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Land Use and Energy

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ARGONNE NATIONAL LABORATORY

Environmental Sciences Division

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LAND USE AND ENERGY

by

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Energy and Environmental Systems Division
Integrated Assessments and Policy Evaluation Group

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EXECUTIVE SUMMARY

Anticipated efforts by the U.S. government to reduce the vulnerability of the United States to foreign oil cutbacks have heightened concern over potential conflicts between energy development and environmental quality. Rapid increases in domestic energy production may impose additional burdens on the environment and cause changes in land use. Regulations that attempt to control land-use changes have been developed at many levels of government. Community zoning regulations or land-use plans specify the general use to which particular plots of land may be put. Geographically specific land-use regulation is generally considered to be the concern of local governments. Certain classes of lands, such as wetlands or floodplains, may be limited by state or federal law to uses that do not destroy the natural functions of the lands. Many states have enacted land-use legislation, for example, to protect fragile lands and to guide local efforts. No land-use legislation as yet exists at the federal level for lands not in the public domain, although a number of federal regulations indirectly affect land-use decisions.

In this report we address the impact of past and future energy development on land use. We estimate the amounts of land required by different phases of the fuel cycle for a number of fuel types and examine the implications of land-use regulations. We discuss major federal legislation that regulates the potential land-use impact of energy facilities and that may influence the location or timing of energy development. We also describe the kinds of state and local regulations that might have effects similar to those of the federal regulations.

The report focuses on national and regional impacts on land use, but such an emphasis does not imply that severe local impacts do not or could not occur with any of the phases of the fuel cycles. Local conflicts will arise with almost any development that will cause permanent or even temporary changes in land use.

1975 LAND USE

The amount of land that was occupied by energy-related activities in the United States in 1975 is roughly estimated at 1.1×10^6 acres (1762 square miles) (see Table 1). This figure is probably a gross underestimate of the amount of land actually devoted to energy uses in that year, however, because it does not include abandoned surface-mined lands or those undergoing reclamation, or the amount of land covered by hydroelectric reservoirs or devoted to transmission corridors. Adding these areas could triple the estimate given above, yielding a total area that accounts for about 0.1% to 0.2% of the continental United States, an area about the size of Connecticut or New Jersey. Comparing this estimate to the amount of land devoted to other uses in the United States in 1971, one finds that energy-related activities occupied about the same amount of land as did airports or railroads, only one-seventh of the area occupied by highways, and only one-tenth of the area taken up by urban uses.

Such comparisons can be misleading, however, because land-use impact can be much greater at the local level than national or regional comparisons

Table 1 Estimated Area Occupied by Energy Activities in 1975

Fuel Cycle Component	Estimated Area (acres)	Comments
Extraction ^a		
Coal	51,400	Disturbed by surface mining in 1975
Oil	196,700	
Natural gas	179,000	
Uranium	2,700	Disturbed in 1975
Geothermal	3,600	
Processing		
Synfuels from coal	300	Pilot plants
Oil refineries	327,400	
Uranium processing	30,700	Milling, conversion, enrichment, and fuel fabrication
Conversion/Combustion		
Coal- and oil-fired power plants	175,000	
Nuclear power plants	123,600	
Hydroelectric facilities	not estimated	
Solid Waste	30,900	Lifetime disposal area requirement for fossil-fueled power plants only
Total	1,121,300	Does not include land requiring or undergoing reclamation, land covered by hydroelectric reservoirs, or land devoted to activities not listed here

^aAssuming no land devoted to oil shale or biomass.

might suggest. Changes in land use associated with energy development can have a significant impact on the quality of the physical, social, economic, and visual environment. Local air quality, water quality, water availability, noise levels, the municipal tax base, land values, job opportunities, and the character of the community itself may be affected. The local population incurs costs but also receives benefits not shared by the larger constituency that the energy development is meant to benefit. New towns may be created, and others may be moved or destroyed. An entire farm could be displaced by a single facility: the average farm size of 400 acres is smaller than most of the average site sizes quoted in the body of this report. These kinds of local impacts are best dealt with on a case-by-case or site-by-site basis. Although they are not addressed in detail in this report, the potential magnitude of local effects should be kept in mind.

INCREASED LAND REQUIREMENTS BY 1990

Potential increases in the amount of land required for energy activities by 1990 are shown in Table 2. To present a worst-case scenario, we chose for this table the highest 1990 projections reported in the text. Thus the total amount of land indicated probably represents the production of more energy than will be needed by that date.

The worst-case estimate thus derived indicates that an additional $18.6\text{--}57.7 \times 10^6$ acres may be required for energy-related activities by 1990. Most of this acreage would be in croplands devoted to energy production; only $1.8\text{--}2.0 \times 10^6$ acres would be in the more intensive energy uses that are more likely to cause adverse land-use impact. These estimates do not include the amount of land required for new hydroelectric facilities, because no acceptable method for calculating that value could be derived. The estimates also do not include land required for new transmission lines and transportation facilities; because these activities can, in many cases, be conducted on existing rights-of-way, additional land requirements by 1990 for these purposes may be small.

To put these estimates into perspective, one can compare them to other land-use changes occurring in America. For instance, the amount of urban land in the United States increased from 61.1×10^6 acres to 89.3×10^6 acres between 1967 and 1977, an average rate of conversion to urban uses of about 2.8×10^6 acres per year. The estimated average rate of conversion of land to nonbiomass uses between 1975 and 2000 is less than one-twentieth of this amount. The potential conversion of rural land to cropland for biomass production can be compared to the rate at which land is "normally" converted to cropland for food and fiber production. Between 1967 and 1975, 48.7×10^6 acres of land, mostly pasture and rangeland, were converted to cropland, an average rate of conversion of about 6×10^6 acres per year. Biomass production may require the conversion to cropland of 1.7 to 5.6×10^6 acres of land per year; the creation of energy farms, then, could possibly double the rate at which the U.S. reserve of potential croplands is depleted. It should be noted, however, that the 5.6×10^6 acres reflects the land required if wheat were the sole energy crop grown; the land estimate drops considerably if other crops are used.

FUEL CYCLE IMPACT

The following text summarizes the land-use impact potentially associated with each kind of energy activity. References are made to the estimates presented in Table 2, estimates based on projections of a high level of activity in all sectors.

The greatest impact on land use occurs when an irreversible change in land use is involved. A conversion to an industrial land use, such as a power plant or oil refinery, is physically or socioeconomically irreversible in most cases. About 517,000 to 523,000 acres of additional land may be required for these kinds of developments by 1990 (see Table 2). Because such developments are often sited near water and/or near transportation networks, there is an increased possibility of conflict with valuable land uses such as wetlands, coastal zone areas, and croplands in river valleys. Industrial developments are also more likely to occur in populous areas of the country,

Table 2 Estimated Additional Area Required for Energy Activities
by 1990^a

Fuel Cycle Component	Estimated Additional Area (10 ³ acres)	Comments
Extraction		
Coal	1,007	Surface mining only; cumulative requirements, 1975-1990
Oil	23	
Oil shale	4-16.5	For shale disposal, assuming 0 in 1980, with linear increase to 1990
Natural gas	3	
Uranium	18-36	Cumulative requirements, 1975-1990
Geothermal	69-241	1990 estimate interpolated from 1985 and 2000 esti- mates
Biomass	16,880-55,740	Grain for ethanol, 17- state central region only
Processing		
Synfuels from coal	24	Coal to gas or liquids
Oil refineries	10.3	
Oil shale retorts	1.2	
Uranium	6.8-13.5	New mills, fuel fabrica- tion facility
Biomass--alcohol production	21	Ethanol from grain; to produce 5.4×10^9 gal/yr
Conversion/Combustion		
Coal- and oil-fired power plants	110.4	
Nuclear power plants	343	
Hydroelectric facilities	not estimated	
Solid Waste	103	Lifetime disposal area requirements for fossil- fueled power plants only
Total	18,643.3-57,712.2	Worst-case estimate:
Without biomass	1,763.3-1,972.2	assumes attainment of highest projected energy production levels re- ported for each fuel and stage of fuel cycle

^aAssuming a high level of production in each component of the fuel cycle.

where they could add to an already rapid conversion to urban uses; they are less likely to directly affect wilderness areas or other preserves.

Other energy developments usually require a more temporary use of the land, with varying degrees of reversibility. The Surface Mining Control and Reclamation Act, for instance, requires that the original land use be restored in mined areas, unless the criteria for a special variance are met. But the temporary conversion to mining use is not totally reversible -- the restoration of original productivity on reclaimed lands is still under question -- and in some areas, such as the arid West, reclamation may not be possible, in which case the change in land use would be permanent. The surface mining of uranium and oil shale will be more likely to cause permanent changes in land use because it will occur almost exclusively in the West. Mining can disrupt virtually any kind of land use, because the resource must be mined where it is found. Surface mining in wilderness areas, prime farmlands, and alluvial valley floors is currently controversial. More than 106 acres could be disturbed by coal and uranium surface mining between 1975 and 2000.

Deep mining affects land use to a lesser extent, and in some cases resources could be mined underground to avoid disturbing valuable surface uses. Planned or unplanned subsidence of deep-mined areas can affect surface uses, however. Impact will be greatest where unplanned subsidence occurs in urban areas. Agricultural activities can also be disrupted if subsidence occurs, especially if drainage patterns are altered.

Recovery of oil, gas, and geothermal steam is a less disruptive use of the land, because each well usually requires less than an acre of land. Though spacing requirements within the well field cause relatively large areas to be devoted to energy use for the life of the operation, only 10-20% of this area is actually disturbed, making the restoration to original use easier to accomplish. The highest projections for 1990 indicate that 89,000 to 261,000 acres may be required for oil, gas, and geothermal well fields by that date, most of it for geothermal facilities.

Like other extraction activities, oil, gas, and geothermal operations must occur where the resource is found, and thus these operations may affect almost any kind of land use. Geothermal operations may be more likely to cause conflicts with historic or cultural values, because such phenomena as hot springs and fumaroles were often sites of early settlements or were endowed with religious significance by native Americans. Moreover, two of the potential geothermal sites occur within national parks and are thus not available for exploitation. Some oil- and gas-rich lands in the Rocky Mountain Overthrust Belt also have been designated wilderness areas and withdrawn from use.

The use of biomass as an energy source will require that large acreages be devoted to crop production for energy uses. Millions of acres may be converted from other rural uses, making biomass potentially the biggest energy-related consumer of land. The direct impact of this conversion is very small, however, because the land surface is not covered or destroyed as it is by mining, drilling, the construction of conversion or combustion facilities, or solid waste disposal. Moreover, the use of common soil-conservation and soil-management practices should minimize the depletion of soil fertility.

Decision on whether to continue using the land for biomass production can be reviewed annually on the basis of the relative value of competing uses of the land. Thus, conversion of large amounts of rural land to biomass production should limit the nation's capacity for producing food and fiber crops only if biomass energy crops are considered to be of more value. Therefore few options are foreclosed by the decision to use the land for biomass.

FEDERAL CONTROLS AFFECTING LAND USE

Comprehensive energy-siting regulations have never been undertaken at the federal level, and comprehensive land-use legislation has never been passed. Instead, a number of individual federal laws affect energy-facility siting. Laws designed to protect specific sectors of the environment (such as air quality) often regulate the indirect, offsite effects of energy development. Other laws designed to protect or preserve fragile lands such as wetlands or flood plains prohibit development in certain areas. The goal of the myriad federal laws and regulations is to allow economic and energy development to proceed while ensuring adequate environmental protection. Several of these laws are pertinent to the problem of potential conflicts between energy and land use. They include the National Environmental Protection Act, Clean Air Act, Federal Water Pollution Control Act, Coastal Zone Management Act, Wild and Scenic Rivers Act, and the Protection of Wetlands Executive Order.

Air quality regulations affect energy development because of the emission limitations required for new facilities and the possible restrictions on the location of new facilities. Locating new industries or expanding existing plants in areas that have not attained federal air-quality standards (nonattainment areas) may be difficult, depending on the ability of other sources to reduce emissions and make room for a new source of emissions. Utility siting will be easier; utilities have more flexibility and can more easily avoid locations in urban and nonattainment areas.

Many recent permit applications for utilities have been in Prevention of Significant Deterioration (PSD) areas. PSD regulations could preclude the use of some sites for energy development. A major new energy source cannot be sited within a Class I area or within some distance of the border of such a pristine area, because the allowed increment in levels of air pollutants would be exceeded. Class II increments may limit the scale and collocation of new facilities and are likely to lead to smaller facilities and more scattered siting patterns; energy parks or individual power plants larger than 3000 MW may be precluded. PSD regulations have been described as disguised land-use regulations based on a single environmental parameter. Such regulations may lead states to review existing siting policies and land-use management programs.

Federal and state legislation and regulations concerning water quality and water use can produce conflicts with the use of land for energy-related activities and can affect the land-use requirements of such activities. Possible conflicts include the following:

- Development may be precluded in an area; for example, on a stream that has been designated as a wild and scenic river.
- Development may be possible in an area, but because of particularly strict requirements on effluents may make development undesirable; for example, development on streams with water-quality limitations may entail extra expenses or difficulties in obtaining permits.
- Development may not be constrained, but regulations may influence the amount of land required for certain activities; for example, land may be required for waste disposal areas or for cooling structures.

Although the Clean Water Act acknowledges the relationship between land-use activities and water quality, it does not appear that water quality will severely constrain energy-related activities such as biomass production, other than to require best management practices.

Land-use concerns related to water use are principally a consequence of state water-allocation laws. Nevertheless, there is also substantial federal involvement. Water-allocation laws are based on either the riparian doctrine or the appropriation doctrine (or, occasionally, a combination of the two). Generally, eastern states follow the riparian doctrine, while western states follow the appropriation doctrine.

Regulations governing water quality can result in the exclusion, or possible exclusion, of energy-related activities (or at least those discharging to public waters) from certain areas, and they can also result in increased land consumption as a consequence of effluent requirements. Problems of water availability will generally not result in increased land consumption but may preclude certain developments that consume water. Physical availability of water may be the primary determinant in specific locations, but institutional or legal considerations may offer more widespread constraints on water availability.

Another legislative constraint on land use, especially regarding energy development, is the existence of federal lands. The federal government owns and administers 760×10^6 acres of land, one-third of the land area of the United States. Most of this land is concentrated in the western states and Alaska, where 30% to 90% of the land area in each state is under federal control. The Bureau of Land Management (BLM) and the United States Forest Service (USFS) are responsible for the bulk of the federal lands, with jurisdiction over 62% and 25% of the total, respectively. It has been estimated that 40% of the nation's coal reserves, 50% of the oil and gas fields, 80% of the oil fields, 40% of the uranium deposits, and 60% of the geothermal fields lie beneath federal land. The recovery of these resources is directly dependent on federal land-management policies. Additional reserves are indirectly affected by problems of access or the inability to conduct an economically viable mining operation without the inclusion of federally owned parcels of land. These problems may be especially acute in the West. For example, in the six western states that account for almost half of the nation's coal reserves (North Dakota, Montana, Wyoming, Colorado, Utah, and New Mexico), 72% of the coal reserves in known recoverable coal resource areas

are federally owned. By comparison, the federal government owns the coal rights to less than 3% of the coal east of the Mississippi.

In addition to the control of resources on land, the 1953 Outer Continental Shelf Lands Act and the 1978 amendments thereto grant the federal government jurisdiction over the lands in the outer continental shelf (OCS) area of U.S. waters, and the authority to lease those lands for resource development. Thus, the federal government controls all of the resources of the OCS, which may include up to 60% of the nation's undiscovered oil and gas reserves.

The large amount of energy resources effectively controlled by the federal government is of concern because (1) the timetable for development of these resources depends directly on federal leasing schedules and (2) large amounts of federal land are being withdrawn or considered for withdrawal from mineral development, in the interest of preserving their wilderness values. The large amount of land being considered for wilderness designation by the USFS and BLM, and the designation of 15 large new national monuments in Alaska have drawn attention to the potential energy consequences of public land withdrawals. The amount of land currently withdrawn from development is 282×10^6 acres, or 37% of the nation's public lands. About 15% of the nation's coal, 19% to 30% of the oil, 15% of the uranium, and 22% of the geothermal fields could be rendered unavailable by these withdrawals.

STATE CONTROLS AFFECTING LAND USE

A legal framework for decisionmaking concerning the location of energy facilities has been provided at the state level only within the last decade. Since 1970, 25 states have adopted some form of power-siting legislation. These efforts focus almost exclusively on electric power plants and have generally been limited to coal-fired electric generating stations and transmission facilities.

In most states, the private sector still makes all siting decisions; state environmental and natural resource agencies review decisions on proposed coal-fired electric generating facilities for violations of state environmental protection regulations. These regulations are related to such federal laws as the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act. Thus, state reviews tend to be incremental in nature, being directed toward separate air quality, water quality, and waste disposal concerns, rather than toward overall compatibility and suitability of the development.

LAND USE AND ENERGY

by

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ABSTRACT

This report provides estimates of the amount of land required by past and future energy development in the United States and examines major federal legislation that regulates the impact of energy facilities on land use. An example of one land use issue associated with energy development -- the potential conflict between surface mining and agriculture -- is illustrated by describing the actual and projected changes in land use caused by coal mining in western Indiana.

Energy activities addressed in the report include extraction of coal, oil, natural gas, uranium, oil shale, and geothermal steam; uranium processing; preparation of synfuels from coal; oil refineries; fossil-fuel, nuclear, and hydro-electric power plants; biomass energy farms; and disposal of solid wastes generated during combustion of fossil fuels. Approximately 1.1 to 3.3×10^6 acres were devoted to these activities in the United States in 1975. As much as 1.8 to 2.0×10^6 additional acres could be required by 1990 for new, nonbiomass energy development. The production of grain for fuel ethanol could require an additional 16.9 to 55.7×10^6 acres by 1990.

Federal laws that directly or indirectly regulate the land-use impacts of energy facilities include the National Environmental Protection Act, Clean Air Act, Federal Water Pollution Control Act, Surface Mining Control and Reclamation Act, and Coastal Zone Management Act. The major provisions of these acts, other relevant federal regulations, and similar state and local regulations are described in this report. Federal legislation relating to air quality, water quality, and the management of public lands has the greatest potential to influence the location and timing of future energy development in the United States. A detailed discussion of the effect of such legislation on energy-related activities is included in the report.

1 INTRODUCTION

Anticipation of increased efforts by the government to reduce the vulnerability of the United States to foreign oil cutbacks has caused heightened concern over potential conflicts between energy development and

environmental quality. A rapid increase in domestic energy production may impose additional burdens on the environment; planning and policy decisions must take this potential for environmental impact into account. This report provides information on one aspect of the environment that has received relatively little attention in the past: land use. Past and potential future impacts of energy development on land use are described, and areas of potential conflict resulting from regulatory constraints or other issues are outlined in this report.

Taken literally, "land use" describes the way in which a certain parcel of land is used. The term has also been used to describe land "cover," which determines and is determined by use. Figure 1.1 shows the relationship between land use and land cover. The distributions of four land use/land cover types in the United States -- cropland, rangeland, forest, and urban land -- are shown in Figs 1.2 to 1.5.

Energy developments are economically productive uses of land that usually change the land cover to an urban-industrial type (see Fig. 1.1). Conflicts arise when a proposed use of the land will preclude the continuation of the existing uses, and when the existing uses are perceived to be irrecoverable, irreplaceable, and/or of more value than the proposed use. Construction in wetland areas, the urbanization of prime agricultural lands, and strip mining in wilderness areas are examples of changes that involve an irretrievable loss of the existing land use at that location.

Regulations have been developed at many levels of government that attempt to control changes in land use. Land-use planning and control have

Fig. 1.1 Land Use and Land Cover Types (arranged, roughly, from more intensive to less intensive land uses and more developed to less developed land cover) [Adapted, in part, from Ref. 1]

Fig. 1.2 Distribution of Cropland in the United States

Fig. 1.3 Distribution of Rangeland (nonfederal) in the United States

Fig. 1.4 Distribution of Forest (nonfederal) in the United States

Fig. 1.5 Distribution of Urban Land in the United States

traditionally been the domain of local governments, and community zoning regulations or land-use plans have often been developed that specify the general use to which particular plots of land may be put. Many states have enacted land-use legislation, particularly to protect fragile lands and to guide local development. Certain classes of lands, such as wetlands and flood plains, may be limited by state or federal law to uses that do not destroy the natural functions of the lands. No general legislation on land use as yet exists at the federal level for lands not in the public domain, though a number of federal regulations indirectly affect land-use decisions. These regulations are briefly described in Sec. 6.

