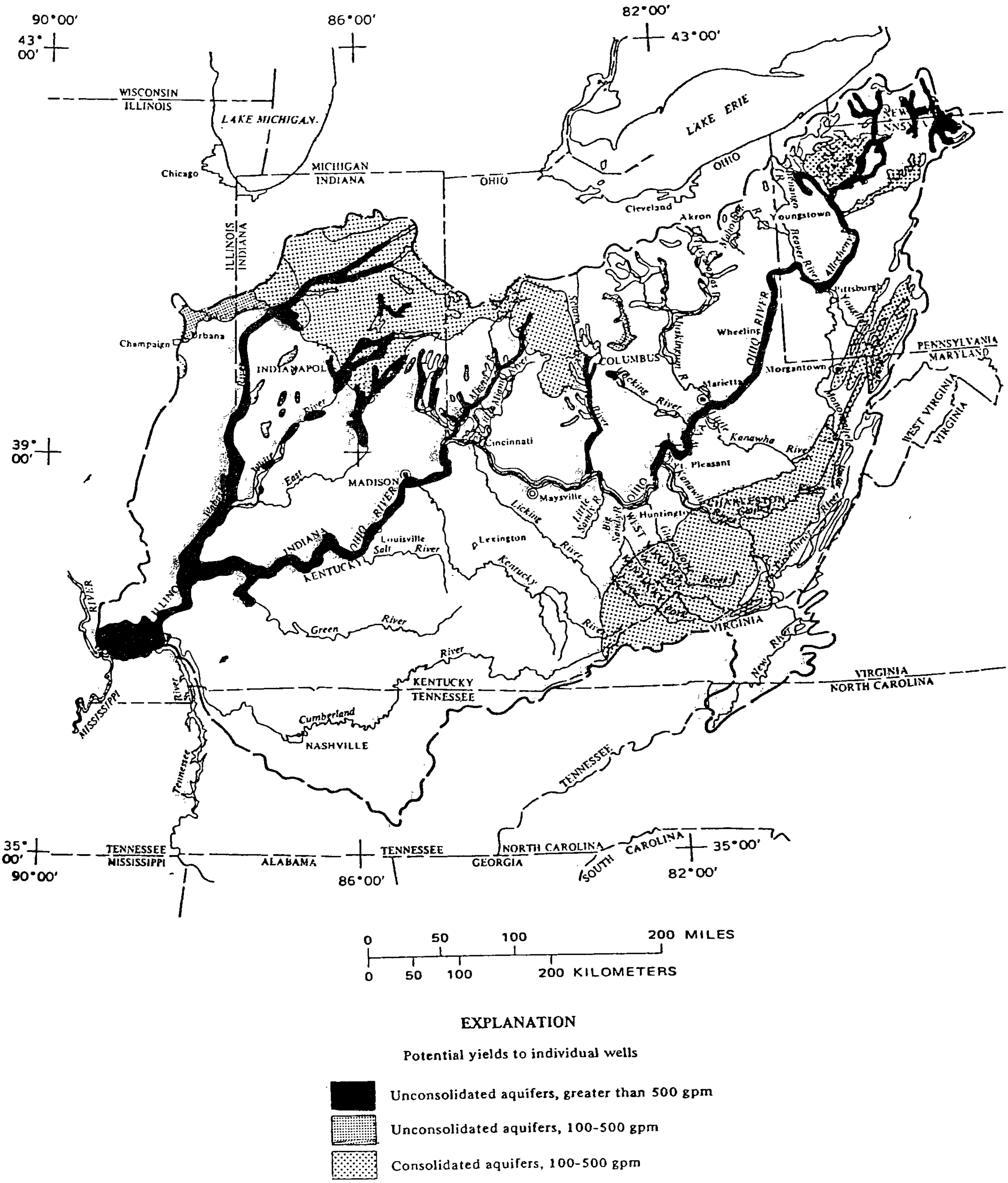


Figure 4-1 High-yield sources of ground water

Yield Characteristics

A. Favorable. Well yields are expected to approach 500 gpm or more.

B. Possible. Well yields are expected to exceed 100 gpm.

C. Unfavorable. Well yields are generally less than 50 gpm.

Accessibility

A. On-site

B. Near by

C. Distant

Table 4-6 lists the primary sites considered in the groundwater analysis and the results of the assessment. Many of the sites show good potential for groundwater development.

The Wabash and White subbasins probably have the highest potential of all Ohio River subbasins for additional groundwater development. It is estimated that about 30,000 billion gallons, or nearly 30 percent of the total potable groundwater available from storage in the Ohio region, is stored in these subbasins[11]. Estimated average annual groundwater recharge in these basins is 7.3 billion gallons per day while 1960 groundwater withdrawal estimates are only about 0.22 billion gallons per day (about 3 percent of recharge) which is only about 0.3 percent of potable groundwater storage. Many very high yield aquifers offer excellent possibilities for use to supply energy development programs. A further discussion of the groundwater situation at the sites having groundwater designated as a possible primary source is found in Appendix 13.

An assessment of the additional secondary sites is given in Table 4-7. Of these, conditions appear to be most favorable for groundwater development in Fayette County, Alabama. With the exception of McCreary and Lee Counties, where little potential appears to exist for large groundwater supplies, development is a possibility at the other sites, depending on actual location.

Unfortunately the groundwater situation is most favorable from alluvial aquifers recharged by major streams in the valley bottoms where surface supplies

TABLE 4-6. ASSESSMENT OF GROUNDWATER AVAILABILITY AT PRIMARY SITES WITH INSUFFICIENT SURFACE SUPPLIES

State	County	Presently Designated Source	Potential Groundwater Yield*	Groundwater Accessibility	Groundwater Feasibility
Alabama	Jefferson	Coosa	Favorable	On-site	Yes
Illinois	Bureau	Groundwater	Favorable	On-site	Yes
	Fulton	Groundwater	Favorable	On-site	Yes
	Saline	Saline	Unfavorable	Near-by	No
	Shelby	Kaskaskia	Possible	Distant	Possible
Indiana	- - - - - - - - - -	- - - - - - - - - -	- all okay -	- - - - - - - - - -	- - - - - - - - - -
Kentucky	Floyd	Levisa Fork	Unfavorable	Distant	No
	Harlan	Cumberland	Unfavorable	Distant	No
	Muhlenberg	Green	Possible	Near-by	Possible
	Pike	Levisa Fork	Favorable	On-site	Yes
Ohio	Tuscarawas	Tuscarawas & GW	Favorable	On-site	Yes
Pennsylvania	Somerset	Casselman	Favorable	On-site	Yes
West Virginia	Mingo	Tug Fork	Favorable	On-site	Yes
	Monongalia	Monongahela	Unfavorable	Distant	No
	Preston	Cheat	Favorable	On-site	Yes

*Favorable = > 100 gpm and likely to approach or exceed 500 gpm
Possible = generally > 100 gpm
Unfavorable = < 50 gpm

TABLE 4-7. ASSESSMENT OF GROUNDWATER AVAILABILITY AT THE SECONDARY SITES

State	County	Present Source	Potential Groundwater Yield*	Groundwater Accessibility	Preliminary Groundwater Feasibility
Alabama	Fayette	Warrior	Favorable	On-site	Yes
	Marion	Tennessee	POssible	On-site	Possible
	Jackson	Tennessee	Possible	On-site	Possible
	DeKalb	Tennessee	Possible	On-site	Possible
Kentucky	McCreary	Cumberland	Unfavorable	Distant	No
	Lee	Kentucky	Unfavorable	Distant	No
Penn.	Clearfield	West Branch	Possible	On-site	Possible
	Cambria	Conemaugh	Possible	On-site	Possible
West Va.	Randolph	Typgart	Possible	On-site	Possible
	Greenbrier	Greenbrier	Possible	On-site	Possible

*Favorable = > 100 gpm and likely to approach or exceed 500 gpm
Possible = generally > 100 gpm
Unfavorable = < 50 gpm

are best, and least favorable from less transmissive consolidated aquifers higher in the watersheds where surface supplies tend to be poorest. Since the aquifer structure is highly fractured in many areas under study, expected well yields can vary tremendously over a county-sized area.

Groundwater Doctrines

The principal groundwater doctrines affecting the use of groundwater involve the concepts of absolute ownership and that of reasonable use. Absolute ownership recognizes a landowner as the owner of all groundwater beneath his land and allows him to use it or interfere with it in any way without being accountable to other uses which may be affected. Although this interpretation is somewhat archaic, it still receives some continued acceptance.

The concept of reasonable use of groundwater is most widely accepted and involves a definition of reasonable use significantly different than that under the Riparian Doctrine of surface supplies discussed previously. As applied to groundwater, any reasonable use in connection with the land from which the groundwater is taken is allowed without regard to impacts the withdrawal may have on other users. Since the rights of property owners are clearly more absolute with regard to groundwater use than in the case of surface water, the development of reliable groundwater supplies for energy production may be preferable in certain areas on the basis of institutional feasibility.

Potential Environmental Impacts

A number of potential hydrologic and environmental impacts are associated with both the traditional coal mining operation and the process of converting the coal produced to synthetic fuels. The mining operation, whether it be underground or strip mining, creates the potential for environmental problems resulting from the earthmoving operation (erosion, sedimentation of stream channels, and scarring the land) and the mine dewatering process (acid mine drainage and depletion of groundwater supplies). Modern mining techniques and reclamation when properly employed can minimize or eliminate the problems associated with earthmoving. Impounding mine drainage for subsequent evaporation or treatment and proper underground mining methods have been used to successfully handle the acid mine drainage problem. The possibility that a mining operation will lower nearby well yields or cause small locally-used shallow aquifers to be depleted is common to nearly all coal bearing regions.

Synthetic fuel plants may produce a number of waste residues that could be detrimental to water quality if discharged into surface waters or if leached into groundwaters after disposal. Planning for the safe disposal of all waste residues is an important consideration of plant development and design. In all of our plant designs, we have minimized the net water consumed and the water content of the wet-solid residuals generated, thereby minimizing the potential for environmental degradation.

The water quality of streams can also be affected by the withdrawal of significant amounts of water to supply the needs of the conversion process. Such withdrawals from the smaller streams reduce the total flow available for dilution of man-made pollutants. The potential impact of this action can be overcome by augmenting conversion plant supplies to the fullest extent possible with lesser quality water from such sources as treated municipal or industrial wastewater effluents or brackish groundwater supplies.

The major potential impact of the coal mining operation common to nearly all coal bearing regions is that the mining will disturb existing aquifers and result in the lowering of nearby well yields or cause small locally used aquifers to be depleted. When a productive aquifer is cut by the mining operation, a large free-surface discharge into the mine may be created which can significantly lower the hydraulic gradient, or water table, of the aquifer in the vicinity of the mine. This problem is very localized and dependent on the underlying aquifer structure. This situation can only be accurately assessed on a site by site basis, on a scale much smaller than the present site definitions allow.

Another potential impact on groundwater systems is the effect of large withdrawal rates for conversion plant supplies. If these withdrawals exceed aquifer recharge or transmissibility rates, they too can lower the local groundwater table. Therefore, the feasibility of using groundwater as a water supply source must be carefully evaluated based on the ability of the local aquifers to supply the required yields without widespread lowering of the water table or other impairments of existing users in the area.

Based on the above considerations a brief qualitative evaluation of potential groundwater impacts was conducted for the primary groundwater supply sites and several other sites where groundwater looks promising as a supplemental source. These assessments are presented in Appendix 13.

Site Specific Summary

This section presents a general summary of the water resources situation at the proposed coal conversion plant sites in each state. Table 4-8 lists first by state the primary specific sites studied in detail and then the additional secondary sites investigated in a general sense only. The water supply source designated for each site in the coal reserve-water supply matrix is listed along with a qualitative (good, fair, or poor) evaluation of the adequacy of the source. This assessment is based on a comparison of high water plant usage with low streamflow conditions and other considerations as described fully in the earlier text. Figures 4-2 and 4-3 summarize Table 4-8 in a graphical manner for the Appalachian and Illinois coal regions.

Alternative sources are suggested where designated sources are not rated "good", and the adequacy of these alternatives is rated based on a brief review of the associated supply condition. Since groundwater may be considered as a supplemental or conjunctive supply in many instances, groundwater availability in the vicinity of each site is rated based on the general aquifer

TABLE 4-8 WATER AVAILABILITY SUMMARY

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Alabama							
Primary Sites							
Jefferson	Coosa R.	Good	-	-	Fair	Coosa	Moderate
Marengo	Tombigbee R.	Fair	Groundwater	Fair	Fair	Tombigbee & GW Augment	Significant
Secondary Sites							
Fayette	Warrior R.	Fair	Groundwater	Fair	Fair	Warrior & GW	Moderate
Marion	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal
Jackson	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal
DeKalb	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal
Illinois							
Primary Sites							
Bureau	Illinois R.	Fair	Groundwater	Very Good	Very Good	Groundwater	Moderate
Fulton	Groundwater	Good	-	-	Good	Groundwater	Moderate
St. Clair	Mississippi	Very Good	Groundwater	Very Good	Very Good	Mississippi	Minimal
Saline	Saline R.	Very Poor	Ohio	Good	Very Poor	Ohio R.	Significant
Shelby	Kaskaskia R.	Poor	Lake Shelbyville	Fair	Fair	Kaskaskia & GW	Moderate
White	Wabash R.	Good	-	-	Fair	Wabash	Moderate
Secondary Sites							
McLean	Illinois R.	Fair	Groundwater	Fair	Fair	Illinois & GW	Moderate
Mercer	Mississippi	Very Good	Groundwater	Very Good	Very Good	Mississippi	Minimal

TABLE 4-8 (continued)

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Indiana							
Primary Sites							
Gibson	White R.	Good	Groundwater	Fair	Fair	White & GW	Moderate
Sullivan	Wabash R.	Good	Groundwater	Good	Good	Wabash R.	Moderate
Vigo	Wabash R.	Good	Groundwater	Good	Good	Wabash R.	Moderate
Warrick	Ohio R.	Very Good	Groundwater	Very Good	Very Good	Ohio R.	Minimal
Kentucky							
Primary Sites							
Floyd	Levisa Fork	Very Poor	Unknown	-	Very Poor	Unknown	Significant
Harlan	Cumberland	Very Poor	Surface	-	Very Poor	Unknown	Significant
Henderson	Ohio R.	Very Good	-	-	Good	Ohio R.	Minimal
Muhlenburg	Green R.	Fair	Groundwater	Fair	Fair	Green & GW	Moderate
Pike	Levisa Fork	Very Poor	Unknown	-	Very Poor	Unknown	Significant
Secondary Sites							
Hopkins	Green R.	Fair	Groundwater	Fair	Fair	Green & GW	-
Lawrence	Big Sandy R.	Fair	Groundwater		Fair	Big Sandy & GW	Moderate
Lee	Kentucky R.	Poor	Unknown	-	Poor	Unknown	-
McCreary	Cumberland	Poor	L. Cumberland	Good	Poor	Unknown	-

TABLE 4-8 (continued)

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Ohio							
Primary Sites							
Galia	Ohio R.	Very Good	-	-	Very Good	Ohio R.	Minimal
Jefferson	Ohio R.	Very Good	-	-	Very Good	Ohio R.	Minimal
Tuscarawas	Tuscarawas	Fair	Groundwater	Very Good	Very Good	Groundwater	Moderate
Secondary Sites							
Morgan	Muskingum	Good	Groundwater	Very Good	Very Good	Muskingum & GW	Moderate
Pennsylvania							
Primary Sites							
Allegheny	Allegheny R.	Good	-	-	Good	Allegheny	Moderate
Luzerne	Susquehanna	Good	-	-	Good	Susquehanna	Moderate
Schuylkill	Susquehanna	Good	-	-	Good	Susquehanna	Moderate
Somerset	Casselman R.	Poor	Quemahoning Res.	-	Good (Highly Variable)	Casselman & GW	Significant
Secondary Sites							
Venango	Allegheny R.	Good	Unknown	-	Fair	Allegheny	Moderate
Clearfield	West Branch	Fair	Unknown	-	Fair	Unknown	-
Cambria	Conenaugh R.	Poor	Unknown	-	Poor	Unknown	-

TABLE 4-8 (continued)

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
West Virginia							
Primary Sites							
Fayette	New R.	Good	-	-	Poor	New	Moderate
Kanawha	Kanawha R.	Good	-	-	Fair	Kanawha	Moderate
Marshall	Ohio R.	Very Good	-	-	Good	Ohio	Minimal
Mingo	Tug Fork	Poor	Groundwater	Fair	Fair	Tug & GW	Moderate
Monongalia	Monongahela	Fair	Groundwater	Fair-Good	Fair-Good	Monongahela & Groundwater	Moderate
Preston	Cheat R.	Poor	Groundwater	Poor	Poor	Unknown	Significant
Secondary Sites							
Randolph	Tygart R.	Poor	Unknown	-	Very Poor	Unknown	-
Greenbrier	Greenbrier	Fair-Poor	Unknown	-	Very Poor	Unknown	-

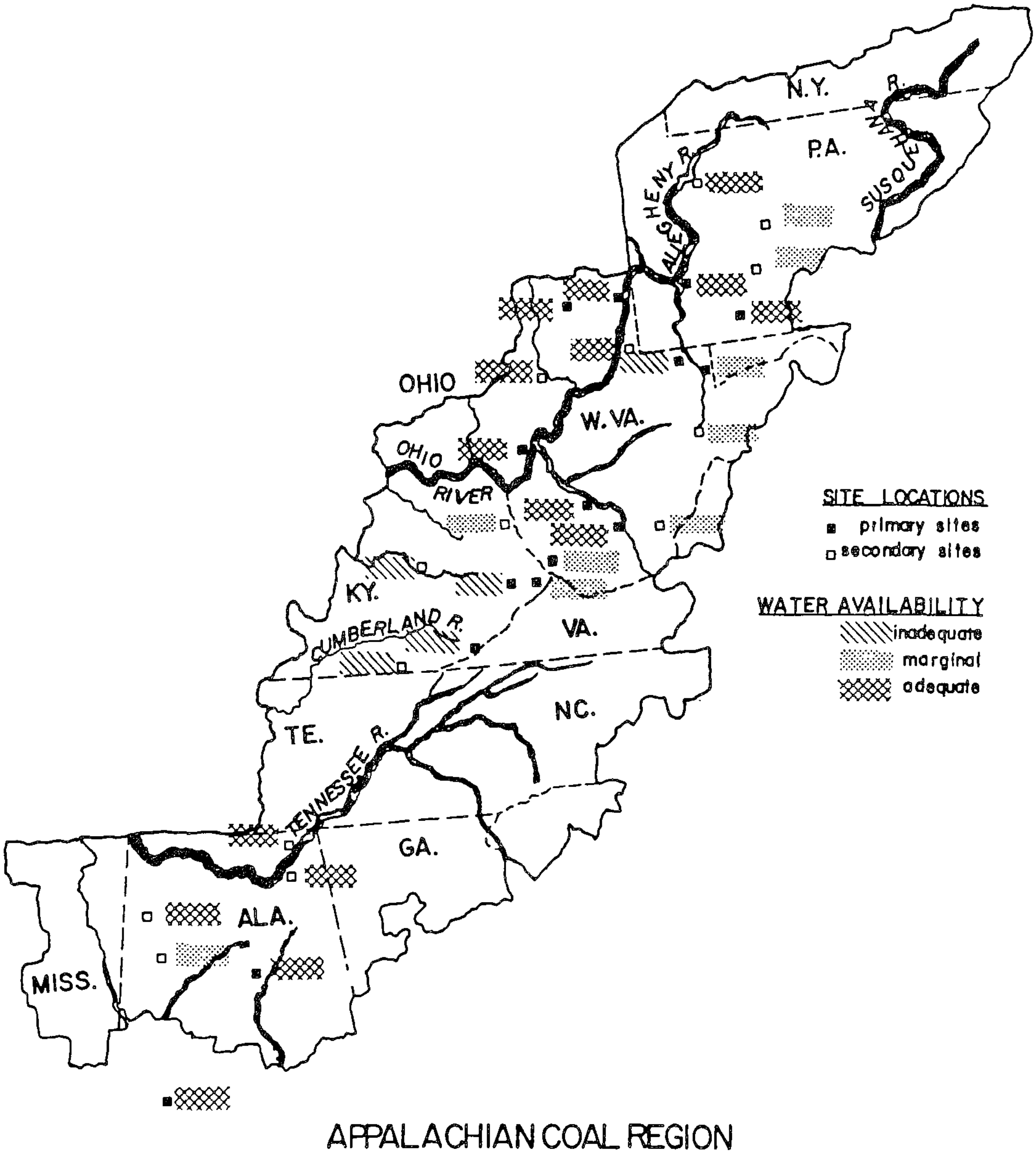


Figure 4-2 Water availability in the Appalachian coal region

Figure 4-3. Water availability in the Illinois coal region.

structure in that area. It must be recognized that actual well yields that may be realized at a given location, particularly those from fractured consolidated aquifers in the Appalachian region, are very site dependent.

Based on the results of the overall investigations conducted, a water supply source or combination of sources is suggested that would appear to best meet the water supply needs at each site. The originally designated sources are used for this purpose to the fullest extent feasible. This evaluation is based on water supply considerations only accounting for the required reasonable sharing of available supplies, but not considering the many other institutional (such as the non-riparian use restriction), political or environmental considerations that may enter into the final selection of the water supply makeup at a particular location. Some indication of the likelihood of environmental impacts at a specific site is given in the last column. This is a qualitative assessment of potential environmental impacts based on the factors discussed earlier and the general area of the site. It must be emphasized that actual environmental effects associated with coal mining and conversion are very site and design/operation dependent, and cannot be reliably evaluated without specific site and design data.

4.3 Western Region

The water resources in the major coal and oil shale bearing regions of the Western United States can be conveniently separated for consideration into two major watershed regions, shown in Figure 3.5; the Upper Missouri River Basin and the Upper Colorado River Basin.

The vast Fort Union and Powder River coal formations cover large areas of the states of Wyoming, Montana and North Dakota in the Upper Missouri River Basin. Other significant coal and oil shale deposits are situated in the Upper Colorado River Basin in the states of Wyoming, Colorado, Utah and New Mexico. Table 4-9 presents a list of 32 specific site locations that were selected for study based on their proximity to readily developable energy reserves. This list covers more sites than the one given in Table 3-12 and provides a larger study area with regards to water availability. The locations of these sites with respect to the major coal and oil shale reserves and the primary water resources characteristics are shown in Figure 3.5.

TABLE 4-9 PLANT SITE LOCATIONS IN THE WESTERN STUDY REGION

State	Mine	County	Deposit	Hydrologic Sub-Region
Upper Missouri River Basin				
Wyoming	Gillette	Campbell	Subbituminous	Belle Fourche-Cheyenne
	Spotted Horse	Campbell	Subbituminous	Powder
	Belle Ayr	Campbell	Subbituminous	Belle Fourche-Cheyenne
	Antelope Creek	Converse	Subbituminous	Belle Fourche-Cheyenne
	Lake de Smet-Banner	Johnson	Subbituminous	Powder
	Hannah Coal Field	Carbon	Subbituminous	North Platte
Montana	Decker	Big Horn	Lignite	Tongue-Rosebud
	Otter Creek	Powder River	Lignite	Tongue-Rosebud
	Pumpkin Crrek	Powder River	Lignite	Tongue-Rosebud
	Moorhead	Powder River	Lignite	Powder
	Foster Creek	Powder River	Lignite	Tongue-Rosebud
	U.S. Steel-Chupp	Dawson	Lignite	Missouri Mainstem
	Coalridge	Sheridan	Lignite	Missour Mainstem
	Colstrip	Rosebud	Subbituminous	Tongue-Rosebud
North Dakota	Slope	Slope	Lignite	Heart-Cannonball
	Dickenson	Stark	Lignite	Heart-Cannonball
	Bently	Hettinger	Lignite	Heart-Cannonball
	Scranton	Bowman	Lignite	Heart-Cannonball
	Williston	Williams	Lignite	Missouri Mainstem
	Knife River	Mercer	Lignite	Missouri Mainstem
	Underwood	McLean	Lignite	Missouri Mainstem
	Center	Oliver	Lignite	Missouri Mainstem
Upper Colorado River Basin				
Wyoming	Kemmerer	Lincoln	Bituminous	Upper Green
	Jim Bridger	Sweetwater	Subbituminous	Upper Green
	Rainbow #8	Sweetwater	Bituminous	Upper Green
	Tract W-a/W-b	Sweetwater	Oil Shale	Upper Green
Colorado	Tract C-a/C-b	Rio Blanco	Oil Shale	Lower Green
	Colony Development	Garfield	Oil Shale	Upper Colorado
Utah	Tract U-a/U-b	Unitah	Oil Shale	Lower Green
New Mexico	El Paso	San Juan	Subbituminous	San Juan
	Wesco	San Juan	Subbituminous	San Juan
	Gallup	McKinley	Subbituminous	San Juan

The Upper Missouri River Basin, on the eastern slopes of the Rocky Mountains, has two major sub-regions with respect to climate. The mountainous regions of western Montana and central Wyoming receive annual rainfalls of up to 40 inches and generate most of the runoff within the basin. Much of the remainder of the basin has the characteristic flat terrain of the northern Great Plains. This area has a semi-arid climate and annual precipitation ranging from about 12 to 24 inches[9]. Throughout the basin most of the precipitation occurs as snowfall during the winter as a result of orographic cooling of the prevailing westerly air flow. The result is that most of the annual runoff occurs in late spring as the mountain snowpack melts. This serves to create short periods of high streamflows and to recharge the alluvial groundwater system. From late summer through winter there is very little natural surface runoff. Annual open surface evaporation rates range from about 28 inches at the higher elevations to about 44 inches on the plains[9].

The Upper Colorado River Basin covers a region on the western slope of the Continental Divide that is located further to the south than the Missouri Basin. Although the Colorado River Basin has a somewhat more arid climate due to its more southerly position and because much of the basin does not benefit from the orographic precipitation caused by the Rockies, the seasonal distribution of overall precipitation is similar to that in the Upper Missouri Basin. Throughout the basin annual precipitation varies from lows of about 8 inches at numerous locations in the Basin to a maximum of about 40 inches at higher elevations in portions of northeastern Utah[9]. Most of the annual surface runoff results from melting mountain snowpacks in the spring with much lower flows occurring over the remainder of the year. Annual evaporation rates over most of the Basin are quite high, ranging from about 32 inches to about 54 inches[9].

The geographic variability of the climate is an important aspect of the assessment of potential water supplies for use in energy development. As indicated above, this variability indirectly affects the seasonal distribution of water supplies throughout most of the study area. Evaporation is also a vital parameter to the water resources of the region since it affects two of the most significant water uses - irrigation requirements and reservoir evaporation losses.

In the West the adequacy of a water supply is dependent on several factors including the average quantity of water available at the intended source; the variability of the supply over time; the manner in which the water is used or committed to use through a prior appropriation; and the environmental and social implications involved in altering the hydrologic region. The Appropriate Doctrine is the code by which water is administered in the Western states of concern. In this system water rights are given priorities dependent on the seniority of the right and independently of the location of the water use with respect to its source. Generally the only requirement regarding the use of water once a water right is confirmed is the need to put the water to "beneficial use", the definition of which is usually very loosely held. Water rights are considered to be property and can be bought and sold as such. On a subregional basis total average annual water yields generally greatly exceed actual use. In many cases, however, legally recognized rights to use water exceed the available supplies during low flow periods. Supplying water for future energy use in many of these cases will require implementation of one or more of the following developments:

1. Additional storage facilities to more evenly distribute the available supplies over the year and from wet to dry years.

2. Importation of surplus supplies from regions with more abundant water yields.

3. Transfer of water use to the industrial sector by the purchase of existing agricultural water rights and state approval of changes in water use.

<u>Surface Water Resources</u>

Upper Missouri <u>River Basin</u>

The Upper Missouri River Basin may be divided into several hydrologic subbasins of interest with respect to water availability for energy development. As shown on Figure 4-4, these study regions are:

1. Upper Missouri River Mainstem (Montana, North Dakota)
2. Yellowstone River Mainstem (Wyoming, Montana)
3. Powder River Basin (Wyoming, Montana)
4. Tongue-Rosebud Basins (Wyoming, Montana)
5. Heart-Cannonball Basins (North Dakota)
6. Bell Fourche-Cheyenne Basins (Wyoming)
7. North Platte Basin (Wyoming)

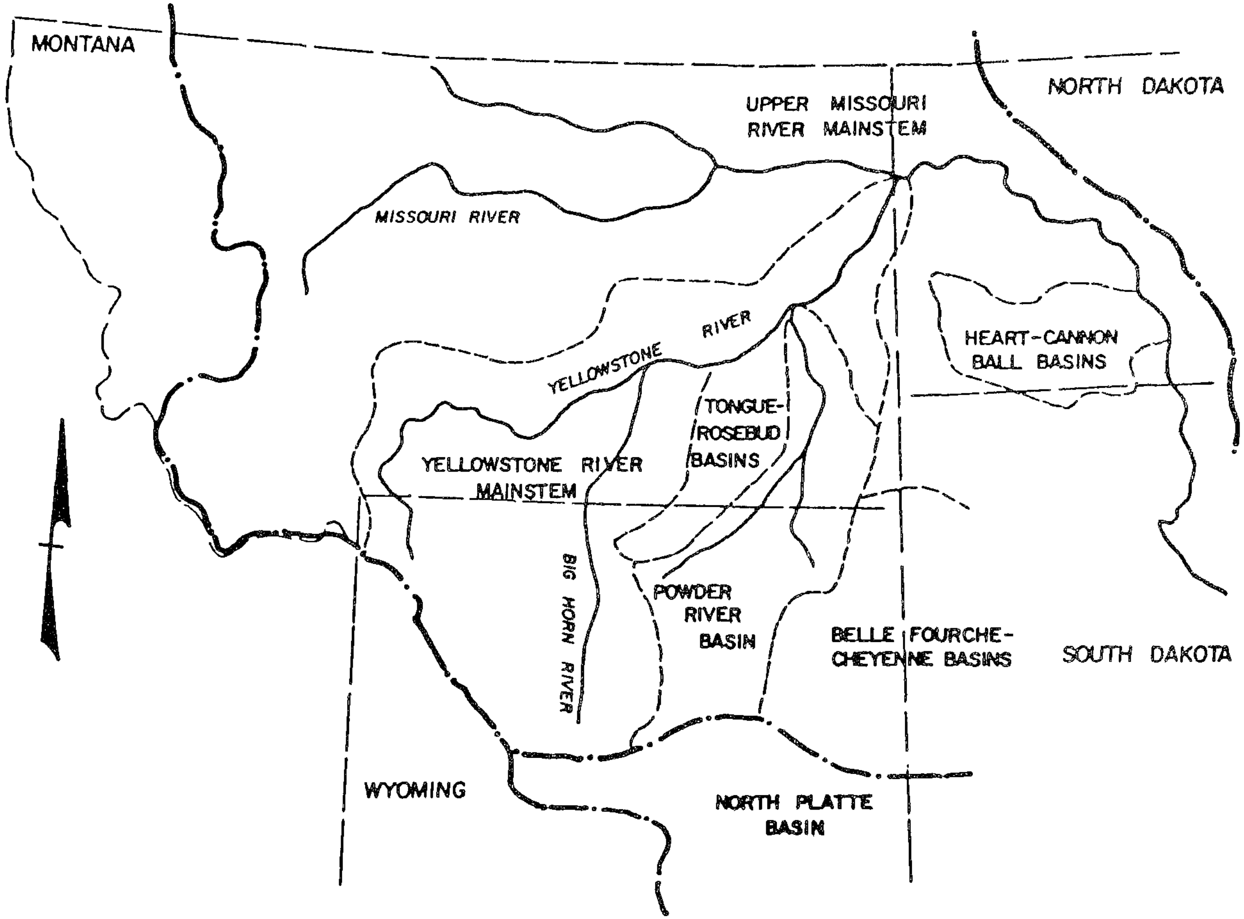


Figure 4-4 Subbasin boundaries - Upper Missouri Basin

This section discusses these subregions with respect to the total surface water resources generated within the regions that is available to all users.

Most of the annual runoff produced in the Upper Missouri Basin originates in the mountainous headwaters of the Yellowstone and Missouri subregions in western Montana and Wyoming. The Yellowstone River Basin is of special interest in this study because much of the most easily retrievable coal is located within its drainage divides, making it a likely source of supply for future development. The Yellowstone Basin covers a drainage area of about 70,000 square miles which is divided nearly equally between Montana and Wyoming, and joins the Missouri River just east of the Montana-North Dakota border. At their confluence the Yellowstone yields an annual flow of about 9.5 million acre-ft/yr which is 22 percent more average flow than the Missouri, although it drains 14 percent less area. The Yellowstone River receives more than one-half of its total yield from waters rising in the mountain ranges upstream of Billings, Montana. The majority of the remaining yield is from the Wind-Bighorn River Basin in north-central Wyoming.

The hydrologic characteristics vary within the Upper Missouri Basin, primarily between the mountain and plains regions. Water yield from the high mountain region in the western basin ranges to over 20 inches per year, while the semi-arid plains covering much of the basin contribute less than one inch of runoff. The total water yields on a subregional basis are shown in Table 4-10.

TABLE 4-10 AVERAGE ANNUAL WATER YIELD - UPPER MISSOURI RIVER BASIN

Subbasin	Drainage Area (sq. mi.)	Average Water Yield in Sub-Region (AF/year)	Average Area Yield (AF/year/sq.mi.)
Tongue-Rosebud	6,660	467,000	70
Powder	13,420	501,900	37
Yellowstone Mainstem	50,040	10,488,100	210
Belle Fourche-Cheyenne (Wyoming only)	11,000	182,400	17
Heart-Cannonball	7,620	337,500	44
Upper Missouri Mainstem (At Oahe Dam)	185,840	23,625,000	127
North Platte (Colorado & Wyoming only)	26,660	1,223,100	46

Table 4-11 gives the recorded surface runoff characteristics of some rivers in the Upper Missouri Basin (Figure 4.5) at selected points. The average discharge is the discharge averaged over the period of record while the maximum and minimum discharges are the instantaneous daily extremes. Runoff is an indicator of a region's water resources, but it should not be used alone as a measure of water sufficiency. Taking a conservative (high) estimate of average water use in a typical mine-plant complex to be 10 ft^3/sec ($6.5x10^6$ gal/day) then Table 4-11 shows that the Missouri, Yellowstone and Bighorn Rivers even at minimum discharge have sufficient capacity under present conditions to support a number of standard size synthetic fuel plants. As in many parts of the West, some of the river flows of the smaller tributaries are highly variable, even with regulation of some of the rivers.

TABLE 4-11 RECORDED SURFACE RUNOFF CHARACTERISTICS IN CUBIC FEET PER SECOND OF RIVERS AT SELECTED POINTS IN THE UPPER MISSOURI BASIN

River and Location	Average Discharge	Maximum Discharge	Minimum Discharge
Missouri, near Culbertson, Montana	10,330	78,200	575
Yellowstone, near Sidney, Montana	13,030	159,000	470
Little Missouri, at Marmarth, North Dakota	343	45,000	0
Knife, near Hazen, North Dakota	183	35,300	0
Cannonball, near Breien, North Dakota	247	94,800	0
Yellowstone, at Miles City, Montana	11,330	96,300	966
Yellowstone, at Billings, Montana	6,858	66,100	430
Tongue, at Miles City, Montana	423	13,300	0
Bighorn, at Bighorn, Montana*	3,851	26,200	275
Powder, at Arvada, Wyoming	272	100,000	0

*Regulated by storage facilities.

The seasonal distribution of runoff also varies throughout the Basin with most of the annual runoff occurring in the spring and early summer due to the

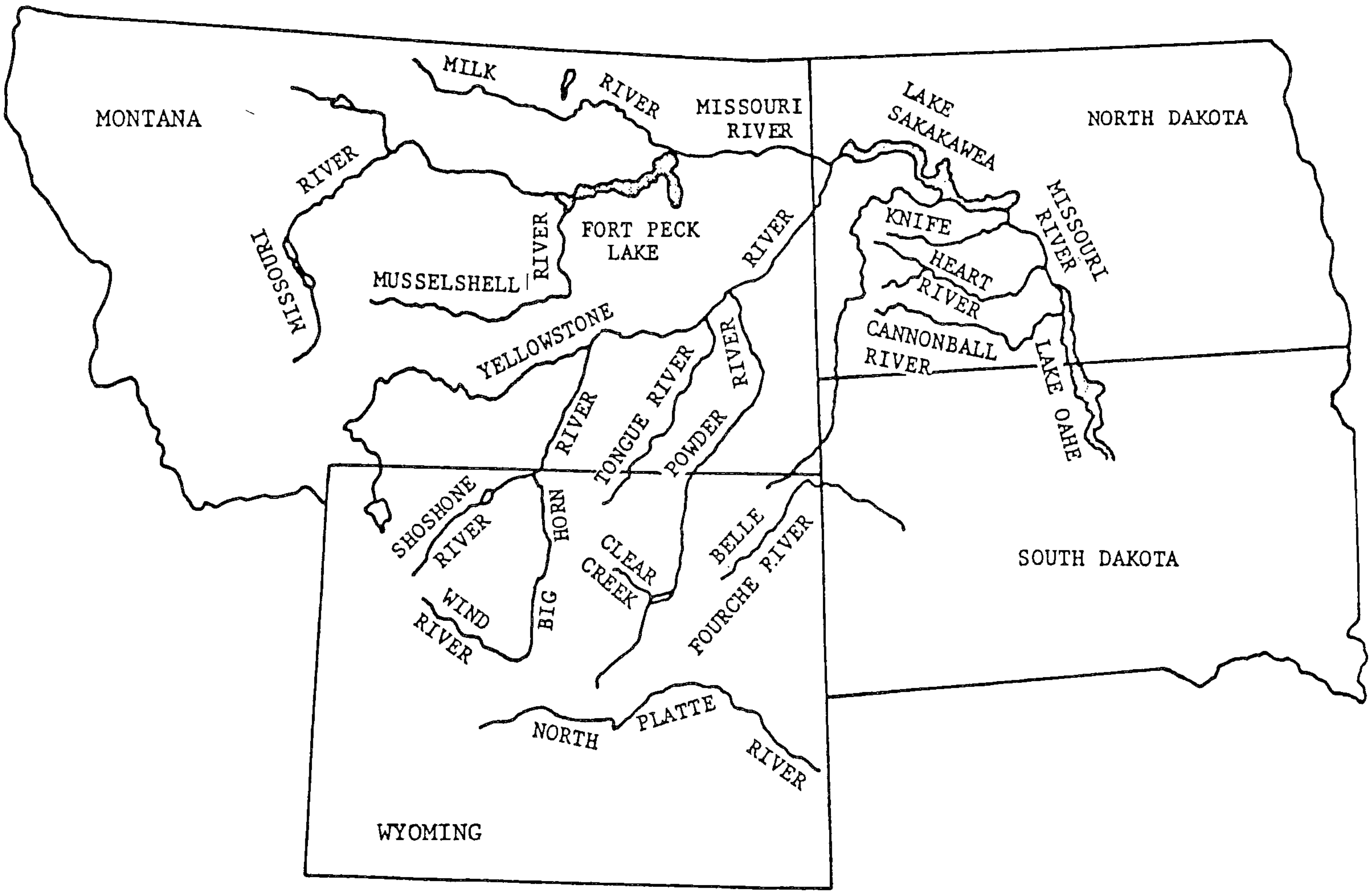


Figure 4-5 Major rivers in the Upper Missouri River Basin

melting of the accumulated snowpack. The largest variation in flow is evidenced in streams in the plains regions where very high flows are typically experienced over a short spring melt season, but where flows often diminish to zero at times during the year because of depletions and little rainfall. Because of this seasonal variability numerous storage reservoirs have been built over the years to retain the spring runoff for use during the remainder of the year. This has been particularly important to the development of the region's agricultural base, since the controls make far more water available for irrigation during the growing season than would be available under natural flow conditions.