A proposed development may not only change the use and environment of the site where it is built, but it may also cause environmental changes that affect the use of adjacent lands or the perceived value of those lands for their existing use. The impact of air and water pollution, the consumptive use of scarce water supplies, noise, and visual intrusion into scenic landscapes are examples of the indirect, off-site effects of land-use changes. These effects are most severely felt locally, and communities can be radically changed as the result of energy development and the land-use and environmental changes associated with it. Local impact is not directly addressed by this report; that topic is better examined on a site-by-site basis using a case study approach than by the overview approach taken here. It should be remembered, however, that local conflicts are likely to arise with any development that causes permanent or even temporary changes in land use.

The goal of this report is to provide information on how energy developments affect land use and to identify where conflicts may arise between energy developments and existing uses of the land. Sections 2 through 5 of this report address the potential effects on land use associated with the extraction, processing, and conversion and combustion of energy resources, as well as the disposal of wastes generated by these processes. For each fuel or energy resource in each part of the fuel cycle, the discussion describes the kinds of direct and indirect effects caused by development activity, and quantifies the area of land required per unit of resource extracted, converted, or burned and per unit of waste generated. Finally, the amount of land affected by each activity in the past and the potential land requirements in the near future (1990) are estimated and discussed. Estimates are given by state and by federal region (see Fig. 1.6), when this level of detail is possible. Several energy-related activities could not be discussed in detail in this report, most notably transportation, energy transmission, and the disposal of toxic substances. The latter topic is emerging as an important environmental issue and could have significant implications for land use.

Section 6 of the report addresses regulatory issues and the effect of federal land-management programs on future energy development. Also discussed in Sec. 6 is major federal legislation that regulates the potential impact of energy facilities on land use, and which can thus influence the location or timing of energy development. State and local regulations that might have a similar effect are also described. Several regulatory issues of particular concern vis-a-vis the impact of energy development on land use are then discussed in more detail. The federal coal leasing program and the possible effect of withdrawals of public land on energy resource availability are also described.

Section 7 examines an example of a particular conflict between energy development and land use, i.e., the problem of surface mining on prime agricultural lands. A case study documents the amount and nature of land consumption by a mine, and addresses the local, state, and regional implications of surface mining in agricultural areas.

Fig. 1.6 Federal Regions

2 EXTRACTION

The extraction of energy resources from the earth is likely to disturb more land than are activities in any other phase of the fuel cycle. All of the land disturbed by mining or drilling and pumping, however, should be reclaimed and returned to some productive use, though permanent changes in land use could be brought about as a result of extraction. This section discusses the impact of activities by which an energy resource is removed from the earth. The following fuels are addressed:

- Coal
- Oil and oil shale
- Natural gas
- Uranium
- Geothermal
- Biomass

2.1 COAL

Coal reserves are dispersed throughout the United States (see Fig. 2.1). Though about half of the nation's reserves by weight are west of the Mississippi River, the Appalachians and the Midwest have historically been the major coal-producing areas. Within the last 10 years, however, increasingly stringent air-quality regulations (see Sec. 6) have made the relatively low-sulfur western coals more attractive to electric utilities despite higher transportation costs and lower Btu content. By 2000, it is expected that about half of the nation's annual coal production will be from the West.

Surface mining* removes surface vegetation, destroys the soil, and changes existing topography and surface and subsurface drainage patterns. Adjacent lands not directly disturbed by the mining may be affected by erosion, acid or alkaline drainage from the mine, dust, noise from mining equipment and blasting, and disruption of groundwater supplies. The Surface Mining Control and Reclamation Act is designed to minimize the potential adverse effects of surface mining by requiring reclamation and imposing stringent requirements for pollution control. Thus, mining should be a temporary use of the land. Reclamation of croplands will probably take 5-6 years; rangelands, because they occur in the more arid regions of the country, may require more than 10 years for reclamation; and forest will take 20-30 years or longer to develop after mining and revegetation.³ The likelihood of restoring pre-mining productivity is still under question, and not all surface-mined lands are returned to their original use. Forest, for example, has often been replaced by pasture lands in the Midwest,⁴ and leaving behind a flat contour suitable for urban or industrial development is often preferred (or is the only feasible option) over restoration to the original mountainous topography in the Appalachians.

*See Ref. 2 for a description of methods of surface mining.

Fig. 2.1 Coal Reserves in the United States

Underground mines cause much less direct surface disturbance, limited to areas required for support facilities, but a large amount of land could be undermined during the extraction process. In traditional room-and-pillar mines* up to 50% of the coal is left in place ("sterilized") to prevent collapse of the mine roof and an associated subsidence of the surface. Subsidence can damage structures on the land or the land itself, alter drainage patterns, and cause an unevenness of the surface that can hinder the use of farm equipment. Thus, urban, residential, and agricultural uses are most likely to be adversely affected by subsidence.

Although numerous precautions are mandated to prevent subsidence, the corrosion of mine pillars over time may weaken the support and cause subsidence many years after mining has ceased. The timing and likelihood of subsidence are hard to predict. It has been estimated⁵ that 23% of the undermined land in the United States has subsided. Thus, the actual amount of land affected by subsidence is only a fraction of the area undermined. Subsidence has been of particular concern in Pennsylvania, where extensive urbanization has often occurred over abandoned underground mines.⁶ That state now has strict mining regulations and an active backfilling program to alleviate the potential damage caused by subsidence. If longwall mining methods are used, almost all of the area undermined will subside, but the greater recovery efficiency of this method (80-85%)^{7,8} means that less area is undermined. The impact of longwall mine subsidence on surface uses of the land may be less severe than that associated with the subsidence of room and pillar mines, because the entire area should settle rather uniformly, with discontinuities only at the edge of the workings. Longwall mining has been used extensively in Europe, but it currently supplies less than 5% of the coal mined underground in the United States.⁹

2.1.1 Land Requirements

The amount of land disturbed by coal mining depends on the mining method used, the thickness of the coal seam, and the density of the coal. The mining method determines the configuration of the disturbance and the recovery efficiency, which ranges from 50% for underground room-and-pillar mines to 80% for surface mines. Western surface mines recover more than 90% of the coal seam being mined.⁷ Less land area will be mined per ton of coal extracted where seams are thick, deposits are dense, and recovery ratios are high. Estimates of the amount of land disturbed or undermined during coal extraction are shown in Table 2.1; the estimates are based on state averages of coal seam thickness and coal density. Surface mines will disturb 21 to 86 acres per 10⁶ tons of extracted coal in the West, where seams are thick and recovery is high; 131 to 277 acres per 10⁶ tons in the Appalachians and the Midwest, where seams are thinner; and up to 400 acres per 10⁶ tons in the central states. Extraction of coal from deep mines may cause 154 to 336 acres to be undermined per 10⁶ tons of coal extracted in the eastern United States, and 50 to 200 acres in the West.

Coal mines will require additional acreage for facilities; for haul roads; and for storage of topsoil and of overburden from the initial cut in a surface mine, and of rock excavated in constructing deep-mine tunnels. This

*See Ref. 2 for a description of underground mining methods.

Table 2.1 Values Used to Calculate the Area Affected by Mining^a

Coal Region	Federal Region	Avg. Coal Density (ton/acre-ft)	State	Avg. Seam Thickness (ft)		Area Disturbed (acres/10 ⁶ ton)	
				Deep	Surface	Deep	Surface
N Appalachia	3,5	1800	Md.	6.2	5.3	179	131
			Oh.	4.5	3.6	247	193
			Pa.	4.5	3.2	247	217
			N W.V.	4.7	4.9	236	142
C Appalachia	3,4	1800	E Ky.	5.3	4.7	210	148
			Tenn.	3.3	2.7	337	257
			Va	5.3	4.5	210	154
			S W.V.	4.7	4.9	236	142
S Appalachia	4	1800	Ala.	4.7	2.5	236	277
Midwest	4,5	1800	Ill.	7.2	5.3	154	131
			Ind.	6.0	4.2	185	165
			W Ky.	5.3	4.7	210	148
C State.	6,7	1800	Ark.	1.8	1.8	617	386
			Ia.	2.4	2.4	403	289
			Kans.	1.7	1.7	654	408
			Mo.	2.4	2.4	463	104
NE Great Plains	8	1750	NE Mont.	12.7	12.7	90	50
			N.D.	11.5	11.5	99	55
NW Great Plains	8	1770	N Colo.	12.0	12.0	94	52
			SE Mont.	22.6	22.6	50	28
			Wyo.	8.3	29.7	136	21
Rockies	8	1800	Colo.	5.4	7.1	206	87
			Utah	9.5	9.5	117	65
Southwest	6,9	1770	Ariz.	16.0	16.0	71	39
			N.M.	11.8	11.8	96	53
Northwest	10	1770	Wash.	8.0	8.0	141	88

^aFrom Ref. 3.

area is assumed to be minor compared to the area disturbed or undermined in the process of extracting the coal. Where traditional contour mining is practiced (i.e., the Appalachians), casting the overburden spoil downslope can disturb one acre for every acre mined. The more stringent reclamation laws now in effect will probably ensure that most overburden will be replaced in previous cuts in the future, and, indeed, the box-cut contour method of mining is gaining in acceptance.

In addition to the land disturbance potentially caused by surface mining and subsidence, the cleaning of coal generates large quantities of waste. Wastes from cleaning surface-mined coal are often returned to the open cut, but wastes from cleaning underground coal are usually not returned to the mine workings. Little coal is cleaned in the West, but in the Appalachians 50% to 99% of the coal mined underground is cleaned, and almost half a ton of refuse is generated for each ton of clean coal.⁹ In the past, these wastes were deposited in unsightly refuse banks which were usually not revegetated. Present regulations require planned disposal of these wastes, which may be deposited in head-of-hollow fills (a method of disposal that fills in small valleys to the level of the adjacent ridge tops, thus creating flat or nearly flat land) or other designated sites. Though the original contour will undoubtedly be lost in waste disposal areas, slopes should be graded and vegetation established on the disposal site.

The amount of land required for waste disposal is determined in large part by the type of disposal method used and the height of the waste pile. A 1972 Bureau of Mines study¹⁰ on coal refuse fires tabulated data on size and volume of waste piles, and determined that 214.6×10^6 yd³ of refuse were contained in waste piles covering a total of 2584 acres throughout the United States. At an average refuse density of 100 lb/ft³,¹¹ this figure converts to a land requirement of 8.9 acres per 10^6 tons of refuse. It is doubtful that this estimate will apply to refuse dumped in head-of-hollow fills, where topographical problems make area estimates very difficult. Head-of-hollow fills may also be used for disposing of excess overburden.

2.1.2 Past and Future Land Use

A Bureau of Mines survey of the amount of land used by the mining industry from 1930-1971¹² reported that 1.47×10^6 acres were disturbed by coal mining during that period. This figure includes the area excavated during surface mining, area used for disposal of wastes from surface and underground mines, and surface area subsided or disturbed as a result of underground workings.¹² Cumulative coal production during that period was more than 20×10^9 tons.* An additional 2×10^9 tons were produced from 1972 to 1975,* and considerable coal was mined before 1930; thus, the amount of land that has been disturbed by surface mining in the past is probably much greater than 1.6×10^6 acres. More than 60% of the land disturbed by coal mining between 1930 and 1971 was reclaimed during that period; in 1971 more land was reclaimed than was disturbed by mining operations.¹²

It can be estimated from 1975 production figures and the acreage estimates in Table 2.1 that 51,400 acres were disturbed by surface mining in

*Estimated from yearly production data in Ref. 2, Table 11.

1975. Many additional acres were also in mining use in that year, including lands undergoing reclamation or remaining unreclaimed and lands devoted to support facilities, cleaning plants, and waste disposal.

Regional coal production forecasts prepared by the Leasing Policy Development Office (LPDO) for a federal study¹³ of future coal leasing projected an annual production of $1.1\text{--}1.86 \times 10^9$ tons of coal by 1990. These projections are shown in Table 2.2. For comparison, the table also shows an Energy Information Administration (EIA) scenario published in the 1978 Annual Report to Congress that projected a different regional pattern of coal production (more Appalachian coal and less Western coal).

Estimates of the acreage potentially disturbed by surface mining or undermined by deep mining in 1990 are shown in Tables 2.3 and 2.4. Approximately 61,700 to 100,000 acres may be devoted to surface mining under the various scenarios. In all cases, the greatest amount of land disturbed occurs in the Appalachians, the central states, and the Great Plains. Deep mining may undermine an additional 118,000 to 149,000 acres of land, with the greatest proportion of the affected acreage in the Appalachians and the Midwest.

A rough estimate of the acreage disturbed over the period 1975 to 1990 is based on assuming a linear increase in production from 1975, when the national production was 648.4×10^6 tons.¹⁰ Under the LPDO low scenario, cumulative production would thus be 13.22×10^9 tons; under the LPDO high scenario, 1975-1990 production would be 18.79×10^9 tons; and under the EIA scenario, cumulative production would be 15.85×10^9 tons. Assuming the same patterns throughout the period as are predicted in 1990, estimates of the amount of land potentially affected by mining range from 0.7 to 1.0×10^6 acres for surface mining, and 1.4 to 1.5×10^6 acres undermined.

Table 2.2 Projected 1990 Coal Production by Region (10^6 tons)

Coal Region	Federal Region	LPDO Scenario ^a						EIA Scenario ^b	
		Low		Medium		High		Total	Surface Mines
		Total	Surface Mines	Total	Surface Mines	Total	Surface Mines		
Appalachia	3,4,5	396.2	96.4	445.3	99.9	478.7	101.0	484.9	137.2
Midwest	4,5	264.2	44.6	312.3	45.1	327.3	45.5	290.5	39.4
Cent. West & Gulf	6,7	71.9	65.9	89.9	83.2	113.7	107.7	83.8	78.9
Great Plains	8	291.5	291.1	551.5	551.1	800.1	799.6	535.4	527.8
Rest of West	6,8,9,10	90.6	62.7	122.0	85.4	137.7	100.9	70.1	31.8
National Total		1,114.4	560.4	1,521.0	864.6	1,856.5	1,154.6	1,464.7	815.1
Estimated Cumulative Production 1975-1990 ^c		13,221	6,648	16,271	9,249	18,787	11,684	15,848	8,819

^aLPDO = DOE Leasing Policy Development Office; derived from data in Ref. 13.

^bDerived from data in Ref. 3.

^cSee text.

**Table 2.3 Estimates of Acreage Disturbed by Surface Mining --
1990 and 1975-1990**

Coal Region	Federal Region	Acres Mined per 10 ⁶ tons ^a	LPDO Scenario				EIA Scenario	
			Low		High		Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)
			Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)	Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)		
Appalachia	3,4,5	184	96.4	17,738	101.1	18,584	137.2	25,245
Midwest	4,5	148	44.6	6,600	45.5	6,734	39.4	5,831
Cent. West & Gulf	6,7	323	65.9	21,285	107.7	34,787	78.9	25,485
Great Plains	8	41	291.1	11,935	799.6	32,784	527.8	21,640
Rest of West	6,8,9,10	66	62.7	4,138	100.9	6,659	31.8	2,099
National Total			560.4	61,696	1154.6	99,548	815.1	80,300
Estimated Cumulative Production 1975-1990 ^c			6,648	731,715	11,684	1,007,426	8,819	868,846

^aUnweighted average of state values in Table 2.1.

^bFrom Table 2.2.

^cSee text.

**Table 2.4 Estimates of Acreage Undermined by Deep Mining --
1990 and 1975-1990**

Coal Region	Federal Region	Acres Mined per 10 ⁶ tons ^a	LPDO Scenario				EIA Scenario	
			Low		High		Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)
			Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)	Amount Produced ^b (10 ⁶ tons)	Area Mined (acres)		
Appalachia	3,4,5	238	299.8	71,352	377.7	89,893	347.7	82,753
Midwest	4,5	183	219.6	40,187	281.8	51,569	251.1	45,951
Cent. West & Gulf	6,7	452	6.0	2,712	6.0	2,712	4.9	2,215
Great Plains	8	93	0.4	37	0.5	47	7.6	707
Rest of West	6,8,9,10	140	27.9	3,906	36.8	5,152	38.3	5,362
National Total			554.0	118,194	701.8	149,373	649.6	136,988
Estimated Cumulative Production 1975-1990 ^c			6,570	1,401,781	7,102	1,511,655	7,029	1,482,210

^aUnweighted average of state values in Table 2.1.

^bFrom Table 2.2.

^cSee text.

The kinds of land use likely to be affected by surface mining were identified in a study of the potential effects on land use associated with reaching an annual production of 2×10^9 tons by the year 2000.³ The coal production scenario used was based on the EIA projections discussed above. This study showed that large amounts of forest may be disturbed in the Appalachians and parts of the Midwest; cropland will be disturbed in the Midwest, North Dakota, and parts of the central states; and rangeland will be most heavily affected in the West. The greatest impact resulting from underground mining may occur in the Midwest, where land sensitive to subsidence, i.e., cropland, is most likely to be undermined.

2.2 OIL AND OIL SHALE

2.2.1 Oil

Oil production in the United States has, until recently, supplied well over half of the domestic oil demand. A maximum production level of 11.3×10^6 barrels a day was reached in 1970 and contributed to 75% of the total U.S. consumption.¹⁴ During 1970, however, the U.S. spare capacity disappeared, and production in subsequent years declined (Table 2.5). Crude oil contains many organic compounds, making its end-use consumption flexible and diverse. This wide variety of oil-based products will continue to make oil valuable and ensure its continued production in future years.

Table 2.5 Consumption of Foreign Oil in the United States^a

Year	Consumption (10^6 bbl/d)	Production (10^6 bbl/d)	Imports (10^6 bbl/d)	Imports (% of consumption)
1960	9.7	8.0	1.8	19
1962	10.2	8.4	2.1	21
1964	10.8	8.8	2.3	21
1966	11.9	9.6	2.6	22
1968	13.0	10.6	2.8	22
1970	14.4	11.3	3.4	24
1972	16.0	11.2	4.7	29
1974	16.2	10.5	6.1	38
1976	17.0	9.7	7.3	43
1979 (est.)	19	10	9	47

^aFrom Ref. 14.

Oil reserves in the United States are estimated at 57×10^9 barrels of identified resources, and $50\text{--}127 \times 10^9$ barrels of undiscovered resources¹⁵ (Table 2.6). Oil fields are found in the central United States, southern California, the Midwest, and the Rocky Mountains, as shown in Fig. 2.2. Reserves in the lower 48 states will provide additional oil from wells in previously undrilled areas and deeper wells and from additional recovery from known fields.⁷ Significant reserves are also found in Alaska and offshore. The greatest production currently comes from wells in Louisiana, Texas, Oklahoma, Utah, Colorado, and California (federal regions 6, 8, and 9).¹⁷

Development of oil resources requires a sequence of activities including exploration, development, refining, and transportation. Only exploration and development are addressed here. The latter two activities are discussed in Sec. 3 of this report.

Table 2.6 U.S. Recoverable Reserves and Resources of Crude Oil (10^9 barrels)^a

Location	Identified Resources		Undiscovered Resources ^b		Total Resources ^c	
	Reserves	Inferred	Range	Mean	Range	Mean
Onshore						
Lower 48 states	20	14	29-64	44	-	-
Alaska	10	6	6-19	12	-	-
Offshore						
Lower 48 states	3	3	5-18	11	-	-
Alaska	-	-	3-31	15	-	-
Total Crude Oil	34	23	50-127	82	107-182	139

^aReserve data are as of January 1, 1978. Data for inferred and undiscovered resources are as of January 1, 1975. No attempt has been made to update the latter data, because updating would involve a highly arbitrary procedure and would not change the figures significantly. Figures may not sum to totals shown because of rounding.

^bThere is a probability of more than 95% that at least the lowest figure is actually available, while there is only a 5% chance that the quantity actually available exceeds the high figure. The third figure is the statistical mean of a lognormal probability distribution function. Ranges cannot be summed arithmetically, and means are not midpoint estimates of the range.

^cWe assume the reserves are known with certainty and equal to the values presented. Thus the interpretation of the range and mean for total resources depends entirely on the interpretation of the range and mean for undiscovered resources.

Source: Ref. 15.

Fig. 2.2 Oil Fields in the United States (Source: Ref. 16)

2.2.1.1 Land Requirements

Exploratory drilling is done at those locations identified by regional and detailed geologic surveys as sites with potential oil resources, to find a geologic stratum containing enough oil to be economically recovered. Before exploratory wells are dug, the land must be cleared, small holding ponds dug for circulating fluid and brine, and access roads constructed. A 100,000 barrel-per-day (bbl/d) oil field typically includes 400 successful holes (that produce oil) and 300 dry holes.¹⁸ Land requirements for this exploratory phase are minimal: about two acres per exploratory well. After drilling, most of the land can be restored to its original condition.

Developmental drilling is done in the same manner as exploratory drilling except that well spacing and the location of the bottoms of the holes (which are not necessarily perfectly vertical) are more carefully controlled.¹⁸ Estimates of the amount of land used for oil production vary and are not well documented. Hittman and Associates¹⁹ indicate that 3.03-6.9 acres are disturbed per 10^{12} Btu/yr extracted. These figures are based on onshore land use ranging from $1/4$ acre to 1 acre per well and offshore land use of 0-1 acre per well. Land use for offshore wells is much less than onshore wells because the only land required for offshore wells is for the onshore processing facilities. A more recent study has estimated that 2,000 acres will be required to produce 100,000 bbl/d (9.45 acres per 10^{12} Btu/yr).¹⁸ These figures are based on a land requirement of five acres per well, which includes the cleared area around the producing well, pipeline rights-of-way, separation facilities, and roads.

2.2.1.2 Past and Future Land Use

Domestic oil production in 1975 was 3.59×10^9 barrels with an energy equivalent of 20.09 quads* (assuming 5.8×10^6 Btu per barrel).¹⁸ Assuming that 2,000 acres of land are used for the production of 100,000 bbl/d of oil, then total land used in 1975 for oil production was almost 197,000 acres. Hittman's figures¹⁹ give a range of about 60,800-138,600 acres.

The potential land requirement for oil production in 1985 and 1990 can be estimated using two moderate, but different, oil production scenarios. For this study, projections from the National Energy Plan I (NEP) and the National Energy Supply System (NESS) are compared.

Table 2.7 indicates that production levels and the consequent land use vary little between the two scenarios. Land use in 1990 ranges from 190,000 to 220,000 acres, and considerably less than that if the Hittman estimates are used. Comparing 1985 and 1990, the trend under the NEP is for a reduction in land use by about 23,000 acres between 1985 and 1990; under the NESS, land requirements would increase through 1990 because of projected increases in oil production.

2.2.2 Oil Shale

The major oil shale deposits in the United States are shown in Fig. 2.3. By 1990, any product recovery from oil shale resources will most likely be liquids from the Green River Formation in Colorado and Utah (shown in Fig. 2.4).

One can recover oil from oil shale either by mining the shale deposit, with methods similar to those used to mine coal, and processing the shale in a surface retort, or by processing the shale essentially in situ and

Table 2.7 Oil Production and Estimated Land Use Under Alternative Oil Production Scenarios

Estimate	1975	1985		1990	
		NEP	NESS	NEP	NESS
Domestic Production (10^{15} Btu)	20.09	21.8	20.35	19.48	22.48
Equivalent Barrels (10^9 bbl)	3.59	3.89	3.63	3.48	4.01
Estimates of Land Required (10^3 acres)					
Ref. 18	197	213	199	190	220
Ref. 19	60-139	66-150	62-140	59-134	68-155

*One quad = 10^{15} Btu.

Fig. 2.3 Distribution of U.S. Oil Shale Resources (Source: Ref. 20)

recovering the oil thus produced from wells. The immediate impact of these extraction techniques on the land would be similar to that described for coal mining or drilling for oil, including potential subsidence, the destruction of surface vegetation and topography, the devotion of large areas of land to well fields, and a need for reclamation. But the amount of land directly disturbed by mining is small compared to that required for disposal of the spent shale. The volume of the shale increases by as much as 30% during the retorting process; therefore the spent shale cannot all be returned to the mine for disposal. The excess may be disposed of by filling in canyons or building up into mesas.²² By far the most serious environmental and health consequences of oil shale are due to the disposal of wastes. About 20×10^6 tons of spent shale per year are generated by a 50,000 bbl/d surface retorting facility.²³

The issue, however, is not only the amount of land covered, but also the problem of revegetating the piles of spent shale. Methods of revegetating shale piles have been studied for several years.²² The vegetation must sustain itself on a thin mantle of soil covering the piles or on the pile itself without soil. It is likely that revegetation will require irrigation to initiate regrowth in large areas. The local water supply may not be adequate for the irrigation requirements, however, and the vegetation may not be able to sustain itself without irrigation.

Much of the Colorado River water is used for irrigation. The water of the Green River Formation area empties into the Colorado River. In the

Fig. 2.4 Oil Shale Areas in Colorado, Utah, and Wyoming
(Source: Ref. 21)

Piceance basin the Mahogany Zone, from which the shale will be extracted, contains a highly saline (primarily sodium) aquifer. The aquifer above the Mahogany Zone is believed to contribute 80% of the surface water supply in the Piceance basin. When the zone is removed, mixing between the upper and lower aquifers is likely, with an eventual increase in salinity in the Colorado River. With a disproportionate increase in the amount of sodium, relative to calcium and magnesium, the water becomes more unacceptable for irrigation, because the sodium becomes increasingly toxic to the plants. The Colorado River already suffers from excess salinity.

In addition to intrusion of saline groundwater, leaching of sodium from the spent shale piles is possible even with expensive control precautions. The leachate from a 100,000 bbl/d operation could increase salinity by 0.3 to 50 mg/L at the confluence of the Upper Colorado River basin.²⁴

The manpower required to operate the industry is large, and the most significant impact from oil shale development is believed to be socioeconomic.²⁵ Boom-town development may be inevitable. The increased populations are

expected to (1) deplete the water supply by consumptive use, thus further increasing the concentration of sodium; (2) require additional land for their communities; and (3) increase the recreational use of the surrounding land. The latter is expected to produce large increases in erosion due to use of recreational vehicles in sensitive terrain.

The air pollution from the development may be the single factor most limiting to the industry's development. Air-borne emissions would reach nearby national parks, thus reducing visibility and the aesthetic value of the parks.

2.2.2.1 Land Requirements and Siting Considerations

Estimates of the amount of land potentially disturbed by surface and underground mines producing 66,000 ton/d of shale (about 50,000 bbl/d of oil) are shown in Tables 2.8 and 2.9. An underground mine of this size may disturb 300 to 485 acres over the life of the mine; a surface mine may disturb 940 to 1620 acres (assuming a 10-year operation). The surface retort associated with either of these mines could require another 200-300 acres for the plant site and associated buildings. About 1000-1200 acres could eventually be required for disposal of spent shale from the 50,000 bbl/d facility.²⁶ A modified

Table 2.8 Surface Areas Disturbed by an Underground Oil Shale Mine Producing 66,000 ton/d

Disturbance	Area Disturbed (acres)
Mine Surface Facilities	25-35
Coarse Ore Conveyor	5-10
Coarse Ore Stockpile	
Temporary	40-55
Initial	35-40
Road Construction ^a	82-115
Water in Dams ^a	150-270 ^b
Total	302-485

^aAs estimated for entire oil shale complex.

^bLand areas required for water storage or ponding vary from site to site. Most developers use the natural terrain to create large reservoirs. The quantity of minewater requiring ponding also varies from site to site.

Source: Ref. 26.

Table 2.9 Surface Area Disturbed by a Surface-Mining Oil Shale Operation Producing 66,000 ton/d

Disturbance	Area Disturbed
Mine Development	15-45 acres per year
Permanent Disposal of Overburden	500 acres (total) ^a
Temporary Storage of Raw Shale	50-100 acrer (total)
Water in Dams	150-270 acres (total) ^b
Other	90-300 acres (total) ^c

^aArea depends on the thicknesses of the overburden and oil shale at the site. Acreage shown is for a Piceance Creek Basin site, with 550 feet of overburden and 450 feet of 30 gal/ton shale.

^bWater storage for entire mining/processing complex is based on requirements for an underground mine. The land area required for water storage or ponding varies from site to site. Most developers use natural terrain to create large reservoirs.

^cRequired area includes access roads, power and transmission facilities, water lines, and natural gas and oil pipelines for entire mining/processing complex. A 60-ft right-of-way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors require 2.4 acres per mile.

Source: Ref. 26.

in-situ oil shale development producing 57,000 bbl/d of oil may require about 180 acres for surface facilities. About 100 additional acres may be required each year for disposal of the shale that is mined out to create the underground voids necessary to initiate the underground retort process.*

If a mature oil shale industry were operating by 1990, it would be centralized in the Piceance basin of western Colorado, with some development in the adjacent areas of Utah. This area is arid and sparsely populated, and the land often slopes steeply from mesas. One of the nation's largest migratory deer herds, endangered bald eagles, and a wild horse population are found in the area. Land uses in the basin include grazing, farming, fishing, and recreation.

2.2.2.2 Past and Future Land Use

To date, oil shale development has been limited to one small pilot plant in Colorado. The capacities of projected facilities, including both modified in-situ (MIS) and surface retorting, are listed in Table 2.10.

*See Ref. 26 for a description of in-situ mining techniques.

Table 2.10 Projected Oil Shale Developments^a

Tract	Process or Location	Size by 1990 (10 ³ bbl/d)
Surface Retort		
1. Long Ridge (Union)	TOSCO-II	50
2. DOW (Colony)	TOSCO-II	47
3. Uintah (White River) U-a and U-b	Phillips-SOHIO-SONOCO	50
4. Naval Oil Shale Reserve No. 1	Carfield County, CO.	50
5. Uintah-Rio Blanco	SONOCO, Phillips, SOHIO, Cleveland-Cliffs	50
6. TOSCO Sandwash	TOSCO-II	50
Subtotal		297
Modified In Situ		
7. Tract C-a (Rio Blanco)		60
8. Tract C-b (Occidental- Tenneco)		40
Subtotal		100
Total		397

^aFrom Ref. 27.

If all the shale for the surface retorting operations were mined underground, it can be calculated, using the estimates given above, that 1800 to 2900 acres may be disturbed by mining and its support activities, and an additional 1200 to 1800 acres for the retort facilities. The modified in-situ operations could be expected to disturb about 360 acres.

Large amounts of additional land would be required for the disposal of spent shale. To provide a perspective on the volume of spent shale for the oil shale developments shown in Table 2.10, the following assumptions are made:

- 1.1 tons of spent shale are produced in a surface retort per barrel of oil produced.
- Compaction of the spent shale produces a material density of 90 pounds per cubic foot.²⁸
- 30% of shale in MIS sites would be mined.

If all mined shale were to be disposed of above ground (which is most likely, because oil shale will probably be mined underground and little backfilling of deep mines is now practiced in the United States), about 360,000 tons (296,000 yd³) would have to be disposed of each day. At an average waste-pile depth of 20 feet, 3,300 acres per year would be covered; at

an average depth of 40 feet, 1,700 acres per year would be covered; and at an average depth of 80 feet, 800 acres per year would be covered. If 70% of the mined shale (except that from MIS) were to be returned to the ground, then data on the spent shale would be as follows:

- 131,000 ton/d
- 108,000 yd³/d
- 1,200 acres/yr at 20-ft average depth
- 600 acres/yr at 40-ft average depth
- 300 acres/yr at 80-ft average depth

Even with the conservative estimate of 40 feet average depth, the amount of land required for the disposal of spent shale is not trivial, especially considering the relatively small area in which oil shale production will take place.

2.3 NATURAL GAS

Natural gas has been used as a source of fuel in the United States for over 150 years, although early use was localized. A rapid increase in end-use consumption of natural gas has occurred over the past 30 years as a result of increased pipeline construction (increased from 218,000 miles in 1945 to 980,000 miles by 1975);²⁹ development of new markets, such as petrochemicals and fertilizers; and, more recently, a demand for low-sulfur fuels.¹⁸ Oil and natural gas are usually found in conjunction with each other, and both are generally produced from the same areas (see Fig. 2.5).

Unlike oil, 85% of the natural gas consumed in the United States is domestically produced.¹⁴ In 1975, 19×10^{12} ft³ of natural gas was produced; peak production levels were reached two years earlier. By 1978, gas production had fallen 12%. The level of proven reserves fell 25% between 1967 and 1978.¹⁴ Although new discoveries have not replaced what has been consumed, it is generally agreed that enough natural gas exists onshore and offshore in the United States to sustain a yearly consumption rate of 20×10^{12} ft³ for 25 to 35 years (Table 2.11).¹⁴ While it is generally agreed that natural gas will play a diminishing energy role in the United States, such a decline is primarily a result of complex economic and regulatory issues and not necessarily of limitations on near-term supplies.

2.3.1 Land Requirements

Exploration for natural gas is conducted in a manner similar to that described for oil. For a gas field producing 250×10^6 ft³/d, it has been assumed that for every 10 producing wells, 8 dry holes will have been drilled.¹⁸ Permanent land usage for the exploratory phase for such a field is 30 acres for drilling and roads.

Land required for the extraction of natural gas is estimated to be about 7 acres per well.¹⁸ This includes the cleared area around the well, pipeline rights-of-way, and roads. The gas is usually processed and prepared

Fig. 2.5 Gas Fields in the United States (Source: Ref. 16)

Table 2.11 Recoverable U.S. Reserves and Resources of Natural Gas and Natural Gas Liquids^a

Gas Location and Form	Identified Resources		Undiscovered Resources ^b		Total Resources ^c	
	Reserves	Inferred	Range	Mean	Range	Mean
Natural gas (10^{12} ft ³)						
Onshore						
Lower 48 states	146 ^d	119	246-453	345		
Alaska	32	15	16-57	32		
Offshore						
Lower 48 states	31 ^d	67	26-111	63		
Alaska	-	-	8-80	44		
Total	209	202	322-655	484	733-1066	895
Natural gas liquids (10^9 barrels)						
	6	6	11-22	16	23-34	28

^aReserve data are as of January 1, 1978. Data for inferred and undiscovered resources are as of January 1, 1975. No attempt has been made to update the latter data, because updating would involve a highly arbitrary procedure, which would not change the figures significantly. Figures may not sum to total shown because of rounding.

^bThere is a probability of more than 95% that at least the lower figure is actually available, while there is only a 5% chance that the quantity actually available exceeds the higher figure. The third figure is the statistical mean of a lognormal probability distribution function. Ranges cannot be summed arithmetically, and means are not midpoint estimates of the range.

^cIt is assumed that reserves are known with certainty and equal to the values presented. Thus, the interpretation of the range and mean for total resources depends entirely on the range and mean for undiscovered resources.

^dThe latest American Gas Association data on reserves, from the Oil and Gas Journal, were not specific according to onshore and offshore occurrence. It is assumed that since 1974, for which USGS Circular 725 specifies onshore and offshore reserves, production and additions to reserves occurred in proportion to 1974 onshore and offshore shares.

Source: Ref. 29.

for distribution at the well field. About 250 acres are required for a processing plant with a capacity of $250 \times 10^6 \text{ ft}^3/\text{d}$.¹⁸ A total of 850 acres would be required for a gas field and associated processing plant producing $250 \times 10^6 \text{ ft}^3/\text{d}$.

2.3.2 Past and Future Land Use

Using the two scenarios described in the oil production section of this report, U.S. gas production is projected to decline by 1990 from the 1975 level. Land requirements in 1975 have been calculated at about 179,000 acres. Land requirements may decline to about 151,000 acres by 1990 under the NEP scenario (Table 2.12). As with oil, unless major changes in natural gas production occur, changes in land use between 1975 and 1990 will likely be minimal.

2.4 URANIUM

About 93% of the uranium currently produced in the United States is derived from uranium ore that is mined by conventional methods. The remaining 7% is leached from low-grade stockpiles or tailings dumps (heap leach) or from ores that remain in the ground (solution mining), or is produced as a by-product of other processes (e.g., the production of phosphoric acid). This section will describe the impact of open-pit and underground uranium mines and of solution mines on the land.

Uranium ore deposits are found mainly in the western United States (Fig. 2.6); the Wyoming Basin and the Colorado Plateau, which includes parts of Utah, Colorado, Arizona, and New Mexico, contain the majority of the nation's proven reserves and potential resources. Two states alone, New Mexico and Wyoming (which also contain the Powder River Basin, a major coal-producing area), contain 87% of the proven reserves of uranium oxide recoverable at \$15/lb, and they provided 74% of the uranium oxide produced in 1978.³¹ One ton of uranium ore contains, on the average, only about four pounds of uranium oxide. Milling of ores to extract the uranium oxide (U_3O_8) is discussed in Sec. 3.

Table 2.12 Domestic Natural Gas Production and Estimated Land Use under Alternative Production Scenarios^a

Estimate	1975	1985		1990	
		NEP	NESS	NEP	NESS
Production (10^{15} Btu)	19.8	17.61	18.8	16.68	19.45
Land Required ^b (10^3 acres)	179	159	170	151	176

^aSame scenarios as described in Sec. 2.2.

^bAssumes $1,032 \text{ Btu}/\text{ft}^3$, measured at 14.7 psia and 60°F, and 850 acres for each $250 \times 10^6 \text{ ft}^3/\text{d}$ natural gas field (Ref. 18).

Fig. 2.6 Uranium Deposits in the Western United States
(Source: Adapted from Ref. 31)

The direct effects of uranium mining on the land are essentially the same as those described for coal mining, because the surface and underground mining techniques are similar (see Sec. 2.1). Surface uranium mines usually take the form of large open pits, as is also true of many western coal mines. The impact of solution mining is similar to that of oil extraction or in-situ oil-shale processes, because solution mining requires the drilling of wells to inject and recover a leaching solution.

2.4.1 Land Requirements

Because uranium ore deposits are found in highly irregular seams, and the uranium oxide content of the ore in different deposits ranges from 0.11% to 0.30%,³¹ it is difficult to estimate the amount of land disturbed per unit of ore or uranium oxide extracted by surface-mining methods. The potential magnitude of the disturbance can be indicated by using empirical data on land requirements of planned or existing mines. For example, a 1,000-ton/d

open-pit operation in Converse County, Wyoming, is expected to mine 575 acres of land over a five-year period.³¹ This figure converts to 315 acres per 10⁶ tons of ore. The average uranium oxide content in ores from New Mexico and Wyoming, the major ore-producing states, is 0.20%; on the average, then, it is likely that 158 acres of land will be mined to extract 1000 tons of uranium oxide.

Additional land is required at a surface mine for support facilities, haul roads, and topsoil and overburden storage. At the Converse County mine cited earlier, it is estimated that the mine shop will require 40 acres, haul roads and settling ponds 130 acres, overburden piles 880 acres, and topsoil storage 148 acres.³¹ These values present total requirements over five years; in some cases the same land will be used for several different purposes over the five-year period. Thus the total estimate of 1,773 acres (including 575 acres of open pit) is probably high. It can be assumed that the total acreage disturbed at a surface mine at any one time may be as much as twice the area of the pit. Areas mined in previous years that are still undergoing reclamation also will contribute to the total acreage devoted to mining uses.

An underground mine causes relatively little surface disturbance. One source estimated that about 10 acres of surface land would be required for a 1500-ton/d underground mine.³¹ The average production of the 305 underground uranium mines operating in 1978 was 30 ton/yr of uranium oxide,³¹ equivalent to approximately 40 ton/d of ore. It can be assumed that 2-5 acres of land will be required for surface activities associated with the average deep uranium mine, since some facilities -- e.g., access roads and mine offices -- are not proportional to the size of the mine. The area undermined cannot be estimated because of the variability of the deposits, as discussed earlier.