Within the Yellowstone River portion of the Basin, the reservoirs are located primarily on the tributaries in northern Wyoming and southeastern Montana. The mainstem of the Yellowstone is presently unregulated and is valued as one of the few remaining major free-flowing rivers in the West. It is doubtful if any future impoundments on the mainstem would be allowed.

The Missouri River mainstem major coal reserve region is highly regulated by a series of large, multi-purpose reservoirs built and operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers. These are as follows:

Reservoir	Location	Active Storage
Fort Peck	Montana	10,900,000 AF
Lake Sakakawea	North Dakota	13,400,000 AF
Oahe	North and South Dakota	13,700,000 AF

These reservoirs form the basis for a reliable and abundant water supply to serve a variety of energy development activities in northeastern Montana and along the mainstem in North Dakota.

Upper Colorado River Basin

The Upper Colorado River Basin may also be divided into several hydrologic subbasins with respect to water availability. As shown in Figure 4-6, these study regions are:

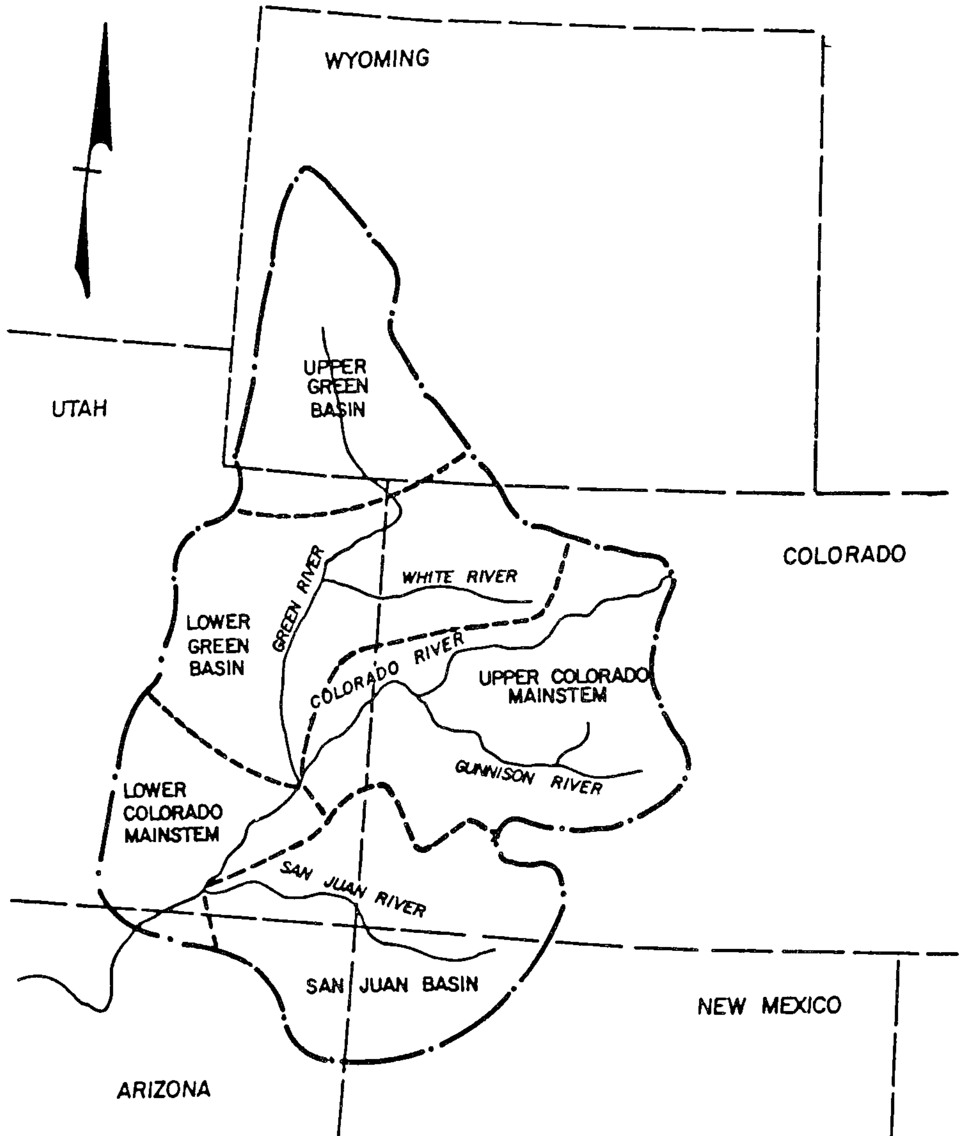


Figure 4-6 Subbasin boundaries - Upper Colorado River Basin

1. Upper Green River (primarily Wyoming)
2. Lower Green River (Colorado and Utah)
3. Upper Colorado Mainstem (Colorado and Utah)
4. Lower Colorado Mainstem (primarily Utah)
5. San Juan River (Colorado, New Mexico, Utah and Arizona)

Most of the annual runoff produced in the Upper Colorado River originates in the western slope mountain headwaters of the Basin in Colorado. The mainstem of the Colorado River and two of its major tributaries, the Green River and the San Juan River, drain portions of the headwaters, but the Colorado produces by far the most runoff. Although the Green River Basin drains about 44,000 square miles or about 70 percent more area than the Colorado River above their junction, the Colorado yields about 25 percent more water. Much of the remainder of the Basin at lower elevations has an arid to semi-arid climate and produces very little additional yield. Water yields range to over 20 inches in the high mountain regions, but less than 0.5 inches over most of the Basin (Figure 4-7). The total water yields on a subregional basis are shown in Table 4-12.

TABLE 4-12 AVERAGE ANNUAL WATER YIELD - UPPER COLORADO RIVER BASIN

Subbasin	Drainage Area (sq. mi.)	Average Water Yield in Sub-Region (AF/year)	Average Area Yield (AF/year/sq.mi.)
Upper Green	14,300	1,926,000	135
Lower Green	29,700	3,534,000	119
Upper Mainstem	26,000	6,838,000	263
Lower Mainstem	20,500	451,000	22
San Juan	23,000	2,387,000	104

The principal rivers and tributaries in the Upper Colorado River Basin are shown in Figure 4-7 with the recorded surface runoff characteristics of some

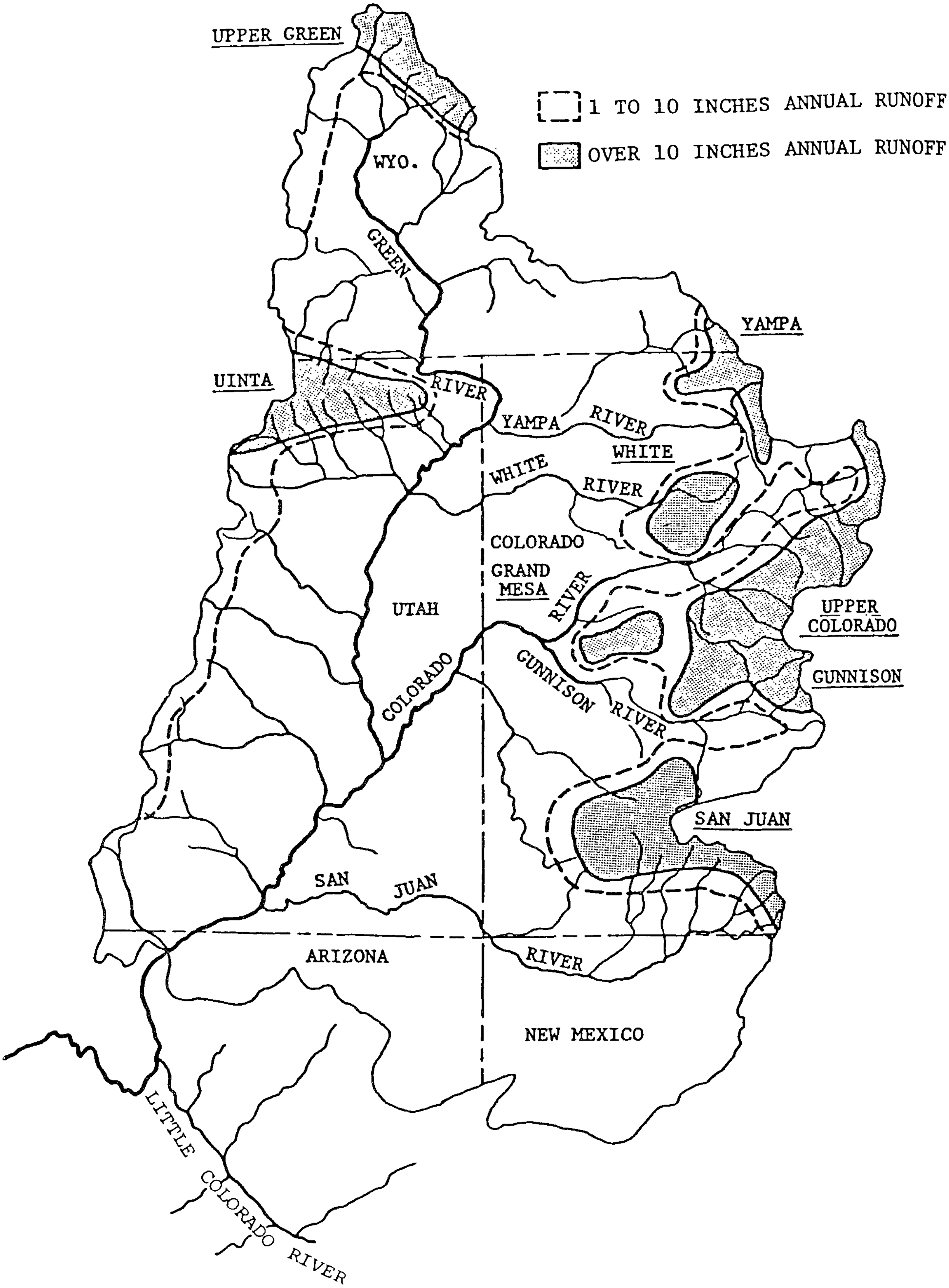


Figure 4-7 Major rivers and runoff producing areas in the Upper Colorado River Basin

rivers at selected points in the region given in Table 4-13. As mentioned previously, the river flows are highly variable even with regulation of some of the rivers. The flow of the San Juan River is stabilized by the Navajo Reservoir with a capacity of over 1.7×10^6 acre-ft (0.55×10^6 gal).

TABLE 4-13 RECORDED SURFACE RUNOFF CHARACTERISTICS IN CUBIC FEET PER SECOND OF RIVERS AT SELECTED POINTS IN THE UPPER COLORADO RIVER BASIN

River and Location	Average Discharge	Maximum Discharge	Minimum Discharge
Colorado River, at Hot Sulphur Springs, Colorado	201	2,500	44
Colorado River, near Colorado-Utah State Line	5,345	33,000	1,570
Gunnison River, near Grand Junction, Colorado	2,072	12,000	500
Green River, near Green River, Wyoming	1,584	10,900	245
Green River, at Green River, Utah	5,811	29,500	1,180
Yampa River, at Steamboat Springs, Colorado	421	4,080	45
White River, near Meeker, Colorado	540	4,010	25
San Juan, at Farmington, New Mexico	2,425	68,000	14
Animas, at Farmington, New Mexico	922	25,000	1
San Juan, near Carracas, Colorado	605	9,730	5

The seasonal variability of runoff is also a very significant aspect of the overall water resources situation in the basin. Most of the annual runoff occurs during the late spring as a result of melting snow. During the remainder of the year most of the smaller tributary streams receive little additional rainfall input and flows frequently diminish to zero. Because agriculture has long been an important part of the region's economy, water resources developments have been developed over the years to more evenly distribute the excess spring runoff over the year, particularly during the growing season. These developments include storage reservoirs, flow diversions and a variety of irrigation works. The result is that the Colorado River System has become one of the most highly regulated river systems in the country.

The major storage reservoirs in the Upper Colorado Basin are the following:

Reservoir	Location	Active Storage
Fontenelle	Green River, Wyoming	190,000 AF
Flaming Gorge	Green River, Wyoming-Utah	3,749,000 AF
Blue Mesa	Gunnison River, Colorado	830,000 AF
Navajo	San Juan River, New Mexico	1,696,000 AF
Lake Powell	Colorado River, Utah-Arizona	25,002,000 AF

Although these facilities and a number of significant flow diversions make more water available along the major interstate rivers than can presently be used, a specific set of legal considerations govern how the water may be used.

Water quality is a more significant issue in the Upper Colorado River Basin than in the Upper Missouri Basin. Although the water in the upper reaches of the major streams is of high quality, the quality deteriorates as the water moves downstream. By far the most significant water quality concern in the Basin is salinity affecting agricultural usage. Surface water quality in the Upper Colorado Basin will be an important consideration for future energy development for two reasons. The presence of high concentrations of certain salts may be a factor affecting the feasibility of using various sources as a water supply for energy conversion, and therefore may be a siting consideration. At the same time, the consumption of high quality supplies in the upper Basin region may reduce the dilution water available and therefore increase salinity downstream.

Groundwater Resources

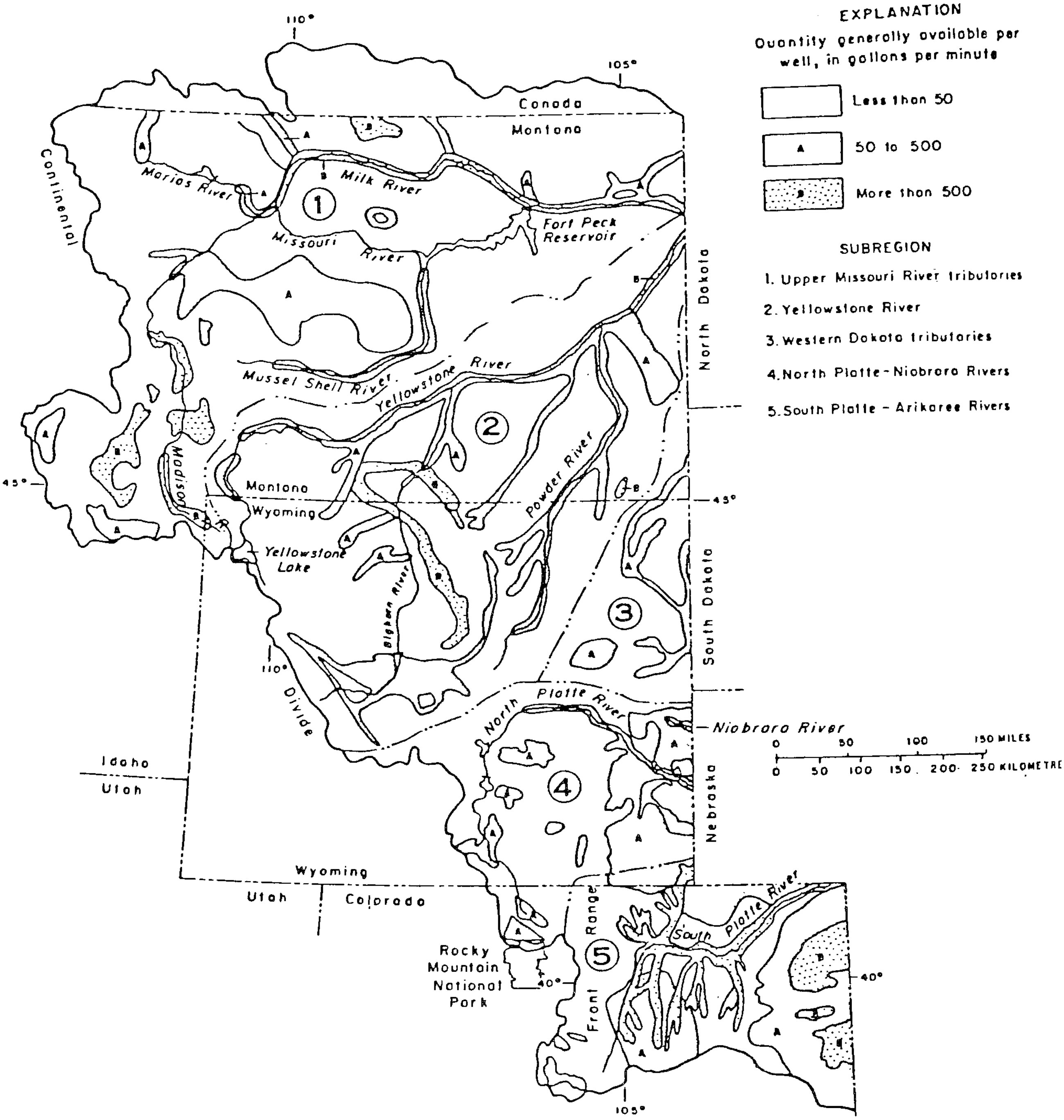
Groundwater is an important but often overlooked water supply source throughout much of the coal region of the West. It is estimated that there is approximately 120 million acre-ft of water stored in natural underground reservoirs at depths within only 200 feet of the surface. This volume is several times the storage capacity of all of the surface reservoirs in the region, yet present groundwater usage accounts for only a relatively small percentage of total water use. The reasons for this are varied, but include: the costs to locate and develop groundwater supplies, poor groundwater quality in some areas, and the preference of certain users to utilize surface supplies. However, groundwater supplies may have certain advantages over surface supplies in that it is often more widely distributed and more dependable throughout the year. As competition for available surface supplies increases in the future, it is anticipated that groundwater will play a larger role in the overall water supply picture in the West.

Groundwater aquifers in the study area fall into two general categories. Shallow aquifers consist of coalbeds, sandstones and the unconsolidated alluvium along major rivers and the principal tributaries in buried preglacial valleys. Deeper strata of limestone and associated carbonate rocks have also shown promise as potential water supply sources, particularly in the northern Great Plains region. General areas underlain by aquifers capable of well yields of 50 gpm or more are shown in Figure 4-8.

Shallow aquifers are present throughout much of the Upper Missouri Basin except in the Bighorn Mountains and Black Hills, where the older Madison Limestone and associated carbonate rocks are exposed. These aquifers generally vary in depth from the surface to a few thousand feet. Most existing wells are less than about 300 feet deep although some alluvial wells less than 100 feet deep yield as much as 500 gpm. Most present shallow aquifer wells yield less than 50 gpm, but this appears to be a limitation related to typical water requirements rather than the capacities of the aquifers. Available data indicates that the sandstone units and associated coal beds in the Fox Hills-Hell Creek-Fort Union-Wasatch sequence may yield up to 500 gpm in appropriately constructed individual wells.

The Madison aquifer underlies most of the northern Great Plains coal region except for the Bighorn, Pryor and Snowy mountains and the Black Hills where it is exposed or absent. Varying in depth from about 5000 feet in the coal region of Montana to about 10,000 feet in portions of the Powder River Basin in Wyoming, this aquifer has produced a few wells yielding up to several thousand gallons per minute. However, yields are highly variable and since the cost involved in tapping this source is so great, data on the potential of the Madison is presently quite limited.

The aquifers that underlie the Upper Colorado River region consist mostly of consolidated and semi-consolidated sedimentary strata with unconsolidated alluvial deposits along reaches of major stream valleys. It has been estimated that the volume of recoverable groundwater within 200 feet of the surface is about 88 million acre-ft which is nearly three times the active storage in all



WESTERN MISSOURI RIVER BASIN

Figure 4-8 Groundwater supply availability (from Ref.26) (continued).

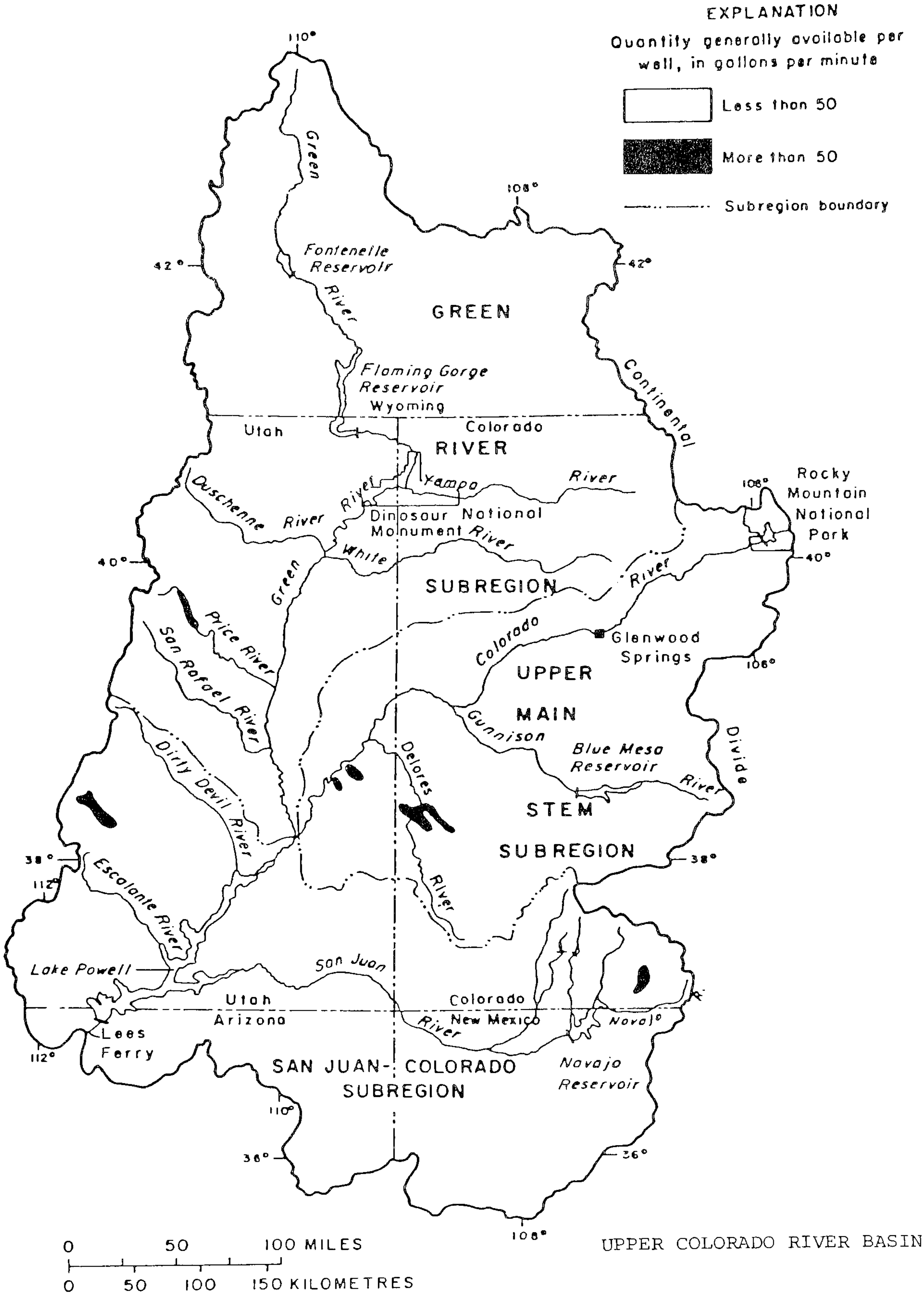


Figure 4-8 (concluded).

of the surface reservoirs in the Colorado River system and that the amount stored in the deeper rocks is several times that within the initial 200 feet zone. It is also estimated that about 4 million acre-ft of groundwater recharge occurs annually from rainfall, principally in the higher mountains and plateaus where rainfall is the highest.

Although the total volume of recoverable groundwater storage is great, the water cannot always be obtained at the desired rates in all places. About 85 percent of the stored groundwater occurs in sedimentary rocks which have relatively low permeability and yield water slowly. Wells yielding more than 50 gpm generally can be expected only in areas consisting of permeable alluvium which accounts for only about 5 percent of the groundwater reserves.

An area that has received specific attention with respect to the availability and impacts of groundwater use for oil shale mining is the Piceance Basin in Colorado. Significant quantities of groundwater are believed to be available in this Basin. Estimates of the volume of water in storage in the deep aquifers in the Piceance Creek Basin range from 2.5×10^6 to 25×10^6 acre-feet[12,13]. Groundwater is also available from shallower alluvial aquifers that are much smaller in areal extent than the deep aquifers. Recharge to the aquifers occurs mainly as a result of snow melt along the margins of the basin. Groundwater flows from the margins of the basin to the central part of the basin[12]. The surface water and ground water systems are hydraulically connected so that if a large quantity of groundwater is withdrawn from an aquifer, flow in the neighboring streams could be decreased or possibly reduced to zero.

Water Use Doctrines

In most of the Western states the Appropriation Doctrine governs the use of water. It is based on the principle that a senior right has diversion priority over a junior right, i.e. in times of limited water availability, the senior diversion right can be completely satisfied before any diversion for the junior right is permitted. This doctrine encourages the beneficial use of water often at the expense of satisfactory streamflow conditions and was established to assure the senior appropriator that he has a reliable supply of water insofar as no other water user is permitted to take any action which could in any way injure the senior appropriator. Thus, water is often regarded as a property right in and of itself. Junior water rights are, in most cases, also protected against injury from any manipulation or change in use of senior water rights, as they are generally entitled to the maintenance of stream conditions as they existed when the junior appropriation was granted.

Typically, each state has a water administration system with characteristics distinct from those in the other western states. A characteristic common to all of the systems of the states under consideration include some degree of appropriation doctrine, a system designed primarily to encourage the efficient beneficial use of water, in an economic sense, while at the same time minimizing conflicts with other water users. This system permits and in many cases requires, the diversion of water from a stream bed or watercourse to establish a water right. Recently, though, the administrative procedures have been changed in several of the states regarding instream appropriations of water; these have been instituted primarily for the purpose of minimizing environmental degradation, e.g., maintaining a minimum stream-flow for fish life and recreational purposes.

The procedures by which water rights can be transferred in title, manner of use, and place of use vary widely from state to state. In some states, irrigation water is tied to the land upon which it is used and can be transferred only with somewhat greater effort than in those systems in which it is recognized that the water is indeed separable from the land. In all cases, however, the prevention of adverse effects of the transfer of other water uses, junior and senior, is of paramount importance. In fact in most cases this is the only restriction on transfer of water on an individual basis. It is typically the case, however, that the burden of proof lies upon those wishing to effect the transfer, whether the change must be adjudicated or approved by an administrator.

Development of storage rights is generally encouraged in the area of interest by water administration systems. Again, they are permitted only when other water users are not materially injured, or when they can be induced to withdraw objection to the project. In general, temporal aspects (e.g., time of year in which water is used) play a large role in the value of the right. Consequently, water storage plays a correspondingly large role in the transfer of water rights. For instance, when an irrigation right which is used in the period May-October each year is transferred to an industrial use which requires a year-round water supply, some storage must be used, even when the total annual volume of the industrial use is equal to or less than that of the irrigation use. This is done primarily to ensure that the hydrologic regime of the river does not change as a result of the change in use and harm a junior appropriator by causing water which was formerly available to him to become unavailable.

Trans-basin diversions can be handled in many ways as simply as a conventional change in use and location. However, the consequences of trans-basin diversions tend to have somewhat greater impact on the hydrologic regimes of rivers; hence, the political and environmental aspects of trans-basin diversion are much more complicated. This is largely a result of the interstate compacts which exist on most of the major interstate rivers. These compacts are discussed individually in Appendix 14. Generally, the interstate compacts tend to come about only after conflicts between the states arise concerning the flows. Since they are a result of tensions between the states, the states watch closely to ensure that they do not get shortchanged by other states. Consequently, interstate compacts affecting trans-basin diversions must satisfy very stringent conditions. For example, one potential problem lies in the lack of any compact or agreement between the states of Colorado and Utah concerning the use of water of the White River. Commonly regarded as one of the most likely sources of water for oil shale development, the absence of any agreement on the disposition of White River water almost guarantees an eventual clash between the states of Colorado and Utah when an attempt is made in either state to put a large amount of water to use. Currently the river remains largely undeveloped.

Groundwater is another resource subject to a variety of differing administrative policies in different states and regions. In most states permits from the statewide administrative agency are required. Typically, one of the main requirements has been that of not adversely affecting the groundwater situation of adjoining landowners. In most cases the deep, non-alluvial aquifers with limited recharge capabilities may only be "mined" at a rate usually set by the state administrator responsible for such matters.

Frequently the administration and regulation of groundwater activities is handled by the same state agencies which administer the surface waters. Although the history of groundwater management is relatively short, significant changes have been made in several states in the recent past. They have moved primarily in the direction of recognizing the hydraulic connections between surface water and tributary groundwater sources. Thus, increasing interaction is taking place between the surface water management systems and the groundwater management systems.

An important factor in the consideration of the water supply possibilities in the area lies in the claims of the Federal Government for its reservations of different types. As discussed below the Reserved Rights Doctrine allows the federal government to reserve sufficient water for whatever use is made of federally reserved lands, which include Indian Reservations and Bureau of Land Management land among other types. Consequently, there has been considerable litigation to force the Federal Government to quantify these claims and file for them through the State Water Administrations.

Federal Reserved Rights are based upon the notion that sufficient water from adjoining watercourses was reserved for whatever use the Federal lands should be put to when the land was claimed by the Federal Government. Since many of these lands were put aside before private water development took place, the priority of the Federally reserved water is better than the other water rights on the river. Generally, this concept has been tested in the courts and firmly upheld. The problem associated with the Federally reserved water rights is that they have not been quantified or even identified, resulting in uncertainty in the past by other water users. Because the Indian Reservations fall into this category, and because they are the Federally reserved lands most likely to be developed, much of the concern has focused upon them - hence the proliferation of court cases concerning them. There has been no resolution of this problem and the uncertainty may well drag on for several years.

Another consideration of Federal water policy is the development of the Wild and Scenic Rivers in the region of concern. When a river is designated as wild or scenic, development along the river is severely restricted in order to maintain the desirable condition of the river. Among the rivers being considered for designation are parts of the Yellowstone, Missouri, Green, Yampa and Colorado in the study area.

Competing Water Uses

An important consideration in assessing water availability is how other alternative uses will compete for the available water of any particular supply source. In this section we will consider the present use of water in each of the various regions of interest, discuss the factors that may lead to changes in the demand structure and then consider a number of potential future demand scenarios.

An important aspect of any discussion of present or future water use in the arid western regions considered here is that the limited geographical and seasonal distribution of water supplies has greatly affected the development of these regions and how water is used. Most of the water supply generated in the region as a whole occurs as winter snowfall at higher elevations in the upper watersheds. Melting of the extensive mountain snowpeaks results in high rates of spring stream runoff and groundwater recharge, but throughout much of the summer and fall seasons, very little additional runoff is produced. This leaves large portions of the region with very little water throughout much of the year except along the major streams. Since most potential water users require a steady and reliable supply, most of the region's development has occurred where natural supplies are most reliable or where man-made control projects have improved the seasonable variability of supplies to an acceptable level.

Historically the primary use of water throughout the region has been for a variety of agricultural uses. Since the growing season extends over much of the dry summer period, continuing water resources developments have been directed at storage impoundments which more evenly distribute the spring runoff throughout the year. Even though the reservoir evaporation losses associated with this may represent a substantial depletion, the total value of the annual runoff is increased since more summer water is available at a substantially higher value per unit than spring water. Many reservoirs have been built and are operating throughout the West for this purpose. As water from these sources has become available in any given area, the demand for the relatively inexpensive water generally increases. This is an indication of the fact that the level of various alternative water uses is highly dependent on the reliability of the supply as well as its economic cost.

The use of water for agricultural purposes which consists primarily of the irrigation of cropland or pasture is by far the largest water use in the West, accounting for an average of 70-80 percent of total present depletions. This depletion in most cases represents only a portion of the water actually withdrawn from a source and applied to the cropland. The net depletion of irrigation water comes about from evaporation or transpiration losses, seepage into the deep groundwater system and water incorporated into growing plants. Multiple reuse of irrigation water has resulted in adverse water quality impacts through the accumulation of dissolved salts that are particularly severe in the Southwestern states.

An extensive system of reservoir storage has been developed throughout the West to more uniformly distribute the spring runoff over the year and particularly through the growing season. These reservoirs often serve multipurpose functions including irrigation, flood control, power generation, municipal and industrial supplies and recreation. Although these developments make far more water available for use when the water is most valuable, on an annual basis the large water surface areas associated with the reservoirs result in substantial water depletions through evaporation.

It has been increasingly recognized during recent years that maintaining streamflows above certain minimum levels that vary according to season is necessary to preserve the habitat for fish and stream-related wildlife. Free-flowing streams also create opportunities for recreation and increase environmental quality in several ways.

For the most part, however, the appropriate water laws in effect in the Western states are weak or lacking in provisions that would insure minimum sustained streamflows. Under present laws streamflows can be and in many cases are appropriated to a level that exceeds the available water supply. A result of this is that theoretically streams can be completely depleted and have no remaining flow during dry months or years. This obviously has serious impacts on local fish and wildlife populations.

Several states presently recognize minimum flows for maintaining fish and wildlife as a beneficial use and, therefore, a use that can be specifically reserved in its own right. Other states are contemplating similar legislation. Studies to more adequately establish the minimum flow regime needed to sustain given stream ecosystem without appreciable degradation will be required as a part of the development and perfection of future instream flow appropriations. In many cases the result may be instream flow requirements that are a major portion of existing low flows.

The sparse population throughout most of the study region results in municipal and industrial water demand sectors being very low by comparison with the agricultural sector. Domestic and industrial users supplied by municipal systems are frequently considered together under the category of Municipal and Industrial (M&I). On the whole, M&I use presently accounts for less than 5% of overall water use and an even smaller fraction of total depletions.

Self supplied industrial users are generally considered separately. The major industrial uses in this category are the mining and minerals industry which uses water primarily in the cleaning and processing of ores and the power industry which uses water in thermal steam-electric power plants for cooling. These major industries as well as many other less significant water users generally fully deplete their water withdrawals because any wastewater produced would be detrimental to the environment if returned to the streams.

Upper Missouri River Basin

Water use in the Upper Missouri Basin is committed largely to agricultural purposes. It has been estimated that fully 80 percent of present use goes towards crop or range irrigation and related uses. Development of the region in fact has depended on reliable water supplies and as such has occurred mostly along the interstate rivers and their major tributaries. Good water availability in western Montana and the Upper Yellowstone Basin in north central Wyoming and south central Montana has led to the development of numerous irrigation projects and associated water control facilities such as reservoirs, irrigation channels and distribution systems. Most of the population centers, power generation facilities, and other industrial development are also located in these regions. Much more limited water supplies are available for development in the plains regions of eastern Montana and Wyoming and western North Dakota, and as a result, these regions have been developed to a far lesser extent.

The way water is presently being used in this region is largely determined by legal considerations as to the right to use the water. This is particularly true in the portions of the Yellowstone River Basin and the Belle Fourche-Cheyenne Basins where some of the most easily retrievable coal reserves are located, but where water at times is already in very short supply. Within each of the major tributaries, various interstate compacts define how much of the available supplies may be used within each state, allowing for reservations recognized prior to the compact dates. Each state's share then is allocated according to existing appropriative rights.

The way in which water is presently being used in the Upper Missouri coal regions is shown in Table 4-14. The water use values given here are for total depletions of the water supplies. Irrigation and municipal use generally would involve larger actual withdrawals with return flows to the waterways, and hence reuse. Industrial and reservoir evaporation involve full depletion of

TABLE 4-14 WATER USE - UPPER MISSOURI RIVER BASIN

Subbasin	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Total
Present Use					
Tongue-Rosebud	187,200	5,000	1,600	8,000	201,800
Powder	181,600	4,400	1,600	29,000	216,700
Yellowstone Mainstem	1,561,200	79,400	24,600	331,900	1,997,100
Belle Fourche-Cheyenne (Wyoming only)	6,000	2,000	3,000	31,000	41,000
Heart-Cannonball	24,300	6,500	2,400	8,000	41,200
Upper Missouri Mainstem (To Oahe Dam)	1,335,300	159,600	(including all industrial)	1,445,000	2,939,900
North Platte (Wyoming only)	574,000	7,000	9,000	177,000	766,000
Projected Future Use (Year 2000)					
Tongue-Rosebud	238,000	11,000	124,000	9,000	382,000
Powder	285,000	10,000	62,000	29,000	386,000
Yellowstone Mainstem	1,785,000	128,000	25,000	332,000	2,270,000
Belle Fourche-Cheyenne (Wyoming only)	7,000	5,000	45,000	31,000	88,000
Heart-Cannonball	61,000	8,000	3,000	17,000	89,000
Upper Missouri Mainstem (To Oahe Dam)		Note (1)			
North Platte (Wyoming only)	918,000	36,000	47,000	180,000	1,181,000

(1) Major water demands in this region will be supplied out of the Mainstem reservoirs which have a supply that greatly exceeds any projected uses.

the water utilized in these sectors.

Estimates of water use in the year 2000 in the Upper Missouri River Basin portion of the study area are also given in Table 4-14. Projections for portions of the subregions in the state of Wyoming are taken from the Wyoming Framework Plan [14] which projects moderate increases in irrigation depletions for food and fiber production, but relatively larger increases in industrial use. Projected Montana water use is from the Montana Department of Natural Resources and Conservation[15]. Figures for the Yellowstone Mainstem and the Heart-Cannonball subregions were disaggregated from estimates for the total Yellowstone Basin[16] and the western Dakota tributaries of the Upper Missouri Basin. No use projections were made for the Upper Missouri Mainstem subregion because it is anticipated that the abundant water supplied available in the Fort Peck reservoir and Lakes Sakakawea and Oahe will be more than adequate to meet the energy and all other water needs of that area well into the future.

In Table 4-14 the figures given for industrial usage include self-supplied industrial uses (municipally-supplied industrial water is included under M&I/Domestic) which are primarily for the mining/minerals industry and thermal power generation. Projections for synthetic fuel production are not included in this category. Data on future reservoir evaporation losses is not available so it has been assumed that these depletions will be the same in the future as at present. The largest increases are for irrigation and industrial uses; the latter increase is primarily for increased water consumption in cooling towers for steam-electric power generation.

Upper Colorado River Basin

Agriculture is also an important part of the economy of the Upper Colorado River Basin. Because much of the Basin has a semi-arid climate and little precipitation over most of the year, most of the region's growth has occurred along the Colorado River and its major tributaries. Since even these major rivers naturally would have large seasonal fluctuations in flow, numerous storage reservoirs have been built throughout the Colorado Basin to more evenly distribute the water supply. Today the Colorado River is one of the most regulated rivers in the country and a uniform, reliable flow can be produced over the entire year.

This has led to the development of many irrigation projects at locations throughout the Basin. Presently water use for irrigation accounts for by far the largest depletions of the available supply. The reservoirs that make this water available for use, however, also cause significant depletions through evaporation. A summary of present water use within each of the study subregions according to the various demand sectors is given in Table 4-15.

Upper Colorado River Basin water use estimates for the year 2000 are also given in Table 4-15. Projections of irrigation depletions are based on OBERS (Office of Business Economics, U.S. Department of Commerce and the Economic Research Service, U.S. Department of Agriculture)[17] projections of agricultural data as disaggregated from figures given for the individual states[18]. M&I and self-supplied industrial (exclusive of synthetic fuel production) projections were derived from figures given in Ref. 5. By the year 2000 it was assumed that each state will be utilizing their allowable share of the mainstem reservoir evaporation which is apportioned to the states based on the Upper Colorado Compact share allotments. Data for future levels of "other" uses is not available, so it was assumed there would be a 50 percent increase in this category over present depletions, primarily for fish, wildlife and other recreational developments. The largest increases are for irrigation and industrial (steam-electric power generation) uses.