An in-situ, or solution, mine requires the drilling of a number of wells throughout the area of the deposit. A leaching solution is introduced into the ore deposit through injection wells and is removed, along with the dissolved uranium oxide, at associated production wells. The wells themselves cause a relatively small surface disruption, but the entire well field is closed to other uses during production. An in-situ operation producing 225 ton/yr of uranium oxide requires 25-50 acres of well field area per year.³¹ Estimated land requirements for the three mining methods discussed above are summarized in Table 2.13.

2.4.2 Past and Future Land Use

A Bureau of Mines study of land utilization by the mining industry reported that uranium mining had disturbed 12,800 acres of land by 1971.¹² Almost 230,000 tons of uranium oxide had been produced in the United States by that time.³⁰ From 1971 to 1978, an additional 103,000 tons of uranium oxide have been produced, almost half again as much as was produced in the preceding 24-year period; one might estimate, then, that almost 18,000 acres had been disturbed by uranium mining before 1978. By 1971, uranium mining had disturbed 6,700 acres in New Mexico (0.009% of the state area) and 4,200 acres in Wyoming (0.006% of the state area).¹²

About 12,300 tons of uranium oxide were produced in 1975; 55% of that amount came from surface mines, and 43% came from 121 underground mines.

Table 2.13 Estimated Land Requirements for
Three Uranium Mining Methods

Method	Acres/10 ³ ton U ₃ O ₈	Acres/Mine
Open-pit mining	158-316 ^a	-
Underground mining	-	2-5 ^b
Solution mining	111-222 ^c	-

^aLower number is for pit alone; higher number includes topsoil storage, haul roads and other associated uses.

^bAverage mine size = 30 tons of U₃O₈ per year.

^cBased on 25-50 acres of well field per year to produce 225 ton/yr of uranium oxide.

Using the estimates in Table 2.13, it can be calculated that 1,300-2,700 acres of land may have been disturbed by uranium mining in 1975.

The amount of land that may be disturbed between 1980 and 1990 by uranium mining is shown in Table 2.14. Three projections of 1990 production levels are used to illustrate a range of possible land requirements. A high production level, 40,400 tons of uranium oxide per year by 1990, was projected by DOE in their 1979 description of the U.S. uranium industry.³⁰ Approximately 310,000 tons of uranium oxide would be produced between 1980 and 1990 under this scenario. A moderate level of production is suggested by the NEP-II energy scenario currently being analyzed by the national laboratories for DOE. The NEP-II projects that the total nuclear generating capacity in the United States will be 12.2 GW by 1990. If it is assumed that a 1000 MW nuclear reactor requires 250 tons of yellowcake (a milling product that is 90% uranium oxide) per year, it can be calculated that this amount of generating capacity would require an annual production of about 36,500 tons of uranium oxide. About 257,000 tons of uranium oxide would be produced between 1980 and 1990 under this scenario. The low production level shown in Table 2.14 assumes that uranium oxide production will stay at the 1978 level -- 20,200 tons³⁰ -- until 1990. Cumulative production from 1980 to 1990 would then be 202,000 tons.

DOE estimates that by 1986, 56% of the uranium produced will come from underground mines, 29% from open pit mines, and 15% from nonconventional sources, primarily solution mining and as a by-product of phosphoric acid production.³¹ The calculations shown in Table 2.14 assume that this pattern of mining will continue until 1990, that about 7% of the uranium from nonconventional sources comes from solution mines, and that the average annual production of uranium oxide from an underground mine is 30 tons.

The calculations in Table 2.14 indicate that 1990 land requirements for uranium mining range from 1835-4049 acres for the low nuclear scenario to 3673-8100 acres for the high nuclear scenario. Open-pit mines, the most disruptive type, constitute 25-50% of this total. From 1980 to 1990, 11,580-23,535 acres of land might be used under the low scenario and 18,121-36,995

**Table 2.14 Estimated Land Required in 1990
for Projected U₃O₈ Extraction**

Uranium Extraction Levels ^a	Mine Type	1990 U ₃ O ₈ Production (tons) ^b	No. of Mines ^c	Land Requirement (acres)	Cumulative U ₃ O ₈ Production ^b (tons)	Land Requirement (acres)
Low	Deep	11,312	377	754-1,885	113,120	754-1,885
	Surface	5,858		925-1,850	58,580	9,256-18,511
	Solution	1,414		156-314	14,140	1,570-3,139
	Total	20,200 ^d		1,835-4,049 ^e	202,000 ^d	11,580-23,535 ^e
Medium	Deep	20,400	680	1,360-3,400	143,920	1,370-3,400
	Surface	10,585		1,672-3,345	74,530	11,775-23,551
	Solution	2,555		278-555	17,990	1,997-3,994
	Total	36,500 ^d		3,310-7,300 ^e	257,000 ^d	15,132-30,945 ^e
High	Deep	22,624	754	1,508-3,770	173,600	1,508-3,770
	Surface	11,716		1,851-3,702	89,900	14,204-28,408
	Solution	2,828		314-628	21,700	2,409-4,817
	Total	40,400 ^d		3,673-8,100 ^e	310,000 ^d	18,121-35,995 ^e

^aSee text.

^bValues for different mining methods calculated on the basis of 56% contribution from underground mines, 29% from open pit, and 7% from solution mines.

^cBased on 30 tons per year per underground mine. Not calculated for surface or solution mines.

^dIncludes production from other sources.

^eAssumes no additional land use for production of uranium as a by-product.

acres if the high projections are reached. Approximately 40-80% of this total would be due to the creation of open pits.

If present mining patterns continue, about 75% of this disturbance would occur in New Mexico and Wyoming. Most of this arid to semi-arid area is covered by native grassland or rangeland, and these are the land uses most likely to be displaced by uranium mining. Reclamation in these areas may be difficult. Much of the resource is in the public domain,³¹ which indicates that preservation uses may also be affected.

2.5 GEOTHERMAL

Geothermal energy is derived from subsurface occurrences of hot rock and heated water or steam. Wells are dug to bring the hot water or steam to the surface, where it can be used directly to drive conventional steam turbines. The only commercial U.S. generating plant using a geothermal energy source is The Geysers in Sonoma County, California. Opened in 1960, the Geysers was producing 502 MW of electricity in 1975 from generators powered by dry steam extracted directly from the earth. There is a large potential for expansion in the Geysers area: total production may reach 3000 MW by the year 2000,³² and the area has a maximum production potential of about 5000 MW.³³

The only other vapor-dominated geothermal systems in the United States are in Yellowstone and Mt. Lassen Volcanic National Parks, which are excluded from geothermal development under the Geothermal Leasing Act of 1970.³⁴ Thus, additional geothermal expansion will have to depend on the more common liquid-dominated systems, which extract a mixture of hot water and steam. There are currently 1.8×10^6 acres of land identified as "Known Geothermal Resource Areas" in the western states and Alaska; an additional 9.6×10^6 acres are defined as having prospective value. All are hydrothermal reservoirs.⁷

Areas of heated rock without naturally occurring water can also be exploited by injection and then recovery of water from artificially induced fractures in the rock. Geothermal systems utilizing hot rock are not expected to be commercially available until the late 1980s,³⁴ and most geothermal resource development in the next 25 years is expected to depend on the hydrothermal resources. All locations likely to be developed in that time period are located in the western third of the nation,^{7,32} including sites in New Mexico, Utah, Nevada, Idaho, Oregon, and California (see Fig. 2.7).

2.5.1 Land Requirements

Generation of electricity from geothermal sources generally depends on a rather large field of noninteracting wells. At The Geysers, for instance, 75 wells are needed to produce sufficient steam for the 502 MW of electrical power produced, 15 wells per 100 MW.^{33,34} Steam production from the vapor-dominated reservoirs decreases with time, and additional wells must be drilled to maintain the supply of steam to the generators; the additional

Fig. 2.7 Likely Areas for Hydrothermal Development
(Source: Ref. 32)

wells required over the next 30 years have been estimated at 35³³ and at 80.³⁴ For the same amount of electrical output, liquid-dominated systems would require more wells (100 wells per 100 MW) and hot rock systems would require considerably fewer (11 wells for 100 MW).³⁴

Spacing of the wells depends on the porosity and permeability of the reservoir rocks; the density of wells in existing geothermal fields throughout the world ranges from one well per 10 acres to one well per 40 acres.³⁴ The construction of each well disturbs approximately one acre of land; the operating well consumes only a small fraction of an acre (the additional land will have been reclaimed).³⁴ On the average, about one-half acre per well is required for access roads and the pipeline system that delivers the hot water or steam to the generators.³⁴ Actual land disturbance within the well field is thus limited to 10-20% of the area,^{7,33} though the entire producing field is closed to other land uses. Operating regulations require that all of the land be returned as near as possible to its original condition after the wells are plugged.

Land is also required for the generating plant at a geothermal facility. A number of relatively small (e.g., 100-110 MW) generating units must be dispersed throughout the resource area to minimize heat loss from the water or steam during transport from the well to the generator. At The Geysers, steam pipeline distance from the well to the power plant is less than a mile.³³ Conversion of heat to electricity at The Geysers occurs in production/generation units of approximately 110 MW, though the earlier units were smaller; six production/generation units contribute to the total Geysers capacity of 502 MW. Capacity additions are planned in increments of about 110 MW. The generating plant at each production/generation unit will require about five acres of land.³³ It is estimated that generating plants utilizing hot-water reservoirs will require about 30 acres and those in hot dry rock systems would require about 15 acres.³⁴ The land requirements for one 110-MW production/generation unit, including well-field and generating plant, are shown in Table 2.15.

Table 2.15 Land Requirements for a 110-MW Generation Unit
at Geothermal Facilities

Resource Type	Wells/Unit	Acres/Well	Acres/ Generating Unit	Total Acres/Unit
Dry steam ^a	15 ^b	40 ^d	5	605 ^b
	35-80 ^c	20 ^e	5	705-1605 ^c
Hot water	100	10-40	30	1030-4030
Hot dry rock	11	10-40	15	125-455

^aThe Geysers.

^bInitial requirement.

^cOver 30-year lifetime of generating unit.

^dFrom Ref. 34.

^eAverage density over 30 years; derived from data in Ref. 33.

2.5.2 Past and Future Land Use

All of the land devoted to geothermal energy production to date in the United States has been at The Geysers, where 167 wells have been drilled in an area of more than 12,000 acres.³³ Development is scattered within that area, and the producing well fields and generating plants probably cover only 3,600 acres.

Projections of U.S. generating capacity from geothermal sources range from 2000-6000 MW for 1985 to 10,000-39,000 MW for 2000 (see Table 2.16). The Geysers may have a capacity of about 1700 MW in 1985 and 3000 MW by 2000.³³ The remainder would have to come from new development of liquid-dominated reservoirs, plus a few hot dry rock systems by 2000. Assuming production/generation units of 100 MW, and using the values in table 2.15, this number converts to a land requirement in 1985 of 13,375 to 22,375 acres for 2000 MW and 54,575 to 183,575 acres for 6000 MW (see Table 2.17). In 2000, $0.09-1.4 \times 10^6$ acres could be devoted to geothermal energy. An energy production scenario (NEP-II) currently being analyzed by the national laboratories projects only 4125 MW of geothermal generating capacity by 1990, of which 3250 MW would be sited in California, 375 MW in Nevada, and 250 MW each in New Mexico and Utah. According to this scenario, which is at the low end of the ranges discussed earlier, 34,760 to 100,760 acres of land may be used for geothermal energy by 1990.

Geothermal fields are generally found in remote areas of the west where population densities average only 3.4 persons per square mile;³² the vegetative cover in these areas is most likely to be natural vegetation. Geothermal development is thus most likely to conflict with scenic and wilderness priorities and with wildlife uses of the land. Some cropland and range may also be affected.

Table 2.16 Projections of Electricity Generating Capacity from Geothermal Resources in the United States, 1985-2000

Source of Projections ^a	Projected Capacity, MW _e	
	1985	2000
Energy Resource Conference, 1975	2,500-5,100	-
ERDA-86, Geothermal Energy Definition Report, 1975	6,000	39,000
Electric Power Research Institute, 1976	3,500	10,000
National Electric Reliability Council, 1976	2,080	-
ERDA, Program Approval Document, 1977	3,000-4,000	20,000-40,000

^aRef. 34, Table 8-7.

Table 2.17 Calculation of Land Potentially Devoted to Geothermal Energy Production^a

Year and Production Estimate	Source	Capacity (MW)	Land (acres)
1985, low	The Geysers	1,700 ^b	10,285
	Hot water	300	3,090-12,090
	Total	2,000	13,375-22,375
high	The Geysers	1,700 ^b	10,285
	Hot water	4,300	54,575-183,375
	Total	6,000	64,860-193,660
1990, NEP-II ^c	The Geysers	2,000	12,100
	Hot water	1,125 ^d	22,660-88,660
	Total	3,125	34,760-100,760
2000, low	The Geysers	3,000 ^e	18,150
	Hot water	6,800	70,040-274,040
	Hot dry rock	200 ^f	250-910
	Total	10,000	88,440-293,100
high	The Geysers	3,000 ^e	18,150
	Hot water	35,800	378,740-1,442,740
	Hot dry rock	200 ^f	250-910
	Total	39,000	397,140-1,461,800

^aRange of projected capacities from a variety of sources, as quoted in Table 2.16; land estimates from Table 2.15.

^bBased on units planned for production before 1985, from Ref. 35.

^cSee text.

^d22 production/generation units at 8 sites.

^eRef. 33.

^fAssuming post-1990 development at about the same pace as historical development at The Geysers.

2.6 BIOMASS

The use of biomass feedstock for energy has received much attention recently. Historically, biomass -- primarily crop residues, timber, and organic residues from the lumber industry -- has provided space heat and process heat through direct combustion. Continued use of these materials as a source of fuel, directly by combustion or indirectly from the production of alcohol, is viewed as a means of reducing United States reliance on fossil fuel. Debate over the role biomass can play in meeting goals of

decreased fossil fuel use centers around whether the various biomass conversion processes provide a favorable net energy balance³⁶ and, further, whether or not sufficient feedstock exists nationally to meet a prescribed energy demand.

Concern has been expressed that the drive by the U.S. government to develop alternative sources of energy may result in competition with agricultural uses of land³⁷ and that biomass power plants could require up to 300,000 acres (10,000 acres per plant-year) of agricultural land to supply feedstocks.¹⁵ The use of grain for ethanol production and wood for methanol production could cause such competition for land and both could result in changes in current land use. The use of crop and lumber residues is not considered by some as a viable source of feedstock to meet large, near-term levels of alcohol production, i.e., levels that would contribute significantly to a national program of gasoline substitution by gasohol.^{38,39} The harvesting of crop residues for the production of ethanol is not considered to have major direct effects on land use, although serious environmental issues have been raised concerning removal of residues. Indirect effects on soil fertility and stability could cause long-term changes in land use.

The question of the availability of feedstock to meet projected demands for alcohol will be addressed in the following discussion, and land-use conflicts that might occur from a biomass energy program will be identified. Wood burning for space heat is not considered here because the focus of this report is toward larger, centralized technologies.

2.6.1 Ethanol from Grain

The level at which alcohol can be substituted for gasoline in an alcohol fuels program is directly related to the availability of grain feedstocks. Most reviews of feedstock availability assume that traditional uses of grain will be satisfied first and that the remainder will be available for ethanol production.^{36,39-41} If, after domestic consumption and export, surplus grain is not available, the common assumption is that set-aside and diverted cropland could be utilized for grain to produce ethanol. If such a resource base were available, the potential production of ethanol from corn could reach several billion gallons per year, assuming 2.6 gallons of ethanol per bushel of corn⁴⁰ and 600-800 x 10⁶ bushels of corn from land that had been set aside.⁴² Reliance on the availability of withheld cropland to support an alcohol fuels program is tenuous, however. Between 1961 and 1972, the United States set aside or diverted to other uses an average of 21.7 x 10⁶ (range, 14-27 x 10⁶) acres of corn land. Land that had been used for growing other grains contributed another 9 x 10⁶ acres set aside during this period. Since 1972, a substantial decline in grain reserve and diversion programs has occurred, with no acreages withheld during 1974-1977.⁴³ In 1978, only 6.1 x 10⁶ acres of corn land and 8.4 x 10⁶ acres of wheat land were in set-aside or diversion programs.⁴⁴

Another approach to estimating available cropland is to use the Soil Conservation Service data on potential cropland.⁴⁵ These data identify pasture, range, forest, and other land, by state, that has a "high" or "medium" potential for conversion to cropland (Table 2.18). These figures do not include existing cropland, cropland in set-aside or diversion programs, or federal lands. Texas, Missouri, and Georgia have the greatest acreage that

Table 2.18 Amounts of Cropland with Potential for Conversion to Pasture, Range, Forest, and Other Land, by State and Region, 1977^a

State and Region	10 ³ acres			
	High Potential	Medium Potential	Conversion Unlikely	Zero Potential
Region 1				
Connecticut	23	89	306	1,420
Maine	29	286	9,093	8,621
Massachusetts	33	144	764	2,353
New Hampshire	27	217	1,996	2,080
Rhode Island	5	18	54	294
Vermont	45	168	931	3,470
Subtotal	162	922	13,144	18,238
Region 2				
New Jersey	116	310	701	1,482
New York	358	1,352	4,569	14,258
Subtotal	474	1,662	5,270	15,740
Region 3				
Delaware	28	87	186	194
Maryland	145	382	1,116	1,466
Pennsylvania	270	1,160	4,326	12,536
Virginia	545	1,605	5,732	9,489
West Virginia	64	388	1,302	10,493
Subtotal	1,052	3,622	12,662	34,178
Region 4				
Alabama	1,064	3,083	7,428	12,923
Florida	1,117	2,534	11,022	8,754
Georgia	2,120	3,670	8,484	11,502
Kentucky	1,302	1,801	2,936	11,011
Mississippi	1,306	2,491	4,934	10,319
North Carolina	1,398	3,661	5,932	9,001
South Carolina	629	1,635	6,128	4,307
Tennessee	1,428	2,351	3,626	10,428
Subtotal	10,364	21,226	50,490	78,245
Region 5				
Illinois	582	1,385	2,414	3,228
Indiana	804	1,008	2,068	2,909
Michigan	561	1,409	5,750	11,790
Minnesota	1,108	2,845	8,516	9,219
Ohio	528	1,394	3,490	4,360
Wisconsin	618	2,041	7,582	8,563
Subtotal	4,201	10,082	29,820	40,069

Table 2.18 (Cont'd)

State and Region	10 ³ acres			
	High Potential	Medium Potential	Conversion Unlikely	Zero Potential
Region 6				
Arkansas	657	2,634	9,243	7,868
Louisiana	1,129	1,864	6,272	10,683
New Mexico	474	822	8,638	37,985
Oklahoma	1,683	4,119	7,564	15,483
Texas	3,534	10,727	46,960	65,280
Subtotal	7,477	20,166	78,677	137,299
Region 7				
Iowa	700	1,488	2,144	2,771
Kansas	1,893	3,673	5,593	9,622
Missouri	2,226	4,395	7,154	10,881
Nebraska	1,083	2,871	7,260	14,916
Subtotal	5,902	12,427	22,151	38,190
Region 8				
Colorado	365	2,369	7,570	19,856
Montana	1,339	4,360	11,264	32,306
North Dakota	984	1,898	4,581	6,568
South Dakota	1,090	4,403	7,602	13,328
Utah	73	447	1,166	12,347
Wyoming	253	1,688	5,064	22,038
Subtotal	4,104	15,165	37,247	106,443
Region 9				
Arizona	155	216	3,625	34,327
California	800	2,009	5,029	30,591
Hawaii	39	62	543	2,674
Nevada	50	238	1,689	7,212
Subtotal	1,044	2,525	10,886	74,804
Region 10^b				
Idaho	525	916	1,727	9,318
Oregon	325	862	3,042	18,549
Washington	506	1,049	3,247	15,669
Subtotal	1,356	2,827	8,016	43,536
National Total	36,136	90,624	268,363	586,742

^aAdapted from Ref. 45.^bAlaska data not available.

is rated as having a "high potential" for conversion to cropland (Fig. 2.8). Eight states have over 5×10^6 acres of land with a "high" or "medium" potential for conversion to croplands (Fig. 2.9). Regions 4 and 6 have the greatest reserve of potential cropland (Table 2.18).

2.6.1.1 Future Land Use

Current ethanol production in the United States is about 21×10^6 gal/yr from two major plants: the Archer-Daniels-Midland Co. in Decatur, Illinois, which produces 19×10^6 gal/yr, and the Georgia-Pacific Corp. in Bellingham, Washington, which produces nearly 2×10^6 gal/yr.³⁸ In a recent statement, Energy Secretary Charles Duncan, supported by President Carter, expressed a desire "to convert 10% of unleaded gasoline to gasohol within one year."³⁸ This goal implies an annual ethanol production of 430×10^6 gal by the end of 1980 (based on a 1979 production level of 42.7×10^9 gal of unleaded gasoline). Bills introduced in the 96th Congress propose ethanol production levels up to 92×10^6 gal/yr by 1982.⁴⁶ Such levels would require $2\text{--}4.4 \times 10^6$ acres of land planted in corn, which could be easily supplied from reserve crop land (assuming pre-1974 reserve levels).

For higher levels of ethanol production, significant conversion to cropland of land with high potential for such conversion might be expected. A study conducted several years ago for a 17-state region in the central United States estimated average requirements for grain under three demand scenarios for ethanol (Table 2.19).⁴⁰ The 100%-gasohol scenario assumed that 10% of all gasoline would be replaced by ethanol (because gasohol is 10% ethanol and 90% gasoline); the 50%-gasohol scenario assumed 5% gasoline replacement, and the 25%-gasohol scenario assumed 2.5% gasoline replacement. Production levels of ethanol under these scenarios ranged from 1.3×10^9 gal to 5.4×10^9 gal in 1990 in the 17-state region. This region has 19.4×10^6 acres of land with a high potential for conversion to cropland and 52×10^6 acres with a medium potential (Table 2.18).³⁶ If only corn were used for ethanol production, 16.9×10^6 acres within the 17-state region would be required by 1990 for a 100%-gasohol program. A feedstock mixture of corn, grain sorghum, and wheat would require 24.7×10^6 acres by 1990.

Estimates for a national 100%-gasohol program have been $10\text{--}12 \times 10^9$ gal/yr.^{47,48} Such production levels might require all 36×10^6 acres of land with a high potential for conversion to cropland and $12\text{--}21 \times 10^6$ acres of the land with medium potential for conversion in the nation. About 40% of the reserve of lands with a high or medium potential for conversion to cropland would be directly converted to crop use. Similar estimates of land requirements have been reported elsewhere.⁴⁹

This analysis assumes that the reserve of potential cropland will remain static over the next 20 years; such an assumption, however, is unrealistic. Between 1967 and 1975, 79.2×10^6 acres of cropland were converted to other uses.⁴⁸ About 24×10^6 acres were permanently lost to agricultural use by being converted to urban and built-up areas and to water uses.⁴⁸ The national loss of prime farmland is estimated at 10^6 /acres/yr or about 4 square miles per day. Over half of this acreage is subdivided or placed into residential use. Rangeland and pasture are being converted to crop use to offset this loss, but this conversion depletes the reserve of potential cropland.

Fig. 2.8 Land with High Potential for Conversion to Cropland, 1977

Fig. 2.9 Land with High to Medium Potential for Conversion to Cropland, 1977

Table 2.19 Cropland Requirements for Ethanol Production
in the 17-State Region,^a 1980-2000^b

Crop	Gasohol Use Scenario ^c	Cropland Required (10 ³ acres)				
		1980	1985	1990	1995	2000
Corn	25%	4,250	4,179	4,217	4,306	4,384
	50%	8,503	8,363	8,438	8,612	8,766
	100%	17,008	16,727	16,880	17,224	17,536
Grain Sorghum	25%	6,950	7,023	7,227	7,574	7,841
	50%	13,906	14,052	14,459	15,149	15,678
	100%	27,811	28,105	28,924	30,297	31,361
Wheat	25%	13,642	13,727	13,927	14,202	14,963
	50%	27,296	27,466	27,865	28,404	29,917
	100%	54,593	54,932	55,740	56,808	59,844
Weighted average of all three	25%	6,210	6,130	6,190	6,340	6,500
	50%	12,420	12,270	12,380	12,680	12,990
	100%	24,840	24,540	24,720	25,360	25,990

^aThe states include Montana, Wyoming, Colorado, Texas, Oklahoma, Kansas, Nebraska, South Dakota, North Dakota, Minnesota, Iowa, Missouri, Illinois, Wisconsin, Michigan, Indiana, and Ohio.

^bFrom Ref. 40.

^c25% Scenario = 2.5% gasoline replacement; 50% Scenario = 5% gasoline replacement; 100% Scenario = 10% gasoline replacement.

During the 1967-1975 period, 48.7×10^6 acres of pasture and rangeland were converted to cropland. However, since 1974, price-cost relationships have made it less economical to convert land to farm use. If the loss of farmland continues at this rate, there will be increasing competition between energy uses and food and fiber production for the land with a high potential for conversion to cropland.

2.6.2 Methanol from Woody Biomass

The use of methanol in a gasoline substitution program has received attention primarily because there is a large amount of woody feedstock that could be used. The nation's standing forests contain an energy equivalent of nearly 300 quads (one quad = 10^{15} Btu) above ground, with 85% of this total in commercial forest⁵⁰ (i.e., forest land that is producing or capable of producing crops of industrial wood and that is not withdrawn from logging use⁵¹). Wood biomass that might be available without causing a major impact on land use include the following:

- Unused mill residues (bark, etc., at forest products processing plants).
- Forest residues (branches, broken pieces, etc.) at logging sites.

- Surplus growth (the net annual growth minus the timber removed from the growing stock).
- Annual mortality of the growing stock.
- Noncommercial timber (rough, rotten, or dead trees).
- Timber on noncommercial forest land (forest land that cannot yield timber crops because of adverse terrain and forest land withdrawn from commercial timber use).

It was estimated in 1976 that about 9 quads of energy is available nationally from the six sources described above.⁴⁷ Projections of future availability of these resources were recently published⁴⁷ and are presented in Table 2.20. According to this study, woody biomass can contribute 9 quads per year of energy in 1975 and 7 quads per year in 1990. The decrease in resource availability is due to an increase in timber use and a decrease in surplus growth. The availability of mill residues may also decrease because increased demand is projected for these residues as process fuel. The woody biomass resources could, in 1990, produce over 57×10^9 gal/yr of methanol, which is substantially more than the 10×10^9 gal/yr required for a 100%-gasohol program. The major regional contributors to a woody biomass program would be the Pacific, Mountain, and Southeast Farm Production Regions; all could contribute over a quad per year in 1990.

Beyond 1990, silviculture energy farms could be developed to provide all the wood biomass required for the gasohol program. Such farms could contribute over 4 quads by 2000, with nearly 80% of the potential resource coming from the eastern United States.⁴⁷ Permanent pasture, forest, range, rotational hay and pasture, hayland, and open land would have to be converted to silviculture. For a wood-to-methanol program, approximately 23×10^6 acres, or about 18% of the land identified as having medium and high potential for conversion to cropland, could be utilized for silviculture energy farms.

2.6.3 Alcohol Production Plants

Table 2.21 provides estimates of land used for the operation of model plants that convert grain to ethanol, crop residues to ethanol, wood to methanol, and wood to ethanol.⁵²

Table 2.20 Potential Wood Feedstock Resources, by USDA Farm Production Regions, for 1976-1990^a

Farm Production Region	Commercial Forest Land					Noncommercial Forest Land		Total			
	Mill Residues, 10 ⁶ DT/yr	Forest Residues, 10 ⁶ DT/yr	Surplus Growth, 10 ⁶ DT/yr	Annual Mortality, 10 ⁶ DT/yr	Noncommercial Timber, 10 ⁶ DT/yr	Reserved & Deferred, 10 ⁶ DT/yr	Unproductive, 10 ⁶ DT/yr	Wood		Methanol Equivalent, ^b 10 ⁹ gal/yr	Percent of Total
	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	10 ⁶ DT/yr	Q/yr	10 ⁹ gal/yr	
1976											
Northeast	1.106	9.235	34.476	14.000	13.706	2.648	0.354	75.519	1.284	10.07	14.41
Northern Plains	0.119	0.236	0.940	0.765	0.825	0	0.177	3.062	0.052	0.41	0.58
Corn Belt	0.800	3.412	3.235	1.941	4.176	0.354	0.059	14.979	0.255	2.00	2.86
Southeast	1.820	18.588	37.058	9.647	10.824	1.001	0.353	79.291	1.348	10.66	15.31
Appalachian	1.361	12.588	40.294	9.353	13.412	1.941	0	78.949	1.341	10.53	15.06
Southern Plains	0.584	3.647	6.471	1.412	3.059	0.059	3.353	18.584	0.316	2.48	3.55
Delta States	1.886	13.235	23.176	6.176	8.706	0.177	0	53.356	0.908	7.11	10.18
Lake States	0.519	4.882	19.824	11.235	3.942	1.000	0.471	81.036	1.378	5.58	7.99
Pacific	2.623	30.236	0	20.294	13.412	7.706	6.675	81.036	1.378	10.81	15.46
Mountain	2.552	6.059	18.529	14.000	14.000	9.824	15.529	77.492	1.318	10.33	14.78
Total: 10 ⁶ DT/yr	13.366	102.118	183.997	88.823	87.062	24.710	27.061	524.141	-	69.98	100.00
Equivalent Q/yr	0.228	1.736	0.315	1.510	1.480	0.420	0.460	-	8.911	-	-
1990											
Northeast	0.509	12.735	12.065	15.652	13.706	2.648	0.354	57.669	0.980	7.69	13.43
Northern Plains	0.055	0.325	0.329	0.855	0.825	0	0.177	2.556	0.044	0.34	0.60
Corn Belt	0.368	4.705	1.132	2.170	5.176	0.354	0.059	13.964	0.237	1.86	3.25
Southeast	0.837	22.826	14.453	10.433	10.824	1.001	0.353	60.727	1.032	8.10	14.15
Appalachian	0.626	17.359	14.103	10.457	13.412	1.941	0	57.898	0.984	7.72	13.49
Southern Plains	0.269	4.478	2.524	1.527	3.059	0.059	3.353	15.269	0.260	2.04	3.56
Delta States	0.868	16.235	9.039	6.679	8.706	0.177	0	41.722	0.709	5.56	9.72
Lake States	0.239	6.732	6.938	12.561	3.942	1.000	0.471	31.883	0.542	4.25	7.43
Pacific	1.207	30.841	0	20.365	13.412	7.706	6.765	80.296	1.365	10.71	18.70
Mountain	1.174	7.034	6.763	12.964	14.000	9.824	15.529	87.288	1.144	8.97	15.67
Total: 10 ⁶ DT/yr	6.148	123.735	67.346	93.663	87.062	24.710	27.061	429.282	-	57.24	100.00
Equivalent Q/yr	0.105	2.096	1.145	1.592	1.480	0.420	0.460	-	7.298	-	-

^aFrom Ref. 47. Units: DT/yr = dry tons/year, Q/yr = quads/year.

^bBased on 133 gal methanol per dry ton of wood.

Table 2.21 Land Required for the Conversion of
Alternative Feedstocks to Alcohol

Facility	Feedstock Requirements ^a	Alcohol Production (10 ⁶ gal/yr)	Land Required	
			Facility (acres)	Feedstock (acres)
Corn Fermentation (ethanol)	25,000 bu/d	20	80	100,000 ^b
Corn and Wheat Residue (ethanol)	1,562 DT/d	25	120 ^c 140 ^d	-
Wood Methanol	1,000 DT/d	56	218	40,000 ^e
Wood Ethanol	1,000 DT/d	33	159	40,000 ^e

^abu/d = bushels per day, DT/d = dry tons per day.

^bAssumes 90 bushels per acre.

^cAcid hydrolysis.

^dEnzymatic hydrolysis.

^eFeedstock derived from energy farm.

3 PROCESSING

Many energy resources need to be processed to prepare them for use. Uranium, for instance, must be extracted from the ore and fabricated into reactor fuel. Processing facilities are industrial developments, which will probably cause a permanent change in land use. This section discusses some of the processing activities that occur in the various fuel cycles, including

- Synfuels from coal
- Oil refining
- Uranium processing

Other processing activities, including coal cleaning, the removal of oil from oil shale, and the preparation of alcohol from biomass, were described in the extraction discussions in Sec. 2.

3.1 SYNTHETIC FUELS FROM COAL

In July 1979, President Carter announced several new policies intended to reduce the amount of petroleum imported into the United States. A major objective of this energy supply realignment is the installation of sufficient domestic synfuel capacity to produce 2.5×10^6 oil-equivalent barrels per day by 1990.⁵³ To date, only test facilities and pilot plants have been constructed at major research centers and industrial installations throughout the country. A DOE program entitled Industrial Fuel Gas Demonstration Project is subsidizing this program, and will subsequently (1) assess the demonstration of the technical, environmental, and economic feasibility of medium-Btu gasification; (2) secure a demonstration plant to advance the current state of the art in medium-Btu gasification technology; and (3) encourage commercialization of this technology. A much larger program undertaken by DOE in March 1980 is targeted at making money available for feasibility studies and cooperative agreements to commercialize synthetic-fuel technologies as rapidly as possible. This money, when released in July 1980, will promote the construction and operation of several synthetic-fuel facilities within each technological category throughout the continental United States.

Effects on land use induced by the construction and operation of a synthetic fuels plant are expected to be very similar to the impact caused by conventional coal-fired power plants (see Sec. 4.1). Approximately the same land area is required for direct and indirect liquefaction and high-Btu coal-gasification plants as is necessary for coal-fueled electrical generating units. Other requirements shared by these processes include a railroad spur, proximity to a water source, adequate coal supply, and a coal-storage pile. On the other hand, the equipment, plant configuration, and chemical effluents associated with direct and indirect coal-liquefaction and coal-gasification technologies closely resemble those of a crude-oil refinery.⁵⁴

It is difficult at this time to accurately describe the impact on land use and the environment of any of the processes to convert coal to liquids because no demonstration and/or commercial-scale facilities are yet in operation. Until that time, or until more detailed data on each process

are released from the companies owning the commercialization rights, the similarities identified above provide the only available basis for estimating effects on land use.

3.1.1 Facility Size and Siting Considerations

The coal-liquid processes that are closest to commercialization, and which therefore provide the greatest economic, technological, and environmental information, are Fischer-Tropsch, Mobil-M, Exxon Donor Solvent, H-Coal, and SRC-I and II. The first three processes convert coal indirectly (i.e., by first processing it with methanol) whereas the latter three are direct processes. The average requirement of land for a 50,000-bbl/d coal-liquid plant is approximately 550 acres. The same area is assumed to be necessary for a 250×10^6 ft³/d high-Btu coal-gasification complex. As with all other energy developments, the amount of land that the plant occupies depends on ownership, topography, economics, process noise, availability, expansion plans, and the plant configuration itself. Synfuel plants will tend to be sited near a source of coal, and many may be mine-mouth plants. They will probably not be sited in air quality-limited areas.

3.1.2 Past and Future Land Use

To date, very little land has been devoted to the production of synthetic fuels from coal. The locations of existing pilot plants and planned demonstration plants are shown in Table 3.1.

Table 3.1 Existing Pilot Plants and Planned Demonstration Plants for Production of Synfuels

Location	Process
Existing Pilot Plants	
Wilsonville, AL	H-Coal
Cattlesburg, KY	H-Coal
Ft. Lewis, WA	Solvent Refined Coal (I)
Baytown, TX	Exxon Donor Solvent
Planned Demonstration Plants	
Memphis, TN	UGAS
Baskett, KY	Ammonia
Perry County, OH	CONOCO (modified)
Morgantown, WV	Solvent-Refined Coal (II)
Newman, KY	Solvent-Refined Coal (II)
Noble County, OH	CONOCO
Muscle Shoals, AL	Ammonia

The four pilot plants combined occupy less than 300 acres. The seven demonstration plants will occupy approximately 2000 acres for their processing and auxilliary equipment and coal piles. The draft environmental impact statements for several of these facilities indicate that land requirements will range from 100 to 700 acres.⁵⁵⁻⁵⁷

Approximately 40 commercial-scale plants will be necessary to satisfy the Presidential order. More than 22,000 acres of land would be required for these plants; their locations are currently indeterminable, because political and economic uncertainties would introduce substantial error into any projection for 1990. The responses received under the DOE Feasibility/Cooperative Agreement identified potential sites in almost every state in the nation, with a possible concentration of sites in the Southeast, Midwest, and Mountain states. The sites identified in the DOE Feasibility/Cooperative Agreement are principally in rural, coal-rich, semi-industrialized areas where several modes of shipment are available.⁵⁸

3.2 OIL REFINERIES

Oil refineries are complex systems with many component parts, and it is difficult to characterize a "typical" configuration, size, and mix of products. Generally, complexity and associated resource requirements increase with product diversity. Refineries specializing in one or more of the four standard products (gasoline, jet fuel, diesel fuel, and fuel oil) are relatively simple and require less land area than a diversified refinery producing a wide range of products.

The initial direct and indirect impacts of the refinery are related to the following construction activities:

1. Ground clearing and reshaping - those operations involving the physical disruption of the ground surface, including stripping of vegetation, grading, excavation, road building, and site restoration.
2. Operation of construction equipment.
3. Channelization, waterway modification, and other water-related activities - all construction activities associated with the water, including channelization of harbors for moving heavy equipment and material to site; construction of breakways, jetties, and other shore-protection devices; construction of docks and terminals for fuel and product transshipment; and the construction of water intake and outlet structures.

Significant long-term effects of a refinery on the land use and general environment of the area can be associated with (1) receiving and storage of crude oil, (2) plant operation, and (3) product storage and shipping. During plant operation, adjacent land may be affected by hydrocarbon emissions, oil leaks and spills, visual intrusion, air pollution (e.g., SO_x , NO_x), solid wastes, and the consumption and discharge of water used in the cooling system or the industrial process.⁵⁹ One effect on land use that should not be overlooked is that the land committed to the facility is not available for other uses.

Transport of crude oil to the refinery from either a domestic well or a tanker that originated in the Middle East, South America, or Indonesia can be accomplished by rail, barge, or pipeline, depending on the source of the crude oil, its viscosity, and the intended final product. The predominant means of moving crude oil to refineries for processing and/or upgrading has been the pipeline, because of its distinct economic advantages. The initial construction of crude-oil pipelines does produce some negative effects on the land; after reforestation and land reclamation, however, the only remaining effect is the pipeline corridor. Given that this corridor does not exceed 50 feet in width (as specified by the Mineral Leasing Act of 1920), together with the fact that pipelines do not require continual service or maintenance, the impact on the surrounding land is minimal except where there is a conflict with mineral extraction processes or unique environmental situations. Therefore, we shall not address this issue further.

3.2.1 Facility Size and Siting Considerations

The amount of land required for the efficient construction and operation of a refinery complex is principally a function of the facility capacity and its configuration. Configuration in this sense refers to plant and product complexity. As refineries diversify into additional products that require more processing, supplemental units must be incorporated into the plant structure. These units and the associated storage tanks required to handle the intermediary products demand more land.

Historically, refineries occupied land areas ranging from 15 to 20 acres per 1000 barrels of products. These plants were constructed in remote areas where land was relatively inexpensive. Currently, only 5 acres per 1000 barrels are assumed to be required when the site of a "grass roots" refinery is assessed. Approximately 10-20% of the total site is specified for process units, 20-35% for tankage, 10% for planned expansion, and the remaining 35-60% for use as a structural buffer, sound barrier, sludge storage area, or greenbelt perimeter.