Demand Variability and Demand Changes

The utility of water for certain uses varies considerably from season to season throughout the year. This is particularly true of agricultural uses which account for a very large portion of total water use in the western study region and which occur primarily during the summer and fall growing seasons. The average duration of the growing season extends from about mid-May through September in the Upper Missouri Basin and from about May through mid-September in the Upper Colorado Basin. Demands for irrigation water, therefore, begin in April, gradually increase to peak requirements in July, and then taper off until about October. The winter months of November through March have no irrigation water requirements[19].

The amount of irrigation water required from year to year also varies, depending on a number of factors among which is the amount of natural rainfall. During dry periods or drought years when the available water supplies are at their lowest levels, irrigation demands tend to be highest. During these periods many of the junior water rights in certain areas cannot be met.

TABLE 4-15. WATER USE - UPPER COLORADO RIVER BASIN

(DEPLETIONS - ACRE-FEET/YEAR)

Sub basin	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Other[1]	Total
Present						
Upper Green	242,000	12,000	16,000	26,000	-	296,000
Lower Green	550,000	6,000	28,000	31,000	154,000	796,000
Upper Mainstem	775,000	15,000	13,000	79,000	194,000	1,096,000
Lower Mainstem	33,000	1,500	1,500	2,000	-	38,000
San Juan	286,000	11,500	31,500	95,000	48,000	472,000
Projected Future (Year 2000)						
Upper Green	407,000	6,000	104,000	73,000	24,000	618,000
Lower Green	655,000	15,000	146,000	144,000	231,000	1,191,000
Upper Mainstem	1,166,000	20,000	108,000	168,000	291,000	1,753,000
Lower Mainstem	58,000	2,000	23,000	18,000	-	101,000
San Juan	696,000	27,000	188,000	117,000	72,000	1,100,000

1 Other losses are consumptive conveyance losses and evaporation attributed to recreation, wildlife and wetlands.

Reservoirs built to carry spring runoff over to the peak agricultural need during the growing season and to some extent from wet years to dry years also account for a water depletion that varies seasonally. Although storage impoundments help to even out the seasonal fluctuation in runoff, significant evaporation water losses result in net decreases in the water available to downstream areas. The variation of reservoir evaporation losses closely resembles that for irrigation demands with evaporation being highest during July/August and diminishing to zero during the winter months when the reservoirs are frozen.

Municipal and particularly industrial demands tend to be much more constant over time. These demands, however, are generally much more dependent on reliable supplies and therefore required priority rights during low flow periods.

Any discussion of potential demand changes must recognize that the limited water supply and associated high economic cost of water in the West have directly influenced growth and development in many areas and has kept use at relatively low levels. Since water demand is a sensitive function of cost for many uses, the overall demand structure in any locale at one unit cost (i.e., supply level) may be very different than the structure at a higher unit cost. This is an important consideration in assessing any potential demand changes affecting the future supply/demand picture, particularly in the primary energy regions of the West, since the value of water for energy production is likely to be higher than the value for agricultural uses. This could result in a significant shift in water use as a result of industrial users acquiring agricultural rights to use water.

As energy and other industrial developments occur in the future, institutional constraints may play a key role in the way water may be distributed or used. Constraints on inter-basin transfers, particularly in the Yellowstone River Basin, presently make development of some prime coal deposits just outside the basin boundary difficult. Also present priority schedules in some states give a low preference to industrial uses of water.

The primary demand sectors which are expected to have an impact tending to increase water use in the future are increased irrigation use for food and fiber production and an increased role of the region in providing for the nation's energy needs.

With regard to the future course of agricultural development, there is considerable disagreement as to whether there will be a net increase or decrease in irrigated agriculture in the study area, and the magnitude of any such change. The relative portion of agriculture in the future competition for water between energy and agriculture depends to a great degree on the national policies and market conditions, which will affect the degree of Federal financing of irrigation developments such as Bureau of Reclamation storage projects.

The nature of future energy development and the water required to support it also depends in large part on national policy and international developments. Depending on the extent to which the nation decides to develop a self-sufficient energy policy and the extent to which nuclear energy is utilized in the program will greatly affect the level of coal and oil shale development occurrin in the study area in the near to intermediate future. The mix between coal-fired thermal electric power generation and synthetic fuel production will also affect the overall water requirements.

As the competition for the increasing scarce water supplies becomes more intense, a number of developments could tend to change the nature of use in several demand sectors. These generally involve the conservation and reuse of water through better management practices. Significant saving in industrial water use could be realized if dry cooling systems are installed more frequently in the future. The use of poorer quality supplies or reuse of wastewater supplies rather than high quality surface supplies represents another avenue that could affect the future industrial demand situation.

Water Supply Availability

In this section estimates are made of the total future unallocated surface water supplies in each of the hydrologic subregions by combining the total annual water supply data with water use projections for uses other than synthetic fuel production.

A summary of projected regional water availability for coal and oil shale conversion in the year 2000 is given in Table 4-16 for both the Upper Missouri River for the Upper Colorado River Basins. Projected increases for steam-electric power generation have been included in the projected depletions

TABLE 4-16. PROJECTED FUTURE WATER AVAILABILITY (YEAR 2000) IN 1000 AF/YR

	Annual Water Supply				Water Use and Commitments				
Subbasin	Natural Yield	Depleted Inflow	Imports	Total Supply	Projected Depletions	Instream Flows	Exports	Total Use	Net Water Availability
Upper Missouri River Basin									
Tongue-Rosebud	467	0	0	467	382	148	0	530	(63)
Powder	502	0	0	502	386	162	0	548	(46)
Yellowstone Mainstem	10,488	0	0	10,488	2,270	4,070	0	6,340	4,148
Belle Fourche Cheyenne	182	0	0	182	88	75	0	163	19
Heart-Cannonball	338	0	0	338	89	138	0	227	111
North Platte	1,223	520	10	1,753	1,181	501	0	1,682	71
Upper Colorado River Basin									
Upper Green	1,926	0	0	1,926	618	960	10	1,588	338
Lower Green	3,534	1,300	0	4,834	1,191	2,400	112	3,703	1,129
Upper Mainstem	6,838	0	0	6,838	1,753	3,400	620	5,773	1,065
Lower Mainstem	451	9,298	0	9,749	101	4,900	0	5,001	4,748
San Juan	2,387	0	130	2,517	1,100	1,260	113	2,473	44

in each Basin.

These summaries consist of three parts for each region: the overall water supply, water use and commitments, and the net remaining water supply. The overall water supply in a subregion consists of the natural water yield within the subregion (as previously given in Tables 4-10 and 4-12), the depleted stream inflows from other subregions, and any water imports from other subregions. Data on possible future intra-basin transfers (imports/ exports) are not specific enough to allow reliable projections of these quantities, so present water transfers have been used in these tables. Water use and commitments are made up of projected future depletions (as previously given in Tables 4-14 and 4-15 , instream flow requirements, and any water exports from out of the subregion. It has been assumed that present unused water commitments will be utilized by the year 2000 and that future use projections include these present commitments. The difference between the total available water supply and the total water use and commitments is the net water supply available for future depletion.

A number of prior studies have considered and described various energy development scenarios that may occur depending on several underlying factors such as the availability and cost of nuclear energy, foreign oil or other forms of energy[1, 14, 16, 20-25]. A summary of expected water requirements in each of the drainage sub-areas for some of these scenarios are presented in Section 6 of Appendix 14. Since these projections are highly variable, we have examined two cases of water demand. For low water demand, we have assumed that one or two standard size coal or oil shale conversion plants are located in each one of the seven drainage basins in the Upper Missouri River Basin and in each one of four drainage basins in the Upper Colorado River Basin; the total number of plants range from 12 to 24.

For high water demand, we will consider a synthetic fuels industry producing $1x10^6$ barrels/day of synthetic crude, or its equivalent in other fuels of $5.8x10^{12}$ Btu/day, in each of the three principal coal bearing regions in the West: Ft. Union, Powder River and Four Corners; and in the principal oil shale region: Green River Formation. The total production in the Western region is $4x10^6$ barrels/day. As a relative measure, in 1977, crude oil was imported at about the rate of $6x10^6$ barrels/day and distilled products at about $2x10^6$ barrels/day. Table 4-17 lists the number of standard size plants required to produce $5.8x10^{12}$ Btu/day for the conversion technology and product output indicated. The range is from 18 coal refining plants producing 10,000 tons/day of solvent refined coal to 24 coal gasification plants producing

TABLE 4-17 NUMBER OF STANDARD SIZE PLANTS REQUIRED TO PRODUCE 1×10^6 BARRELS/DAY OF SYNTHETIC CRUDE OR ITS EQUIVALENT OF 5.8×10^{12} BTU/DAY

Conversion Technology	Product	Unit Output	Number of Standard Size Plants
Coal gasification	Pipeline gas	250×10^6 scf/day	24
Coal liquefaction	Fuel oil	50,000 barrels/day	19
Coal refining	Solvent refined coal	10,000 tons/day	18
Oil shale	Synthetic crude	50,000 barrels/day	20

250×10^6 scf/day of pipeline gas. In summary, low water demand represents production of about 0.5 to 1.0×10^6 barrels/day of synthetic crude, or its equivalent, while high water demand represents production of 4×10^6 barrels/day.

The sub-areas used to report energy development and water requirements are generally different than the drainage sub-areas. In order to arrive at some consistency between the two, we have assigned drainage sub-areas to each of the coal and oil shale bearing regions in the West. This is shown in Table 4-18. In the Powder River and Ft. Union coal regions there may be some overlap of the drainage sub-areas. Low water demand requirements were determined by assuming that two standard size gasification plants were located in each of the drainage sub-areas of the coal bearing regions and two standard size oil shale conversion plants were located in three of the drainage sub-areas of the Upper Colorado River Basin The Lower Colorado River Mainstem was not considered. As will be shown in Section 5, gasification plants have the largest water consumption The water requirements for each region were calculated based on the data shown in Table 5-6 for a high degree of wet cooling. For high water demand, we have assumed that the water requirements for each of the drainage sub-areas within a coal or oil shale region are equal. The water requirements for low water demand and high water demand are given in Table 4-18 for each of the hydrologic sub-regions. We should point out these estimates are conservative because a high degree of wet cooling was assumed. In fact, as will be shown later, intermediate or minimum practical wet cooling should be primarily used in the West, reducing the water requirements given in Table 4-18 by about one-third.

Comparison of the consumptive water requirements in Table 4-18 with the water availability results in Table 4-16 gives an indication of the relative

TABLE 4-18 SUMMARY OF WATER REQUIREMENTS FOR COAL AND OIL SHALE CONVERSION IN EACH OF THE DRAINAGE SUB-AREAS (10^6 GPD OR 1000 AF/YR*)

	Low Water Demand	High Water Demand
Powder River Coal Region		
Powder (UMRB)	4	40
Yellowstone Mainstem (UMRB)	4	40
Bell Fourche-Cheyenne (UMRB)	4	40
North Platte (UMRB)	4	40
Ft. Union Coal Region		
Heart-Cannonball (UMRB)	4	50
Upper Missouri Mainstem (UMRB)	4	50
Tongue-Rosebud (UMRB)	4	50
Four Corners Coal Region		
San Juan (UCRB)	14	180
Green River Oil Shale Formation		
Upper Green (UCRB)	6	60
Lower Green (UCRB)	6	60
Upper Colorado Mainstem (UCRB)	6	60

*Based on a load factor of 90%.

adequacy of water supplies for coal and oil shale production in the drainage subbasins. Except for the Tongue-Rosebud and Powder River drainage areas, the water required for the low water demand can be accommodated by the available supplies in most of the subbasins. However, in the Belle Fourche-Cheyenne and San Juan basins the water demands for synthetic fuel production are greater than about twenty percent of the total water availability; this may be considered excessive. For high water demand, the projected loads cannot be accommodated by the available supplies in most subbasins. In the Upper Green, Heart-cannonball and North Platte subbasins, the water demands are greater than twenty percent of the total water availability. Only in the Yellowstone, Upper Missouri, Lower Green and Upper Colorado mainstem subbasins does it appear that sufficient supplies are available for the expected loads of energy production. However, it should be pointed out that water availability within the Upper Colorado River Basin may be limited because all of the water rights to most of the free flowing water in the Basins are already allocated. These rights would have to be transferred to support additional energy developments. Lack of sufficient water could be a limiting factor in the other regions unless additional supplies can be made available through surface and/or ground-water development or through the acquisition of existing rights.

Alternative Water Supply Sources

Some of the possibilities for water supply for energy conversion have been evaluated. All possibilities have not been fully evaluated, or even identified, and since the study has been performed at long distance, there may be some inaccuracies in the broad-level analysis. The evaluation of water rights is difficult without extensive field work, and for this reason, the purchase of water rights is acknowledged in many of the water supply alternatives, although no estimates are made of the prices or the different manipulations of water rights which would be necessary in any such program.

In general, there are several sources of water for large demands including groundwater, purchase of water used for irrigation, construction of storage facilities, purchase of water from existing storage facilities, and inter-basin transfers of water. Each of the alternatives given is comprised of one or more of these water sources.

The alternatives presented are compatible with those for the other river basins, even when inter-basin water transfers are involved. Thus it is possible to combine any alternative from one river basin with any project from another river basin. In several cases, projects for more than one river basin could be combined and cost efficiency increased.

A summary of the water supply alternatives for the subbasins in the Upper Missouri River and Upper Colorado River Basins is presented in Table 4-19. Comments on each subregion are given below.

Tongue-Rosebud River Basins

The Tongue River and Rosebud Creek drainage basins, adjacent to the Powder River Basin, have a high demand for the scant available water in the drainage basin. Because these rivers are both tributaries of the Yellowstone River, importations to the Tongue and Rosebud Basins from other parts of the Yellowstone Basin are permitted by the Yellowstone River Compact. There are several sites in the Basin for which reservoirs have been proposed, and these are included as possible alternatives for water supply.

TABLE 4-19 SUMMARY OF WATER SUPPLY ALTERNATIVES

Subbasin	Low Water Demand	High Water Demand
Upper Missouri River Basin		
Tongue-Rosebud	Additional storage alone, or with water rights acquisition	Additional storage or aqueduct from Bighorn or Yellowstone
Powder	Acquisition of water rights, or construct Moorhead or Lower Clear Creek Reservoir	Ultimate Powder River development, or aqueduct from Bighorn or Yellowstone
Yellowstone Mainstem	Mainstem diversion	Mainstem diversion to offline storage, or Ft. Peck Reservoir
Belle Fourche-Cheyenne	Reservoir development, or groundwater development	Reservoir and groundwater development or aqueduct from Bighorn or Yellowstone
Heart-Cannonball	Reservoir development	Aqueduct from Sakakawea or Oahe Reservoirs
Upper Missouri Mainstem	Mainstem diversion	Aqueduct from Ft. Peck, Sakakawea or Oahe Reservoirs
North Platte	Acquisition of water rights and/or groundwater development	Same Low Demand, or importtation from Green Basin
Upper Colorado River Basin		
Upper Green	Additional local storage facilities	Aqueducts from Fontenelle and/or Flaming Gorge
Lower Green	Reservoir development on the White River	White River storage plus diversion from Green River
Upper Mainstem	Diversion from the main stem to utilize existing storage	Same as Low Demand
Lower Mainstem	Although no significant energy development has been projected from the Lower Mainstem hydrologic subregion large supplies are available from Lake Powell.	
San Juan	Groundwater development and/or diversion using Navajo Reservoir storage	Diversion using all available Navajo Reservoir storage and extensive groundwater development

Powder River Basin

In general the Yellowstone and Bighorn have sufficient water supplies for all anticipated in-basin requirements, whereas the Tongue and Powder drainage basins, with the largest supplies of coal, have a more limited supply of water relative to the total demand.

Large amounts of coal lie very near the indistinct drainage divide between the Powder River and the Belle Fourche River, in the Belle Fourche River drainage basin. The water supply of the Belle Fourche is very limited, thus forcing investigation of trans-basin imports of water. However, the nearest sources of water are tributaries of the Yellowstone, subject to constraints imposed by the Yellowstone River Compact upon the export of water from the Yellowstone River.

Yellowstone and Missouri River Basins

The Yellowstone and Missouri Rivers have ample water supplies for any of the projected water demand scenarios for their entire length. Although the Yellowstone River is free-flowing for its entire length, there are two very large reservoirs on the Missouri in the area of interest, Ft. Peck Reservoir and Lake Sakakawea. Additionally, there are two reservoirs on the Bighorn River, a major tributary to the Yellowstone River, which can provide storage for water along the stretch of concern of the Yellowstone River.

Because it is still free-flowing, the Yellowstone River is presently being studied for inclusion in the Wild and Scenic Rivers Section. If it is so designated, severe restrictions will be placed on the construction of storage and water use facilities of the mainstem river.

Heart and Cannonball River Basins

The Heart and Cannonball Rivers both lie completely within North Dakota and are tributary to the Missouri River. Due to their relatively small watershed area, they both have limited streamflow. Since the drainages are adjacent and parallel to each other, with a low drainage divide between them, it is assumed the transfer of water between the basins is possible without major problems. There are no compacts concerning either of these rivers which would hinder their development from institutional considerations.

Platte River Basin

While there is a large amount of water in the Platte River Basin, it is present being used for a variety of uses, with agriculture being the largest user. In this situation there are two directions in which one can proceed to obtain the water necessary for new purposes: (1) develop new sources of water, and (2) purchase and transfer of water presently being used for other purposes. The possibility of groundwater development remains, but will not be further discussed here.

Importation of water from the Green River Basin is one of the most likely possibilities for the development of new water in the Platte Basin. There exists a large amount of storage in the North Platte Drainage Basin, but it is all currently used, primarily for agricultural purposes.

Developments in the water use of Platte River water will be closely monitored by Nebraska and significant increases in consumptive use will probably be protested.

Upper Green River Basin

The Green River in Wyoming is that state's major contributor to the Colorado River drainage. There is currently very little development in the region, and most of the water allotted to Wyoming under the terms of the Upper Colorado River Basin Compact flows unused out of the state. This means that large amounts of water in the Green River are available for development and beneficial use.

There are two reservoirs on the Green River in Wyoming, Fontenelle and Flaming Gorge, both of which are part of the Upper Colorado River Basin Storage Project. With the storage capacity of these reservoirs, adequate water supplies are available for the energy demands presently envisioned for the Green River Basin in Wyoming.

For these reasons, the anticipated source for all of the scenarios would be the Green River, with its storage capabilities in the Fontenelle and Flaming Gorge Reservoirs.

Lower Green River Basin

For each of the demand scenarios, the same sources of water exist. These are the Green River, the White River, the Colorado River and possibly the Strawberry-Duchesne Rivers. In general the Green River is seen as a probable source of water for the Utah energy requirment, with excellent storage capacity in Fontenelle and Flaming Gorge Reservoirs.

The White River is also a very good potential source of water for the Utah demand. However, the lack of a White River compact between Utah and

Colorado combined with the potential utilization of White River water in Colorado make it risky to depend on this source without assurance of continued supply in Utah.

The Colorado is seen as an unlikely source of water because of its distance from the proposed sites. The proposed Starvation Reservoir on the Strawberry River could supply a portion (about 30,000 AF) of the required amount. This would be carried by the Duchesne River, whence an aqueduct would carry to the point of use.

Upper Colorado Mainstem

There are two major surface water sources which are being considered seriously. They are the White River and the Colorado River. Either one has sufficient average annual flow to supply the major portion of the requirement. It is anticipated, however,that both rivers will be used, as the sites vary in their proximity to each river. There exists currently a large amount of storage capacity in the Colorado River, but very little in the White River. There have been several dam sites identified, but none of them are expected to be built by Federal agencies. Instead, they may be developed by private groups, such as a consortium of energy companies.

San Juan River Basin

There exist two major sources of water in the San Juan River Basin in New Mexico which could supply the amounts of water required by coal conversion plants. These are the San Juan River and groundwater. It must be realized, however, that there will be strong competition for the water from a variety of sources, among whom a very important one is the rapidly developing uranium mining and processing industry. New Mexico is one of the centers of the uranium mining and milling industry, and this industry's development will closely follow the general development of nuclear power activities in the United States and the world.

One of the most important effects of both uranium and coal mining will be the consequences of dewatering on the surrounding areas, and on the water supply picture in general. Mine dewatering will produce a large amount of water of varying qualities available for immediate consumption. However, this has the effect of mining the aquifer of its water, and could potentially have very serious and far-reaching long-term consequences. For this reason the mine dewatering will necessarily be closely monitored by the New Mexico

Department of Environmental Improvement, which is concerned mainly with the pollutional aspects. Until now, no policy has been established in New Mexico with respect to this problem. It is possible that this will change in the near future.

The San Juan River is the other major possibility for a large supply of water. A tributary of the Colorado River, it is the only major river flowing through the northwest quadrant of New Mexico. The only significant reservoir on the San Juan River is the Navajo Reservoir which has approximately 100,000 AF/year allotted for industrial purposes, most or all of which will be energy-related. This river is subject to the Colorado River Compact and the Upper Colorado River Basin Compact. Because the San Juan River is essentially the entire Colorado River drainage of New Mexico, New Mexico receives its allotment of Colorado River water from the San Juan River.

The water required for low water demand, of about 14,000 AF/year, would probably come from the Navajo Reservoir on the San Juan River, with groundwater sources as a supplement. For high water demand of 180,000 AF/year, water could also be supplied primarily from the Navajo Reservoir. However, it would require an arrangement with local Indian tribes in which part of their water allocations would be used for industrial purposes. There would be severe complications in supplying the high demand scenario, due to institutional problems of water transfer. It is not known at this time to what extent groundwater can serve as a source for the water demand. An extensive study examining this problem is currently underway by the U.S. Geological Survey.

Conclusions on Water Supply Availability

Based on the data presented earlier in this section, several conclusions can be drawn concerning the role of water availability in future energy developments in the West. It is apparent from future use projections that in most regions, actual water use other than for energy will be considerably less than the total available surface water supply. Of the remaining water, however, significant quantities may already be legally committed to other uses, or may be required for instream flow uses. In many cases, therefore, water to meet energy requirements will have to be acquired through the purchase of existing rights, diverted from major interstate rivers and piped to the point of intended use, or a combination of these.

The results of this investigation indicate that synthetic fuel plant water requirements will most easily be accomplished for those plant sites located along the main stems of the major rivers and in areas where the level of competing use is projected to be small relative to overall water availability. Subbasins in this category include the following:

1. Yellowstone River Mainstem
2. Missouri River Mainstem
3. North Platte River
4. Upper Green River
5. Upper Colorado Mainstem

Although overall water availability is generally favorable within these regions, individual plant sites may be located considerable distances away from the water sources and require major water delivery developments to transport the water to the required places.

On the other hand, in several areas the expected level of future water needs for energy development will be very difficult to meet from the available sources within the region without major disruptions to the present water use structure. Some of the most readily developable coal reserves in the Powder River and Fort Union coal formations of northeast Wyoming and North Dakota are located in basins with these characteristics. These subbasins include the following:

1. Tongue-Rosebud
2. Powder River
3. Belle Fourche-Cheyenne
4. Heart-Cannonball

In these regions the energy water requirements probably can best be met by trans-basin diversions from more adequate supplies outside the regions.

4.4 Water Supply to Chosen Sites

The water to meet energy requirements will probably have to be transported to the point of use from major interstate rivers and riverways. In this section we estimate the cost of building and operating a pipeline for a number of different water supply options. Details of the calculations are found in Appendix 15.

Figure 4-9 shows the total annual cost (expressed in terms of $/1000 gal) of building and operating a pipeline as a function of pipe diameter for a typical set of conditions. For a particular pipeline diameter and pipeline flow velocity, the total annual cost has a minimum. The total annual cost increases more rapidly for diameters smaller than the minimum cost diameter than for diameters larger than the minimum cost diameter. The friction pumping costs dominate the total costs for the former, while the pipeline construction costs dominate for the latter.

Figure 4-10 shows the minimum cost of transporting water. The capital and friction pumping costs do not include the cost of pumping against a static head. The static head pumping costs are given in the lower part of the figure and should be added to the capital and pumping costs to arrive at a total annual cost. At a flow rate of about 6×10^6 gpd, corresponding to the high end of the water requirements for a standard size coal gasification plant, the unit cost of water supply is about 2.5¢/1000 gals-mile, while for a flow rate of 60×10^6 gpd the unit cost of water supply is 0.25¢/1000 gals-mile. This illustrates the capital intensive nature of pipeline construction and operating costs and indicates that if at all possible, pipelines should be built to supply the needs of a particular region rather than a specific plant.

We have considered the case of a single pipeline supplying water to a single coal conversion plant in the Upper Missouri Basin and the Four Corners Region. We have assumed that the water supply comes from the nearest reliable water source of sufficient size. Trans-basin diversions are presumed possible. Table 4-20 lists the total cost of water conveyance for all of the plant-site combinations. The minimum distance for transporting water was 1 mile (Decker to North State Line Reservoir) and the maximum distance was 96 miles (Gallup, N.M. to San Juan River). The cost varied from $0.023/1000 gals to $3.45/1000 gals. It should be pointed out that this is the minimum cost of transporting water and does not include the purchase of water rights or the cost of the water itself.

As will be shown in Section 5, the cost of water determines the degree to which wet cooling should be used. At a site where water is plentiful and inexpensive to transport, high wet cooling would be used. In regions where water is marginally available or moderately expensive to transport, intermediate cooling would be used, and where water is expensive to transport or scarce, minimum practical wet cooling would be used. High wet cooling does not mean

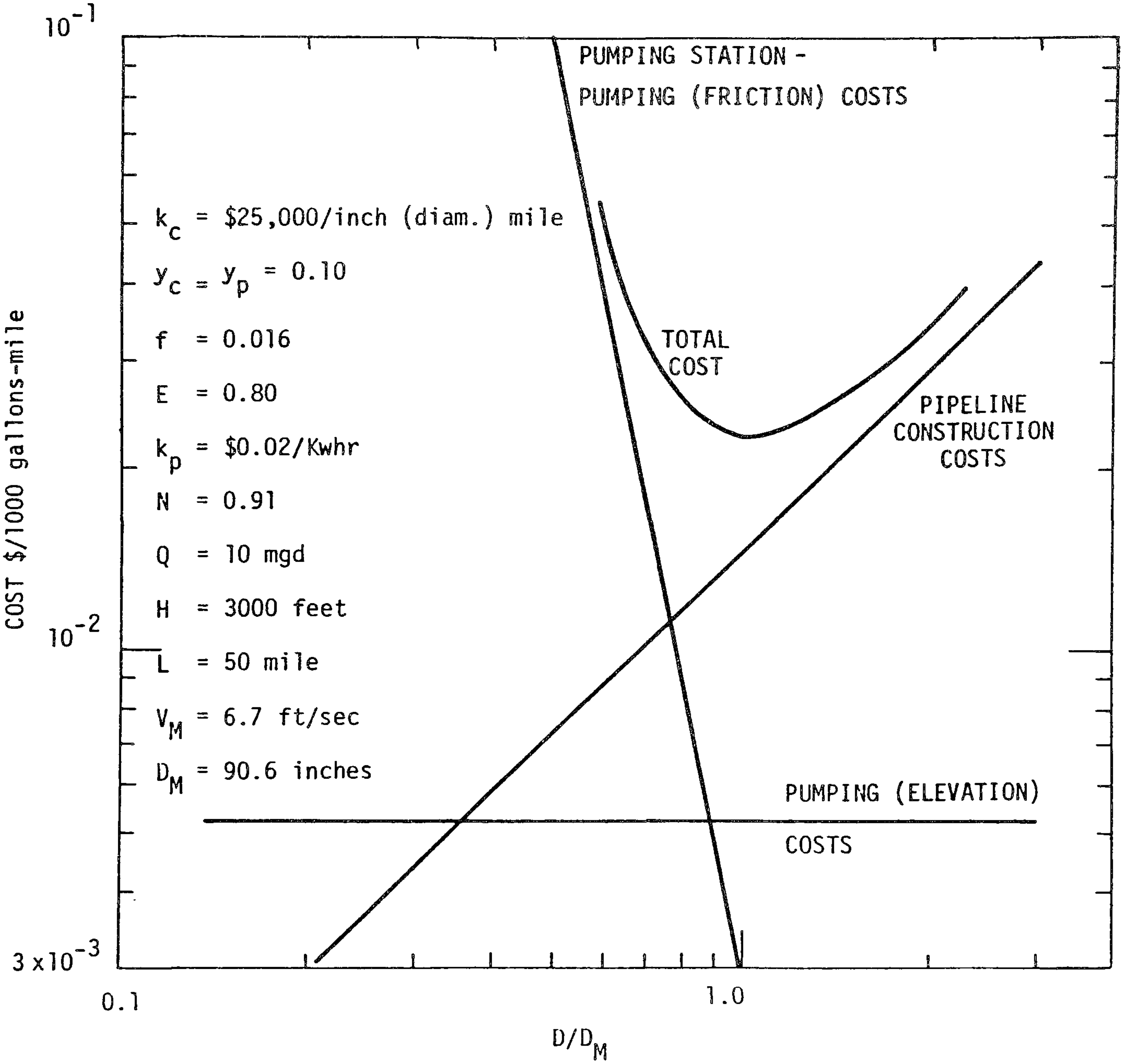


Figure 4-9 Total annual costs for transporting water as a function of pipe diameter.

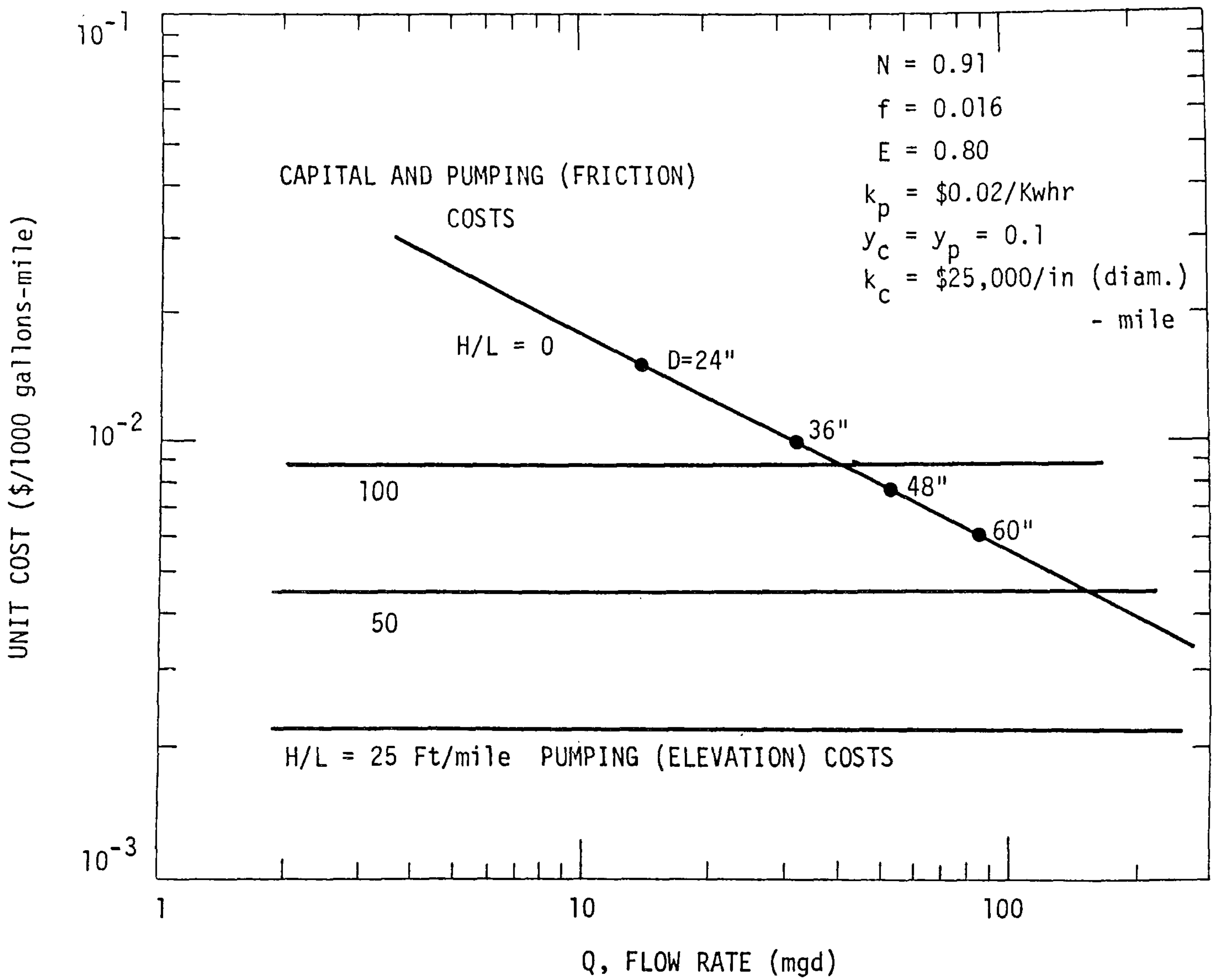


Figure 4-10 Unit cost of water supply

TABLE 4-20. LOCAL SUPPLY TO INDIVIDUAL PLANTS

Location	Water Source	Distance (miles)	Static Head (feet)	Total Cost $/1000 gals	Total Cost $/acre-ft
Beulah	Lake Sakakawea	16	50	0.43	140
Williston	Lake Sakakawea	8	250	0.16	53
Center	Missouri River	16	300	0.37	120
Underwood	Lake Sakakawea	8	150	0.13	43
U.S. Steel	Yellowstone River	10	600	0.26	83
Coalridge	Medicine Lake	16	400	0.40	130
Gillette	Crazy Woman Creek	45	940	1.20 1.26	390 411
Antelope Creek	Beaver Creek Reservoir	72	1000	1.90 2.08 2.03	620 678 661
Lake-de-Smet	Lake-de-Smet	5	200	0.12	39
Spotted Horse	Clear Creek Reservoir	16	400	0.47	154
E.Moorhead	Moorhead Reservoir	22	700	0.61	198
Decker Cr.	North State Line Reservoir	1	50	0.03 0.02	8 7
Otter Cr.	Moorhead Reservoir	20	200	0.48	156
Foster Cr.	Tongue River	16	350	0.43	139
Pumpkin Cr.	Tongue River	24	600	0.60	197
Colstrip	Yellowstone River	28	700	0.74 0.66 0.67	241 216 220
Belle Ayr	Crazy Woman Reservoir	54	850	1.37	446
Slope	Mott Reservoir	44	350	1.32	431
Dickinson	Mott Reservoir	50	100	1.29	420
Bentley	Mott Reservoir	10	150	0.26	86
Scranton	Thunderhawk Reservoir	42	550	0.91	295
Hanna	Seminoe Reservoir	20	100	0.43	140

Continued

TABLE 4-20. (concluded)

Location	Water Source	Distance (miles)	Static Head (feet)	Total Cost $/1000 gals	Total Cost $/acre-ft
Kemmerer	Fontanelle Reservoir	70	900	1.53	505
				2.13	695
Jim Bridger	Flaming Gorge Reservoir	18	400	0.50	164
				0.44	144
Rainbow #8	Flaming Gorge Res.	18	500	0.37	121
Gallup	San Juan River	96	1800	2.52	823
				2.54	827
				2.25	732
Wesco	San Juan River	30	400	0.66	213
El Paso	San Juan River	50	800	1.23	401
				1.10	358

that all of the unrecovered heat is dissipated by wet cooling, since an appreciable fraction will be lost directly to the atmosphere. Minimum practical wet cooling does not mean that none of the unrecovered heat is dissipated by dry cooling, since this is not economical. The largest difference in total net water consumed occurs between high wet cooling and intermediate cooling; there is very little difference in water consumption between intermediate wet cooling and minimum practical wet cooling. If water costs more than $1.50/1000 gals, minimum practical cooling would be used. Intermediate wet cooling would be used if the water cost is between $0.25/1000 gals to $1.50/1000 gals, while high wet cooling would be used if water costs less than $0.25/1000 gals.

On Figure 4-10 we have shown those sites where the cost of transporting water to the site for a standard size plant is less than $0.25/1000 gals and greater than $1.50/1000 gals. It is clear that except for plants located near the main stem of the major rivers, intermediate cooling would be desirable for a large majority of the sites in the Upper Missouri Basin and the Four Corners Region. In general we could extend this result to the Upper Colorado River Basin, as a whole.

If a large scale synthetic fuel industry is to be developed in the West, large quantities of water will be required. It is clear that it is more economical to have a large single pipeline built to transport water to a large number of plants than to have a large number of individual pipelines supplying individual plants. Table 4-21 shows the total cost of transporting water for a number of mine groupings for 50, 100, 150 and 300×10^6 gpd; the cost does not exceed $1.63/1000 gals for all the cases that we have considered.

In the previous section we showed that the water requirements for high water demand for each of the drainage sub-areas is about 50×10^6 gpd, except in the Four Corners Region where the demand would be about 180×10^6 gpd. Figure 4-12 shows the cost of transporting these quantities of water to some of the major coal producing regions. Here again, except for large scale development near the main stems of the major rivers, intermediate cooling would be desirable for most of the study sites.

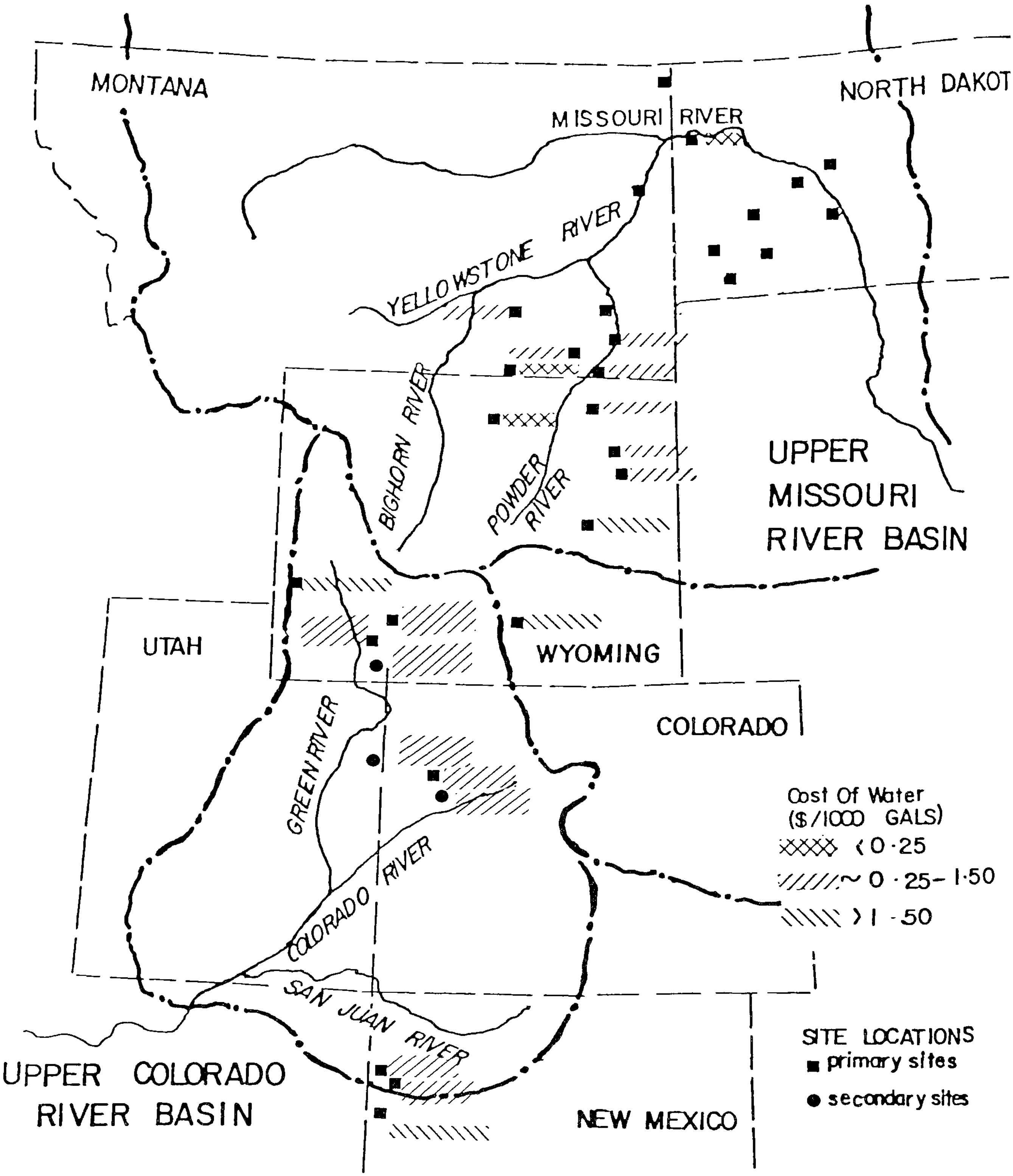


Figure 4-11 Cost of transporting water to specific site locations.