Choosing a location for a refinery is a function of two countervailing forces. One is the necessity of locating close to the product market or the distribution system to reduce transportation costs. The second is the necessity of meeting environmental criteria related to air quality, aesthetics, noise, etc. Refinery companies attempt to balance these two requirements by locating on sites isolated from the surrounding population. How these two forces balance depends on the specific situation, and is difficult to generalize.

Other resource requirements can influence the siting of a refinery and its consequent impact on surrounding land uses. Water supply and wastewater disposal were extremely important considerations in past siting decisions, but modifications of component configurations and the incorporation of air cooling (greater recycling) have lessened the importance of this resource. Transportation, too, especially with regard to crude-oil supply, was one of the most important economic criteria considered in refinery siting. Today, with a greatly expanded crude-oil pipeline network, product transport is now more expensive than moving the crude oil. Refineries are thus more likely to be located near their product market. This trend may indicate that future

refineries will be located in the vicinity of large metropolitan markets such as the East Coast, the Great Lakes, the West Coast, and the Gulf Coast.⁵⁹

The final site selection, though, has come to be increasingly determined by public acceptance of the ultimate location. Therefore, it has been and will be important that public opinions and attitudes be considered in site selection, especially with regard to relevant air- and water-quality issues, aesthetics, conflicting land uses, and the economic impact on property values and taxes.

3.2.2 Past and Future Land Use

An estimate of the total land area occupied by oil refinery complexes can be determined by using the average figures cited earlier. The geographic distribution of these plants is shown in Fig. 3.1. Refineries are located in 41 out of the 50 states, but are principally concentrated in the states of California, Illinois, Kansas, Louisiana, Oklahoma, Pennsylvania, Texas, and Wyoming. It is not a coincidence that these same states are very large producers of crude oil, and/or have favorable deep-water port facilities, and/or are principal market-distribution areas. Table 3.2 illustrates the approximate acreage per state and region that is designated for industrial use by refineries as of January 1, 1980. The total area in the country that is supporting oil refinery structures, tankage, greenbelt perimeters, sound barriers, environmental controls, and transportation networks approaches 328,000 acres. Approximately 45% of this area is in Region 6, and particularly in the states of Texas and Louisiana. The proposed refinery complexes to be constructed between 1980 and 1990 are displayed in Table 3.3.* Because only feasibility studies are being performed at this time, it is unknown whether all this new capacity will be operational by 1990. Furthermore, as a result of regulatory uncertainties and citizen opposition to the Hampton Roads and Pittston refineries, construction schedules may be tenuous. Nevertheless, Table 3.3 conveys the number and crude capacity of these prospective new refineries.

Region 6 will be expected to absorb the greatest number of, and many of the largest, refineries and consequently will have the most land area utilized for crude oil processing. Because many of the areas where the prospective plants are to be constructed are in close proximity to other refineries, however, and are probably already classified for industrial use, the impact on alternative land use should be dampened. Many of the other proposed refineries will be sited in relatively populated areas adjacent to water (a channel, major river, or ocean port); aquatic ecosystems and coastal zones may thus be affected. One final point is that numerous 3,000- to 4,000-bbl/d plants are planned. The construction and operation of these diversified plants may precipitate greater land use conflicts than would be caused by several large (150,000-250,000 bbl/d) processing facilities. The consequences of such a tradeoff are too site-specific to generalize.

*Expansion of existing refineries was not addressed because it was assumed that sufficient land had been acquired for expansion when the plant was originally built.

Fig. 3.1 Refinery Capacity by County in 1975 (Source: Ref. 17)

Table 3.2 Land Allocation for Existing Refineries

Region and State	Number of Plants	Crude Oil Capacity (bbl/s-d) ^a		Occupied Land Area (acres)
		Total	Average	
Region 1				
Connecticut	-	-	-	-
Maine	-	-	-	-
Massachusetts	-	-	-	-
New Hampshire	1	13,000	13,000	228
Rhode Island	-	-	-	-
Vermont	-	-	-	-
Subtotal	1	13,000	13,000	228
Region 2				
New Jersey	5	732,578	146,516	12,820
New York	3	146,400	48,800	2,462
Subtotal	8	878,978	109,872	15,282
Region 3				
Delaware	1	150,000	150,000	2,625
Maryland	2	30,000	15,000	525
Pennsylvania	10	849,395	84,940	14,864
Virginia	1	55,000	55,000	963
West Virginia	3	21,100	7,033	369
Subtotal	17	1,105,495	65,029	19,346
Region 4				
Alabama	6	144,700	24,117	2,432
Florida	1	14,000	14,000	245
Georgia	2	24,000	12,000	420
Kentucky	4	252,500	63,125	4,419
Mississippi	7	371,564	53,081	6,502
North Carolina	1	12,495	12,495	219
South Carolina	-	-	-	-
Tennessee	1	43,820	43,820	767
Subtotal	22	863,079	39,230	15,004
Region 5				
Illinois	11	1,274,156	115,832	22,297
Indiana	6	641,787	80,223	11,231
Michigan	6	143,816	23,969	2,417
Minnesota	3	224,905	74,968	3,936
Ohio	7	618,000	88,286	10,815
Wisconsin	1	46,800	46,800	819
Subtotal	34	2,949,464	86,750	51,515

Table 3.2 (Cont'd)

Region and State	Number of Plants	Crude Oil Capacity (bbl/s-d) ^a		Occupied Land Area (acres)
		Total	Average	
Region 6				
Arkansas	4	67,150	16,788	1,175
Louisiana	30	2,429,510	80,984	42,516
New Mexico	9	133,139	14,793	2,330
Oklahoma	12	577,145	48,095	10,100
Texas	56	5,130,504	91,616	89,184
Subtotal	111	8,337,448	75,112	145,905
Region 7				
Iowa	-	-	-	-
Kansas	11	486,131	44,194	8,507
Missouri	1	111,000	111,000	1,943
Nebraska	1	6,160	6,160	108
Subtotal	13	603,291	46,407	10,558
Region 8				
Colorado	3	59,500	19,833	1,041
Montana	6	162,000	27,000	2,835
North Dakota	3	68,200	22,733	1,194
South Dakota	-	-	-	-
Utah	8	172,668	21,584	3,022
Wyoming	12	206,584	17,215	3,615
Subtotal	32	668,952	20,905	11,707
Region 9				
Arizona	1	6,315	6,315	111
California	41	2,618,547	63,867	47,000
Hawaii	2	119,894	59,947	2,098
Nevada	1	4,500	4,500	79
Subtotal	45	2,749,256	61,095	49,288
Region 10				
Alaska	4	120,410	30,103	2,107
Idaho	-	-	-	-
Oregon	1	15,789	15,789	276
Washington	7	403,367	57,624	7,009
Subtotal	12	539,566	44,965	9,468
National Total	295	18,708,528	62,992	327,399

^aBarrels per stream-day.

Source: Ref. 60.

Table 3.3 Proposed New Refineries: Location, Capacity, and Land Area

Region and Company	Location	Crude Oil Capacity (bbl/s-d) ^a	Land Area (acres)
Region 1			
Pittston	Eastport, ME	250,000	1,250
Region 3			
Hampton Roads Energy	Portsmouth, VA	175,000	875
Tiber Petroleum Corp.	Harvey, PA	30,000	150
Region 4			
Brunswick Energy Corp.	Brunswick County, NC	150,000	750
Wallace and Wallace Chemical & Oil Corp.	Tuskegee, AL	150,000	750
Region 6			
Apex Oil Company	Luling, LA	100,000	500
Barbour Energy	Brownsville, TX	150,000	750
Dow Chemical	Brazoport, TX	180,000	900
Novex, Inc.	Houston, TX	30,000	150
Petromay Refining	Houston, TX	30,000	150
Petrounited, Inc.	Sunshine, LA	40,000	700
Sooner Refining	Egan, LA	6,000	30
Refinery Corp.	Magnolia, LA	200,000	1,000
Twin Oaks Refinery	Vacherie, LA	NA	NA
Ventech Refining	Knotz Springs, LA	22,000	110
Region 8			
Mobil Oil Corp.	East of Rockies	150,000	750
Region 9			
MacMillan Ringfree	Carson, CA	40,000	700
Solar Vistas Assoc.	Phoenix, AZ	3,000	15
UCO Oil	Martinez, CA	10,000	50
Region 10			
Alaska Petrochemical	Valdez, AK	150,000	750
Total		1,866,000	10,330

^aBarrels per stream-day.

Source: Ref. 61.

The combined effect of expanded refinery capacity and increased utilization of domestic (continental and Alaskan) oil necessitates the construction of new pipelines to transport the crude oil to refineries and product markets. Four proposals for northern pipeline systems have been filed with the Department of Interior to obtain federal land permits under PL 96-617, The Public Utility Regulatory Policies Act of 1978 (PURPA). Other pipelines that have been proposed include the Midcontinent Pipeline System and the PACTEX Pipeline Project. Because of insufficient data on these prospective projects and their regulatory, economic, financial, and legislative uncertainties, the completion of any of these projects prior to 1990 is tenuous and, therefore, not evaluated here for possible effects on land use.*

3.3 URANIUM PROCESSING

The development of a commercial nuclear electricity-generating industry during the past two decades has given rise to a number of industrial operations to produce and process uranium fuel. The extraction of uranium oxide from the ore and its conversion to a form suitable for use in nuclear reactors is a four-step process that includes the following activities:

1. Milling of the ore to produce "yellowcake," a semi-refined uranium oxide (U_3O_8) concentrate;
2. Conversion of U_3O_8 into uranium hexafluoride (UF_6);
3. Enrichment of UF_6 to a concentration of about 2% to 4% in the isotope uranium-235; and
4. Fabrication of reactor fuel by converting the enriched UF_6 to uranium dioxide (UO_2), loading the UO_2 into fuel rods, and assembling the rods into a fuel element.

3.3.1 Uranium Milling

The basic purpose of the conventional milling process is to extract the U_3O_8 from uranium ore and concentrate it into "yellowcake" (which contains approximately 90% U_3O_8). Uranium oxide is also produced (as a by-product) in the preparation of phosphoric acid; the recovery of U_3O_8 from old uranium dumps and tailings piles and from copper dumps; and in solution-mining operations, which were discussed under uranium extraction. Only 7% of the uranium produced in the United States in 1978 came from these other sources.

Construction of a mill results in land being removed from its previous use and being committed instead to industrial use for at least 10 years, the normal lifetime of a milling operation. The largest part of the land disturbed by a conventional uranium mill is devoted to the disposal of mill tailings, because nearly the entire mass of ore processed by the mill ends up in the tailings. This land may be closed to other uses for a much longer period. After mills are shut down, environmental regulations, particularly

*For a detailed examination of these pipeline routes, their economic feasibility, and the domestic crude oil supply/demand transportation situation, see Ref. 62.

the Resource Conservation and Recovery Act (RCRA), stipulate that the tailings areas be covered with earth and planted to prevent soil erosion and the spread of radioactive material by wind and water. The covered and planted areas are restored to resemble the surrounding terrain. Current practice is to withhold such land from unrestricted future use so as to minimize exposure to radiation. Besides requiring operators to provide assurance that funds will be available for reclamation of the tailings areas, the following restrictions apply to land on which tailings are stored:

- The owner must not permit the exposure and release of the tailings material to the surrounding area.
- No structure that man or animal can occupy may be built on the covered surface.
- The covered surface may not be subdivided.
- No private roads, trails, or rights-of-way may be established across the covered surface.

These restrictions are expected to be binding on the applicant while he owns the land, and on successive owners thereafter, for a period of 50 years or until such time prior to the expiration of the 50-year period as government regulations are approved that control disposition of uranium mill tailings.⁶³ This type of disposal is temporary, pending completion of studies to develop acceptable procedures for ultimate disposal of mill tailings.

The indirect effects of the mill on the land use surrounding the facility originate from its effluents. In addition to the gaseous effluent associated with the generation of electric power for the mill, small quantities of sulfuric acid fumes, kerosene, and dust may be released to the atmosphere from mill processes. To date, airborne concentrations of these contaminants have, on the average, been maintained below EPA standards. The result of this compliance is a low probability of deleterious effects on the biota or potential land uses.

Accidental release of process effluents must also be considered. The most likely types of accidents with uranium mill operations are inadvertent discharges of tailings or solutions to nearby surface waters or a fire in a solvent-extraction circuit. Potential failures that could result in offsite release of tailings include failure of a tailings dam, rupture of a tailings pipeline, or overflow of a tailings pond.

The principal radiological concern of the milling operation is the release of radon-222 from the ore and mill tailings and the potential exposure of the mill workers. Population doses from these sources are low because the mills are generally located in remote and sparsely populated areas.⁶⁴

3.3.1.1 Land Requirements

The land required for a uranium mill varies depending on the process type, disposal technique, topography, and facility size. Besides this variability, the literature presents divergent estimates of the dimensions of a mill or a mine-mill complex. The draft Environmental Impact Statement on

Uranium Milling⁶⁵ stipulates that for a 1100-ton/d U_3O_8 mill complex, approximately 750 acres are required, of which 250 acres are designed for the impoundment of tailings and 125 acres for the mill. The remaining land is unused during operation of the mill but is affected during the construction phase. The draft environmental statement concerning the Bear Creek Project⁶⁶ states that the construction and operation of a 1000-ton/d mill to process uranium ore will remove 420 acres from other uses. This area includes not only the land occupied by the mill and the tailings retention system, but also that occupied by the access road, power lines, septic leach field, parking lots, and the ore-storage piles. An older study⁶³ states that only 300 acres are occupied by a uranium mill producing 1060 tons of U_3O_8 per day. The mill site includes an ore-storage and blending area, a crushing and sampling building, a building containing grinding equipment, a solvent-extraction building, a tailings-retention system of about 250 acres, a sewage-treatment system, and several ancillary buildings used for offices and maintenance. A recent Department of Energy report⁶⁷ used the same land area and facility composition. For the purpose of this study, the land areas in Table 3.4 will be assumed for the conventional milling process of converting uranium ore to yellowcake.

Because of economic factors such as haulage costs, conventional uranium mills are usually located near the source of ore. Thus, mills are concentrated in the western United States, principally in the relatively sparsely populated areas of Wyoming, New Mexico, Colorado, and Utah (see Fig. 3.2). A typical mill is located in an arid, isolated region. The total population within a 50-mile radius is typically 60,000 people. The population density, approximately 5-10 people per square mile, is less than the average population density (11.5 people per square mile) in this four-state mining area.⁶³ Most of the area is public land administered by the Bureau of Land Management. The principal land uses are desert shrubland, subhumid grassland, semiarid grazing land, and rangeland. The sparsely distributed urban centers are located in select floodplains where the dominant industrial employers are usually the other scattered mineral-extraction industries located throughout the Overthrust Belt and coal regions.

3.3.1.2 Past and Future Land Use

In the past most of the land devoted to uranium milling has been concentrated in the West, particularly in the states of New Mexico, Wyoming, Colorado, Utah, and, more recently, Texas and Washington. Table 3.5 indicates the location, technology, and size of the uranium mills operating in the United States as of January 1, 1977. Table 3.6 indicates the distribution of the operating mills among the three size categories in each state and gives an approximation, based on the values in Table 3.4, of the total land area occupied by operating mills. The amount of land occupied by phosphoric acid by-product and heap-leaching

Table 3.4 Land Area Required for Conventional Milling Processes

Nominal Capacity (ton/d)	Acres
450-1200	420
1200-3000	750
3000-7000	1875

Fig. 3.2 Uranium Mills in the United States Operating as of January 1979 (Source: Ref. 30)

**Table 3.5 U.S. Uranium Mills Operating
as of January 1979**

Operator	Plant Location	Nominal Capacity (Ore, ton/d)
<u>Conventional Mills</u>		
The Anaconda Copper Company	Grants, NM	6,000
Atlas Minerals Corporation	Moab, UT	1,400
Bear Creek Uranium Company	Powder River Basin, WY	1,400
Conoco-Pioneer Nuclear	Falls City, TX	3,200
Cotter Corporation	Canon City, CO	450
Dawn Mining Company	Ford, WA	450
Exxon Minerals Company, USA	Powder River Basin, WY	3,000
Federal-American Partners	Gas Hills, WY	950
Kerr-McGee Nuclear Corporation	Grants, NM	7,000
Pathfinder Mines Corporation	Gas Hills, WY	1,650
Pathfinder Mines Corporation	Shirley Basin, WY	1,800
Petrotomics Company	Shirley Basin, WY	1,500
Rio Algom Corporation	LeSal, UT	750
Sohio Natural Resources Company	Cebolleta, NM	1,600
Union Carbide Corporation	Uravan, CO	1,300
Union Carbide Corporation	Natrona County, WY	1,200
United Nuclear Corporation	Church Rock, NM	3,000
United Nuclear - Homestake Partners	Grants, NM	3,400
Western Nuclear, Inc.	Jeffrey City, WY	1,700
Western Nuclear, Inc.	Wellpinit, WA	2,000
Total (Ore)		43,810 ^a
<u>Solution Mining Operations</u>		<u>(U₃O₈, ton/yr)</u>
IEC Corporation	Pawnee & Ray Point, TX	-
Mobil Oil Corporation	Bruni, TX	-
Union Carbide Corporation	Palangana, TX	-
United States Steel Corporation	George West, TX	-
U.S. Steel-Niagara Mohawk	George West, TX	-
Wyoming Mineral Corporation	Bruni, TX	-
Wyoming Mineral Corporation	Ray Point, TX	-
Wyoming Mineral Corporation	Irigaray, WY	-
Total (U ₃ O ₈)		600-1,000
<u>Phosphoric Acid By-product</u>		
Freeport Uranium Recovery Corporation	Uncle Sam, LA	-
Uranium Recovery Corporation	Mulberry, FL	-
Wyoming Mineral Corporation	Pierce, FL	-
Total (U ₃ O ₈)		500-700
<u>Heap Leaching: Dumps, Tailings, or Copper Dumps</u>		
Durita Development Corporation	Naturita, CO	-
Solution Engineering, Inc.	Falls City, TX	-
Union Carbide Corporation	Maybell, CO	-
Wyoming Mineral Corporation	Bingham Canyon, UT	-
Total (U ₃ O ₈)		100-300
Grand Total (Ore and U ₃ O ₈ , as U ₃ O ₈)		17,200-20,000

^aEquivalent to 16,000-18,000 tons of U₃O₈ per year.

Source: Ref. 30.

Table 3.6 Estimated Area Devoted to Conventional Uranium Mills as of January 1979

State	Nominal Ore Capacity (ton/d)			Estimated Land Required ^a (acres)
	450-1200	1200-3000	3000-7000	
Region 6				
New Mexico	-	1	4	8,250
Texas	-	-	1	1,900
Region 8				
Colorado	1	1	-	1,200
Utah	1	1	-	1,200
Wyoming	1	6	1	6,800
Region 10				
Washington	1	1	-	1,200
Total	4	10	6	20,550

^aEstimated using values in Table 3.4.

processes is probably less than 100 acres nationwide. Land requirements of solution mining are discussed under extraction.

The distribution of production centers is expected to remain proportional to what currently exists.* The states expecting new production capacity in the near future are shown in Table 3.7. The possible location of these facilities is shown in Fig. 3.3. If it is assumed that new production centers in Florida and Louisiana will be associated with phosphoric acid production, that new production centers in Texas will be primarily solution mines, and that the average size of the conventional mills will fall within the 1200-3000 ton/d range of nominal capacity, then the prospective land commitment can be estimated. Using the conversion factors previously identified, it can be estimated that 6,000 to almost 13,000 acres may be devoted to new uranium mills between 1980 and 1990 (see Table 3.7).

The potential impact of these prospective production centers on land use should not differ substantially from the effects of the operating uranium mills, because future mills will be located within the immediate vicinity of existing sites (Fig. 3.2). Because many of the uranium reserves are in the western states and are adjacent to (or in) the Overthrust Belt, the extraction and milling of uranium may conflict with the extraction of the various other resources located in these areas. These conflicts would depend on the relative timing of each development, mineral value, simultaneous extraction economics, and resource ownership.

*Given the production-capacity statistics presented in Ref. 30.

Table 3.7 Potential New Uranium-Oxide Production Centers

States	Centers with Construction Commitments	Estimated Land Requirements (acres)	Potential Centers, No Commitment ^a	Estimated Land Requirements (acres)
New Mexico	3	2250	1	750
Texas	1	b	1	b
Florida	3	c	2	c
Louisiana	1	c	1	c
Colorado	1	750	3	2250
Wyoming	4	3000	2	1500
Utah	-	-	2	1500
Arizona	-	-	1	750
Total	13	6000	13	6750

^aSufficient lead times exist to warrant construction during the 10-year period starting January 1, 1978.

^bAssumed to be solution mines - see extraction section.

^cAssumed to be phosphoric acid by-product operations with minimal land requirements.

Source: Ref. 30.

It is expected that future modifications in conventional uranium milling processes will improve operating efficiency, increase uranium recovery, and decrease the impact on the environment, especially with respect to land reclamation. These process improvements will tend to counteract the effects of the current trend toward the use of lower-quality ore, which causes more tailings to be produced per ton of yellowcake. It is also expected that solution mining and by-product recovery operations will supply a larger fraction of future uranium requirements. This situation would tend to eliminate the formation of tailing piles and reduce emissions of radon, but could marginally increase the contamination of ground water.⁶⁸ The impact of these process improvements (which might decrease the adverse effects per ton of yellowcake produced) is difficult to assess at this time.

3.3.2 Uranium Conversion

A necessary step in the uranium fuel cycle is conversion of concentrated uranium ore to uranium hexafluoride (UF₆), a gaseous compound used as feed to a uranium-enrichment facility. At present, two conversion plants in the United States supply the domestic commercial requirements for UF₆, with a total capacity of 23,000 tons of UF₆ per year. These plants -- located in Metropolis, Illinois, and Sequoyah, Oklahoma -- are in relatively remote areas where the principal land uses are forestry, rangeland, and agriculture.

Each site is a fairly industrialized complex that covers about 1,400 acres. It is expected that about 10% of the disturbed land will be permanently committed to building foundations, slabs, and on-site burial of low-activity calcium fluoride and other solids. If a plant is designated to be

KEY:

● Construction Commitments Made as of Jan. 1978

1. Bokum Resources Corp.: Marquez, N.M.
2. Chevron Resources Co.: Panna Maria, Texas
3. Wyoming Mineral Corp.: Pierce, Fla.
4. Freeport Uranium Recovery Co.: Uncle Sam, La.
5. Gardinier, Inc.: Tampa, Fla.
6. Gulf Mineral Resources Co.: San Mateo, N.M.
7. Homestake Mining Co.: Marshall Pass, Colo.
8. IMC Chemicals Corp.: Mulberry, Fla.
9. Kerr-McGee Nuclear Corp.: Powder River Basin, Wyo.
10. Minerals Exploration Co.: Red Desert, Wyo.
11. Phillips Uranium Corp.: Nose Rock, N.M.
12. Rocky Mountain Energy Co.: Nine Mile-Reno, Wyo.
13. United Nuclear Corp.: Morton Ranch, Wyo.

▲ Potential Construction Commitments 1978-1988

14. Agrico-Chem Williams: Donaldsonville, La.
15. Anaconda Copper Co.: Rhode Ranch, Texas
16. CF Industries: Bartow, Fla.
17. CF Industries: Plant City, Fla.
18. Cleveland-Cliffs Iron Co.: Pumpkin Buttes, Wyo.
19. Crownpoint: Crownpoint, N.M.
20. Energy Fuels Nuclear, Inc.: Blanding, Utah
21. Minerals Exploration Co.: Wickenburg, Ariz.
22. Pioneer Uranium, Inc.: Slick Rock, Colo.
23. Plateau Resources, Ltd.: Hanksville, Utah
24. Power Resources Corp.: Grover, Colo.
25. Cyprus Mines Corp.: Tallahassee Creek, Colo.
26. Rocky Mountain Energy Co.: Copper Mt., Wyo.

Fig. 3.3 Potential New Uranium Production Centers Identified as of January 1978
(Source: Ref. 30)

built before 1990, either to replace or to supplement existing capacity, it will probably be larger and thereby occupy more land area than those conversion plants now operating. At one time, when the forecast for the number of nuclear power plants operating by 1990 and 2000 was much greater, the current installed capacity was expected to satisfy demand only until 1981-1987, with a 400%-capacity increase necessary by 2000 (without uranium or plutonium recycling).⁶⁸ Now that fewer plants will attain operating status prior to 1990, it is believed that current UF_6 capacity will suffice to meet their fuel demands. Therefore, no adverse effect on land use is now projected for this component of the uranium fuel cycle.

The conversion processes used at UF_6 production facilities require high levels of support and operating technology, plus relatively expensive raw materials. These limitations have precluded locating UF_6 conversion plants at remote mill sites in the United States. The major safety problems and environmental hazards associated with a UF_6 conversion facility preclude its siting in densely populated and environmentally sensitive areas. New facilities would be expected to be located near a water source that would provide a reliable supply and permit discharge of treated liquid wastes and cooling water. A final consideration in the location of future plants may be relative proximity to uranium enrichment facilities, in order to minimize transportation costs.⁶⁸

3.3.3 Uranium Enrichment

The enrichment process provides a mixture of uranium that is enriched in U-235 above natural levels, as is needed for reactor fuel. Enrichment of U-235 can take place with either virgin or recycled feed material. At present, uranium from commercial nuclear reactors has not been recycled, but under DOE's Enrichment Program existing enrichment plants have received limited amounts of material from defense projects for recycling.

Uranium can be enriched by either gaseous diffusion or gas centrifugation. Gaseous diffusion is the predominant enrichment process in this country. Three gaseous diffusion plants, all in the Ohio River Valley, are operated by private industry under contract to the federal government. A plant of this type has a large number of compressors that move UF_6 through many separate enrichment stages. Much electricity is needed to operate these compressors and other auxiliary equipment: approximately 98% of the electrical energy consumed in the entire nuclear fuel cycle is used in the enrichment process.

The gas-centrifuge enrichment process is currently undergoing engineering design and development, and a plant is under construction in Portsmouth, Ohio. Compared to the existing gaseous diffusion technology, which requires large facilities to be cost-effective, gas centrifugation will consume less power and can be done in smaller plants economically.

The most significant difference between the gaseous diffusion and gas-centrifuge processes is power use. A centrifuge plant requires only about 4% of the power needed for a diffusion plant of equal separative work output.

Thus, for a plant of 8.8×10^6 SWU*/yr capacity, approximately 2,400 MW of electric power would be necessary for a diffusion plant, but only about 100 MW for a centrifuge plant.⁶⁴

Both enrichment processes produce a by-product UF_6 , called tails, which is depleted in U-235. This UF_6 is stored in solid form in cylinders on site, pending future use (this product may be recycled to recover additional uranium). The storage of this by-product waste may cause conflicts with other land uses.⁶⁷ In addition to this by-product, the gas centrifuge process generates large quantities of contaminated solid waste, consisting primarily of nonreusable parts and materials from failed machines. A burial ground must be provided for disposal of these solid wastes and spent absorbates and sludge dredged from the settling basin.

3.3.3.1 Facility Size and Siting Considerations

The requirement for continuous horizontal processing through approximately 1,700 stages to produce 4% enriched UF_6 makes the present gaseous diffusion plants among the largest industrial facilities in the world, in terms of roofed area. As a result of the unusually large requirement for continuous floor area, gaseous diffusion plants have been built on relatively flat land capable of sustaining a load factor of 2,500 lb/ft². Sites were initially chosen for several factors, including ready and reliable access to abundant and inexpensive electric power, adequate water supply for process cooling, and proximity to a uranium conversion plant.

3.3.3.2 Past and Future Land Use

The diffusion facilities in Oak Ridge, Tennessee, and Portsmouth, Ohio, were constructed during the period 1943-1955, on sites originally chosen for remote location, low population density, and marginal utility as agricultural land; the Paducah, Kentucky, centrifuge plant was built on a government-owned site previously occupied by an ordnance works. About 1,500 acres is currently occupied by this plant. About 80% of this land is covered by eight 400-ft wide by 650-ft long process buildings housing the centrifuge machines, which are operated in numerous cascades in parallel. The exact land requirements for the centrifuge plant being constructed in Ohio cannot be predicted at present; the new plant will be on a property adjacent to the existing Portsmouth gaseous diffusion plant.

Current developmental efforts consist primarily of support and maintenance of this mature technology. There are, however, two major expansion programs to enlarge the existing capacity of the diffusion complex, namely, the Cascade Improvement Program (CIP) and the Cascade Upgrading Program (CUP). The CIP will provide a significant increase in separative work capacity by improving the efficiency of process equipment. The CUP will increase the throughput of the three gaseous diffusion plants by increasing their power capacity from 6065 to 7380 MW of electric power. The additional separative

*The separative work unit, or SWU, is the measure of effort required to accomplish isotopic separation (enrichment).

work achieved will be approximately 4.6×10^6 SWU/yr. Neither of these two programs will affect the uses of the land surrounding the sites.⁶⁴

3.3.4 Fuel Fabrication

Most of the commercial power reactors in operation or under development use a fuel element fabricated from fertile and/or fissile material in the form of pellets or particulate matter which is loaded into fuel rods. The rods are then assembled into a fuel element. The process of pelletization and fuel fabrication includes the following steps:

- Converting UF_6 enriched in U-235 into uranium dioxide (UO_2),
- Pressing UO_2 into cylindrical pellets,
- Sealing the pellets into zirconium alloy tubes, and
- Assembling the tubes in bundles to make finished nuclear fuel assemblies.

Land use for the fabrication facility itself is essentially temporary, because almost all the land disturbed can be ultimately reclaimed. The plants must be licensed [as described in 10 CFR 70.22 (f)] and monitored under various quality assurance programs of the Nuclear Regulatory Commission to ensure that the structures, systems, components, and operations will perform satisfactorily. To date, there have been no off-site environmental effects from accidents in low-enrichment fuel fabrication plants. Accidents have been rare because plant design and operation are safety-oriented.

3.3.4.1 Facility Size and Siting Considerations

Table 3.8 identifies the 10 operating plants in the United States that prepare fuel for light water reactors. Plant input and output products and site sizes are also shown. The area occupied by the plant sites and adjacent holdings ranges from a few acres up to 1,650 acres, but fuel fabrication plant sites need not be that large. No unusual characteristics influence the siting of these facilities either within a region or in relation to the enrichment facilities or natural resources. Similarly, because these facilities are sited in industrial complexes in populated areas, the impact on land use is not likely to be significant, although the land is probably permanently committed to industrial use.

3.3.4.2 Past and Future Land Use

A total of more than 5,000 acres is currently devoted to fuel fabrication plants (Table 3.8). A new Westinghouse plant, to be located in Prattville, Alabama, is scheduled to be in operation by 1983 and will occupy 800 acres. Little impact on the environment or on land use is expected.⁶⁹

Table 3.8 Fuel-Fabrication Plants for Light Water Reactors

Federal Region and Licensee	Plant Location	Plant Feed Material	Plant Product	Site Size (acres)
Region 1				
Combustion Engineering	Windsor, CN	UO ₂ Powder	Fuel Assemblies	532
Gulf United Nuclear	New Haven, CN	UO ₂ Pellets	Fuel Assemblies	76
Region 3				
Babcock & Wilcox	Lynchburg, VA	UO ₂ Pellets	Fuel Assemblies	506
NUMEC	Apollo, PA	UF ₆	Fuel Assemblies	5
Region 4				
General Electric	Wilmington, NC	UF ₆	Fuel Assemblies	1650
Nuclear Fuel Services ^a	Erwin, TN	UF ₆	UO ₂ Powder or Pellets	58
Westinghouse	Columbia, SC	UF ₆	Fuel Assemblies	1140
Region 6				
Kerr-McGee ^a	Crescent, OK	UF ₆	UO ₂ Powder or Pellets	1000
Region 7				
Gulf United Nuclear	Hematite, MO	UF ₆	UO ₂ Powder or Pellets	150
Region 10				
Jersey Nuclear	Richland, WA	UF ₆	Fuel Assemblies	160
Total				5277

^aFrom USAEC Regulatory files.

Source: Ref. 63.

4 CONVERSION/COMBUSTION

This section presents information about the impact on land use of those activities by which energy resources are converted to electricity, including

- Fossil fuel combustion in electric utilities
- Nuclear power plants
- Hydroelectric power

The generation of electricity using steam from geothermal resources is included as part of the extraction discussion (Sec. 2). Other fuel uses, such as the combustion of gasoline in automobiles or the direct combustion of biomass, were not included in this report because the land impact associated with these uses is probably minimal.

4.1 FOSSIL FUEL COMBUSTION IN ELECTRIC UTILITIES

As with any industrial development, the direct consumption of land by utility and industrial combustors is highly variable, depending on such things as land availability, location of coal and water resources, and existing environmental conditions. Compared to other industries, electric utilities generally require larger parcels of land and have greater water requirements, while their location may be less dependent on market factors, transportation networks, and availability of workforce.

Direct effects on land use from fossil-fueled electric utility plants results from removal of land from its previous usage in order to construct permanent structures. These structures include the powerhouse, fuel-handling system, air- and water-pollution control systems, cooling systems, stacks, and administration and laboratory buildings. Given a typical power plant lifespan of over 30 years, it is doubtful that reclamation of a used utility site will ever be attempted. Thus, the change in land use involved is essentially permanent.

The physical structures occupy only a fraction of the total site area. Coal-storage piles, access roads, landscaping, etc. compose most of the site. Some utilities may prefer larger sites to allow for future expansion in generation capacity or to have a buffer zone around the plant. Cooling lakes built for power plants add greatly to the total land area affected by utilities; about 1,000-3,000 acres of pond are required per 1,000 MW.⁷⁰

A major concern associated with the combustion of fossil fuels is the possible effect of air pollutants emitted from the facility on crops and natural vegetation. Effects of both chronic and acute levels of sulfur dioxide (SO_2) and other gaseous pollutants on crop yields are well documented.⁷¹ Crops and natural vegetation sensitive to sulfur dioxide have been identified and the SO_2 doses (a function of concentration and exposure time) that have been observed to cause damage have been summarized.^{72,73} The synergistic or antagonistic effects caused by simultaneous exposure to a variety of pollutants, however, make it difficult to predict effects with

confidence.⁷⁴ Decreases in productivity of the vegetation could result in long-term changes in species composition and, consequently, changes in society's perceptions of how the land should be used.

Also of concern is the effect of acid precipitation on crops. A number of air pollutants, including sulfur oxides, nitrogen oxides, and particulates can be transported several hundred kilometers ("long-range transport") and are further oxidized to more acid species. Sulfur dioxide is responsible for about two-thirds of the acidity in precipitation. There is substantial evidence that acid rainfall is harmful to crops. While the subject of acid precipitation is currently under extensive study, it is believed that increased coal combustion by electric utilities is a major contributor to the overall increase in rainfall acidity in the northeastern United States.⁷⁵

A 1000-MW coal-fired power plant with cooling towers operating at an annual load factor of 60% would consume about 7,800-11,300 acre-feet of water per year. For those plants using cooling ponds, the consumption would be 9,600-16,000 acre-feet per year.⁷⁶ Use of such large amounts of water for electric utilities could divert water from other uses, such as agriculture, and thus affect the productivity of croplands that are not directly affected by construction of the plant.

4.1.1 Facility Size and Siting Considerations

In general, the amount of land required per megawatt of plant capacity is not necessarily directly proportional to plant capacity. Also, older plants, particularly those located in urban areas, tend to make maximal use of the site area. The actual amount of land required per facility is highly variable. To illustrate this point, Table 4.1 provides several estimates of site sizes for coal-fired and oil-fired power plants. Structures may occupy only a small portion of the site, as mentioned above. For instance, the powerhouse for a 3000-MW coal-fired power plant requires about 6-7 acres; the switchyard needs 10-15 acres; and stacks, precipitators, and walkways require

Table 4.1 Land Areas Required by Fossil-Fueled Power Plants

Plant Size (MW)	Fuel	Land Required (acres)	Reference
500	Coal	500-1000	77
1000	Coal	475-1000	78
1000	Coal	330	79
3000	Coal	200-1200	70
3000	Oil	150-350	70
1000	Oil	80	16

another 6-7 acres. Coal-fired power plants also need to store enough coal for 90-120 days of operation. A 40-foot storage pile for a 3000-MW plant would require about 40 acres.⁷⁰ Mechanical-draft and natural-draft cooling towers require about 28 acres per 1000 MW of generating capacity.⁷⁰ The distribution of structures on the site may be influenced by the site terrain or by a need to maximize plume dispersion (e.g., to prevent plume downwash by wind forced over a nearby building).

An analysis of trends in power-plant siting¹⁶ revealed a tendency toward the construction of larger generating stations. Nationally, the median generation capacity per site has increased from 250 MW at older sites to 850 MW at new sites. The maximum capacity per site increased from 3050 MW to 3700 MW. The average site area for fossil-fired power plants may also be expected to increase.

There is also a pronounced trend toward the siting of new fossil-fueled utility plants in rural areas, although in the past they have been located in or near the urban areas which they served. This new trend is not surprising given the utilities' desire to construct larger base-load units. Rural siting allows the utility more flexibility in land acquisition. Table 4.2 illustrates this trend of utilities to add new capacity at greater distances from urbanized areas.¹⁶ In two regions of the country, electric utilities added, or planned to add, 10% of their new fossil fuel-fired capacity at distances greater than 100 miles from the nearest urbanized area. The figures in Table 4.2 include new peaking plants, which are generally located in urban areas. If these additions were excluded from the calculations, the general trend toward siting base-load and intermediate-load power plants in rural areas would be even more obvious.

Rural siting is also desirable because of air quality considerations. Power plants will continue to be sited in rural areas where air quality increments (allowed increases in ambient concentrations of air pollutants) will be available as prescribed under the Prevention of Significant Deterioration (PSD) program of EPA (see Sec. 6). The PSD regulations could limit siting near Class I areas such as national parks and monuments by creating a type of exclusion zone in which major pollution sources such as power plants might have difficulty locating. For example, dispersion modeling indicates that a 300-MW power plant burning low-sulfur coal and having scrubbers operating at 70% efficiency will need to be sited at least 37 km (22 mi) from a Class I area if located on the upwind side of the restricted area. If 90% of the sulfur dioxide is removed from the plant emissions, the plant could be sited as close as 7 km (4.2 mi).⁸⁰ Actual siting of individual plants will be determined on a case-by-case basis and will depend heavily upon such factors as other emission sources, terrain, and local meteorology.

Power plants must generally avoid siting in rough terrain to avoid violating ambient air quality standards or regulations. For example, a 300-MW plant meeting New Source Performance Standards (NSPS) must locate a minimum of 3 km (1.8 mi) from high terrain to meet the National Ambient Quality Standards, and 7 km (4.2 mi) to meet the PSD Class II increment.⁸⁰ Thus, utilities often seek to site new plants in flat, often more desirable areas.

Table 4.2 Locations of Fossil-Fueled Capacity Additions in Relation to Urban Areas^a

Census Region	Maximum Distance to Nearest Urban Area (mi)	
	50% of Capacity Additions	90% of Capacity Additions
New England (Conn., Me., Mass., N.H., R.I., Vt.)	1	20
Middle Atlantic (N.J., N.Y., Pa.)	5	30
South Atlantic (Del., Fla., Ga., Md., N.C., S.C., Va., W.V.)	15	50
East North-Central (Ill., Ind., Mich., Ohio Wisc.)	20	50
East South-Central (Ala., Ky., Miss., Tenn.)	15	60
West North-Central (Iowa, Kans., Minn., Mo., Neb., N.D., S.D.)	25	55
West South-Central (Ark., La., Okla., Tex.)	25	50
Mountain (Ariz., Colo., Id., Mont., Nev., N.M., Utah, Wyo.)	130	195
Pacific (Calif., Ore., Wash.)	0	120
National	20	135

^aFrom Ref. 16.