TABLE 4-21. LARGE SCALE WATER CONVEYANCE COSTS

Location	Group of Mines	Water Source	Distance (miles)	Static Head (feet)	Flow (mgd)	Total Cost $/1000 gals	Total Cost $/acre-ft
Midpoint between Wesco and El Paso	Wesco, El Paso	Navajo Reservoir via San Juan River	38	500	50	0.35	115
					100	0.26	86
					150	0.22	73
					300	0.17	56
Highlight	Gillette, Belle Ayr, Antelope Creek	Boysen Reservoir	150	0	50	1.22	398
					100	0.86	281
					150	0.71	230
					300	0.50	163
Rock Springs	Jim Bridger, Rainbow #8	Green River	14	400	50	0.15	49
					100	0.12	38
					150	0.10	33
					300	0.08	27
Gillette	Foster, Pumpkin, Moorhead, Spotted Horse, Gillette, Belle Ayr, Antelope Creek	Boysen Reservoir	180	-253	50	1.47	478
					100	1.04	338
					150	0.85	276
					300	0.60	195
		Yellowstone at Miles City	165	2300	50	1.55	505
					100	1.16	376
					150	0.98	319
					300	0.75	246
		Bighorn River at Hardin	180	1840	50	1.63	531
					100	1.20	391
					150	1.01	329
					300	0.76	249
Stanton	Center, Underwood, Knife River	Lake Sakakawea	14	100	50	0.12	40
					100	0.09	29
					150	0.07	24
					300	0.06	18

TABLE 4-21. (concluded)

Location	Group of Mines	Water Source	Distance (miles)	Static Head (feet)	Flow (mgd)	Total Cost $/1000 gals	Total Cost $/acre-ft
Stanton	Center, Underwood, Knife River	Missouri River	1	0	50	0.008	3
					100	0.006	2
					150	0.005	2
					300	0.003	1
DeSart	Slope, Scranton, Bentley, Dickinson	Lake Sakakawea	86	900	50	0.78	254
					100	0.58	188
					150	0.48	158
					300	0.37	119
		Lake Oahe	120	1100	50	1.08	351
					100	0.79	257
					150	0.66	216
					300	0.50	162
		Yellowstone River at Glendive	122	700	50	1.06	344
					100	0.77	326
					150	0.64	207
					300	0.47	152
Loesch	Foster Creek, Pumpkin Creek	Yellowstone River at Miles City	60	850	50	0.56	184
					100	0.42	137
					150	0.36	117
					300	0.28	90
Quietus	Decker, Otter Creek, Moorhead, Spotted Horse	Yellowstone River at Miles City	108	1900	50	1.05	342
					100	0.79	258
					150	0.68	221
					300	0.53	172
		Bighorn River at Hardin	102	1400	50	0.96	311
					100	0.71	232
					150	0.60	197
					300	0.46	151

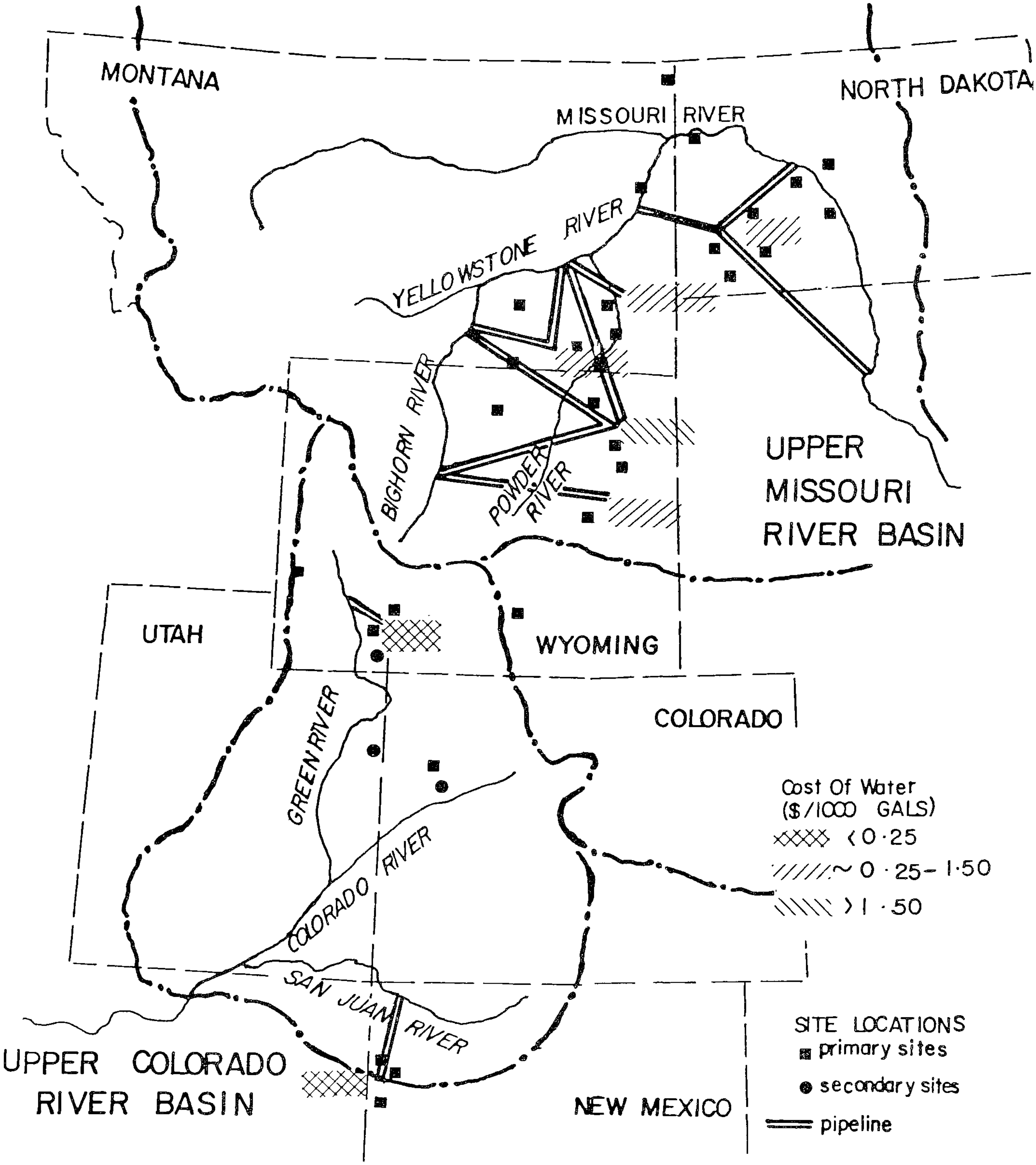


Figure 4-12 Cost of transporting water to coal regions.

References - Section 4

1. Energy Research and Development Administration, "Alternative Fuels Demonstration Program. Final Environmental Impact Statement", ERDA-1547, Washington, D.C., September 1977.

2. Harte, J. and El-Gasseir, M., "Energy and Water", Science, 199, February 10, 1978.

3. Brill, E.D., Jr. et al, "Issues Related to Water Allocation in the Lower Ohio River Basin," Vol III-G, Ohio River Basin Energy Study, U.S. Environmental Protection Agency, Washington, D.C., May, 1977.

4. Smith, W.H. and Stall, J.B., "Coal and Water Resources for Coal Conversion in Illinois," Cooperative Resources Report No. 4, Illinois State Water Survey and Illinois State Geological Survey, Urbana, Illinois, 1975.

5. U.S. Department of the Interior, "Report on Water for Energy in the Upper Colorado River Basin," U.S. Gov't. Printing Office, Washington, D.C., 1974.

6. U.S. Department of the Interior, "Report on Water for Energy in the Northern Great Plains Area with Emphasis on the Yellowstone River Basin," U.S. Gov't. Printing Office, Washington, D.C., 1975.

7. Northern Great Plains Resources Program, "Report of the Work Group on Water," Denver, Colorado, Dec. 1974.

8. U.S. Department of the Interior, "Westwide Study Report on Critical Water Problems Facing the Eleven Western States," U.S. Gov't. Printing Office, Washington, D.C., 1975.

9. Geraghty, J.J., Miller, D.W., Leeden, F., Von Der and Troise, F.L., Water Atlas of the United States. Water Information Center, Port Washington, New York, 1973.

10. Ohio River Basin Commission, "The Ohio Mainsteam-Water and Related Land Resources Study Report and Draft Environmental Impact Statement," Cincinnati, Ohio, January 1978.

11. Bloyd, R.M., Jr., "Summary Appraisal of the Nation's Groundwater Resources-Ohio River," U.S.G.S. Professional Paper 813-A, 1974.

12. Week, J.B., Leavesley, G.H., Weider, F.A. and Saulnier, G.J., Jr., "Simulated Effects of Oil-Shale Development on the Hydrology of the Piceance Basin, Colorado," Geological Survey Professional Paper 908, U.S. Gov't. Printing Office, Washington, D. C. 1974.

13. Price, D. and Arnow, T., "Summary Appraisals of the Nation's Groundwater Resources-Upper Colorado Region," Geological Survey Professional Paper 813-C, U.S. Gov't. Printing Office, Washington, D. C., 1974.

14. "Wyoming Framework Water Plan," Wyoming State Engineer's Office, 1973.

15. "Water Use in Montana", Montana Department of Natural Resources and Conservation, Inventory Report No. 13, Helena, Montana, April 1975.

16. "Analysis of Energy Projections and Implications for Resource Requirements," Harza Engineering Company, 1976.

17. Office of Business Economics, U.S. Department of Commerce; and Economic Research Service, U.S. Department of Agriculture field data.

18. "Upper Colorado Region Comprehensive Framework Study, Appendix X, Irrigation and Drainage", Upper Colorado Region State-Federal Interagency Group, 1971.

19. Climatic Atlas of the United States, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, 1974.

20. "Energy from the West: A Progress Report of a Technology Assessment of Western Energy Resource Development," Science and Public Policy Program, Univ. of Oklahoma, EPA-600/7-77-072, July, 1977.

21. National Petroleum Council, Committee on U.S. Energy Outlook, "Coal Availability," 1973.

22. National Petroleum Council, Committee on U.S. Energy Outlook, "Oil Shale Availability," 1973.

23. Federal Energy Administration, Interagency Task Force on Synthetic Fuels from Coal, "Project Independence Blueprint-Synthetic Fuels from Coal," U.S. Gov't. Printing Office, Stock No. 4118-00010, Washington, D.C., November, 1974.

24. Federal Energy Administration, "Project Independence Report," U.S. Gov't. Printing Office, Stock No. 4118-00029, Washington, D.C., November, 1974.

25. Commerce Technical Advisory Board, "CTAB Recommendations for a National Energy Program," U.S. Department of Commerce, U.S. Gov't. Printing Office, Washington, D.C., 1975.

26. West,S.W., "The Role of Groundwater in Resource Planning in the Western United States," U.S. Geological Survey, Western U.S. Water Plan,Working Document, Open File Report 74-125, Denver, Colorado, March 1975.

5. WATER REQUIREMENTS AND RESIDUALS

5.1 Total Water Consumed and Residuals Generated

In this section the total water consumed and wet solid residuals generated in standard size mine-plant complexes located in the principal coal and oil shale bearing regions of the United States are summarized. The totals are summarized by conversion technology for the United States as a whole with no distinction made between coal rank; and then for each coal and oil shale region. In the four sections following this one the totals are broken down into a number of water use categories and each category is summarized by conversion technology and region. The details of the various analyses and calculations that we have performed in arriving at the summary tables and graphs have been omitted in this section. They can be found in the Appendix volume of this report.

Water consumption is based on net water consumption. All effluent streams are assumed to be recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated process condensate waters and the highly saline water blown down from the cooling system. Water is released to evaporation ponds as a method of salt disposal. However, we have generally assumed that the highly saline waters can be disposed of with the coal ash. We have not considered the recovery of water from the drying of high moisture content coal such as lignite, because the costs are high, in the range of $1.30 to $1.50 per 1000 gallons[2]. However, recovery is a serious possibility when water is particularly scarce, especially in the West. The rest of the water leaves the plant as vapor, as hydrogen in the hydrocarbon products, or as occluded water in the solid residues. Dirty water is cleaned but only for reuse and not for returning it to a receiving water. No waters are returned to the receiving waters. The totals for wet-solid residuals include the solid residue as well as the occluded water in the solid residue.

In selecting the various process-site combinations for study (Section 3), we considered the following process criteria: (a) low temperature gasifiers and (b) high temperature gasifiers for converting coal to pipeline gas, (c) coal refining to produce a de-ashed low sulfur solvent refined coal and liquefaction to convert coal to low sulfur fuel oil and (d) direct and indirect surface retorting for converting oil shale to synthetic crude. The results are summarized by conversion technology, as shown in Table 3-3, as well as by the processes chosen to illustrate them. In addition, the results are presented by coal and oil shale region and by coal rank within each region in contrast to a breakdown by state, as was done in Section 3. Table 5-1 shows the sites comprising each major coal and oil shale bearing region.

Mining Rates

The daily coal and oil shale mining rates for a standard size synthetic plant are summarized in Table 5-2 for each rank of coal and for high grade shale with no distinction made between sites. The coal mining rates vary from approximately 13,000 to 45,000 tons per day, reflecting the variation in the heating value of the different rank coals, while from 73,000 to 105,000 tons per day of oil shale are mined. The daily mining rates are also given per unit of heating value in the product fuel enabling the results to be scaled to plant sizes different than the standard size plants.

In Tables 5-3 and 5-4 the daily coal and oil shale mining rates are given by coal and oil shale region (Table 5-1). For a limited number of process-region-coal rank combinations not covered in this study, we have used the results given in Ref. 1.

Total Net Water Consumed

Table 5-5 summarizes the total net water consumed for three different cooling options for all of the conversion technologies and processes studied. The range in the total water consumed reflects the variation with site. The three cooling options represent different levels of wet evaporative cooling which are used based on the availability and cost of water. Below we will define more quantitatively the levels of cooling (also see Appendix 7). For oil shale only intermediate cooling was considered.

TABLE 5-1 STUDY SITES COMPRISING COAL AND OIL SHALE BEARING REGIONS

Coal Region	Coal Conversion: Coal Rank	Coal Conversion: Site
East and Central States		
Appalachian	Lignite	Marengo, Alabama
	Bituminous	Jefferson, Alabama Floyd, Kentucky Harlan, Kentucky Pike, Kentucky Ohio (all sites) Pennsylvania (all sites) West Virginia (all sites)
Illinois	Bituminous	Illinois (all sites) Indiana (all sites) Mulhlenberg, Kentucky
Western States		
Four Corners	Subbituminous	New Mexico (all sites)
Powder River and Fort Union	Lignite	U.S. Steel Chupp Mine, Montana Coalridge, Montana East Moorhead, Montana Otter Creek, Montana Pumpkin Creek, Montana North Dakota (all sites)
	Subbituminous-Bituminous	Colstrip, Montana Decker, Montana Foster Creek, Montana Wyoming (all sites)

Oil Shale Region	Oil Shale Conversion: Shale	Oil Shale Conversion: Site
Western States		
Green River Formation	High Grade	Parachute Creek, Colorado

TABLE 5-2 COAL AND OIL SHALE MINING RATES FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	1000 tons/day			100 lb/10^6 Btu		
Conversion Technology	Lignite	Subbituminous	Bituminous	Lignite	Subbituminous	Bituminous
Coal Gasification						
Lurgi	29.7-43.3	19.4-26.0	16.7-19.4	2.5-3.6	1.6-2.2	1.4-1.6
Synthane	-	22.1-23.7	16.1-18.6	-	1.8-2.0	1.3-1.6
Hygas	24.5-29.2	14.6-21.4	13.6-16.8	2.0-2.4	1.2-1.8	1.1-1.4
Bigas	26.3-32.1	-	13.1-16.6	2.2-2.7	-	1.1-1.4
Coal Liquefaction						
Synthoil	-	18.9-25.7	14.9-18.4	-	1.2-1.7	1.0-1.2
Coal Refining						
SRC	28.2-44.8	25.3-28.9	18.9-21.9	1.8-2.8	1.6-1.8	1.2-1.4
	High Grade Shale			High Grade Shale		
Oil Shale						
Paraho Direct	92			6.3		
Paraho Indirect	105			7.2		
TOSCO II	73			5.0		

TABLE 5-3 REGIONAL SUMMARY OF COAL AND OIL SHALE MINING RATES IN 1000 TONS PER DAY FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners	Green River Formation
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification							
Lurgi	16.2*	43.3	17.4-19.4	16.7-26.2	29.7-35.1	19.4-26.0	-
Synthane	16.1-18.6	-	17.5-17.8	22.1-23.7	30.5*	25.9*	-
Hygas	13.6-16.8	29.2	16.0-16.8	15.4-21.4	24.5	14.6-19.3	-
Bigas	-	-	15.1-16.6	13.1	26.3-32.1	-	-
Coal Liquefaction							
Synthoil	14.9-16.7	-	17.5-18.4	24.7-25.7	31.6*	18.9	-
Coal Refining							
SRC	18.3*	44.8	18.9-21.9	19.9-28.9	28.2-42.8	28.3*	-
Oil Shale							
Paraho Direct	-	-	-	-	-	-	92
Paraho Ind.	-	-	-	-	-	-	105
TOSCO II	-	-	-	-	-	-	73

*From data in Ref. 1

TABLE 5-4 REGIONAL SUMMARY OF COAL AND OIL SHALE MINING RATES NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN 100 LBS/10^6 BTU

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners	Green River Formation
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification							
Lurgi	1.4*	3.6	1.5-1.6	1.4-2.2	2.5-2.9	1.6-2.2	-
Synthane	1.3-1.6	-	1.5	1.8-2.0	2.5*	2.2*	-
Hygas	1.1-1.4	2.4	1.3-1.4	1.3-1.8	2.0	1.2-1.6	-
Bigas	-	-	1.3-1.4	1.1	2.2-2.7	-	-
Coal Liquefaction							
Synthoil	1.0-1.1	-	1.1-1.2	1.6-1.7	2.0*	1.2	-
Coal Refining							
SRC	1.1*	2.8	1.2-1.4	1.2-1.8	1.8-2.7	1.8*	-
Oil Shale							
Paraho Direct	-	-	-	-	-	-	6.3
Paraho Ind.	-	-	-	-	-	-	7.2
TOSCO II	-	-	-	-	-	-	5.0

*From data in Ref. 1

TABLE 5-5 SUMMARY OF NET WATER CONSUMED FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	Total Water Consumed (10^6 gpd)			Total Water Consumed (gal/10^6 Btu)		
	High Wet Cooling	Intermediate Cooling	Minimum Practical Cooling	High Wet Cooling	Intermediate Cooling	Minimum Practical Cooling
Coal Gasification						
Lurgi	4-7	2-5	2-5	18-30	9-22	7-21
Synthane	5-6	4	4	22-27	16-19	15-17
Hygas	5-6	4-5	4-5	21-26	16-19	15-19
Bigas	6	4	3-4	25-27	16-18	14-17
Coal Liquefaction						
Synthoil	5-6	3-5	3-4	17-21	11-14	10-14
Coal Refining						
SRC	4-7	3-4	2-4	13-21	8-13	7-11
Oil Shale						
Paraho Direct		5			18	
Paraho Indirect		8			28	
TOSCO II		8			29	

The water requirements for standard size plants range from 4 to 7 x 10^6 gpd for coal gasification and coal refining and from 3 to 6 x 10^6 gpd for coal liquefaction; the range of net water consumed for oil shale conversion is 5 to 8 x 10^6 gpd.

In order to explain the similarities and differences in net water consumed between the conversion technologies it is necessary to examine the totals on a regional basis (Tables 5-6 and 5-7). As we have done previously, data from Ref. 1 has been added for a limited number of cases. We should note that a larger percentage of the unrecovered heat in the Lurgi process is dissipated by wet cooling in Ref. 1 as compared to the present study, while for the SRC process the overall conversion efficiency is lower in the present study than that assumed in Ref. 1, resulting in larger wet cooling loads. However, the data of Ref. 1 presents a useful data base for the present study. Figures 5-1, 5-2 and 5-3 show a breakdown of the average net water consumption by region and by process and for the three cooling options. Four water use categories are presented for each coal conversion process in each region: net process water based on reuse of all condensate; cooling water, flue gas desulfurization water, if necessary; and water for mining, dust control, solids disposal, water treatment, revegetation and other uses. For oil shale it is most convenient to break down the water use categories in a slightly different way to reflect the large quantities of water required for spent shale disposal: net process water for retorting and upgrading; cooling water; water for spent shale disposal and revegetation; and water for dust control, mining and other uses. For the cases where the net process water is negative (i.e., net water is produced in the process), the cooling water requirements can be obtained from Figures 5-1,-2,-3 by adding the absolute value of the process water to the cooling water component.

Except for the Hygas process, the net water consumed for the Four Corners region is higher than for the other regions because of the larger amount of water needed for dust control and the handling of ash for the high ash Navajo, New Mexico coal. Water is required for revegetation in New Mexico because the rainfall is less than 10 inches per year, but is not required at any other location. For the Hygas process there are many competing demands which make the above generalization invalid.

TABLE 5-6 REGIONAL SUMMARY OF NET WATER CONSUMED IN 10^6 GPD FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	Appalachian Region						Illinois Region			Powder River/Ft. Union Regions						Four Corners			Green River Formation
	Bituminous			Lignite			Bituminous			Subbituminous-Bituminous			Lignite			Subbituminous			Oil Shale
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	2
Coal Gasification																			
Lurgi	6.4*	5.7*	4.3*	4.3	2.1	1.7	6.2-6.8	4.5-5.0	4.1-4.7	5.6-6.9	3.7-5.1	3.3-4.8	5.3-5.7	3.3-3.6	2.9-3.2	7.0-7.2	5.1-5.3	4.7-4.9	-
Synthane	5.2-5.7	3.8-4.2	3.6-3.9	-	-	-	5.3-5.5	3.9-4.1	3.6-4.1	6.0-6.4	4.1-4.4	3.7-4.1	5.7*	3.5*	3.1*	6.5*	4.1*	3.8*	-
Hygas	5.6-6.1	4.3-4.6	4.2-4.5	5.0	3.7	3.5	5.8-5.9	4.5-4.6	4.3-4.5	4.9-5.4	3.7-4.2	3.5-4.0	5.0	3.8	3.6	5.4-5.5	4.2-4.3	4.0-4.1	-
Bigas	-	-	-	-	-	-	6.0-6.4	3.9-4.2	3.5-3.9	5.9	3.7	3.4	6.3-6.5	4.2-4.3	3.9-4.0	-	-	-	-
Coal Liquefaction																			
Synthoil	5.5-6.4	3.9-4.7	3.6-4.4	-	-	-	5.7-5.8	4.0-4.1	3.7-3.8	5.2-5.3	3.3-3.4	3.0-3.1	6.1*	4.3*	4.0*	6.0-6.7*	4.3-5.1*	4.0-4.8*	-
Coal refining																			
SRC	3.2*	1.8*	1.7*	6.6	3.9	3.4	4.7-5.5	3.2-4.0	2.9-3.7	4.3-4.9	2.6-3.0	2.3-2.6	4.9-6.5	2.9-3.7	2.5-3.1	4.8*	3.4*	3.3*	-
Oil Shale																			
Paraho Direct																			5.1
Paraho Indirect																			8.2
TOSCO II																			8.3

1 = High Wet Cooling, 2 = Intermediate Wet Cooling, 3 = Minimum Practical Wet Cooling
*Data from Ref. 1; only applies to particular number and not range.

TABLE 5-7 REGIONAL SUMMARY OF NET WATER CONSUMED NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN GAL/10^6 BTU

	Appalachian Region						Illinois Region			Powder River/Ft. Union Regions						Four Corners			Green River Formation
	Bituminous			Lignite			Bituminous			Subbituminous-Bituminous			Lignite			Subbituminous			Oil Shale
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	2
Coal Gasification																			
Lurgi	27*	24*	18*	18	9	7	25-28	19-21	17-19	23-29	15-21	14-20	22-24	14-15	12-13	29-30	21-22	20-21	-
Synthane	22-24	16-17	15-16	-	-	-	22-23	16-17	15-16	25-27	17-19	16-17	24*	15*	13*	28*	18*	16*	-
Hygas	23-26	18-19	17-19	21	16	15	24-25	19-20	18-19	21-23	16-18	15-17	21	16	15	23	18	17	-
Bigas	-	-	-	-	-	-	25-27	16-18	15-16	24	16	14	26-27	18	16-17	-	-	-	-
Coal Liquefaction																			
Synthoil	18-21	13-15	12-14	-	-	-	19	13	12	17	11	10	19*	14*	13*	20-22*	14-16*	13-16*	-
Coal Refining																			
SRC	11*	7*	6*	21	12	11	15-17	10-13	9-12	13-15	8-9	7-8	15-21	8-9	7-8	15*	11*	10*	-
Oil Shale																			
Paraho Direct																			18
Paraho Indirect																			28
TOSCO II																			29

1 = High Wet Cooling, 2 = Intermediate Wet Cooling, 3 = Minimum Practical Wet Cooling

* Data from Ref. 1; only applies to particular number and not range.

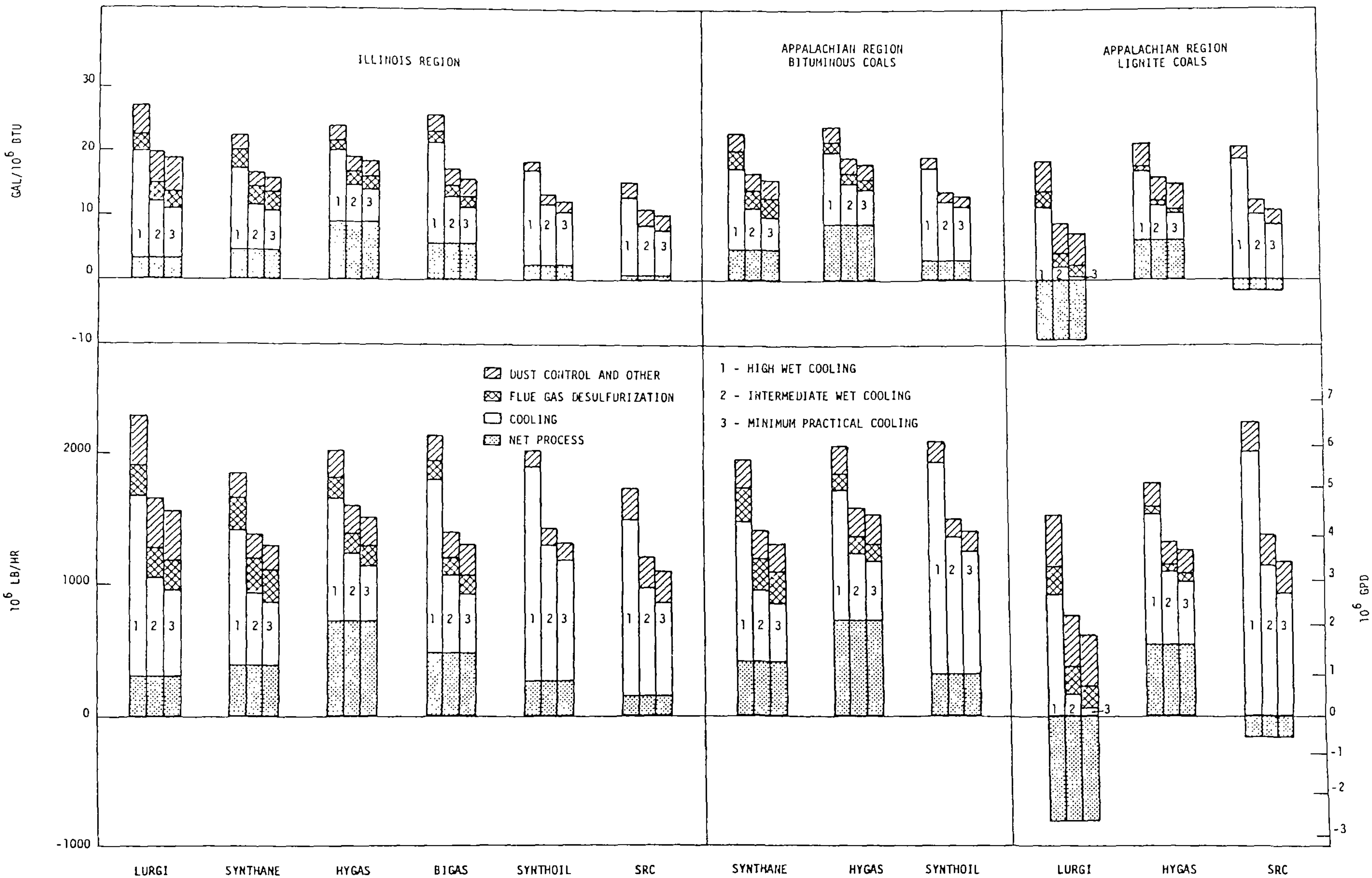


Figure 5-1 Summary of average net water consumed for standard size coal conversion plants located in the Central and Eastern states

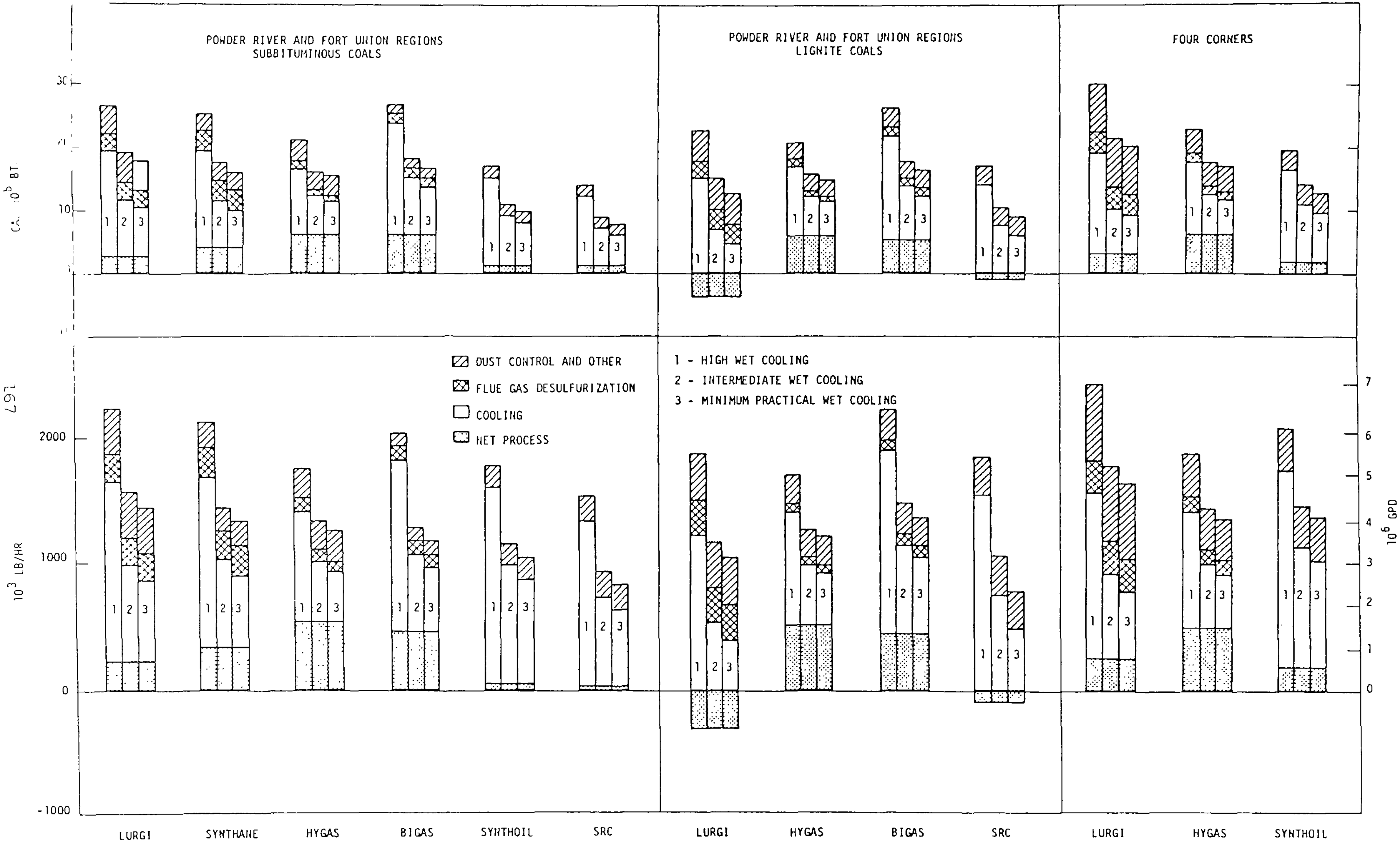


Figure 5-2 Summary of average net water consumed for coal conversion plants located in the Western states

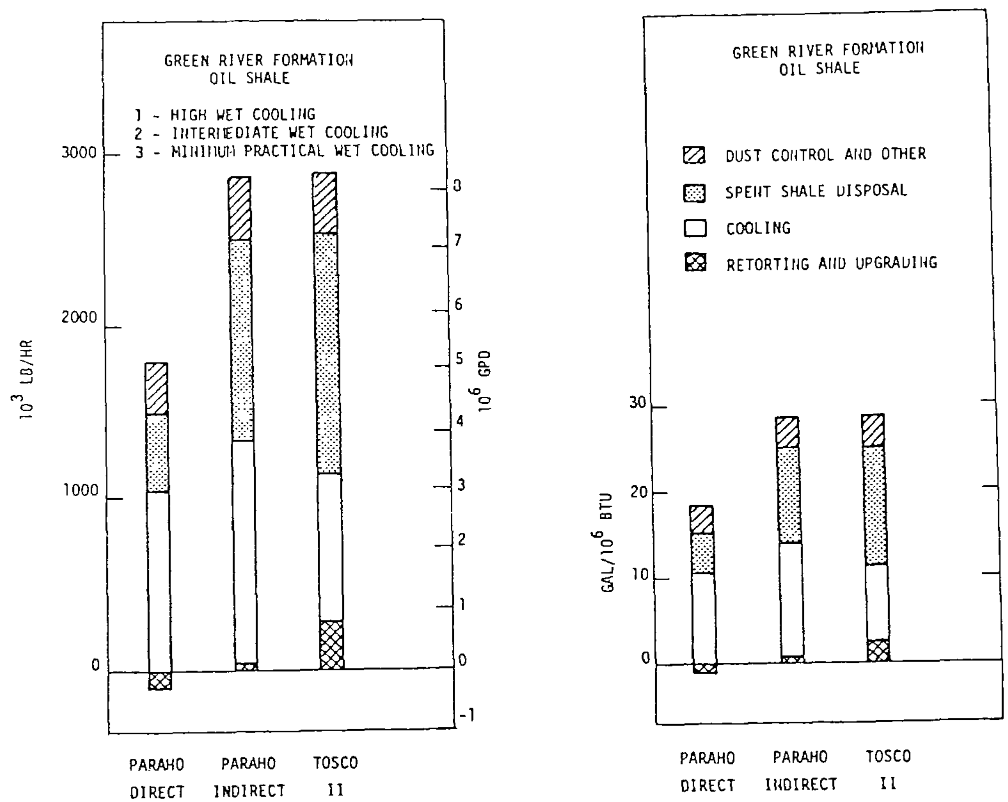


Figure 5-3 Summary of net water consumed for oil shale conversion plants located in the Western states

In the Illinois coal region, the average water requirements for coal gasification are relatively insensitive to the particular conversion process, with the variation being no more than 15 percent for the high and intermediate wet cooling options and no more than 25 percent for the minimum practical wet cooling option. The water required for coal gasification is larger than that for coal liquefaction which, in turn, is larger than that for coal refining. The water requirements range from a low of 9 gal/10^6 Btu to a high of 28 gal/10^6Btu, greater by more than a factor of three. In the Appalachian coal region the water requirements (normalized with respect to the heating value of the product fuel) for coal gasification are higher than those for coal liquefaction for plants utilizing bituminous coal; for plants utilizing lignite coal, the water requirements for coal gasification are slightly lower than those for coal refining. In the latter case this can be attributed to the high moisture content of the lignite coals and the very large quantities of process water produced in the Lurgi process. The Lurgi process accepts wet coal and the large quantities of dirty condensate produced are treated for reuse (at a cost) and are subtracted from the process requirement. We should also point out that the net water consumed in the Synthane, Hygas and Synthoil processes is virtually identical in both the Illinois and Appalachian coal regions for bituminous coals. However, the net water consumed in the SRC process is higher for lignite coals than for bituminous coals because of the lower conversion efficiency attributed to the larger quantity of energy required for drying the higher moisture lignite coals prior to dissolution. The slight difference in the results for the Hygas process is due to the different process water requirements for lignite and bituminous coals.

For each of the three basin-coal combinations in the West, the net water requirements are largest for coal gasification, followed in turn by coal liquefaction and coal refining (see Figure 5-2). The larger requirement for the Four Corners region is attributed to the high ash Navajo, New Mexico coal. In the Powder River and Ft. Union coal regions the average wet water requirements for the Lurgi, Hygas and Bigas processes are virtually identical for lignite and subbituminous coals. The differences in the SRC water requirements between the lignite and subbituminous coals are attributed to the large difference between the moisture content of the two coals.

The net water requirements for the Synthoil and oil shale plants can be compared since the products are roughly the same. The water consumed in the Synthoil and Paraho Direct processes is about equal. However, the water consumed in the two indirect heated oil shale processes is 60 percent higher due mainly to the larger requirements for spent shale disposal and revegetation.

Differences in water consumption between the Illinois coal region and the Powder River and Fort Union regions for subbituminous coals for a given coal conversion process are relatively small, being no more than 15 percent with the absolute difference being no more than 2.5 gal/10^6 Btu. However, for lignite coals, differences between the Appalachian coal region and the Powder River and Ft. Union regions are much larger, the maximum being about 6 gal/10^6 Btu for the Lurgi process and 4 gal/10^6 for the SRC process, with the Lurgi water requirements being smaller in the Appalachian region and the SRC requirements being smaller in the Powder River and Ft. Union regions.

In a particular coal bearing region, differences in the water requirements for the four coal gasification processes that we have considered are due principally to the differences in the process water requirement and the differences in the estimated overall efficiency resulting in different cooling water requirements.

Total Wet Solid Residuals Generated

Solid residuals generated in coal and oil shale conversion plants are generally disposed of wet with occluded water. Table 5-8 summarizes the total wet solid residuals generated in the standard size plants with no distinction made between sites, but with overall ranges given. Also shown are the residuals normalized with respect to the heating value in the product fuel. The principal residuals in coal conversion plants are coal ash, and where flue gas scrubbing is used, the flue gas desulfurization sludge. In the oil shale plants the principal residual is the spent shale. Sludges from water treatment plants have also been considered. Between 3 to 15 x 10^3 tons/day of wet solids are disposed of for coal gasification plants, 1 to 4 x 10^3 tons/day for coal liquefaction plants, and from 2 to 6 x 10^3 tons/day for coal refining plants. Outstripping all of the coal conversion residuals by an order of

TABLE 5-8 SUMMARY OF WET SOLIDS RESIDUALS GENERATED FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	Total Wet Solids	
	10^3 tons/day	lb/10^6 Btu
Coal Gasification		
Lurgi	7 - 15	59 - 126
Synthane	5 - 7	40 - 56
Hygas	4 - 8	32 - 64
Bigas	3 - 7	27 - 61
Coal Liquefaction		
Synthoil	1 - 4	7 - 28
Coal Refining		
SRC	2 - 6	12 - 40
Oil Shale		
Paraho Direct	76	520
Paraho Indirect	104	630
TOSCO II	68	470

magnitude are those from oil shale processing where the primary residual is spent shale.

The quantity of the residuals depends on: the ash content of coal, the salt content of the source water, and the sulfur content of coal when flue gas desulfurization is used on coal-burning plant boilers. The maximum residuals produced by each process depends on the site. The largest quantities of residuals for the Lurgi, Hygas and Synthoil processes occur in those areas having the highest ash coals, i.e., Jefferson, Alabama (16.9% ash) and El Paso (19.2% ash) and Wesco (25.6% ash), New Mexico. For the Synthane and SRC processes the largest residuals are generated at those sites utilizing groundwater. For the Bigas process the quantities of both ash and flue gas desulfurization sludge determine the sites with the largest residuals.

Tables 5-9 and 5-10 show the range of wet solid residual totals on a regional basis, while Figures 5-4, 5-5 and 5-6 show a breakdown of the average wet solid residuals by region and by process. Three categories are presented for each coal conversion process: ash sludge, flue gas desulfurization sludge, if required, and water treatment sludge. Only the category of wet spent shale is shown for oil shale conversion. Flue gas scrubbing is not required for the Synthoil and SRC processes.

In the Synthane process most of the ash produced is fly ash which is handled dry, i.e. water is added to wet the ash equal to ten percent of the ash weight. Except for the Synthane process, most of the ash that is produced is bottom ash which is sluiced with recycled sluice water. The thickened ash slurry removed is 35 percent water.

In the Illinois coal region for coal gasification, except for the Lurgi process, the wet solids generated are relatively insensitive to process. The difference between the wet solids generated for the Lurgi process and the other three gasification processes is due to the large quantity of boiler feed treatment wastewater required for the Lurgi process. This will be explained in the next section. The total wet residuals normalized with respect to the heating value of the product are comparable for the Synthoil and SRC processes, with the SRC process having a slightly larger value. The larger quantities of wet residuals for coal gasification are attributed to the flue gas desulfurization sludge, which is not required for the liquefaction and coal refining processes. The only differences between the wet solids generated in the

TABLE 5-9 REGIONAL SUMMARY OF TOTAL WET RESIDUALS GENERATED IN 10^3 TONS/DAY FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners	Green River Formation
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification							
Lurgi	3.5*	11.5	7.8-11.3	7.6-8.5	7.3-10.0	7.1-15.1	-
Synthane	5.5-6.4	-	4.8-5.6	5.5-6.7	3.9*	7.0*	-
Hygas	3.5-6.6	3.9	4.8-5.5	3.8-5.5	4.2	4.7-7.7	-
Bigas	-	-	3.3-6.8	3.6	4.1-8.3	-	-
Coal Liquefaction							
Synthoil	1.1-4.3	-	1.9-2.5	3.3-4.0	5.3*	3.2-11.2*	-
Coal Refining							
SRC	4.0*	3.7	2.7-6.3	2.0-3.8	3.2-4.7	13.7*	-
Oil Shale							
Paraho Direct							76
Paraho Ind.							104
TOSCO II							68

*Data from Ref. 1; only applies to particular numbers and not range.

TABLE 5-10 REGIONAL SUMMARY OF TOTAL WET RESIDUALS GENERATED
NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN LBS/10^6 BTU

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners	Green River Formation
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification							
Lurgi	29*	96	65-95	61-68	61-83	59-126	-
Synthane	40-54	-	44-47	46-56	33*	59*	-
Hygas	29-55	32	40-46	32-46	35	39-64	-
Bigas	-	-	27-56	30	34-69	-	-
Coal Liquefaction							
Synthoil	7-28	-	12-16	21-26	34*	28-72*	-
Coal Refining							
SRC	25*	23	17-40	12-24	20-34	19-86*	-
Oil Shale							
Paraho Direct							520
Paraho Ind.							630
TOSCO II							470

*Data from Ref. 1; only applies to particular number and not range.

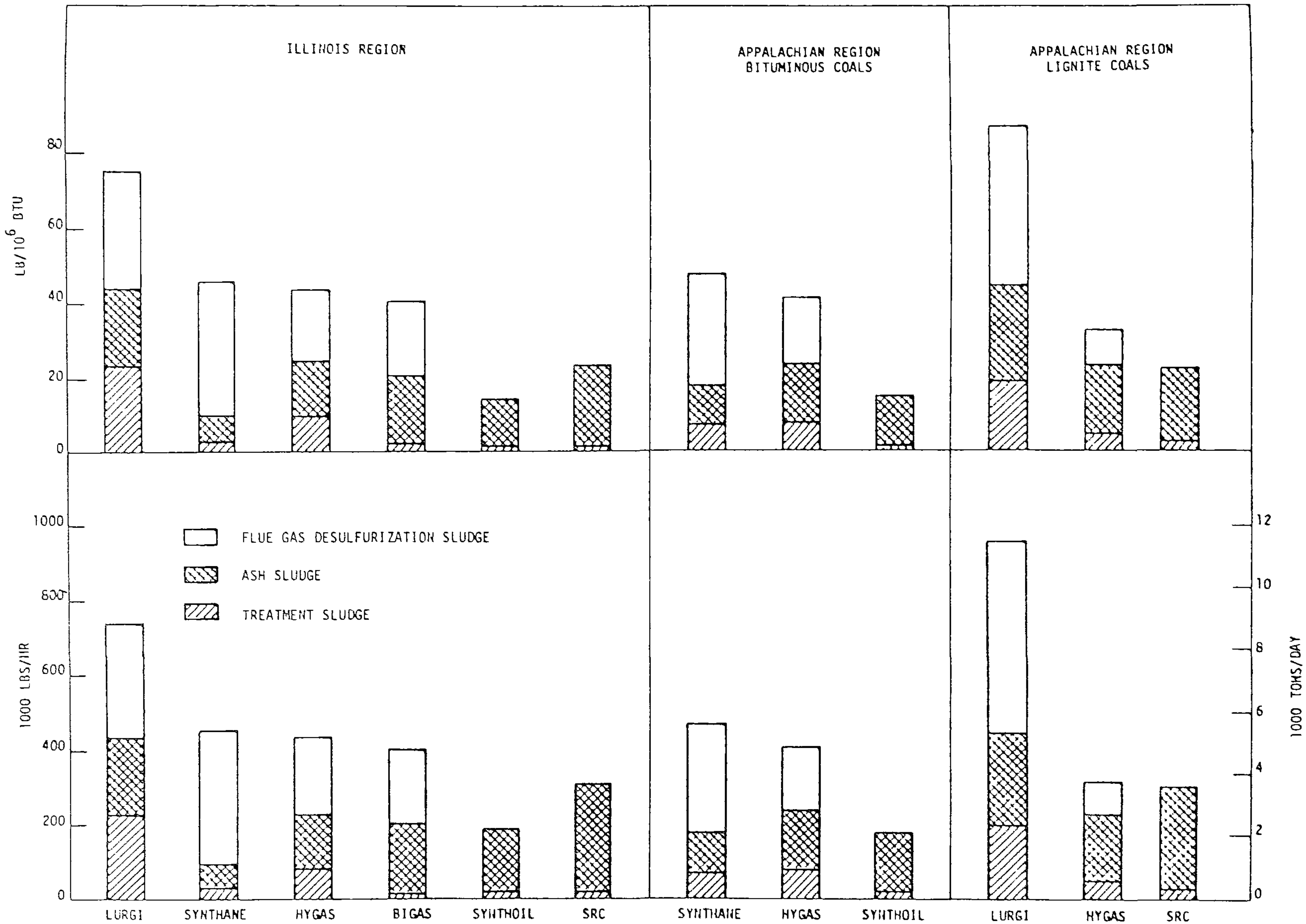


Figure 5-4 Summary of average wet-solid residuals generated from standard size coal conversion plants located in Central and Eastern states

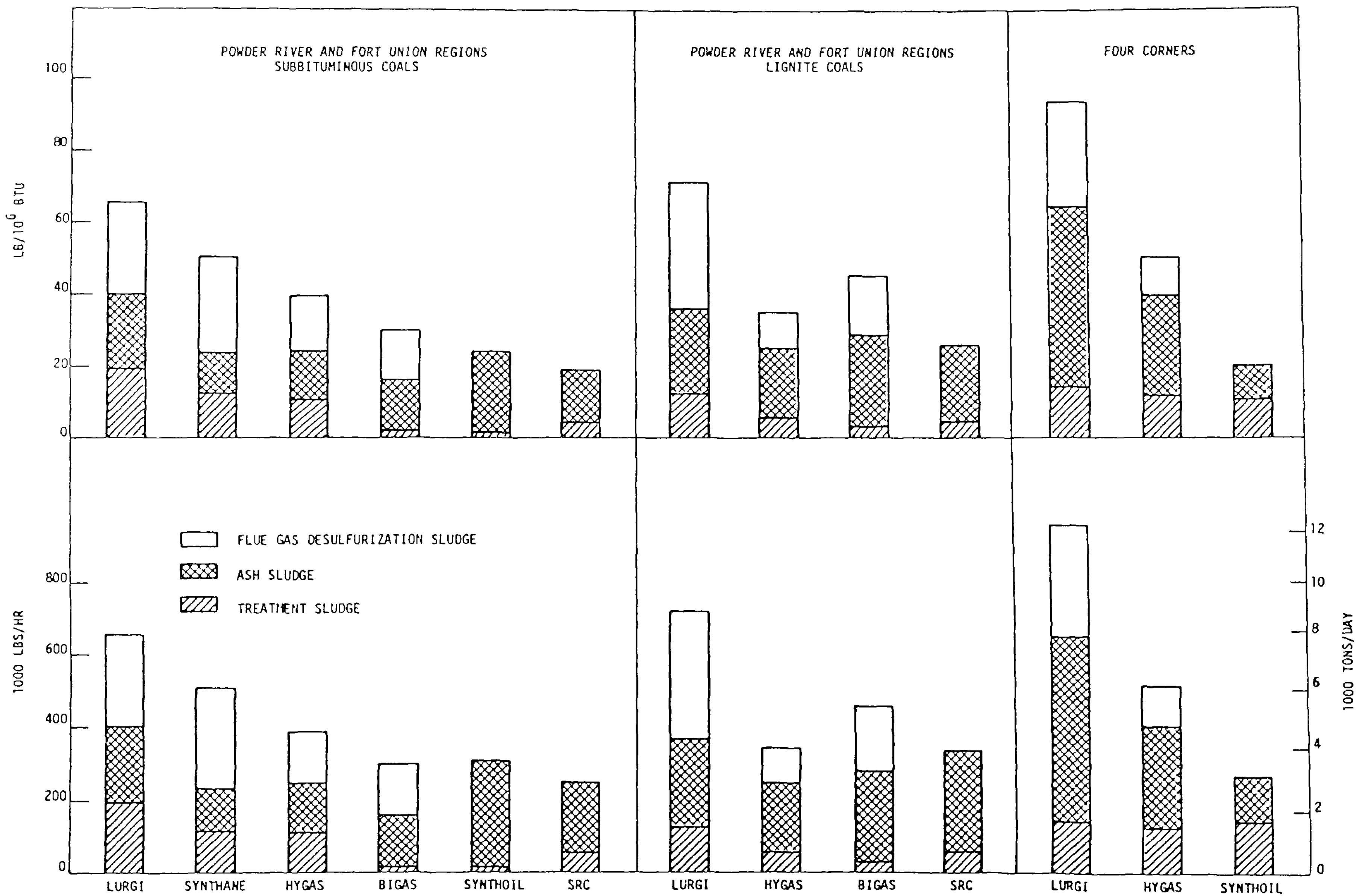


Figure 5-5 Summary of average wet-solid residuals generated from

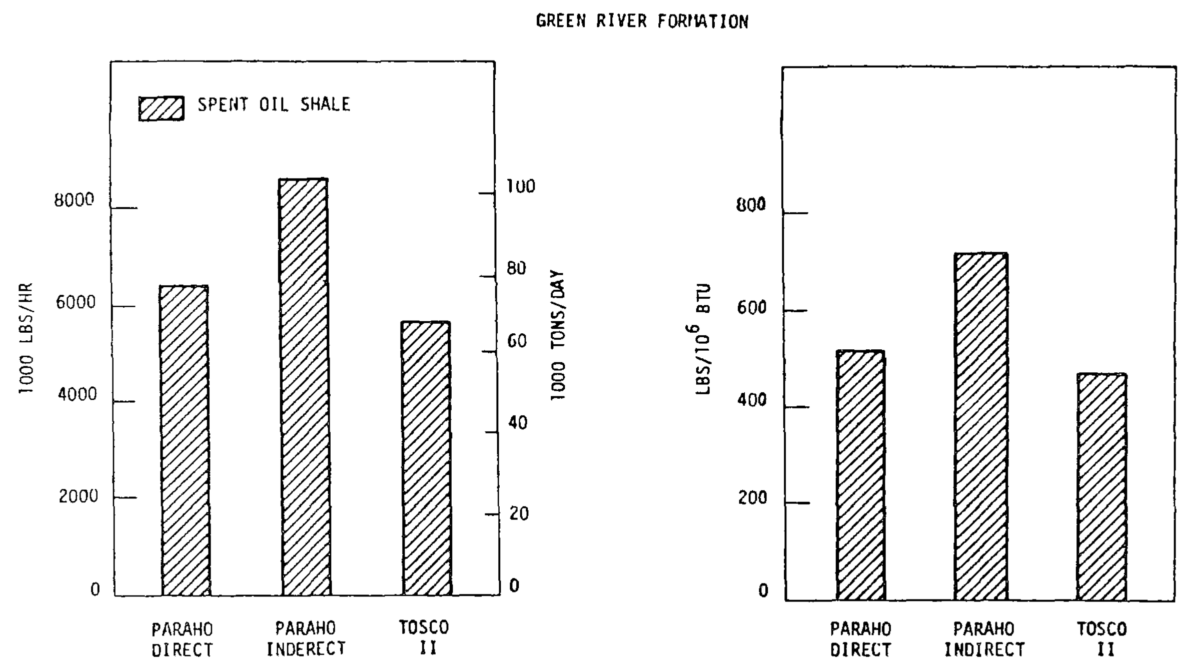


Figure 5-6 Summary of average wet solid residuals generated from standard size oil shale plants located in the Western states.

Illinois coal region and those generated in the Appalachian coal region can be attributed to differences in the sulfur and ash content of the coals.

In the Four Corners and the Powder River and Ft. Union regions, coal gasification generates the largest quantity of wet residuals with respect to the heating value of the product fuel, followed in turn by coal liquefaction and coal refining. For the same processes there are no significant variations with coal rank in the Powder River and Ft. Union coal regions except for the Bigas process; for Bigas the variation is due to the higher ash coals. As mentioned previously, the large quantities of wet solids generated in the Four Corners region is due to the high ash content of the Navajo coal.

A comparison of the total wet residuals generated in the Illinois coal region and the Powder River and Ft. Union regions (subbituminous coals) show that they are comparable, as are the results for the Appalachian region and the Powder River and Ft. Union coal regions for lignite coals. However, there are some differences between the three categories of sludges. In general water treatment sludges in the Western states are larger than those for the Eastern and Central states, while the reverse is true for flue gas desulfurization sludges.

5.2 Process Water Requirements

Figures 5-7 and 5-8 show the quantity of steam and boiler feed water required for the conversion process, the amount of dirty and intermediate quality condensate coming out of the process, and the net process water consumed. The raw water source must be treated to produce the high quality steam and boiler feed water required for the process, while the dirty and intermediate quality condensate must be treated for reuse since disposal is not practical, requiring cleaning before disposal to meet environmental regulations. Methanation water for the process is reused without any treatment. This process water is not shown on the figures. Neither are quench water for the Synthoil process and dirty water input for Bigas, which do not require treatment.

Large quantities of steam and boiler feed water and dirty condensate must be treated in the Lurgi process, although net process water may be produced in the process. The Lurgi process accepts wet coal, resulting in large quantities of dirty condensate. In general the low temperature coal gasification processes require more costly treatment than either the coal liquefaction and coal refining processes. High temperature gasification processes do not require extensive water treatment because the process condensate is of relatively

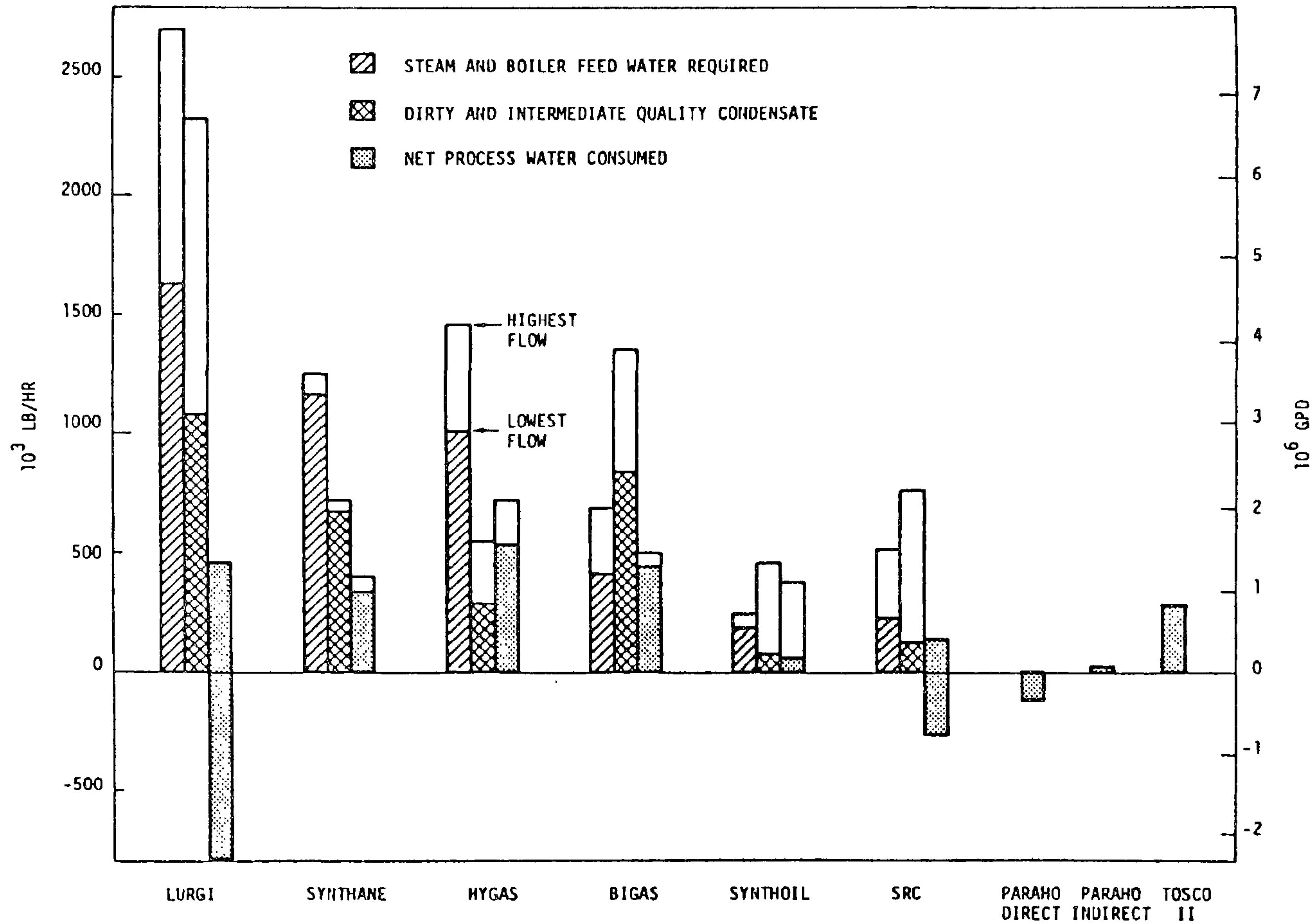


Figure 5-7 Range of process water flows for standard size synthetic fuel plants

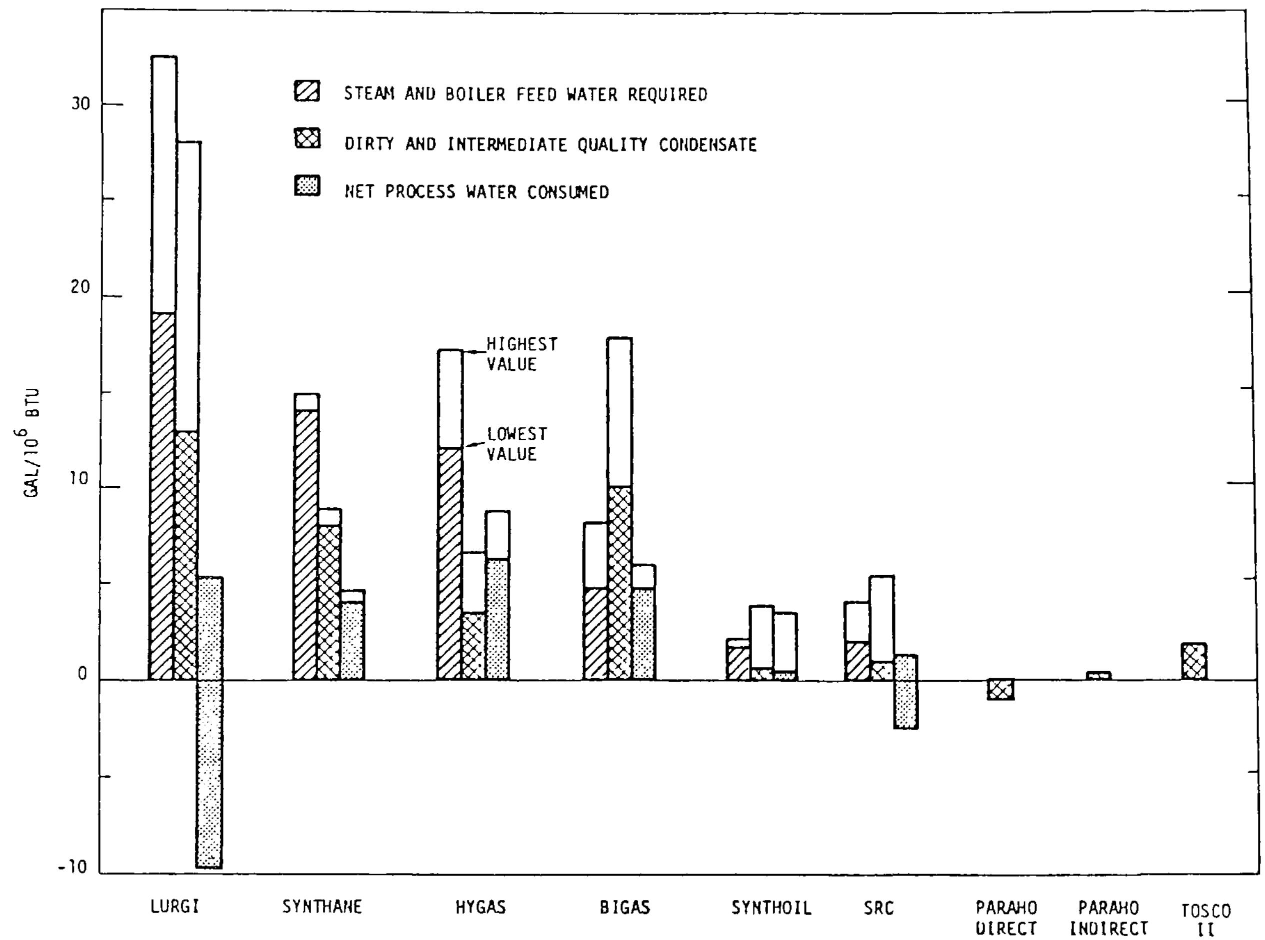


Figure 5-8 Range of process water flows in gal/10^6 Btu

good quality. Process requirements for the Synthane plants are less than those for Hygas plants because the Synthane process makes char and passes more coal through the gasifier. This makes more hydrogen available from coal.

The summary of process water flows are shown for each coal region in Figures 5-9 and 5-10. The net water consumed for the Hygas, Bigas and Synthane processes are relatively independent of site. Figure 5-11 shows that the net process water consumed in the Lurgi process is a function of the moisture content of the coal. For the Synthoil and SRC processes, the net process water consumed is a function of both the moisture and oxygen contents of the coal (Figures 5-12, 5-13 and 5-14). The highest process water requirement is in the Appalachian region which has the lowest oxygen content coals and the lowest requirement is in the Powder River and Fort Union regions. In the SRC process when hydrogen is produced from very moist coals, principally lignite, without predrying the coal, the net process water will be less than that indicated by the oxygen content (Figure 5-13). The process water consumption or production in the oil shale plants relate directly to the amount of water produced in the retort itself.

5.3 Cooling Water Requirements

The cooling water consumed in coal conversion processes comprises the largest percentage of the total water requirements. Three cooling options were considered representing different kinds of wet evaporative cooling for turbine condensers and gas-compressor interstage coolers.

At a site where water is plentiful and inexpensive to transport, high wet cooling should be used. The cooling loads on both the turbine condensers and interstage coolers are taken to be all wet cooled. For the Lurgi process a detailed thermal balance is not available: wet cooling is assumed to be used to dispose of 33 percent of the total unrecovered heat. The same value was one estimated for the Synthane process to facilitate comparison. This value falls within the range of Lurgi design data. The El Paso[3] design indicates that 36 percent of the unrecovered heat is dissipated by evaporative cooling while the Wesco design[4] indicates 26 percent. In regions where water is marginally available or moderately expensive to transport, intermediate cooling should be used. Intermediate cooling assumes that wet cooling handles 10 percent of the cooling load on the turbine condensers and all of the load of the interstage coolers (Appendix 7). For the Lurgi process 18 percent

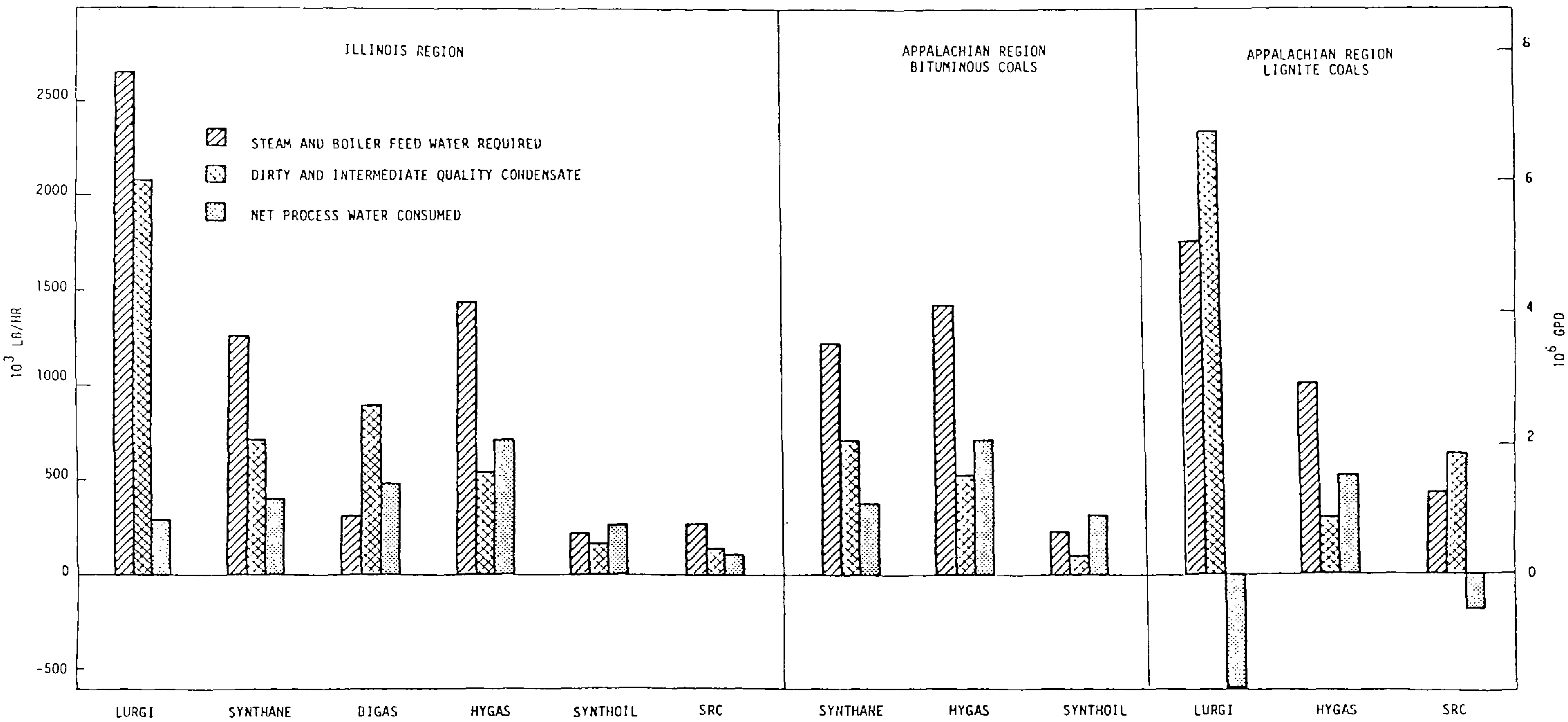


Figure 5-9 Summary of average process water flows for standard size fuel plants located in the Central and Eastern states.

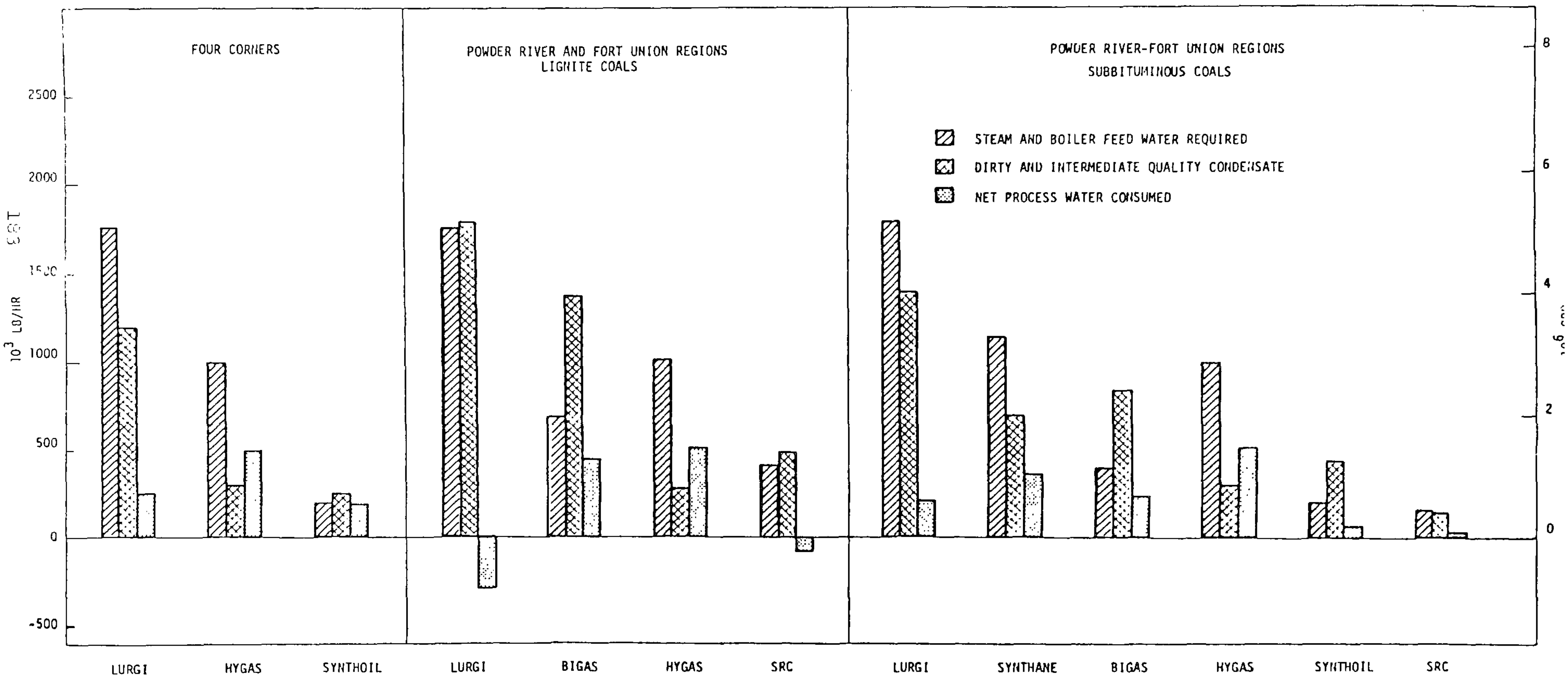


Figure 5-10 Summary of average process water flows for standard size synthetic fuel plants located in the Western states.

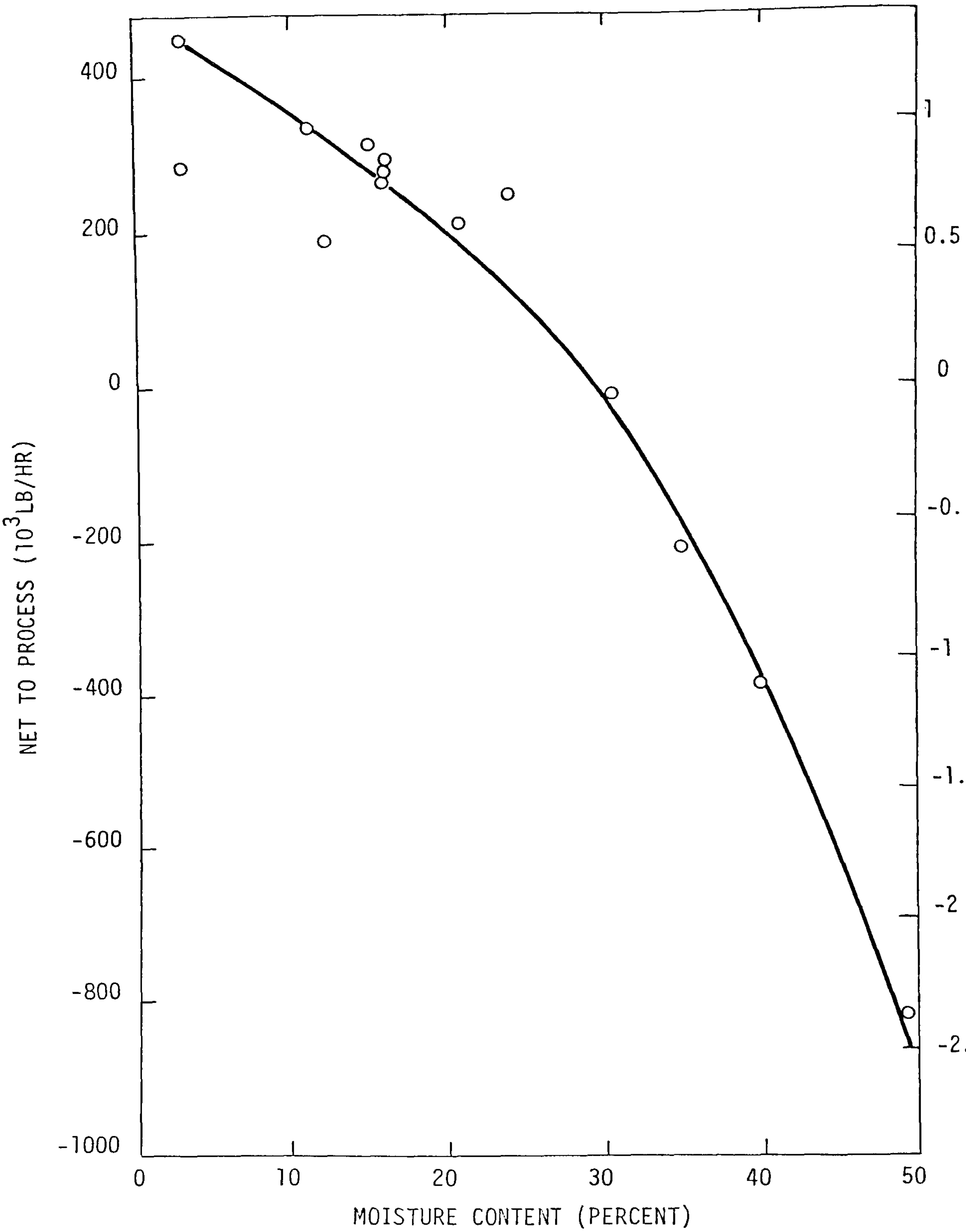


Figure 5-11 Net process water consumed in Lurgi process. (from calculations of Appendix 6 for specific coals).

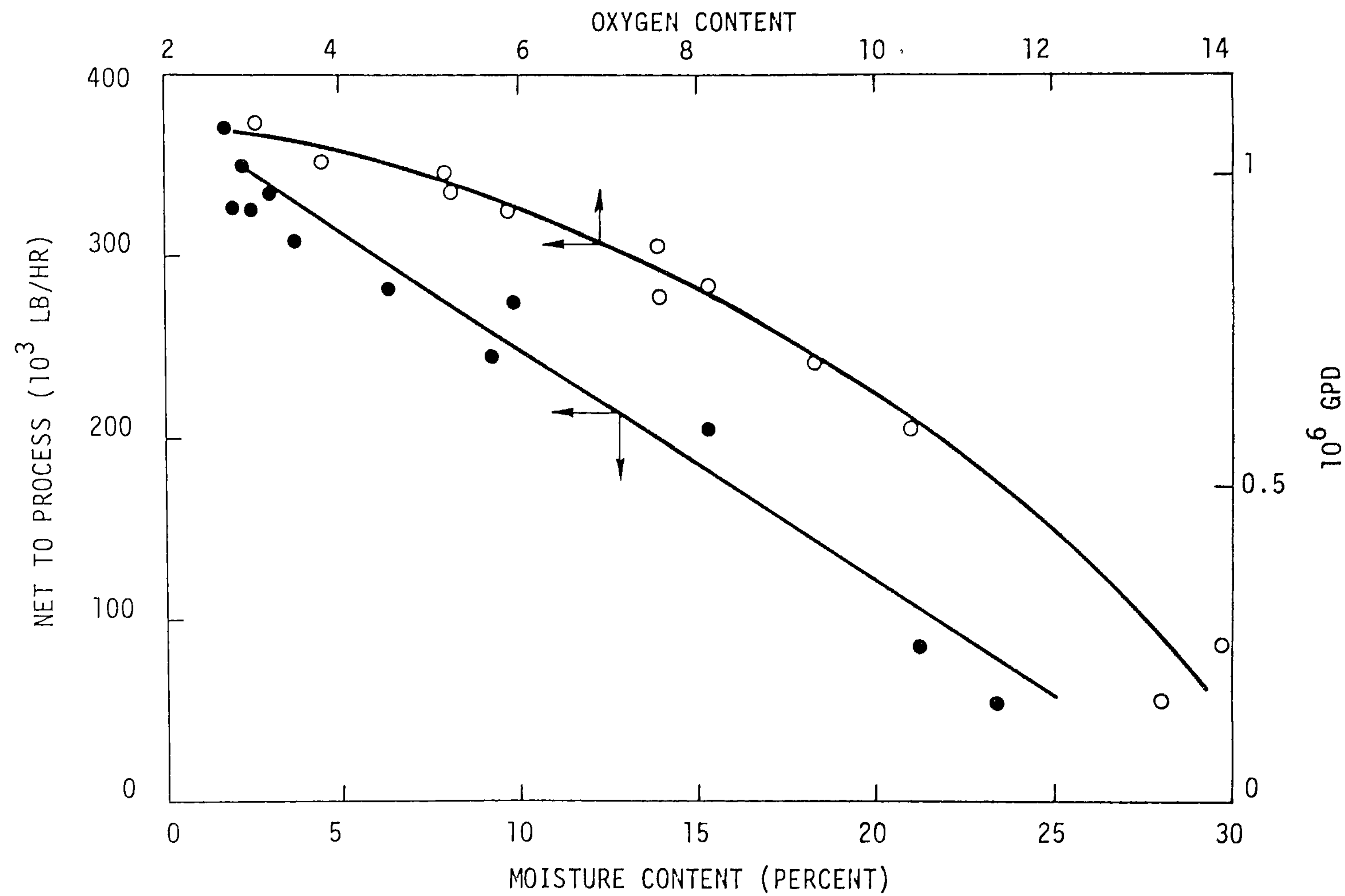


Figure 5-12 Net process water consumed in Synthoil process (from calculations of Appendix 2 for specific coals).

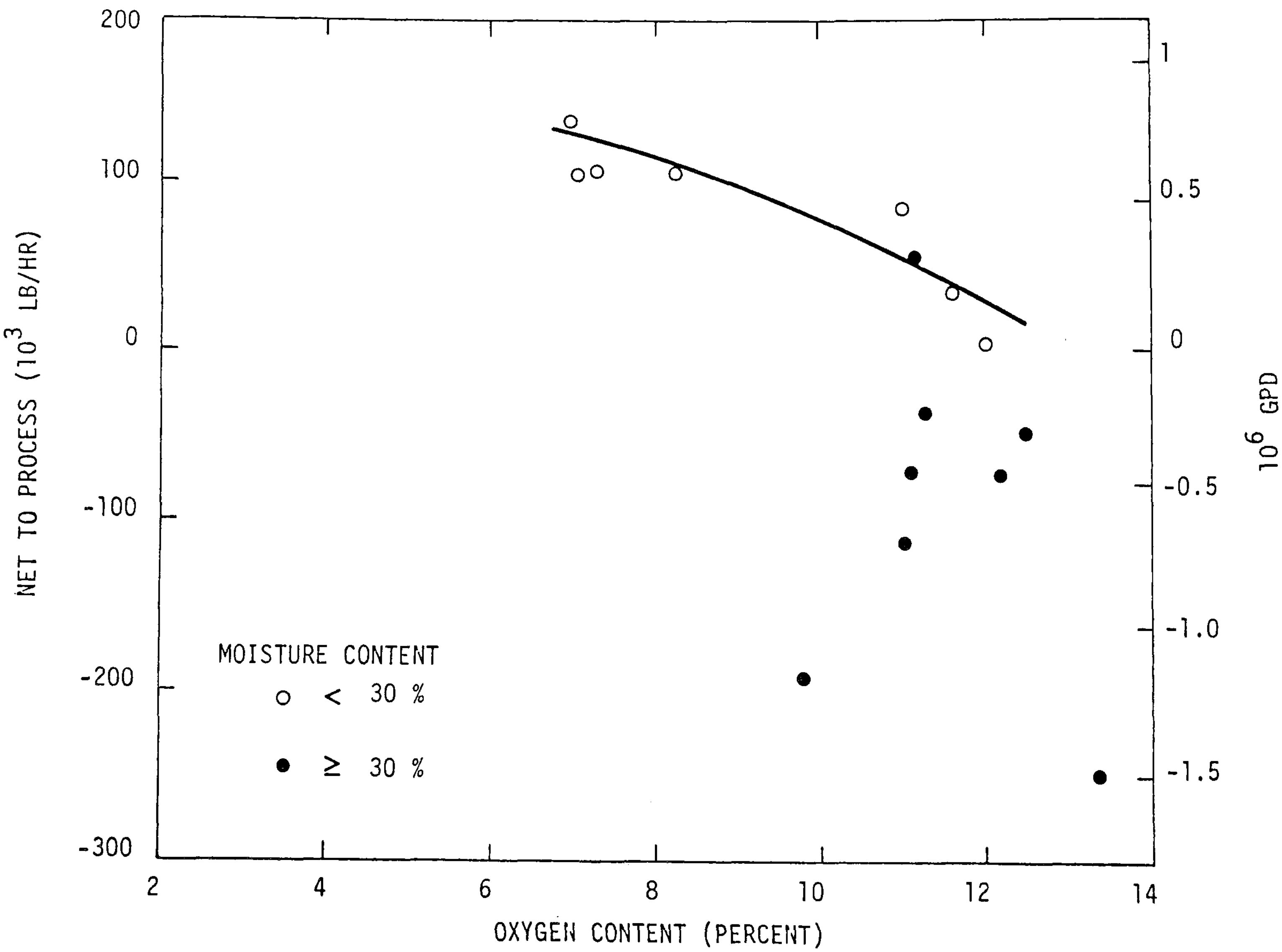


Figure 5-13 Net process water consumed in SRC process - variation with oxygen content (from calculations of Appendix 1 for specific coals).

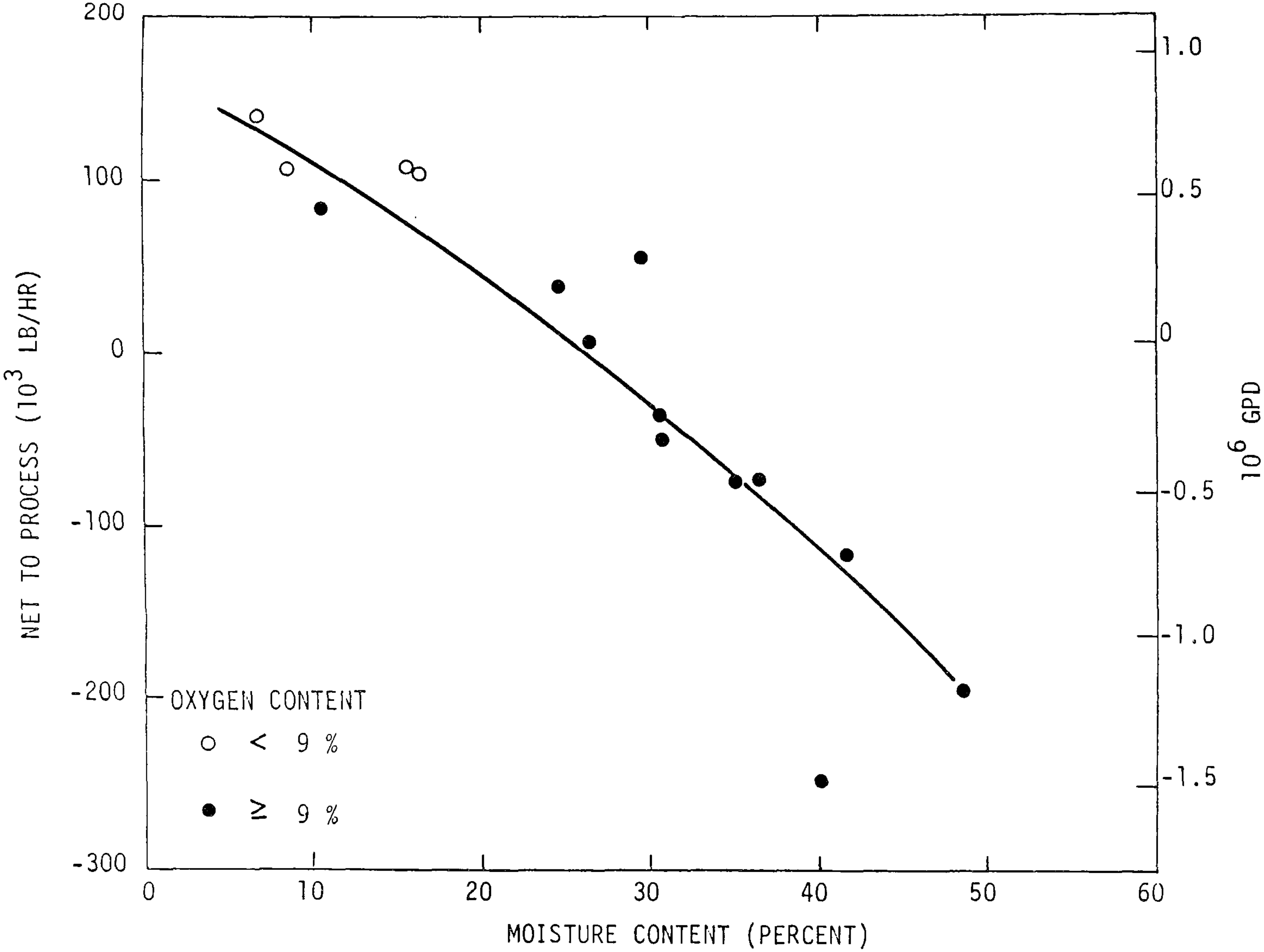


Figure 5-14 Net process water consumed in SRC process - variation with moisture content (from calculations of Appendix 1 for specific coals).

of the unrecovered heat is dissipated by wet cooling. Again, this is based on Synthane process estimates. The oil shale processes are assumed to use an intermediate degree of wet cooling. For the Paraho Direct process, 28 percent of the unrecovered heat is dissipated by wet cooling. For the Paraho Indirect and TOSCO II processes 18-19 percent is dissipated.

In regions where water is expensive to transport or scarce, minimum practical cooling should be used. Minimum practical wet cooling assumes that wet cooling dissipates 10 percent of the cooling load on the turbine condensers and 50 percent of the load in the interstage coolers (Appendix 7). For this case the Lurgi process is assumed to dissipate about 15 percent of the unrecovered heat by wet cooling. Again it is based on the estimates for the Synthane process.

The degree to which wet cooling should be used is determined by the cost of water. If water costs more than about $1.50 per 1000 gallons minimum practical cooling should be used. Intermediate cooling should be used if the water cost is between $0.25 per 1000 gallons and $1.50 per 1000 gallons, while high wet cooling should be used if water costs less than $0.25 per 1000 gallons (Appendix 7).

For a given size coal conversion plant the quantity of water consumed by cooling mainly depends on the overall conversion efficiency and the percent of unrecovered heat dissipated by wet cooling. All of the unrecovered heat not dissipated by wet cooling is lost directly to the atmosphere while the rest of the heat is transferred to the atmosphere by direct cooling. As discussed above, the choice depends on the availability and cost of water. Table 5-11 lists the range of conversion efficiency for each conversion process as well as the percent of unrecovered heat dissipated by wet cooling. For the SRC process the low conversion efficiency corresponds to plants sited at Marengo, Alabama and Coalridge, Montana where the feed coals are lignites having high moisture contents. The low conversion efficiency is the result of large quantities of energy required for coal drying. The conversion efficiencies for all of the coal gasification processes are comparable, while those for coal liquefaction and coal refining are also comparable, but slightly higher

TABLE 5-11 OVERALL CONVERSION EFFICIENCY AND PERCENT UNRECOVERED HEAT DISSIPATED BY WET COOLING

	Overall Conversion Efficiency* (Percent)	Percent Unrecovered Heat Dissipated by Wet Cooling		
		High Wet Cooling	Intermediate Cooling	Minimum Practical Cooling
Coal Gasification				
Lurgi	65-67	33	18	15
Synthane	65-73	30-33	15-18	12-16
Hygas	65-74	23-35	13-20	11-17
Bigas	66-70	40-46	20-21	16-17
Coal Liquefaction				
Synthoil	72-79	44-54	25-36	22-33
Coal Refining				
SRC	59-82	34-51	18-33	15-30
Oil Shale				
Paraho Direct	71		28	
Paraho Indirect	57		19	
TOSCO II	68		18	

*(Heat content of product fuel plus combustible byproducts)/(Heat content of coal or oil shale)

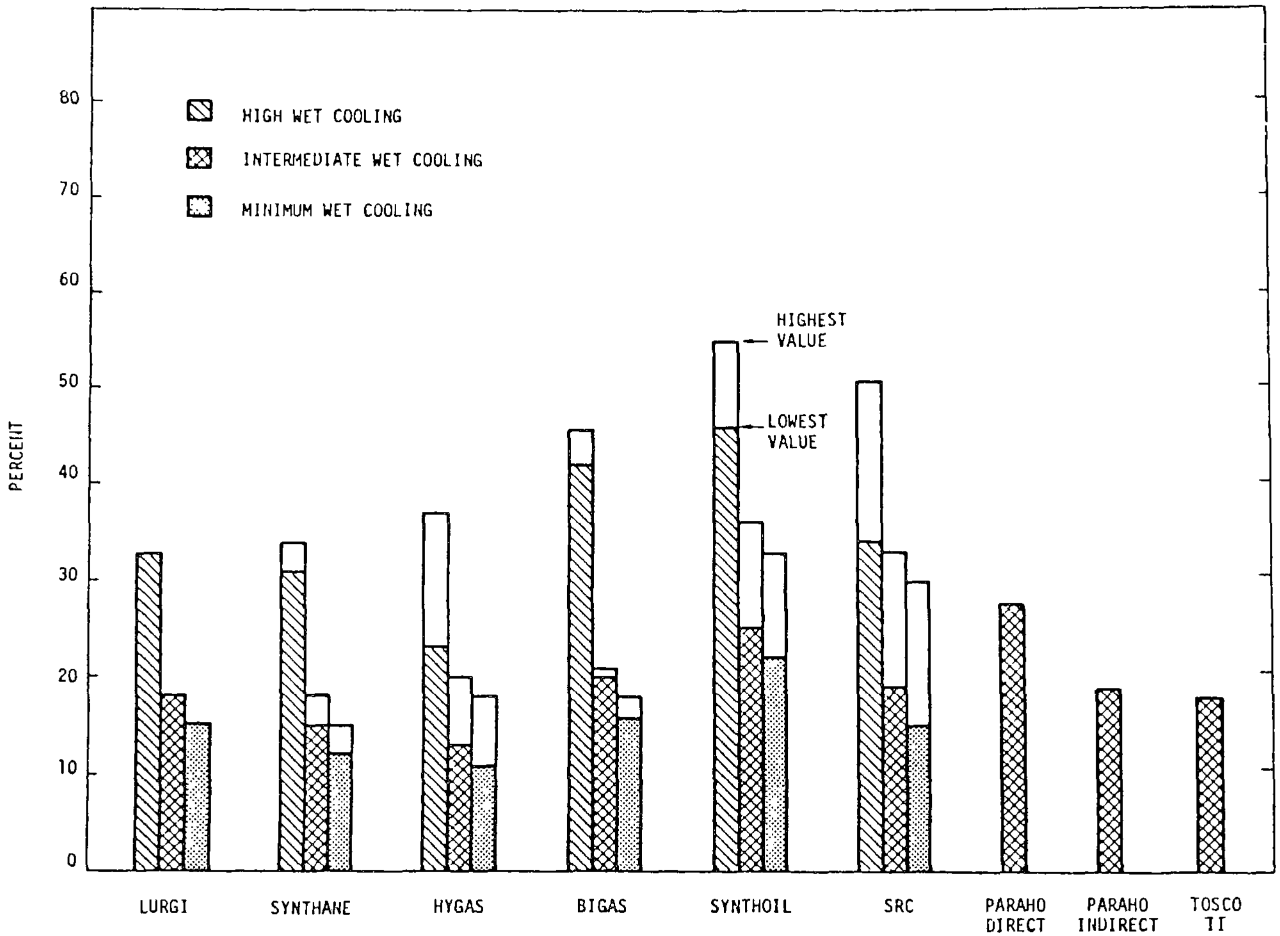


Figure 5-15 Percent of unrecovered heat removed by wet cooling.

than those for coal gasification. We should note that the conversion efficiencies for coal liquefaction may be a little high because not all of the energy loads were considered in the SRC designs of Appendix 2. The conversion efficiency for the Paraho Direct process is comparable to that for coal gasification. The percent of unrecovered heat dissipated by wet cooling for coal liquefaction and coal refining are also comparable and, in general, higher than that for coal gasification (Figure 5-15). The fraction of heat used to evaporate water in the indirect oil shale processes is somewhat lower than the direct process. This may be explained by the fact that in the indirect heated retorting process part of the unrecovered heat is lost up a furnace stack, which is not lost that way in the direct processes.

Figure 5-16 shows the range of water consumed by cooling for standard size synthetic fuel plants; the same data is shown normalized with respect to the heating value in the product in Figure 5-17. The maximum difference in water consumption between high wet cooling and minimum practical cooling for the processes taken as a whole is about 10 gal/10^6 Btu. The SRC process shows the largest difference between the highest and lowest value of cooling water consumed for a given cooling option.

Figures 5-18 and 5-19 show the average water consumed by cooling in each of the regions considered. For each process, the average water consumed is relatively insensitive to the coal bearing region and variations for a given cooling option from site to site within the region are expected to be small for all of the processes except for possibly the SRC process, as discussed above. However, within a given region there might be large variations in water availability and water costs; and different cooling options at different sites will produce large differences in the cooling water consumed and the plant water requirements.

5.4 Other Water Requirements

In this category we include the water requirements for flue gas scrubbing, ash or spent shale disposal, dust control, water treatment wastewaters and other needs. The methods for estimating these quantities are given in Appendices 8, 9, 11 and 12.

The largest single factor in the water requirement for flue gas scrubbing is the moisture content of the coal or char fed to the boilers. For this reason the flue gas requirement is greatest for the coals from the Appalachian

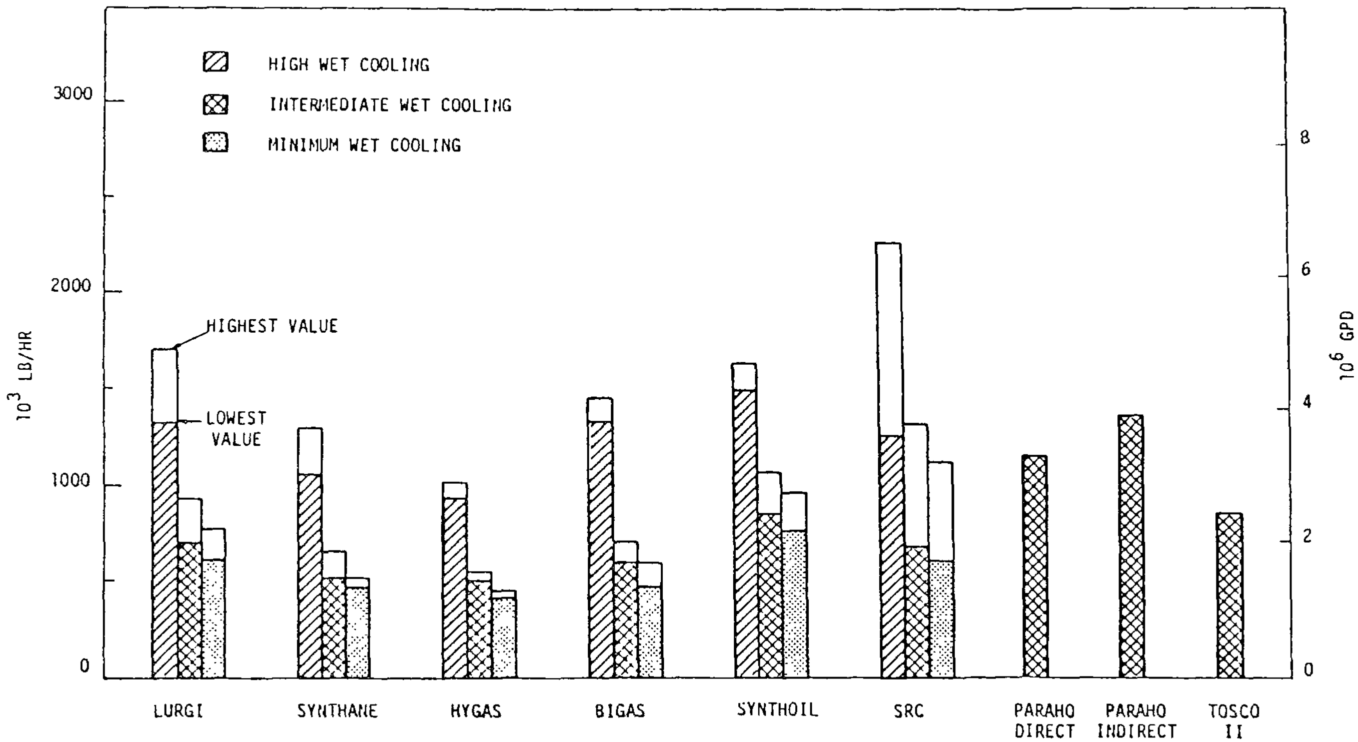


Figure 5-16 Cooling water consumed by evaporation for standard size synthetic fuel plants.

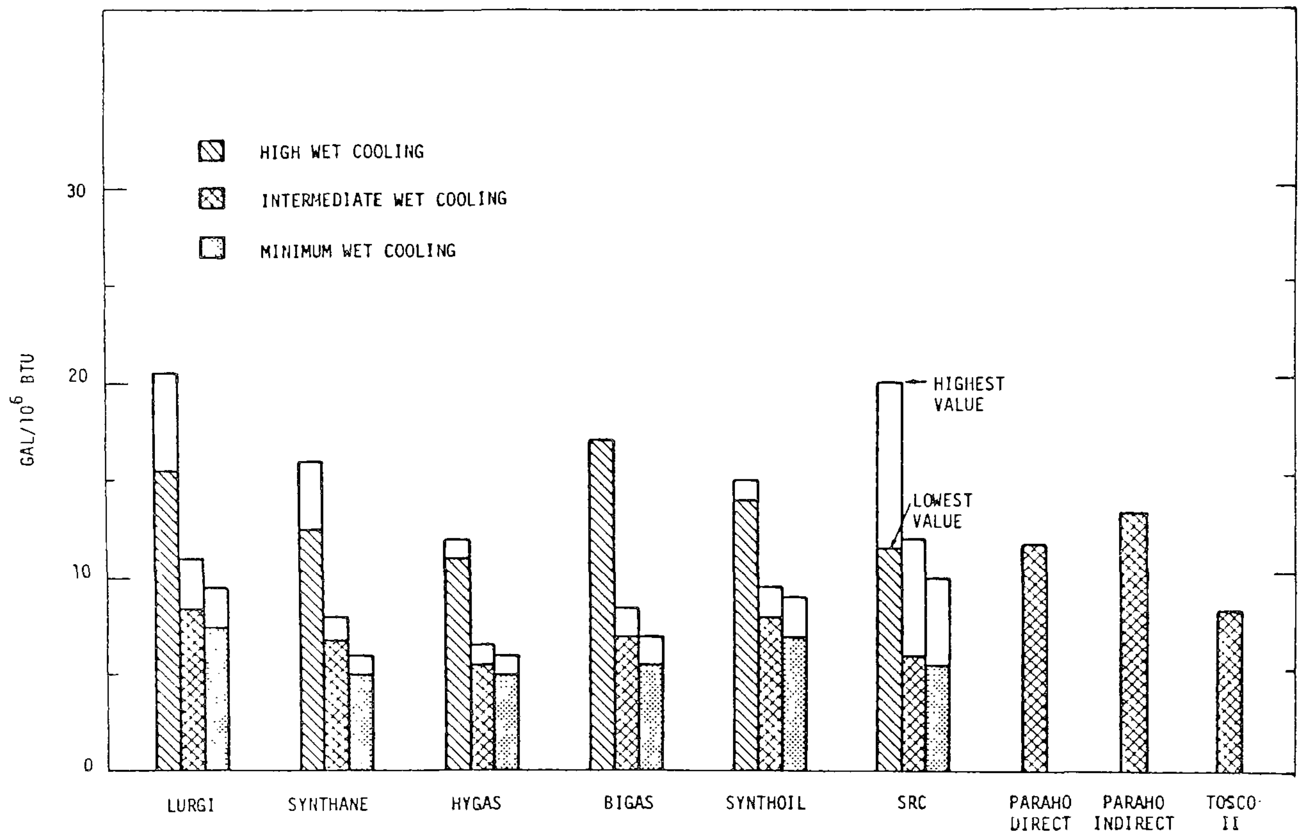


Figure 5-17 Cooling water consumed by evaporation in $gals/10^6$ Btu.

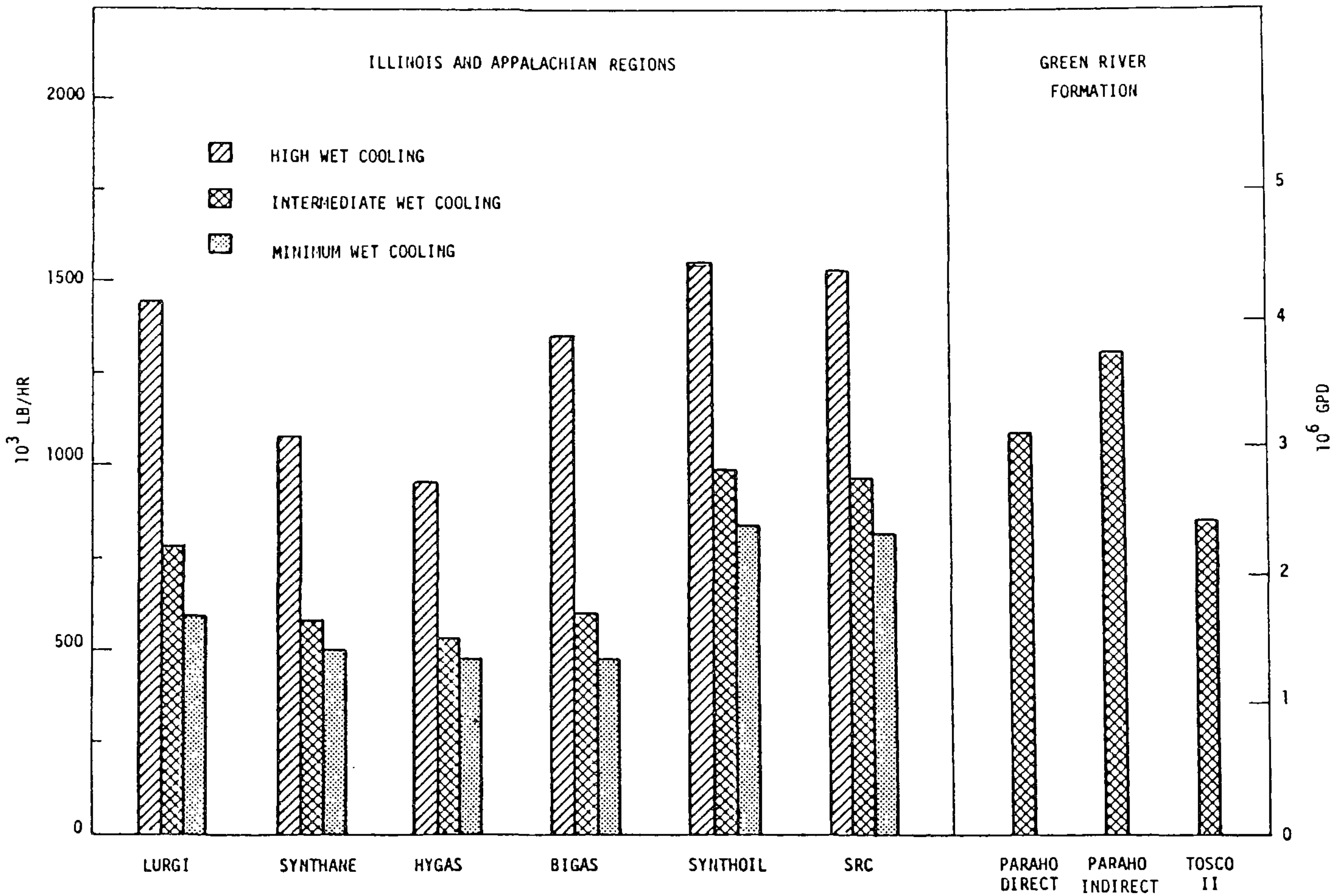


Figure 5-18 Average cooling water consumed for coal conversion in the Illinois and Appalachian coal regions and consumed for oil shale conversion in the Green River Formation.

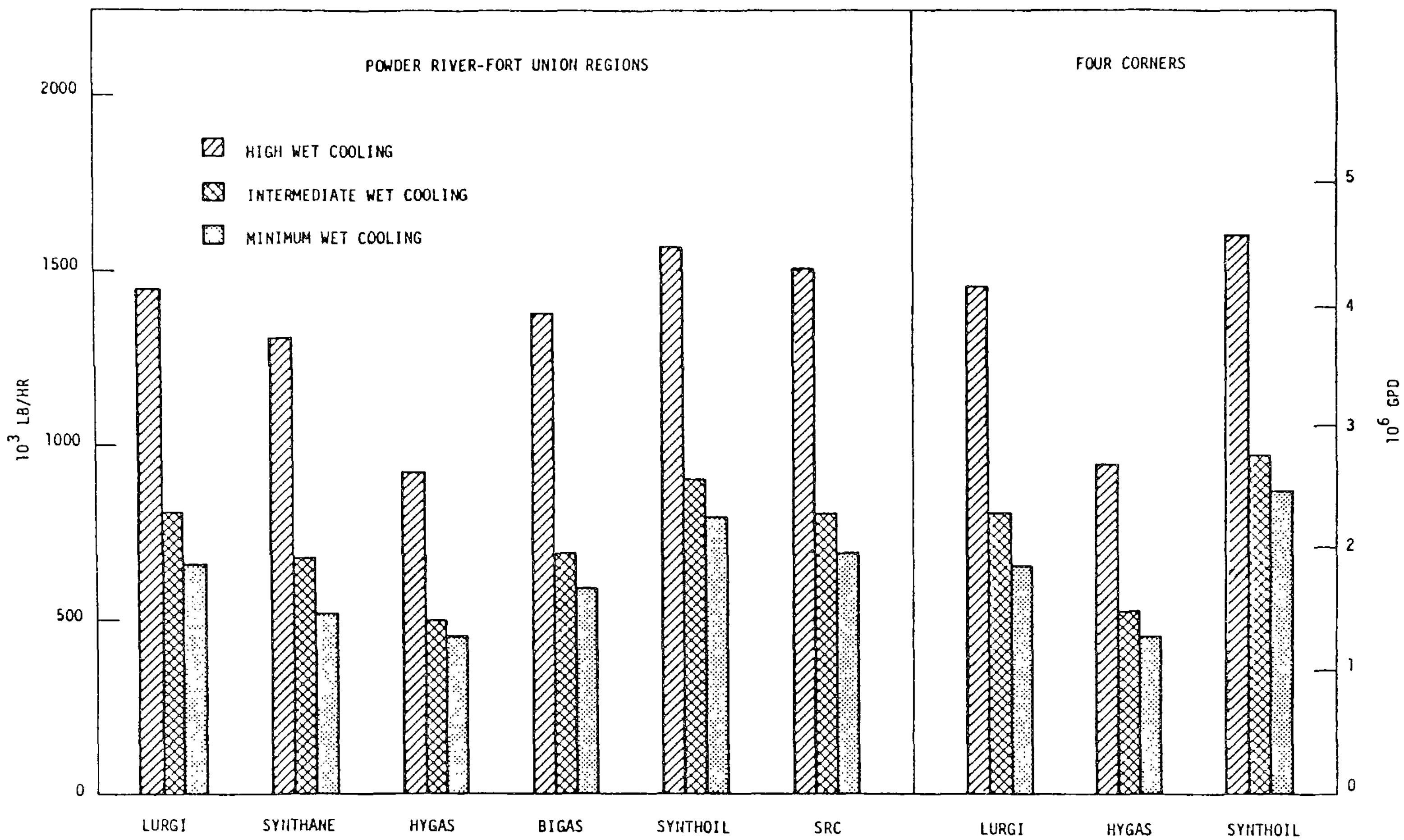


Figure 5-19 Average cooling water consumed for coal conversion in the Western states.

and Four Corners regions which are relatively low in moisture. In all Synthane plants dry char is fed to the boiler making the scrubbing water requirements high. Coal is not fed to the boilers in the Solvent Refined Coal and Synthoil designs considered.

The water required for ash disposal, dust control and other needs cannot be readily generalized because of the many competing factors. However, the water requirements for the Four Corners region are higher than for the other four regions because of the high ash coal and the revegetation requirement. The water requirements for the disposal of spent shale and subsequent revegetation differs considerably between processes, depending on the operator's assumption about the amount of water necessary to properly dispose of the spent shale. In the proposed TOSCO II design it is assumed that the addition of water to the spent shale leads to cementation of the shale after compaction while in the proposed Paraho designs the spent shale is simply compacted dry. The water consumption for the Paraho design is mainly for revegetation whereas in the TOSCO II design it is in large part for compaction.

The largest quantity of water treatment wastewaters are consumed in the Lurgi process because of the large steam and boiler feed water requirements. Generally the wastewaters for all of the other conversion processes do not exceed one percent of the total water consumed except where the feed water is a hard well or brackish groundwater where the wastewaters may exceed about five percent.

5.5 Residuals

In coal conversion plants the residuals include coal ash, flue gas, desulfurization sludges where flue gas scrubbing is used, and water treatment sludges. In the oil shale plants the principal residual is the spent shale. The methods for estimating these quantities are given in Appendices 8, 9, 11 and 12.

In the four coal gasification processes, coal or char is burnt to raise steam in a boiler. The furnaces are assumed to be a dry bottomed pulverized coal type with 80 percent of the ash as fly ash and 20 percent as bottom ash. As occurs in some 65 percent of the power generating stations today, fly ash is assumed to be handled dry; that is, water is added to wet the ash equal to ten percent of the ash weight. Furnace bottom ash is assumed sluiced (as it usually must be) with recycled sluice water. The thickened ash slurry removed is 35 percent water. All ash from all coal conversion reactors is assumed handled with the bottom ash. The water evaporated to quench gasifier ash is included in the wet cooling load of the various processes. In the Synthane process all of the ash from the gasifier enters the boiler where it is fired with 80 percent of the ash leaving as fly ash and 20 percent as bottom ash. This ash is handled as discussed above.

Flue gas desulfurization sludge is not generated for the coal liquefaction and coal refining processes. For the four coal gasification processes the flue gas desulfurization sludge is related directly to the sulfur content of the coal, being highest in the Eastern and Central states and lowest in the Western states.

References - Section 5

1. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives, MIT Press, Cambridge, Mass. 1978.

2. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion Processes," Report No. EPA-600/7-77, Environmental Protection Agency, Research Triangle Park, N.C., June 1977.

3. Gibson, C.R., Hammons, G.A. and Cameron, D.S., "Experimental Aspects of El Paso's Burnham I Coal Gasification Complex," in Proceedings, Environmental Aspects of Fuel Conversion Technology (May 1974, St. Louis, Missouri), pp. 91-100, Report No. EPA-650/2-74-118 (NTIS PB 238304), Environmental Protection Agency, Research Triangle Park, N. C., October 1974.

4. Berty, T.E. and Moe, J.M., "Environmental Aspects of the Wesco Coal Gasification Plant," in Proceedings, Environmental Aspects of Fuel Conversion Technology (May 1974, St. Louis, Missouri), pp. 101-106, Report No. EPA-650/2-74-118 (NTIS PB 238304, Environmental Protection Agency, Research Triangle Park, N.C., October 1974.

6. CONTROL TECHNOLOGY

6.1 Water Treatments

In the preceding section we have summarized the quantities of net water consumed and wet solid residuals generated by conversion technology and by coal and oil shale region. In making these estimates we have assumed that no water streams leave the mine-plant boundaries and that all effluent streams are recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated waters generated in the conversion process, which are unfit for disposal without treatment, and the highly saline water blown down from evaporative cooling systems. Water is only released to evaporative ponds as a method of salt disposal when the usual inorganic concentration of released wastes is about two percent (for example, ion exchange regeneration wastes and cooling tower blowdown when more than 10 cycles of concentration are used and less than 10 percent of the intake water is released). We have generally assumed that these wastes are disposed of with the coal ash. The rest of the water consumed leaves the plant as vapor, as bonded hydrogen (after hydrogenation) in the hydrocarbon product, and as occluded water in the solid residues. The water treatment plants are not designed to return flow to receiving waters. Returning water to a source is not economic when the water must be cleaned to a quality equal to or better than the source water to meet environmental constraints. All wet solid residuals must be disposed of in an environmentally acceptable manner. Toxic and soluble organic materials must be destroyed and toxic heavy metal salts must be converted to insoluble forms. Soluble inorganic sludges and toxic residuals from the coal ash or spent shale must be contained in disposal sites to prevent leaching into drinking water sources.

In this section we will summarize the individual water treatment blocks and water flow diagrams, each applicable to one or more processes at many sites. The estimated costs and energy requirements of the water treatment section of each process-site combination will also be summarized. Detailed calculations for each plant-site combination are found in Appendix 11, while the background information on the water treatments used is found in Refs. 1 and 2. We have not selected the means of disposal of the wet solid residuals nor have we estimated their costs. This was beyond the scope of the study. We have also not considered the costs of water treatment for shale oil conversion.

The cost and energy estimates for water treatment are much less well defined than the water quantities. Although the water treatment technologies considered are achievable, the experimental evidence for coal conversion process waters is not available to fully assess them. For this reason designs and costs must be regarded with a greater degree of uncertainty than the estimates of water quantity requirements. Furthermore, because of the large number of plant-site combinations, we could not, within the limitations of the study, look at all of the various water treatment options for each plant-site combination. Instead we have used one or two water flow diagrams, each applicable to one or more processes at many sites. The water treatment plants are designed to prevent water streams from leaving the mine-plant boundaries and to recycle and reuse all effluent streams within the mine or the plant. The costs and energy requirements for disposal are not included in this study. For example, the costs of evaporation ponds used to hold highly saline blowdown waters have not been estimated.

In any synthetic fuel plant high quality water is required for the process, intermediate quality is required for cooling, and low quality for disposal and mine uses. Figure 6-1 is a simplified water reuse scheme which assumes that the effluent from the process is of low quality and insufficient to meet all of the plant's cooling needs. The process condensate for the liquefaction and coal refining processes and for the low temperature coal gasifiers is quite dirty. The process condensate for the Hygas high temperature gasifier is of intermediate quality; clean condensates are produced from the Bygas process. The scheme further assumes that the raw water supplied to the plant is from a fresh water source and of medium quality. If the source of supply were of poor quality and expensive, as from a brackish groundwater aquifier,

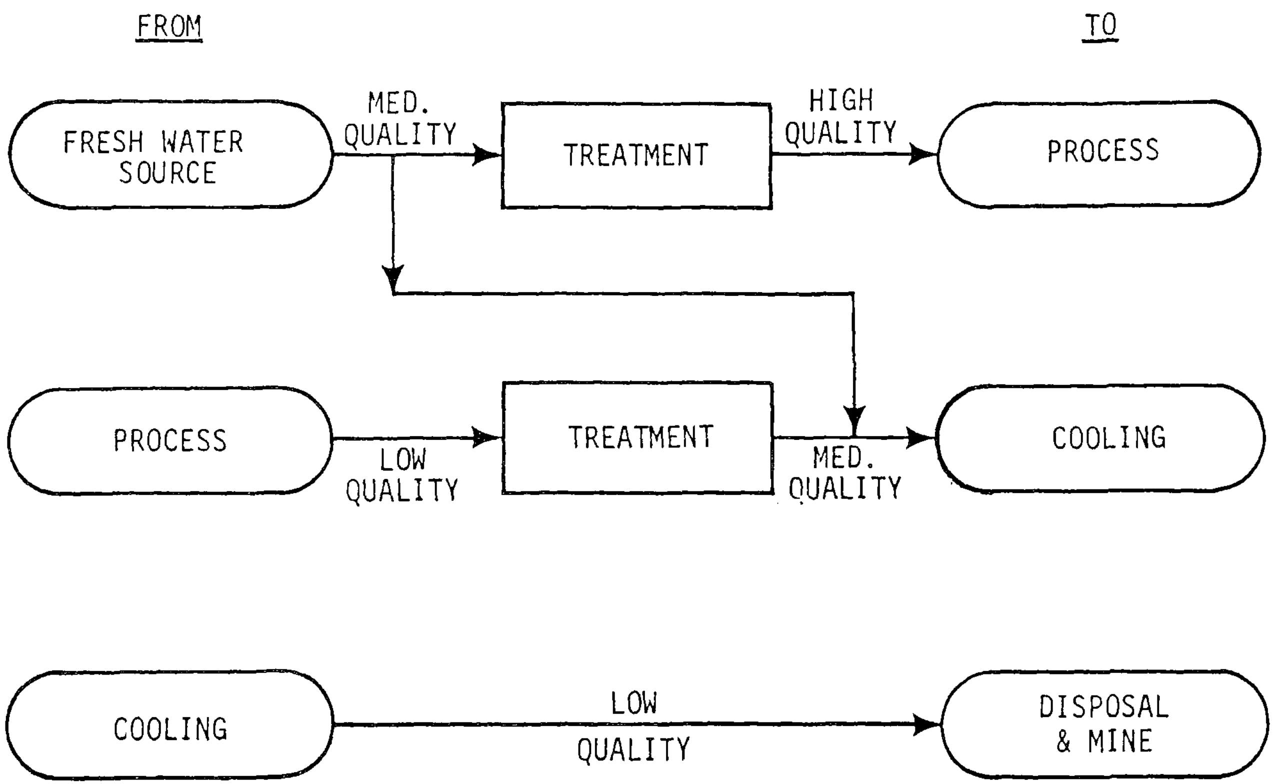


Figure 6-1 Simplified water use diagram (Reprinted from Ref. 2 with the permission of The MIT Press. Copyright 1978 by the Massachusetts Institute of Technology).

it might be economical to take the medium quality water resulting from treating the dirty process stream and feed it back for treatment to high quality boiler feed water.

Figure 6-2 is an amplification of Figure 6-1 and represents a general water treatment scheme for a coal conversion plant generating dirty process water. The scheme is not unique, but does contain the main components of any water treatment plant: boiler feed water preparation, process water or condensate cleanup,and cooling water treatment. The three main streams are shown with heavy lines. Figure 6-3 shows the water treatment block diagrams used for all of the processes. Details are given in Appendix 11.

Boiler feed water preparation includes occasional lime soda softening, electrodialysis on all plants when the raw intake water is brackish, and ion exchange. Three different ion exchange schemes have been chosen based on the quality of the intake water. The cost of ion exchange depends on the quantity and quality of the intake water, which are usually site dependent, and on the pressure of the steam raised in the boiler. All of the plants use a lot of high pressure steam for driving machinery, but this condensate is returned with less than 2 percent loss. The largest requirement for boiler water makeup is for steam which enters into the conversion reactions. The Lurgi, SRC and Synthoil plants require low pressure steam, while the Hygas, Bigas and Synthane require higher pressure steam. The Lurgi process requires the most steam, followed by the Hygas and Synthane processes which require comparable amounts, and then by the Bigas process which requires the least boiler feed water for coal gasification (Figures 5-7 and 5-8). The SRC and Synthoil processes require little steam. In some cases reverse osmosis is used to return treatment condensate to the boiler in those Lurgi plants where all of the condensate is not required in the cooling tower. This is followed by activated carbon adsorption. It may be necessary for the carbon bed to precede reverse osmosis so as to prevent membrane fouling, but the arrangement shown in Figure 6-3B is preferable because it reduces the load on the carbon.

Foul condensate treatment includes phenol extraction, ammonia separation and biotreatment. Phenol extraction, involving solvent extraction of phenolic compounds in which phenol is recovered and sold to help defray the costs,

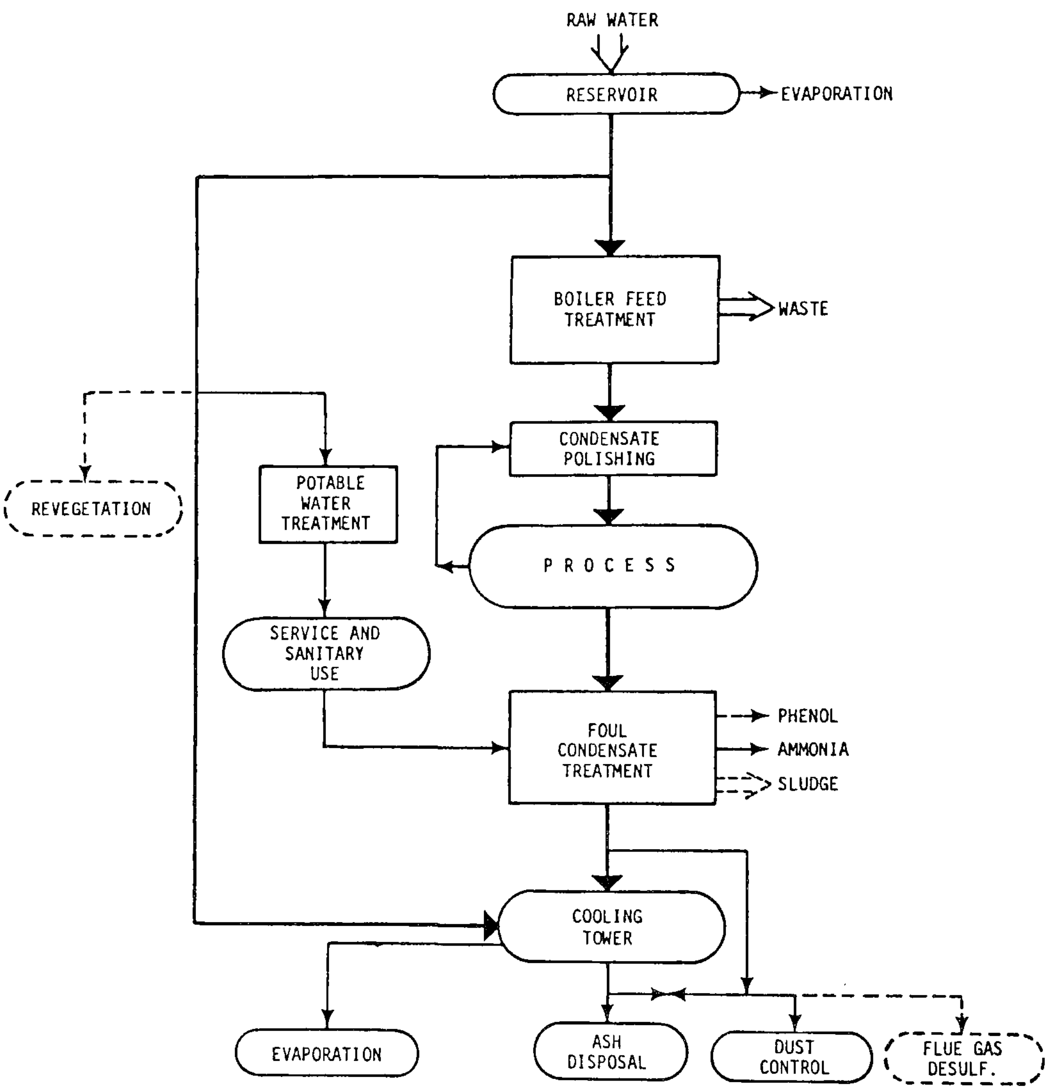
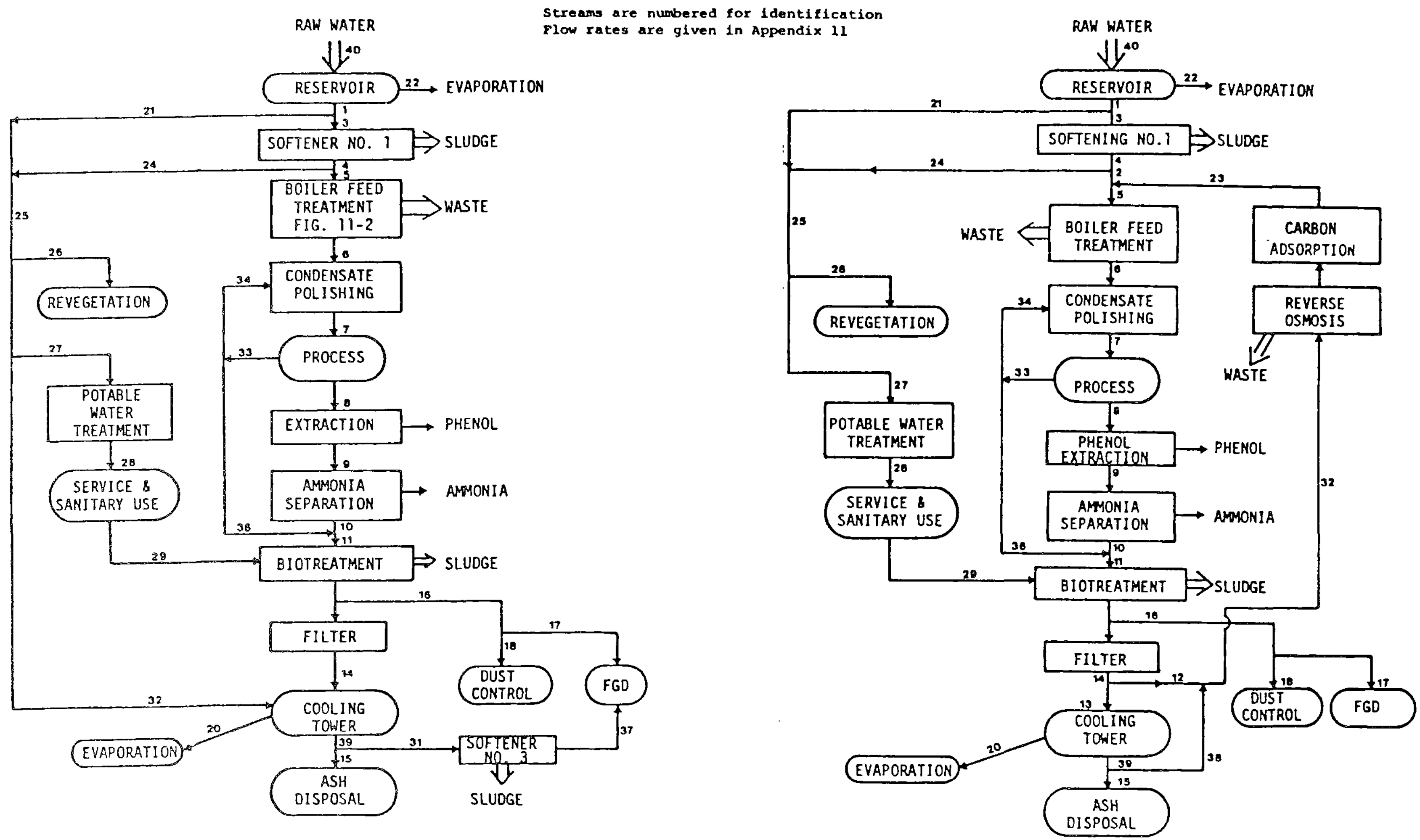


Figure 6-2 Water treatment flow diagram for coal conversion plant generating dirty process water (dashed boxes indicated the requirements are not necessary for every plant). (Reprinted from Ref. 3 with the permission of The MIT Press. Copyright 1978 by the Massachusetts Institute of Technology).



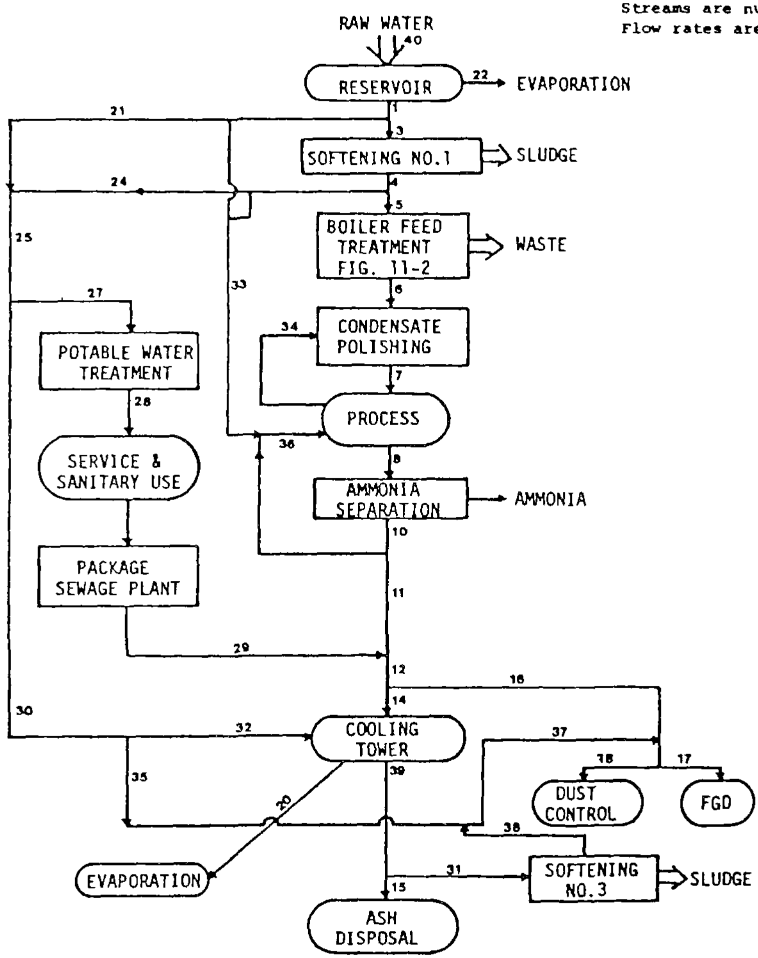
A. Water treatment plant block diagram for all Synthane, some Lurgi and all Hygas.

B. Water treatment plant Block diagram for some Lurgi.

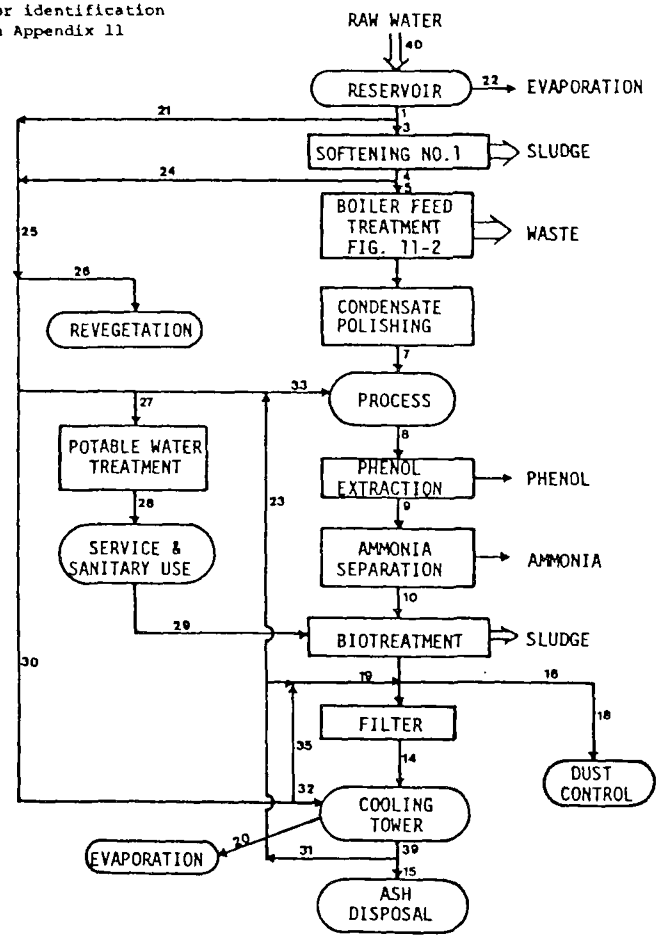
(continued)

Figure 6-3 Water treatment block diagrams.

Streams are numbered for identification
Flow rates are given in Appendix 11



C. Water treatment plant block diagram for Bigas process.

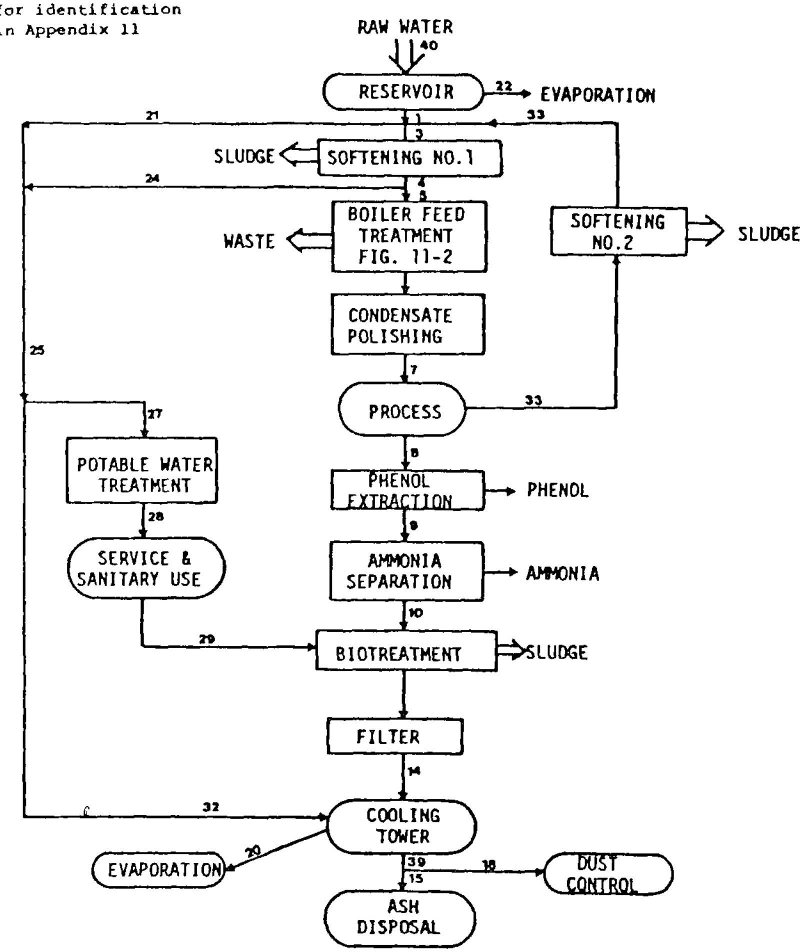


D. Water treatment block diagram for Synthoil process.

(continued)

Figure 6-3 (continued)

Streams are numbered for identification
Flow rates are given in Appendix 11



E. Water treatment block diagram for SRC process.

Figure 6-3 (concluded)

is used only when the foul condensate is highly concentrated. The process was not used for Lurgi or Synthane plants fed by bituminous coal, nor was it used for Hygas and Bigas. Ammonia separation, used for all process-site combinations is a distillative, extractive process, where the ammonia is assumed recovered as a 30 wt % solution and sold to help defray costs. Because of the lack of information on how much organic contamination is acceptable in cooling water, biotreatment is used, when extraction is not used, on dirty condensate from all plants except Bigas.

Cooling water treatment involves lime soda softening of the raw water for cooling tower makeup, filtration of the effluent water from biotreatment, acid treatment of all high alkalinity cooling water makeup streams, the addition of biocide anticorrosion chemicals and suspending agents, and lime soda softening of the cooling tower blowdown. Potable water treatment is just chlorination; the quantity is low and the cost is treated as zero.

We have also made some assumptions in considering specific conversion processes. Since so much of the ash is removed from Synthane plants as dry fly ash, not enough cooling tower blowdown can be disposed of with the ash to control the tower. To maintain the concentration in the circulating cooling water at 10 cycles, blowdown is removed, softened and used as makeup to the flue gas desulfurization scrubber. All Synthane plants are shown on Figure 6-3A. Higas plants use the same flow scheme as Synthane. Because of moisture in the coal, many Lurgi plants yield more treated condensate than is required in the cooling tower. These plants use flow diagram Figure 6-3B. When all the condensate is consumed in the cooling tower, the same flow diagram as Synthane is used (Figure 6-3A). In selected plants, and as required, cooling tower blowdown in addition to that used for ash handling is taken to maintain 10 cycles of concentration. Figure 6-3C applies to all Bigas plants and to no others. In some plants, fresh water or softened tower blowdown is used for dust control and FGD makeup because there is not enough condensate. Where necessary the tower is blown down to maintain 10 cycles.

Synthoil plants take in large amounts of quench water into the hydrogen production train and put out large amounts of condensate. Figure 6-3D applies to all Synthoil plants, and on this figure Stream 33 is the net of input minus output water to the hydrogen plant. Furthermore, all cooling towers are blown down at 10 cycles to Stream 33. In doing this we have assumed that the inorganic salts dissolved in the quench water are removed with fly ash somewhere beyond the point of quench and do not accumulate in the system. If the plant were not designed this way, or if this were not possible, then the quench water would have to be of boiler feed quality with hydrogen plant condensates returned through a polishing demineralizer. Figure 6-3E is used for all SRC plants. Condensate from the hydrogen plant is usually softened before use as makeup to the cooling tower. The treated organically contaminated Stream 14 is small and with little organic matter in the cooling tower the blowdown is used for dust control as well as ash disposal. Tower cycles of concentration sometimes reach as high as 14; when high cycles are used, the makeup is softened to ensure satisfactory operation.

6.2 Costs

Table 6-1 summarizes the range of water treatment costs for standard size plants for each of the conversion processes. The costs are also shown in ¢/10^6 Btu of product heating value. For each process, except Bigas, the largest water treatment cost corresponds to the case where brackish water is used as a raw water source and reflects the large costs of boiler feed water treatment associated with demineralization. The highest cost for the Bigas process is for a lignite coal in North Dakota and reflects the high cost of process condensate treatment by ammonia separation. It is clear that the highest cost for any process is for Lurgi because the quantities of steam required and dirty condensate produced are greater than those for any of the other processes. The costs of water treatment for the other coal gasification processes are comparable and are determined by the costs of both boiler feed water treatment and condensate treatment. The lowest costs are those for the coal liquefaction and SRC processes. Although the process condensates for these processes have the worst quality, the costs are determined primarily by the quantities of process condensate produced and boiler feed water required, which are quite low for the Synthoil and SRC processes. If the cost of the product fuel is about \$2-3/10^6 Btu, the water treatment charge, after taking credit for byproduct ammonia, is one which is not likely to exceed 7 percent of the sale price of the product fuel for any of the plants.

Table 6-2 is a regional summary of the costs of water treatment in ¢/10^6 Btu. In most of the cases the range of water costs in each region is quite narrow, except for some unusual cases. For example, as we have pointed out above, the largest costs are incurred when brackish water is used as the water source. This is particularly true for the Lurgi and SRC processes in the Illinois coal region; the Synthane, Hygas and SRC processes in the Powder River-Ft. Union regions for subbituminous coals; and the SRC process in the Powder River-Ft. Union regions for lignite. In the Powder River-Ft. Union regions, the Lurgi plant at Kemmerer, Wyoming requires treatment of the return treatment condensate to the boiler by reverse osmosis and carbon adsorption, increasing the costs substantially. The cost of phenol extraction at the Lurgi plant at Wesco, Four Corners and some Synthoil plants in Ohio and Kentucky is quite high.

TABLE 6-1 SUMMARY OF WATER TREATMENT COSTS
FOR STANDARD SIZE SYNTHETIC FUEL PLANTS

	$/hr	$1000/day	¢/10^6 Btu
Coal Gasification			
Lurgi	530 - 1400	12.6 - 33.1	5.3 - 14.0
Synthane	170 - 430	4.0 - 10.2	1.7 - 4.3
Hygas	230 - 410	5.5 - 9.9	2.3 - 4.1
Bigas	160 - 280	3.8 - 6.6	1.6 - 2.8
Coal Refining			
Synthoil	55 - 129	1.3 - 3.1	0.4 - 1.1
Clear Coal			
SRC	60 - 220	1.5 - 5.2	0.4 - 1.6

A summary of the average costs of water treatment in a given region is shown in Figures 6-4 and 6-5. These results indicate that the costs of cooling water treatment are quite low and that the costs of condensate treatment in general exceed those of boiler feed treatment. However, there are

TABLE 6-2 REGIONAL SUMMARY OF THE COST OF WATER TREATMENT IN SYNTHETIC FUEL PLANTS IN ¢/10^6 BTU

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous
Coal Gasification						
Lurgi	-	12.5	9.80-13.80	6.70-8.70	8.40-8.60	5.40-7.30
Synthane	1.87-3.00	-	1.64-2.83	2.91-4.26	-	-
Hygas	2.31-2.75	2.89-2.95	2.35-2.77	2.65-4.13	2.66	2.94-3.64
Bigas	-	-	1.79-1.89	1.57	2.52-2.81	-
Coal Liquefaction						
Synthoil	0.33-0.55	-	0.59-0.60	0.65-0.70	-	1.05
Coal Refining						
SRC	-	1.16-1.42	0.57-1.42	0.67-1.53	1.00-1.64	-

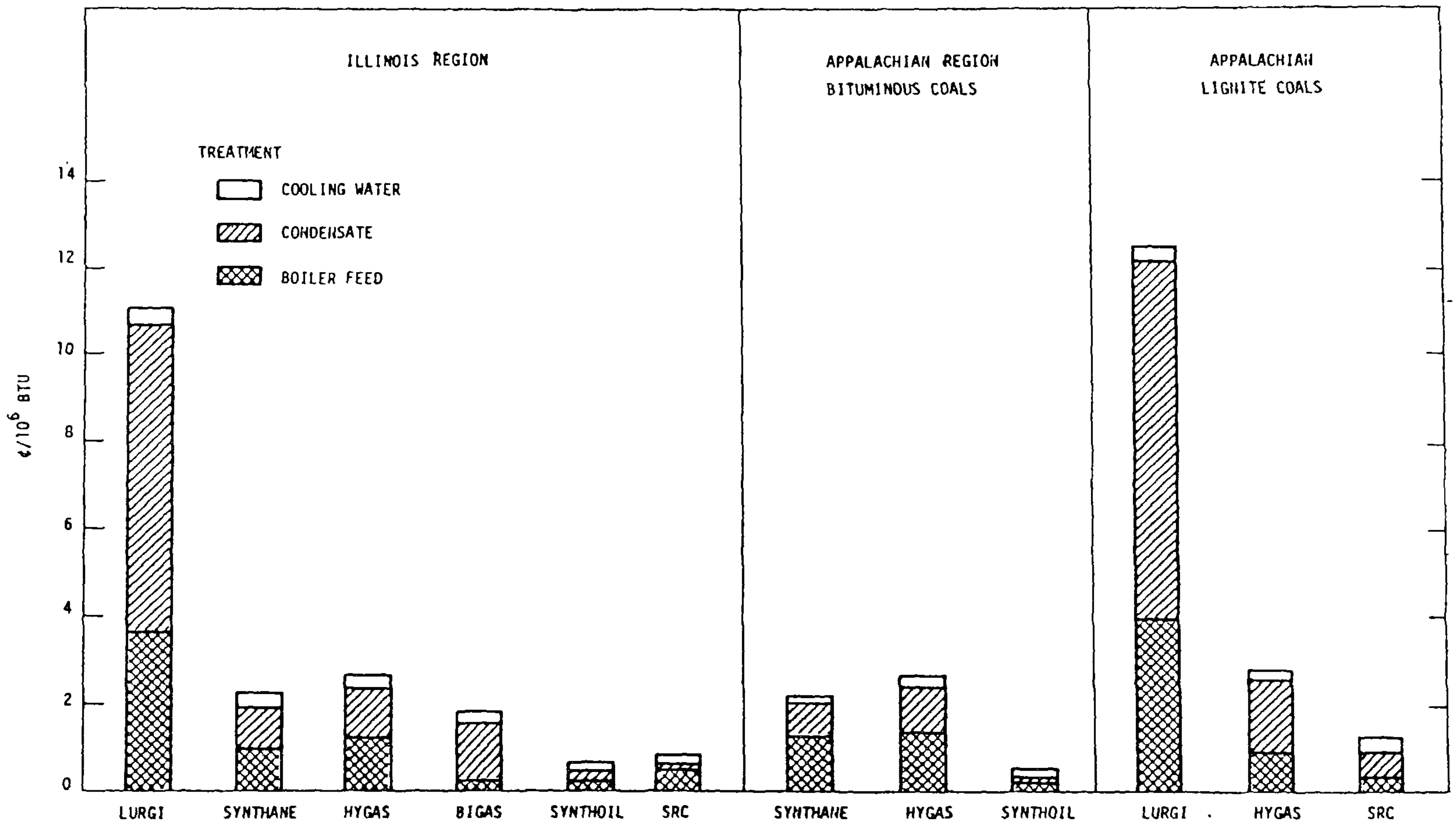


Figure 6-4 Regional summary of the average costs of water treatment ($¢/10^6$ Btu in product) in coal conversion plants located in the Central and Eastern states.

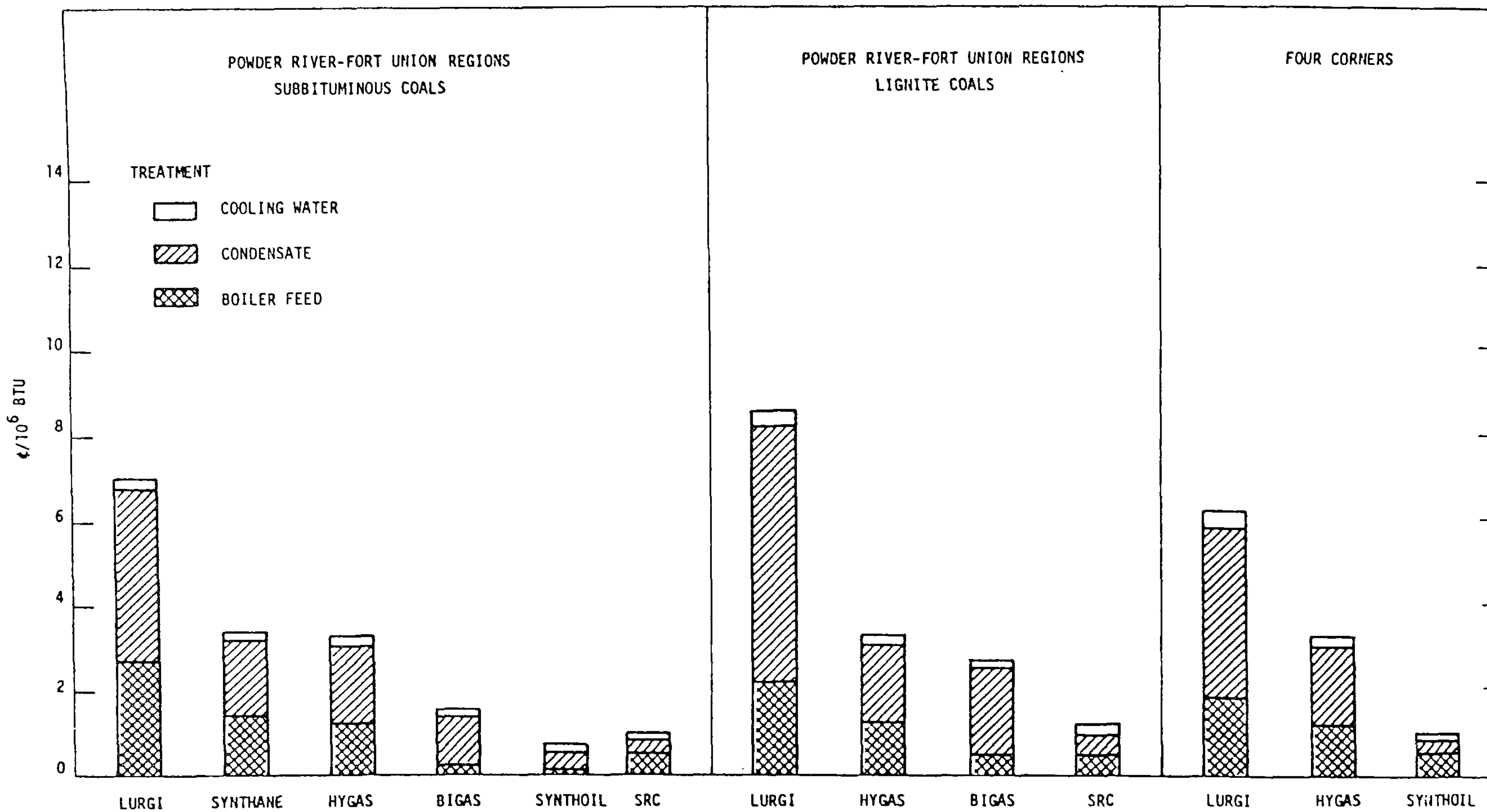


Figure 6-5 Regional summary of the average costs of water treatment ($¢/10^6$ Btu in product) in coal conversion plants located in the Western states.

some situations in which the opposite is true and generalizations are difficult to make because of many competing demands. Nevertheless, comparison of Figures 6-4 and 6-5 with the process flow quantities in Figures 5-9 and 5-10 give some indication of the strong dependence of the costs on flow rate.

6.3 Energy Requirements

The energy requirements for water treatment in standard size synthetic fuel plants are shown in Table 6-3. The energy requirements are also shown as a percent of the product energy. The largest energy requirements for any conversion process are for the Lurgi process, followed by the three other gasification processes, which are comparable. Again, the coal liquefaction and coal refining processes have the lowest energy requirements. For all of the processes, the energy required for the water treatment plants is controlled by the amount needed for ammonia separation, which is directly proportional to the rate of production of foul condensate. Therefore the largest energy

TABLE 6-3 SUMMARY OF THE ENERGY CONSUMED IN WATER TREATMENT IN STANDARD SIZE SYNTHETIC FUEL PLANTS

	10^6 Btu/hr	10^7 Btu/day	Percent Product Energy
Coal Gasification			
Lurgi	230 - 830	550 - 1980	2.3 - 8.3
Synthane	130 - 220	310 - 520	1.3 - 2.2
Hygas	100 - 400	240 - 950	1.0 - 4.0
Bigas	170 - 300	410 - 720	1.7 - 3.0
Coal Liquefaction			
Synthoil	5 - 80	12 - 190	0.039 - 0.62
Coal Refining			
SRC	16 - 130	38 - 310	0.12 - 0.96

requirements generally correspond to those plant-site combinations that produce the most foul condensate. For Lurgi this would be at Marengo, Alabama (lignite coal); for Bigas, at Slope, North Dakota (lignite coal); for Synthoil, at Lake-de-Smet, Wyoming (subbituminous coal); and for SRC, at Coalridge, Montana (lignite coal). The highest energy requirements for the Synthane and Hygas processes are at Antelope Creek, Wyoming where the raw water is brackish and electrodialysis is used to treat the boiler feed water, requiring large amounts of energy. The total energy requirements for the water treatment plants fall in the range of 0.04 to over 8 percent of the product energy, or about 0.03 to 6 percent of the energy in the feed coal.

Table 6-4 shows the energy consumed by region. As mentioned above, the principal variations are due to the variations in the process condensate produced, with some variations due to the raw water quality.

Figure 6-6 and 6-7 present the average energy requirements by region for all of the processes. Most of the energy requirements are for process condensate treatment with very little for boiler feed water treatment and none for cooling water treatment. The energy requirements for boiler feed water treatment are for treatment of the raw water by electrodialysis and treatment of the process condensate for return to the boiler in those Lurgi plants where all of the condensate is not required in the cooling tower. Table 6-5 shows representative values of the energy required for the three different process condensate treatments as a percentage of the total energy required for process condensate treatment. It is clear that ammonia separation is the largest energy consumer in water treatment.

References - Section 6

1. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion Processes," Report No. EPA-600/7-77, U.S. Environmental Protection Agency, Research Triangle Park, N.C., June 1977.

2. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives, The MIT Press, Cambridge, Mass., 1978.

TABLE 6-4 REGIONAL SUMMARY OF THE ENERGY CONSUMED IN WATER TREATMENT IN SYNTHETIC FUEL PLANTS IN PERCENT OF PRODUCT ENERGY

	Appalachian Region		Illinois Region	Powder R/Ft. Union Region		Four Corners
	Bituminous	Lignite	Bituminous	Subbituminous -Bituminous	Lignite	Subbituminous
Coal Gasification						
Lurgi	-	8.3	6.8-7.9	2.3-4.8	6.0-6.6	3.7-5.2
Synthane	1.3-1.5	-	1.3-1.5	1.8-2.2	-	-
Hygas	1.1	1.0	1.1	1.0	1.0	1.0
Bigas	-	-	1.7-2.0	1.8	2.7-3.0	-
Coal Liquefaction						
Synthoil	0.039-0.22	-	0.22-0.29	0.62	-	0.46
Coal Refining						
SRC	-	0.68-0.72	0.12-0.39	0.32-0.68	0.62-0.96	-

TABLE 6-5 ENERGY REQUIRED FOR WATER TREATMENT AS A PERCENTAGE OF THE TOTAL ENERGY REQUIREMENTS FOR PROCESS CONDENSATE TREATMENT

	Phenol Extraction	Ammonia Separation	Biotreatment
Coal Gasification			
Lurgi	35	60	5
Synthane		80	20
		95	5
	35	60	5
Hygas		95	5
	35	60	5
Bigas		100	
Coal Liquefaction			
Synthoil	30	50	20
Coal Refining			
SRC	30	50	20

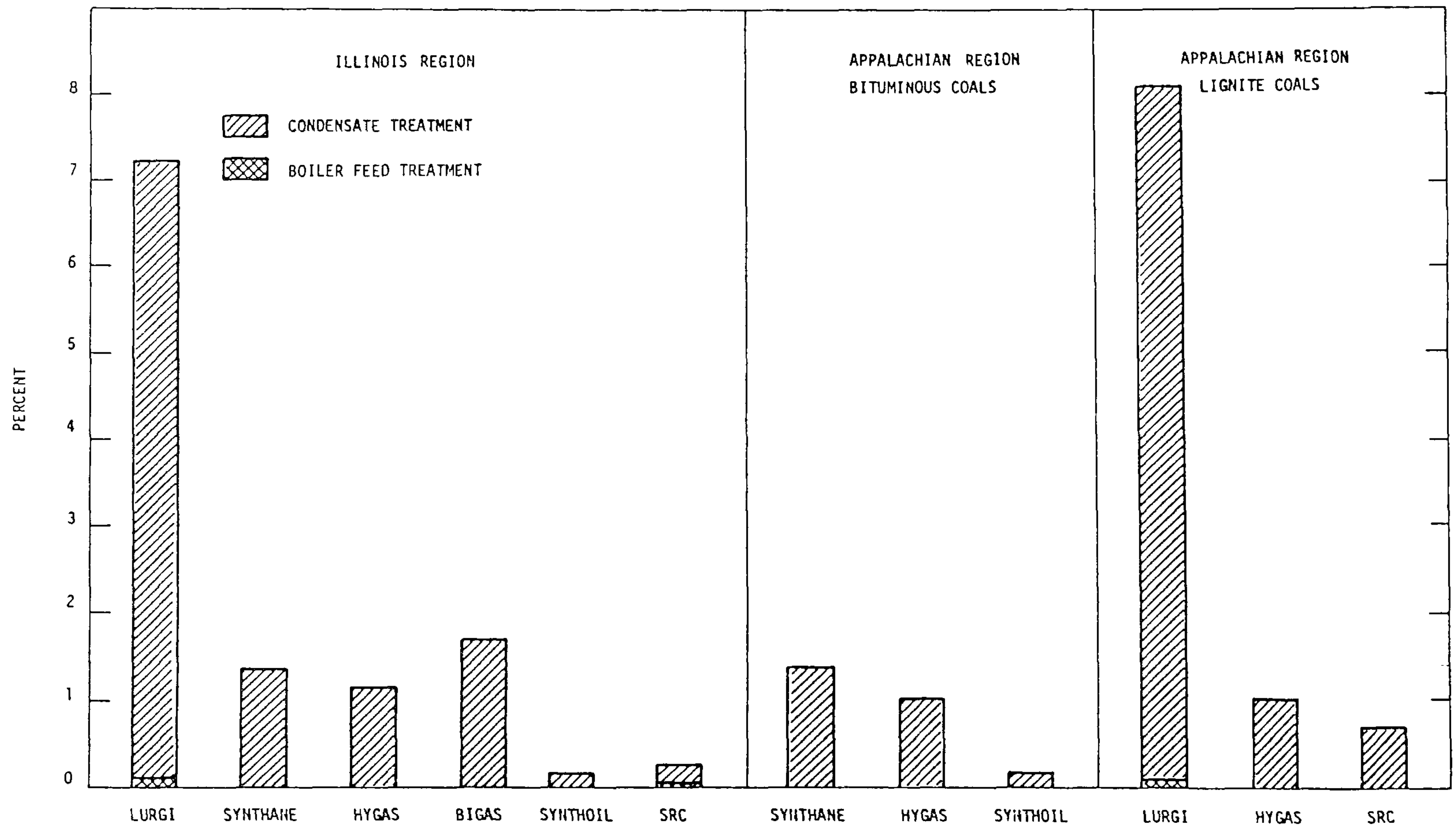


Figure 6-6 Regional summary of the average energy consumed for water treatment in percent of the heating value of the product fuel in coal conversion plants located in the Central and Eastern states.

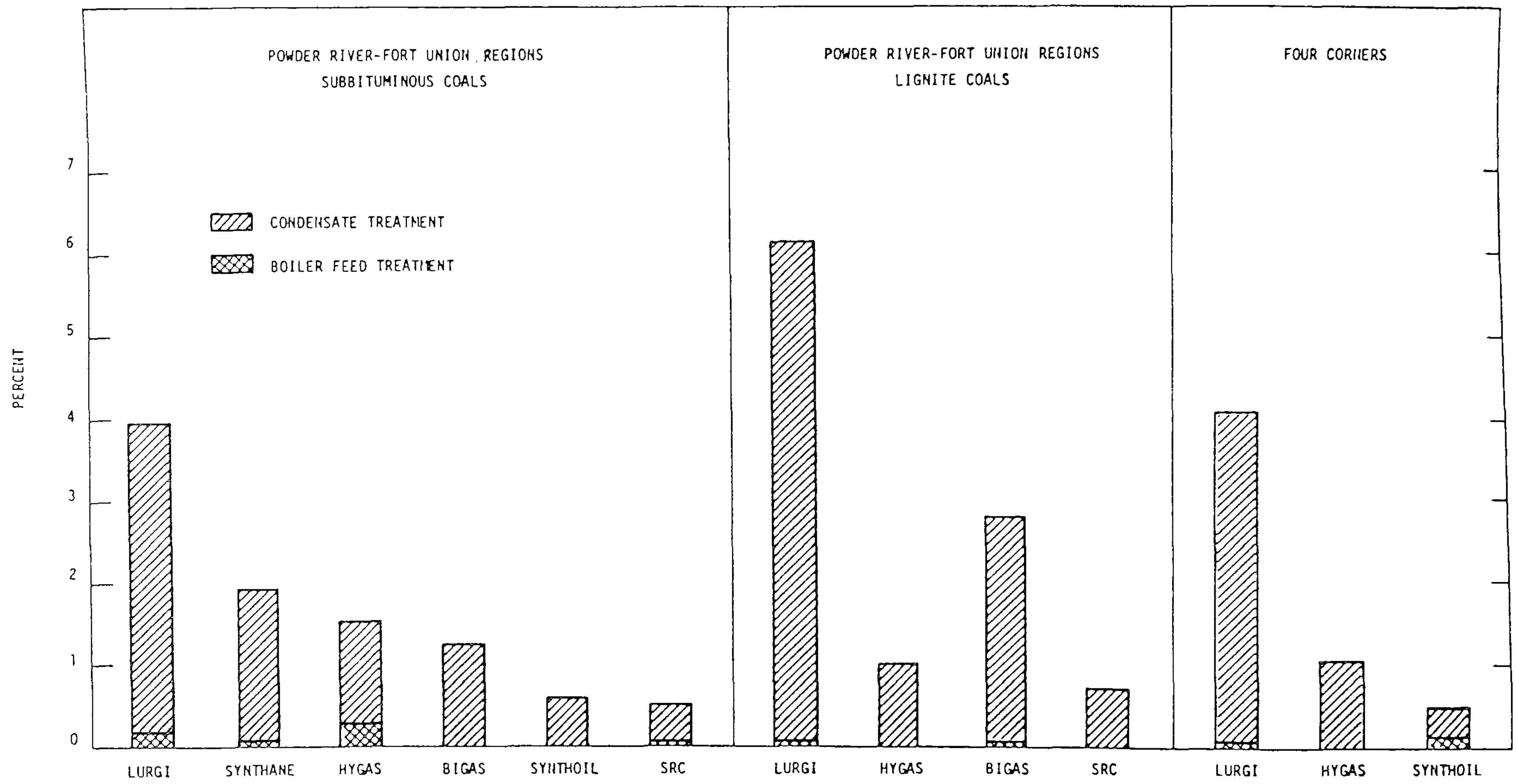


Figure 6-7 Regional summary of the average energy consumed for water treatment in percent of the heating value of the product fuel in coal conversion plants located in the Western states.

7. GENERALIZATION OF RESULTS

7.1 Process-Coal Combinations

In Table 7-1 we have summarized the results presented in Sections 5 and 6 by conversion process with no distinction made between coal rank except for the mining rates. The results have been normalized with respect to the heating value of the product. In Table 7-2 we have summarized the results by coal rank and process; the results are shown graphically in Figure 7-1. The difference in mining rates is due to the variation in the heating values of the different rank coals and the different conversion efficiencies of the processes considered.

In general the net water requirements are largest for coal gasification, followed by coal liquefaction and coal refining. The difference between the last two processes is relatively small. The differences in net water consumption as a function of coal rank are small, except for the Lurgi process where the smallest requirement is for the wet lignite coals. The Lurgi process accepts wet coal and the large quantities of dirty condensate produced are treated for reuse and are subtracted from the process requirement. For intermediate wet cooling the water requirements for the Paraho Direct process are comparable with the Synthoil process, which roughly produces the same product. However, the Paraho Indirect and TOSCO II processes have the largest net water requirements due mainly to the larger requirements for spent shale disposal and revegetation.

The maximum difference in water consumption for coal gasification between high wet cooling and minimum practical wet cooling, with no distinction made between site and gasification process, is about a factor of four, pointing up the importance of the choice of process and cooling design in the amount of water consumed in synthetic fuel production. The maximum difference in water consumption between high wet cooling and minimum practical wet cooling at a given site is approximately 10 gal/10^6 Btu. Minimum practical wet cooling will be used if water is relatively expensive, that is about $1.50/1000 gal or more. Even so, minimum practical cooling will cost about 1.5¢/10^6 Btu more than high wet cooling because of the higher annual capital costs of dry cooling systems.

TABLE 7-1 SUMMARY OF RESULTS BY CONVERSION PROCESS

	Reactor Type	Mining Rates ($lb/10^6$ Btu) Lignite	Subbituminous	Bituminous	Net Water Consumption ($gal/10^6$ Btu) High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	Wet Solid Residuals ($lb/10^6$ Btu)	Water Treatment Cost (¢/10^6 Btu)	Water Treatment Energy (% Prod. Energy)
Coal Gasification										
Lurgi	Fixed Bed	250-360	160-220	140-160	18-30	9-22	7-21	59-126	5.4-14.0	2.3-8.3
Synthane	Fluid Bed	250 [a]	180-220 [a]	130-160	22-27	16-19	15-17	40-56	1.7-4.3	1.3-2.2
Hygas	Fluid Bed Hydrogasifier	200-240	120-180	110-140	21-26	16-19	15-19	32-64	2.3-4.1	1.0-4.0
Bigas	Entrained Flow	220-270	-	110-140	25-27	16-18	14-17	27-61	1.6-2.8	1.7-3.0
Coal Liquefaction										
Synthoil	Catalytic Fixed Bed	-	120-170	100-120	17-21	11-14	10-14	7-28	0.3-1.1	0.04-0.6
Coal Refining										
SRC	Dissolver	180-280	160-180	110 [a] -140	13-21	8-13	7-11	12-40	0.7-1.6	0.1-1.0
Oil Shale			High Grade Shale							
Paraho Direct	Direct Retorting		630			18		520		
Paraho Ind.	Indirect Retort.		720			28		630		
TOSCO II	Indirect Retort.		510			29		470		

a Data from Ref. 1. Refers only to number and not to range.

TABLE 7-2 SUMMARY OF RESULTS BY CONVERSION PROCESS AND COAL RANK OR GRADE OF OIL SHALE

LIGNITE COAL

	Mining Rate ($lb/10^6$ Btu)	Net Water Consumption ($gal/10^6$ Btu) High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	Wet Solid Residuals ($lb/10^6$ Btu)	Water Treatment Cost (¢/10^6 Btu)	Water Treatment Energy (% Prod. Energy)
Coal Gasification							
Lurgi	250-360	18-24	9-15	7-13	61-96	8.4-12.5	6.0-8.3
Synthane	310*	24*	15*	13*	33*		
Hygas	200-240	21	16	15	32-35	2.7-3.0	1.0
Bigas	220-270	26-27	18	16-17	34-69	2.5-2.8	2.7-3.0
Coal Liquefaction							
Synthoil	200*	19*	14*	13*	34*		
Coal Refining							
SRC	180-280	15-21	8-12	7-11	20-34	1.0-1.6	0.6-1.0

SUBBITUMINOUS COAL

	Mining Rate ($lb/10^6$ Btu)	Net Water Consumption ($gal/10^6$ Btu) High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	Wet Solid Residuals ($lb/10^6$ Btu)	Water Treatment Cost (¢/10^6 Btu)	Water Treatment Energy (% Prod. Energy)
Coal Gasification							
Lurgi	160-220	23-30	15-22	14-21	59-126	5.4-7.5	2.3-5.2
Synthane	180-200*	25-28*	17-19	16-17	46-59	2.9-4.3	1.8-2.2
Hygas	120-180	21-23	16-18	15-17	32-64	2.7-4.1	1.0-4.0
Bigas							
Coal Liquefaction							
Synthoil	120-170	17-22*	11-16*	10-16*	21-72*	0.7-1.1	0.5-0.6
Coal Refining							
SRC	160-180	14-21*	8-11*	7-10*	19-86*	0.9-1.5	0.5-0.7

*Data from Ref. 1. Refers only to number and not to range.

TABLE 7-2 (continued)

BITUMINOUS COALS

	Mining Rate (lb/10^6Btu)	Net Water Consumption (gal/10^6 Btu) High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	Wet Solid Residuals (lb/10^6 Btu)	Water Treatment Cost (¢/10^6 Btu)	Energy (% Prod. Energy)
Coal Gasification							
Lurgi	140-160	25-29	19-21	17-20	65-95	9-14	5-8
Synthane	130-160	22-23	16-17	15-16	40-54	1.6-3.0	1.3-1.5
Hygas	110-140	23-26	18-20	17-19	29-55	2.3-2.8	1.1
Bigas	110-140	24-27	16-18	14-16	27-56	1.6-1.9	1.7-2.0
Coal Liquefaction							
Synthoil	120-170	18-21	13-15	12-14	7-28	0.3-0.6	0.04-0.3
Coal Refining							
SRC	160-180	13-17	8-13	7-12	12-40	0.6-1.4	0.1-0.4

OIL SHALE

	Mining Rate (lb/10^6Btu)	Net Water Consumption (gal/10^6 Btu) Intermediate Minimum Wet Cooling	Wet Solid Residuals (lb/10^6 Btu)
Oil Shale			
Paraho Direct	630	18	520
Paraho Indirect	720	28	630
TOSCO II	510	29	470

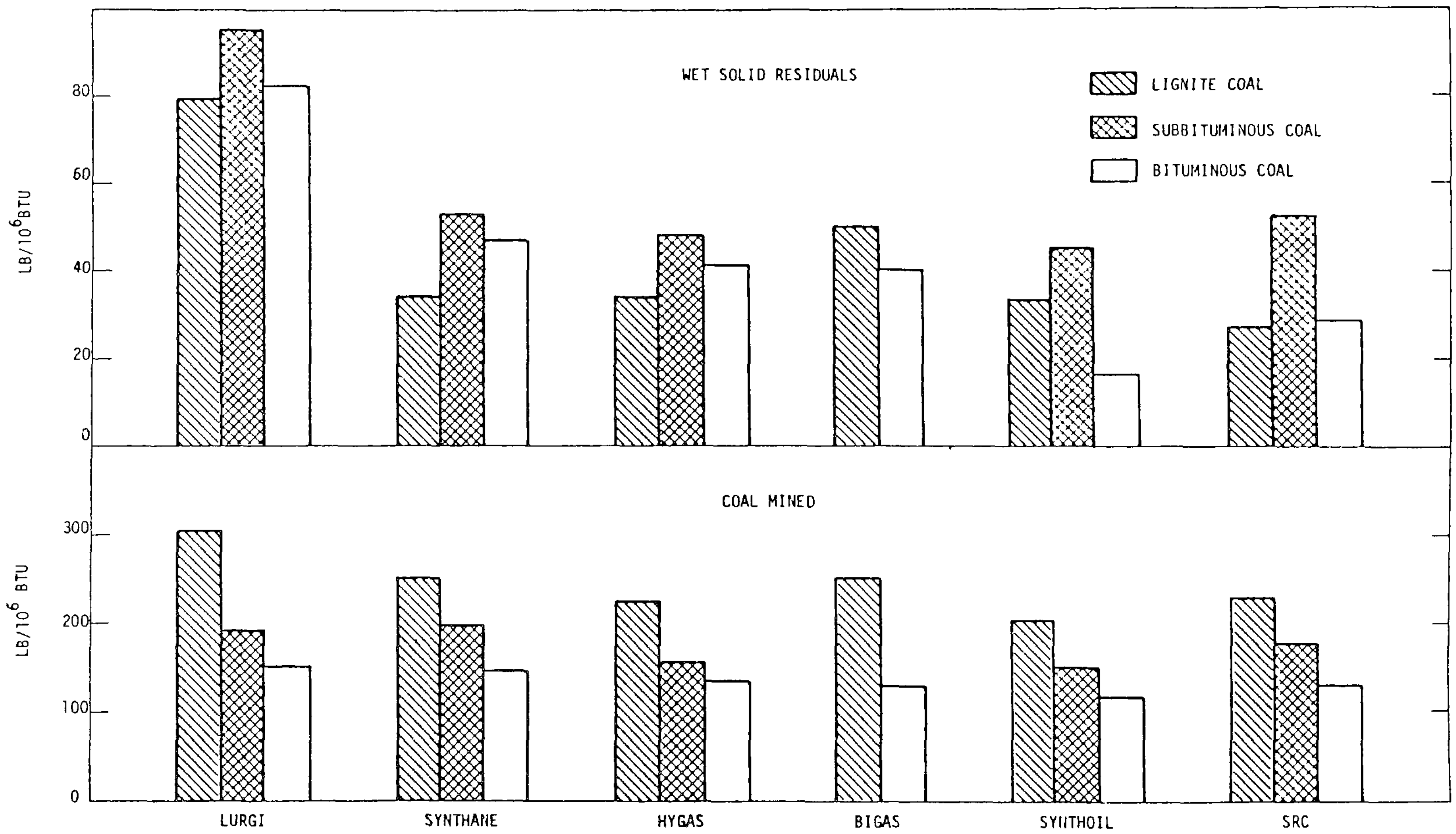


Figure 7-1 Summary of process-site results

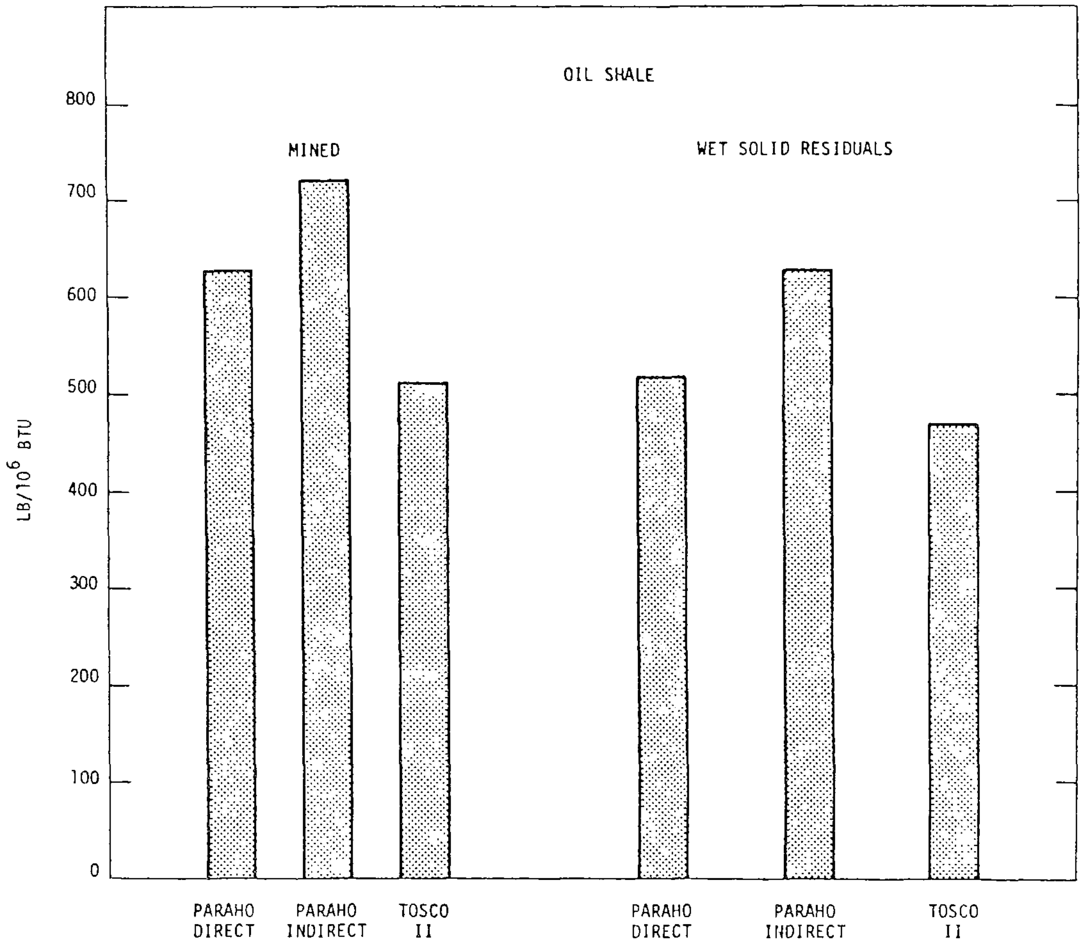


Figure 7-1. (continued)

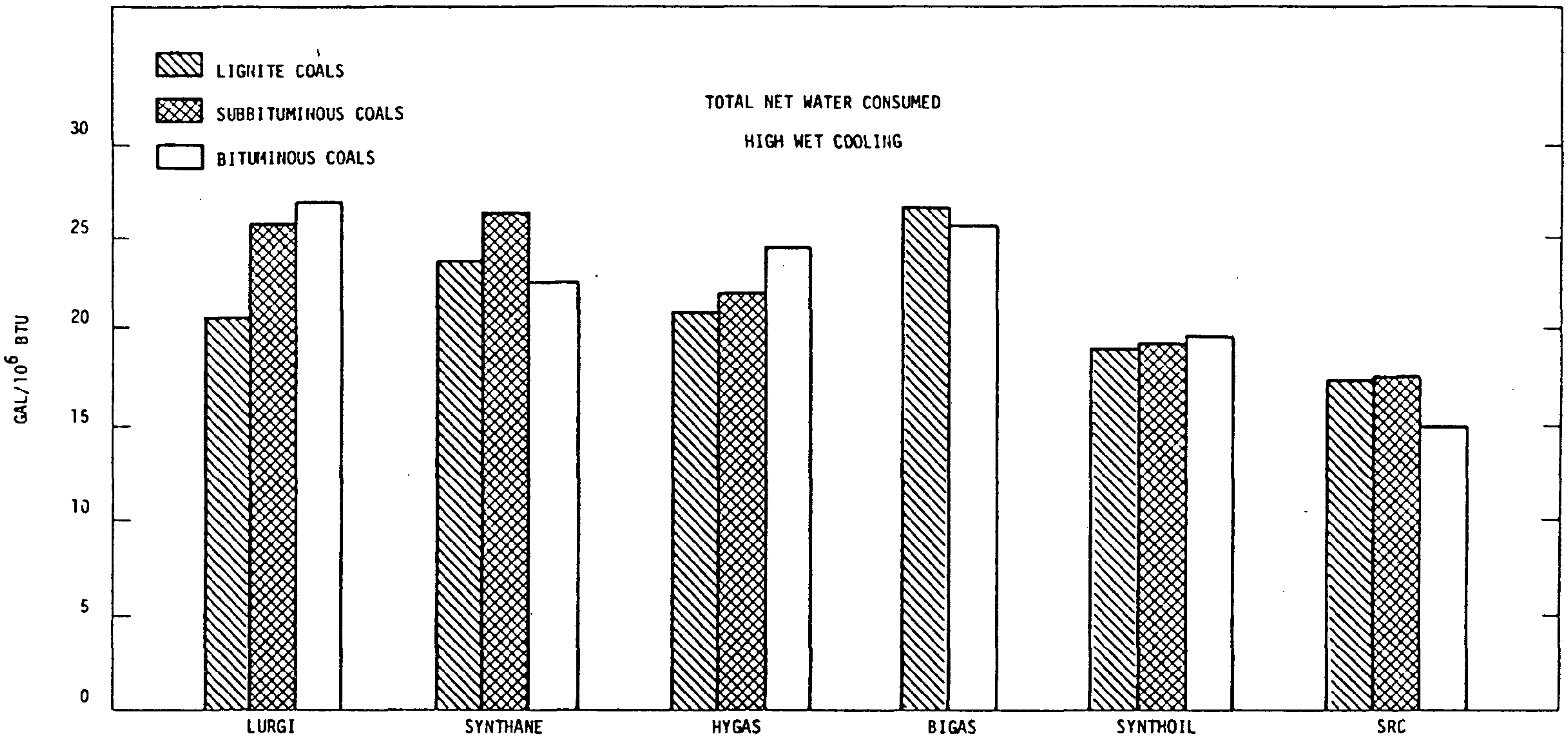


Figure 7-1 (continued)

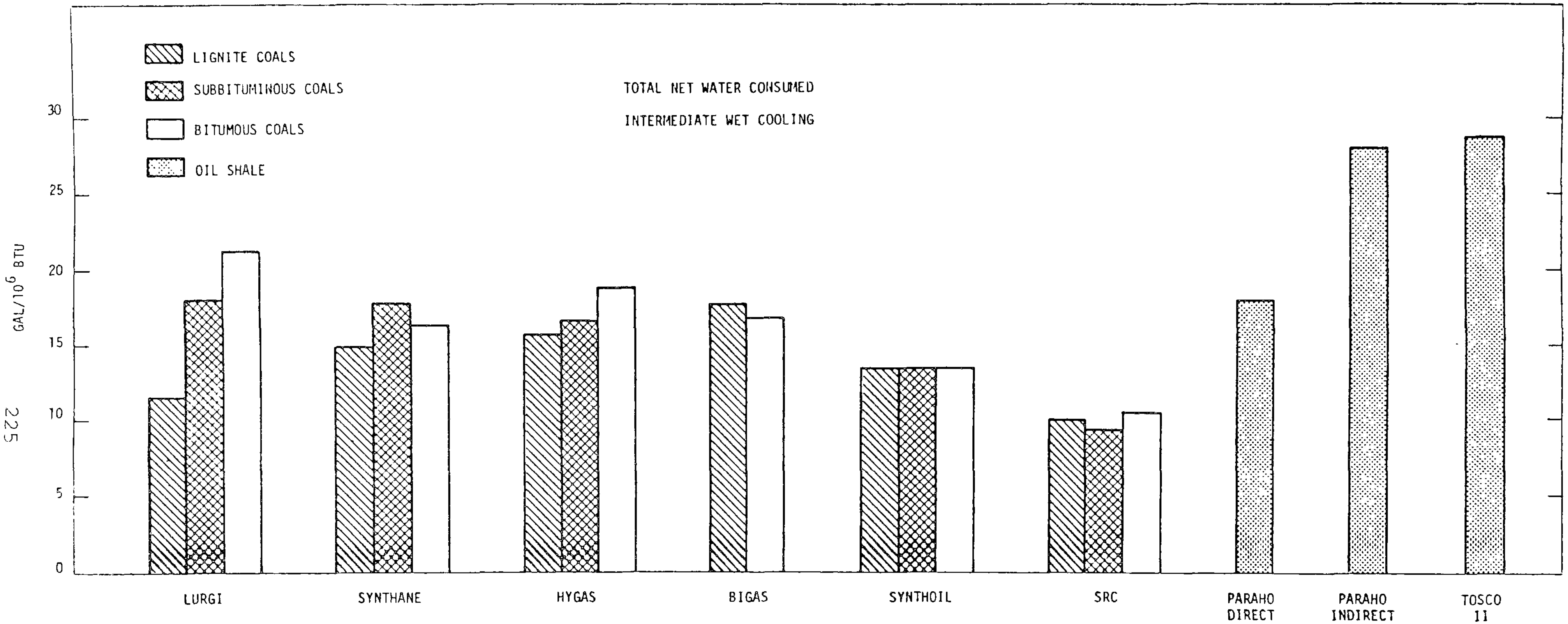


Figure 7-1 (continued)

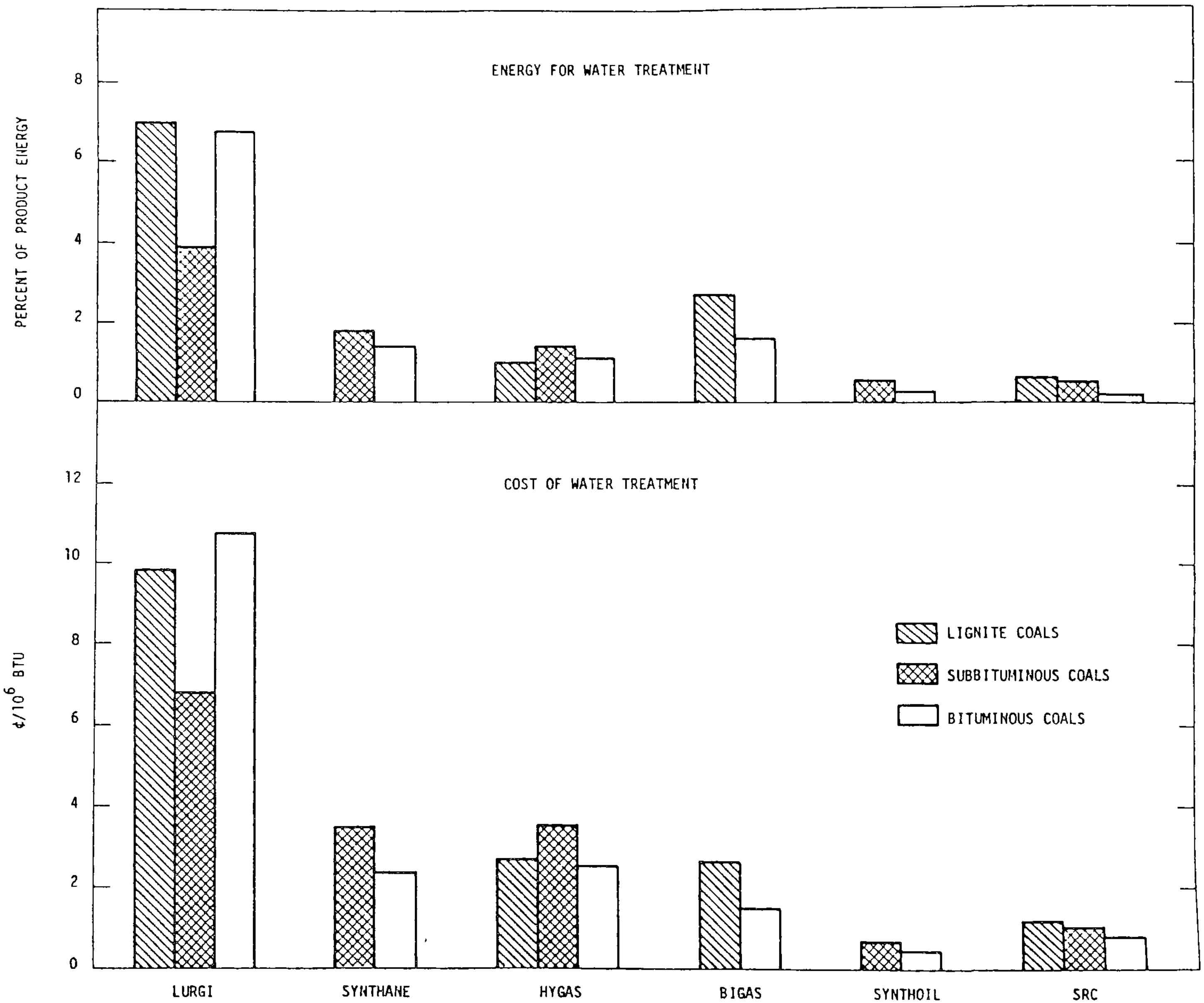


Figure 7-1 (concluded)

As we have pointed out in Section 5, the largest quantities of wet solid residuals for the Lurgi, Hygas and Synthoil proccesses occur in areas with the highest ash coals. For the Synthane and SRC processes the largest residuals are generated at sites utilizing groundwater since large amounts of wastewater from the boiler feed water treatment plants must be disposed of. For the Bigas process, the quantities of both ash and flue gas desulfurization sludge determine the sites with the largest residuals.

The highest cost of water treatment is for the Lurgi process because the quantities of steam required and dirty condensate produced are greater than those for any of the other processes. The costs of water treatment for the other three processes are comparable and reflect the sum of the costs of boiler feed water treatment and dirty process condensate treatment. The lowest costs are for the coal liquefaction and coal refining processes because of the small quantities of process condensate produced and boiler feed water required, although these condensates have the worst quality of any of the other processes. The variation in cost between coal rank is small, except when brackish water is used as a raw water source.

The energy requirements for water treatment, in general, follow the same trend as the costs of water treatment. For all of the processes the energy required for the water treatment plants is controlled by the amount needed for ammonia separation, which is directly proportional to the rate of production of foul condensate.

7.2 Process-Site Combinations

A breakdown of the results by conversion technology and for each coal and oil shale region was presented in Section 5 and 6. In Sections 4 and 5 we specified the cooling option that would be most suitable in a given region, based on the availability and/or cost of water at a particular site. In the East and Central regions we have picked the cooling option based on the availability of water, since in general the cost of transporting water in these regions is very low because of the close proximity of the coal conversion plant to the water source (Riparian Doctrine). Figures 4-2 and 4-3 shows those areas where water is plentiful, marginally available and scarce; the results are generally valid for both low water demand where approximately one or two standard size coal conversion plants are located in each one of the coal regions; and high water demand, where approximately $1x10^6$ barrels/day of synthetic crude, or its equivalent in other fuels of $5.8x10^{12}$ Btu/day are to be produced in each one of the coal regions.

In the Western region the cooling option is based on the cost of transporting water. For low water demand, Figure 4-11 shows that except for plants located near the main stem of the major rivers, intermediate cooling would be used for a large majority of sites in the Upper Missouri Basin and the Four Corners region. In general we could extend this result to the Upper Colorado Basin. For high water demand, $1x10^6$ barrels/ day of synthetic crude, or its equivalent in other fuels, are produced in each of the three principal coal bearing regions: Ft. Union, Powder River and Four Corners; and in the principal oil shale region, Green River Formation. The water requirements for each of the drainage subareas within a coal or oil shale region have been divided equally. Figure 4-12 shows the cost of transporting water to some of the major coal producing regions. Here again, except for large scale development near the main stem of the major rivers intermediate or minimum practical cooling would be desirable for most of the regions.

Table 7-3 shows the range in total net water consumption for intermediate and minimum practical cooling as a percentage of the total net water consumption for high wet cooling. The numbers in parentheses are the averages for all of the sites for a given conversion process. For coal gasification and liquefaction the total net water consumption with intermediate wet cooling is about 72 percent of the total net water consumption for high wet cooling, and 66 percent with minimum practical wet cooling. The percentages for coal refining are 63 and 56 percent, respectively. The cost and energy for water treatment are relatively insensitive to the degree of wet cooling.

The average total net water consumed for all the processes is shown in Table 7-4 in 10^6 gpd for standard size plants and in gal/10^6 Btu.

TABLE 7-3 TOTAL NET WATER CONSUMPTION FOR INTERMEDIATE AND MINIMUM PRACTICAL WET COOLING AS A PERCENTAGE OF TOTAL NET WATER CONSUMPTION FOR HIGH WET COOLING

	Intermediate Wet Cooling	Minimum Practical Wet Cooling
Coal Gasification		
Lurgi	0.63-0.74 (0.71)	0.55-0.68 (0.65)
Synthane	0.68-0.74 (0.72)	0.62-0.70 (0.67)
Hygas	0.74-0.79 (0.77)	0.72-0.76 (0.74)
Bigas	0.64-0.68 (0.67)	0.58-0.62 (0.60)
Coal Liquefaction		
Synthoil	0.64-0.73 (0.71)	0.58-0.70 (0.65)
Coal Refining		
SRC	0.56-0.72 (0.63)	0.47-0.68 (0.56)

7.3 Large Scale Synthetic Fuel Production

In this section results are presented for a synthetic fuel production level of 1×10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 5.8×10^{12} Btu/day. Table 7-5 lists the number of standard size plants required to produce 5.8×10^{12} Btu/day for the conversion technology and product output indicated. The range is from 18 clean coal plants each producing 10,000 tons/day of solvent refined coal to 24 coal gasification plants producing 250×10^6 scf/day of pipeline gas. For coal gasification the low and high ends of the range were derived using the high and low values in Table 7-1 for all four gasification processes.

References - Section 7

1. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives, MIT Press, Cambridge, Mass. 1978.

TABLE 7-4 TOTAL NET WATER CONSUMED BY CONVERSION PROCESS

	10^6 gpd			$gal/10^6$ Btu		
	High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling
Coal Gasification	5.8	4.1	3.8	24	17	16
Coal Liquefaction	5.9	4.3	4.0	19	14	13
Coal Refining	5.1	3.2	2.9	16	10	9
Oil Shale						
Direct Retort		5.3			18	
Indirect Retort		8.4			29	

TABLE 7-5 NUMBER OF STANDARD SIZE PLANTS REQUIRED TO PRODUCE 1×10^6 BARRELS/DAY OF SYNTHETIC CRUDE OR ITS EQUIVALENT OF 5.8×10^{12} BTU/DAY

Conversion Technology	Product	Unit Output	Number of Standard Size Plants
Coal gasification	Pipeline gas	250×10^6 scf/day	24
Coal liquefaction	Fuel oil	50,000 barrels/day	19
Coal refining	Solvent refined coal	10,000 tons/day	18
Oil shale	Synthetic crude	50,000 barrels/day	20

TABLE 7-6 SUMMARY OF RESULTS FOR THE PRODUCTION OF 1 x 10^6 BARRELS/DAY OR ITS EQUIVALENT IN OTHER FUELS OF 5.8 x 10^{12} BTU/DAY

	Mining Rates (1000 tons/day)			Net Water Consumption (10^6 gal/day)			Wet Solid Residuals	Water Treatment	
	Lignite	Subbi-tuminous	Bituminous	High Wet Cooling	Intermediate Wet Cooling	Min. Practical Wet Cooling	(1000 ton/day)	Cost ($\$10^3$/day)	Energy (10^{10} Btu/day)
Coal Gasification	580-1040	350-640	320-460	100-170	50-130	40-120	80-360	93-810	5-50
Coal Liquefaction	-	350-490	290-350	100-120	60-80	60-80	20-80	20-70	0.3-3
Coal Refining	520-810	460-520	320-410	75-120	50-75	40-65	35-115	40-90	0.6-6
Oil Shale		High Grade 1480-2090			100-170		1360-1830		

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-78-197a	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Water-related Environmental Effects in Fuel Conversion: Volume I. Summary		5. REPORT DATE October 1978
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Harris Gold and David J. Goldstein		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Water Purification Associates, 238 Main Street, Cambridge, Massachusetts 02142		10. PROGRAM ELEMENT NO. EHE623A
		11. CONTRACT/GRANT NO. 68-03-2207
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development, Industrial Environmental Research Laboratory, Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 10/76 - 9/78
		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Chester A. Vogel, Mail Drop 61, 919/541-2134.

16. ABSTRACT The report gives results of an examination of water-related effects that can be expected from siting conversion plants in the major U.S. coal and oil shale bearing regions. Ninety plant-site combinations were studied: 48 in the Central and Eastern U.S. and 42 in the Western. Synthetic fuel technologies examined include: coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low sulfur fuel oil; coal refining to produce a de-ashed, low-sulfur solvent refined (clean) coal; and oil shale retorting to produce synthetic crude. Results presented include the range of water requirements, conditions for narrowing the range and optimizing the use of water, ranges of residual solid wastes, and cost and energy requirements for wastewater treatment. A comparison of water requirements with those of two recently published studies shows widely varying estimates and emphasizes the need for both site- and design-specific calculations. A review of various combinations of cooling requirements indicates a factor of 4 difference in water consumption across all processes studied. Where water costs < 25¢/1000 gal., a high degree of wet cooling appears best. If >$1.50/1000 gal, a minimum of wet cooling should be considered. Between these, a more balanced mix needs to be reviewed. All water requirements of this study are based on complete water re-use; i.e., no direct water discharge to streams or rivers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Crude Oil	Pollution Control	13B	
Water Consumption	Water Cooling	Stationary Sources		13A
Coal Gasification	Waste Water	Fuel Conversion	13H	
Coal	Wastes	Synthetic Fuels	21D	
Shale Oil	Water Treatment	Coal Refining		
Liquefaction	Waste Treatment	Solvent Refined Coal	07D	
Fuel Oil		Solid Waste		

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 253
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)