4.1.2 Past and Future Land Use

In 1975, there were approximately 195,000 MW of coal-fired capacity and 78,000 MW of oil-fired capacity in the United States, distributed as shown in Fig. 4.1. Assuming that existing coal-fired power plants use an average of 0.5 acre per MW and oil-fired sites use 0.08 acre per MW, about 97,500 acres of land were occupied by coal-fired power plants and 6,300 acres by oil-fired power plants in 1975.

To estimate the amount of land that will be directly affected by fossil-fuel electric utilities in the future, the land requirements shown in Table 4.3 were used. The size and location of future fossil-fueled power

Fig. 4.1 Fossil-Fueled Generating Capacity, 1975

Table 4.3 Values Used to Calculate Future Land Requirements of Power Plants

Fuel	Plant Size (MW)	Site Size
Coal	<500	300 acres
	500-1000	500 acres
	1000-2000	1,000 acres
Oil	All	0.08 acre/MW (minimum 10 acres/site)

plants were identified by means of the high oil-price scenario from the Regional Issues Identification and Assessments (RIIA-II) program currently being prepared for DOE by the national laboratories. According to this scenario, there will be a total of about 141,600 MW of new coal-fired capacity and about 17,200 MW of new oil-fired capacity in 1990. The scenario specified the counties in which new facilities were projected to be built (Fig. 4.2). The total 1990 and existing capacity, by state and region, based on the RIIA-II scenario, are given in Table 4.4. The land directly occupied in 1990 by new coal- and oil-fired power plants, not including land required for solid waste disposal, was estimated using the projected capacities shown in Table 4.4 and the land requirements shown in Table 4.3. If there were more than 2000 MW sited in a particular county, it was assumed that the capacity would be broken into separate sites in the 1000-2000 MW range.

The results of these calculations, shown in Table 4.4, indicate that the new coal-fired power plants may require about 109,000 acres and the new oil-fired power plants may require approximately 1,400 acres in 1990. Only four states -- Indiana, Oklahoma, Pennsylvania, and Texas -- would be expected to have new land requirements of more than 5,000 acres by 1990. Power plant siting in Texas would require the largest amount of land, approximately 15,000 acres (0.01% of the state area). Added to the estimates of acreage occupied in 1975, the total land area devoted to coal and oil power plants may be more than 214,000 acres. This does not include land required for cooling ponds, which could double the area devoted to power plant use in some parts of the country.

4.2 NUCLEAR POWER PLANTS

The technology used in nuclear power plants to generate electricity is similar to that used in fossil-fueled power plants. A nuclear steam supply system replaces the conventional fossil-fueled boiler, and the nuclear fuel core replaces the fossil-fuel supply. There are currently four types of reactors: the light water reactor (LWR), the high temperature gas reactor (HTGR), the liquid metal fast breeder reactor (LMFBR), and the light water breeder reactor (LWBR). Light water reactors are the types used commercially, and they should retain that status until 1990.⁶⁷

Fig. 4.2 Projected Additional Fossil-Fueled Generating Capacity, 1990

Table 4.4 Estimated Direct Land Use by New and Existing Fossil-Fuel Power Plants

Region and State	Existing - 1975				New - 1990			
	Coal		Oil		Coal		Oil	
	MW	Acres	MW	Acres	MW	Acres	MW	Acres
Region 1								
Conn.	0	0	4,169	335	0	0	0	0
Maine	0	0	452	35	600	500	600	50
Mass.	1,739	870	5,435	435	1,045	1,000	560	45
N.H.	455	230	630	50	0	0	0	0
R.I.	0	0	314	25	0	0	0	0
Vt.	30	30	4	10	0	0	0	0
Subtotal	2,224	1,130	11,004	890	1,645	1,500	1,160	95
Region 2								
N.J.	1,967	980	4,731	380	0	0	0	0
N.Y.	2,663	1,330	1,264	100	3,573	2,500	2,837	230
Subtotal	4,630	2,310	5,995	480	3,573	2,500	2,837	230
Region 3								
Del.	340	170	1,050	85	400	300	0	0
D.C.	0	0	177	15	0	0	0	0
Md.	2,844	1,420	2,594	210	1,695	1,300	0	0
Penn.	15,349	7,670	4,071	325	6,670	5,300	1,220	95
Va.	2,825	1,410	3,664	295	0	0	0	0
W.V.	11,610	5,810	0	0	2,725	2,000	0	0
Subtotal	32,968	16,480	11,556	930	11,490	8,900	1,220	95
Region 4								
Ala.	8,785	4,390	0	0	3,152	2,300	0	0
Fla.	3,846	1,920	11,039	885	5,010	3,800	3,890	325
Ga.	7,520	3,760	446	35	5,092	3,000	179	15
Ky.	11,125	5,560	113	10	7,315	4,300	0	0
Miss.	1,084	540	869	70	2,300	1,800	503	40
N.C.	11,641	5,820	0	0	2,160	2,000	0	0
S.C.	3,222	1,610	933	75	840	500	0	0
Tenn.	9,241	4,620	0	0	0	0	0	0
Subtotal	56,464	28,220	13,400	1,075	25,869	17,700	4,572	380
Region 5								
Ill.	14,732	7,370	2,005	160	3,020	1,400	2,540	210
Ind.	12,145	6,070	716	60	9,345	7,800	450	35
Mich.	10,097	5,050	3,542	285	2,517	2,100	631	50
Minn.	2,980	1,490	677	55	3,460	2,500	0	0
Ohio	21,164	10,830	352	30	4,190	3,300	0	0
Wis.	5,101	2,550	355	30	3,037	2,600	0	0
Subtotal	66,219	33,360	7,647	620	25,629	19,700	3,621	295

Table 4.4 (Cont'd)

Region and State	Existing - 1975				New - 1990			
	Coal		Oil		Coal		Oil	
	MW	Acres	MW	Acres	MW	Acres	MW	Acres
Region 6								
Ark.	126	60	315	25	6,128	4,500	0	0
La.	0	0	820	65	3,760	3,000	550	45
N.M.	2,497	1,250	365	30	2,048	2,000	0	0
Okla.	0	0	0	0	5,910	5,100	490	15
Texas	2,322	1,160	1,163	95	19,101	15,000	2,304	190
Subtotal	4,945	2,470	2,663	215	36,947	26,900	3,344	250
Region 7								
Iowa	3,352	1,680	116	10	2,960	2,600	0	0
Kans.	1,990	1,000	65	10	3,885	3,000	0	0
Mo.	7,728	3,860	121	10	4,547	3,900	0	0
Nebr.	1,234	620	182	15	1,922	1,650	0	0
Subtotal	14,304	7,160	484	45	13,314	11,150	0	0
Region 8								
Colo.	2,405	1,200	144	10	5,270	3,600	0	0
Mont.	544	280	70	10	1,730	1,000	0	0
N.D.	1,276	640	8	10	2,633	1,800	0	0
S.D.	577	290	75	10	0	0	0	0
Utah	880	440	24	10	4,215	4,000	0	0
Wyo.	2,513	1,260	9	10	3,060	2,800	0	0
Subtotal	8,195	4,110	330	60	16,908	13,200	0	0
Region 9								
Ariz.	1,616	810	1,545	125	3,327	2,800	0	0
Calif.	0	0	21,648	1,730	0	0	292	25
Hawaii	0	0	1,241	100	0	0	0	0
Nev.	1,798	900	0	0	2,360	1,500	0	0
Subtotal	3,414	1,710	24,434	1,955	5,687	4,300	292	25
Region 10								
Alaska	0	0	40	10	0	0	0	0
Idaho	0	0	0	0	0	0	0	0
Oreg.	0	0	0	0	500	500	175	20
Wash.	1,335	670	86	10	0	0	0	0
Subtotal	1,335	670	126	20	500	500	175	20
National								
Total	195,207	97,620	77,639	6,290	141,567	109,150	17,221	1,420

The major physical components of a nuclear power station belong to one of three functional categories: the nuclear island, the condenser cooling system, and balance of plant. The nuclear island contains the nuclear steam supply system (the components and piping within the reactor-coolant pressure boundary and the directly related auxiliary systems), engineered safety features, and associated auxiliary systems, including the central building, diesel generator building, fuel building, and radwaste building. The condenser cooling system is usually considered separately from the balance of plant because of its variability in design and the critical role it plays in governing impact on the environment. The main condenser and any affiliated structures and systems such as cooling towers, impoundments, and discharge canals are associated with the cooling system.⁸¹ Finally, the balance of plant is that portion of the facility exclusive of the reactor island and the cooling system. This category encompasses the turbine-generator building, administration building, switchyard, intake and discharge structures, and access roads.

The only constraint imposed on the balance-of-plant system concerns the type and location of intake and discharge structures and the layout of the service water system. Although site conditions dictate the type and location of intake and discharge structures, common practice is to situate the intake structure on the shoreline of the body of water that supplies the principal water requirements of the facility and to submerge the discharge structure offshore.⁸¹

Siting a nuclear power plant on a tract of land effectively withdraws that land from other uses. Actions directly connected with plant construction can produce important changes in the physical appearance of the terrain, especially if a cooling pond is included in the facility configuration. Additional land is required for offsite transmission lines and access rights-of-way, which can adversely alter existing land uses and the ecological processes in the area.

Indirectly, the facility may affect the utilization of surrounding land by encouraging alternative land uses (e.g., attracting industrial development or encouraging recreational development on the shores of the cooling lake.) Other offsite effects are related to the cooling system employed. Water vapor and waste heat from cooling towers can modify the weather in the vicinity of the site. These undesirable modifications may take the form of fogging and icing, increased precipitation, increased cloudiness, and continual atmospheric instability as far as 20 miles from the plant. The cooling-tower vapor plume could also mingle and react chemically with nearby industrial plumes containing reactive substances. The degree to which any of these is classified as undesirable depends on the present and future uses of the surrounding land.

The water requirements of a facility place a continuous burden on the source from which the water is drawn. The depletion can be significant if the source is incapable of replenishing the supply both in quality and quantity. Because the majority of water consumed in a LWR facility is lost through evaporation, a considerable amount of water is not returned to the supply source. Depletion of reserves and/or lower flow rates can cause ecosystem disturbances, conflicts over water rights, and modification of land uses on downstream or adjacent properties. Lowering the quality of water through the

release of radioactive contaminants and rejected heat from the cooling systems may compound these effects.⁸¹

Beyond the fact that the total heat rejected per kilowatt hour is substantially higher for nuclear power plants than for comparable fossil systems, all the waste heat goes to the cooling-water system (cooling tower or water source) from a nuclear plant, whereas only 10% of the waste heat is lost thus in a fossil fuel facility. This higher heat-rejection rate results in an increase in cooling system requirements, in terms of both flow across the condenser and land required for system components. The problem of water quality and thermal impact has been increasingly resolved, however, by closed-cycle cooling methods, but this has been done at the expense of introducing new land-use problems. Strict standards for thermal and chemical discharges have encouraged the use of cooling ponds, canals, and cooling towers, all of which require large areas of land.

The radioactive wastes not released directly to the environment comprise a disposal problem for the facility. It has been stated that because the preparation and handling of solid radwastes is a closely supervised internal operation of the facility, the radiation exposure hazard at the site boundary from such material is nil.⁸¹ These types of wastes are generated by the liquid radwaste-treatment system and impose a continuous waste-disposal burden. Spent fuel rods and other highly radioactive components that require special handling do not belong in the same category; they require unique disposal locations and handling systems.⁸¹

4.2.1 Facility Size and Siting Considerations

An analysis of existing and proposed nuclear power plant sites shows that sizes range from approximately 100 to 30,000 acres. A 1974 report on land use and nuclear power plants found the average site size to be 2,730 acres with an average station size of 135 acres, roughly 5% of the total site area.⁸² The station includes the power house, reactor and related buildings, and cooling structures but does not include ponds or canals or onsite switching and transmission equipment. If the facilities using cooling ponds or canals are excluded, the average total site and station sizes are 1,335 acres and 123 acres, respectively. These figures indicate that, even without cooling systems (which require a large land commitment), nuclear sites are much larger than generating requirements alone would dictate. The amount of land required for cooling systems is shown in Table 4.5.

Table 4.5 Land Requirements for Cooling Systems

Cooling Structure	Nuclear	Fossil Fuel
Once-Through	1	1
Natural-Draft Towers	15	10
Mechanical-Draft Towers	68	45
Spray Canals	150	100
Ponds	3000	2000

Source: Ref. 83

Many site-dependent factors influence the land requirements of a facility. The site area is related to local conditions (e.g., topography, land use, zoning, land cost, taxes) and to the size of the exclusionary areas required for radiation health and safety purposes. Title 10 CFR, Part 100 (Statement of Consideration, Reactor Site Criteria) specifies a three-tiered system of population-related criteria that must be met in siting a nuclear facility. The criteria,⁵⁹ illustrated in Fig. 4.3, are as follows:

- An exclusion area, which is that area surrounding the reactor in which the reactor licensee must have the authority to determine all activities including exclusion or removal of personnel and property from the area. Activities unrelated to operation of the reactor may be permitted in an exclusion area under appropriate limitations, but the licensee must be in a position to clear the area promptly in the event of an emergency. For example, the area may be traversed by a highway, railroad, or waterway, provided these are not so close to the facility as to interfere with normal operations of the facility and provided appropriate and effective arrangements are made to control traffic on the highway, railroad, or waterway in case of emergency.
- A low population zone, immediately surrounding the exclusion area, in which the total number of residents and the population density are small enough to provide a reasonable probability that appropriate protective measures could be taken in their behalf in the event of a serious accident. AEC regulations do not specify a permissible population density or total population within this zone because the situation varies from case to case. Whether a specific number of people can, for example, be evacuated from a specific area, or instructed to take shelter, on a timely basis will depend on many factors such as location, number and size of highways, scope and extent of advance planning, and distribution of residents within the area.
- A population center distance, which is the distance from the reactor to the nearest boundary of a densely populated center containing more than about 25,000 residents.

The exclusion areas of the 75 existing and proposed nuclear power sites identified in Ref. 82 range from 0.13 to 1.32 mi in radius. The principal land uses in a 5-mi radius are agriculture, wooded area, or grasslands. The site and the surrounding area are usually flat or have rolling hills.

Several other considerations influence the size of the site required. These include (1) additional land to provide adequate noise buffering, especially in the case of mechanical draft cooling towers; (2) the necessity to restrict the potential impact of water vapor plumes from the cooling system; (3) provisions for multiple use of inactive areas of the site (e.g., controlled public access to shoreline areas and cooling ponds); and (4) the visual relationships between the facility and the setting, the scenic worth of the setting, types of surrounding topography, and the types of vegetative ground cover and its seasonal variations.⁶³

Fig. 4.3 Exclusion Area, Low Population Zone, and Distance to Nearest Population Center (Source: Ref. 63)

Other requirements for a nuclear reactor location include (1) an adequate water supply, (2) transportation access (for movement of fuel and wastes and delivery of large components during construction), (3) specific hydrological and meteorological environments, and (4) appropriate seismic and geologic conditions.⁵⁹

4.2.2 Past and Future Land Impacts

Figure 4.4 illustrates the counties where nuclear reactors with operating licenses are sited. An estimate of the amount of land dedicated to nuclear power facilities in 1975 is presented in Table 4.6. It shows that about 60,000 acres were probably occupied by reactor structures in 1975, with an additional 63,500 acres dedicated to transmission line corridors, exclusion areas, and barrier space.

An energy scenario (NEP-II) currently being analyzed by the national laboratories projects that nuclear capacity is expected to expand to 161,421 MW by 1990. The distribution of additional generating capacity is presented in Fig. 4.5, which illustrates that the greatest number of reactors and the most generating capacity will be shared by Regions 4 and 5. It is evident from Tables 4.6 and 4.7 that all regions will experience an increase in

Fig. 4.4 Nuclear Generating Capacity, 1975

Table 4.6 Estimated Land Area Occupied by Nuclear Reactor Facilities in 1975

Region	Capacity (MW)	Number of Reactor Sites	Site Area (Acres)	Total Area (Acres) ^a	Number of Sites in SMSA ^b
1	5,753	6	4,307	12,322	1
2	3,642	4	1,987	6,801	3
3	5,463	5	3,863	13,253	3
4	5,400	4	32,470	44,794	2
5	10,081	10	9,931	26,201	2
6	836	1	1,164	4,880	0
7	1,733	3	1,972	7,217	1
8	0	0	0	0	0
9	2,506	4	3,341	6,581	2
10	862	1	1,089	1,569	0
Total	36,276	38	60,124	123,618	14

^aIncludes site area, transmission line corridors and sub-stations, railroad spurs, and water supply facilities.

^bSMSA: Standard Metropolitan Statistical Area.

the number of nuclear plants and, correspondingly, in the land area required for those facilities. Growth will be greatest in Regions 4 and 5, where the land area devoted to nuclear power production is expected to increase by more than 100%. What is not obvious from the tables or figures is that nuclear reactors are being sited increasingly in rural areas and, moreover, are tending to have larger generating capacity.⁸⁴ Rural siting will increase the amount of agricultural and grazing lands that will be affected by this industry.

4.3 HYDROELECTRIC POWER

Hydroelectric power in the United States has developed rapidly during the twentieth century. Installed capacity doubled between 1921 and 1940, and tripled between 1940 and 1960.⁸⁵ Since the late 1960s, however, the rate of expansion of hydroelectric power has declined from these earlier levels for two main reasons:

1. The most favorable sites were already developed, and undeveloped sites were not so attractive when compared to other energy sources.
2. Electrical demand increased rapidly during the 1950s and 1960s, while concomitant expansion of cheap oil and natural gas, as well as optimistic forecasts concerning nuclear technologies, led to a decreased interest in further development of hydroelectric.

Fig. 4.5 Projected Additional Nuclear Generating Capacity, 1990

Table 4.7 Potential Land Area to be Occupied by Nuclear Reactor Facilities in 1990^a

Region	Capacity (MW)	Number of Reactor Sites	Site Area (Acres)	Total Area (Acres)	Number of Sites in SMSA ^b
1	10,822	8	5,626	19,721	2
2	10,291	6	2,892	12,214	5
3	16,973	8	24,163	39,915	4
4	47,723	22	136,205	196,495	4
5	33,510	23	42,032	76,478	7
6	13,093	7	30,883	46,806	0
7	5,183	5	13,072	36,409	1
8	330	1	2,238	2,551	0
9	9,595	4	16,709	18,749	3
10	13,901	5	13,793	17,261	0
Total	161,421	89	287,613	466,599	26

^aGenerating capacities and siting locations based on the high oil-price scenario used in the RIIA program.

^bSMSA: Standard Metropolitan Statistical Area.

During the past several years, rising costs of fossil fuels and higher costs of meeting tough environmental standards for nuclear facilities have made hydroelectric power more attractive to both the public and the utilities.⁸⁶ In addition, further advances in hydroelectric construction methods, improved water turbines, and new techniques for management of hydroenergy have made this source of energy more competitive.⁸⁷

As a result of the recent need for increasing our domestic supplies of energy, and because of the improved competitive position of hydroelectric power, President Carter, in his comprehensive energy plan, supported an increase in the hydroelectric generating capacity of the United States. The President consequently directed the U.S. Army Corps of Engineers to survey all existing and potential hydroelectric sites and to recommend where additional hydroelectric capacity could be installed.^{85,86}

The Corps of Engineers study identified about 50,000 existing small dams in the United States, of which less than 1000 are producing electricity. Many of the dams had at one time generated electricity, but had suffered equipment failure or became uneconomical to operate. While the current capacity of the existing hydroplants exceeds 64,000 MW, the Corps suggested that an additional 5100 MW could be obtained from these existing sites with improved turbines and more powerful generators. They further suggested that an additional 16,000 MW could be obtained from existing dams with the installation of additional turbines and generators. Finally, nearly 34,000 MW could be generated by the conversion of nonhydropower dams to hydropower.⁸⁵⁻⁸⁷ The total potential hydropower resource base in the United States is, therefore, 119,100 MW. Estimates of lower potential hydroelectric capacities have been reported.⁸⁸

Much interest has been directed recently toward using pumped-storage hydroelectric power. Its greatest value lies in reducing costs by using cheap, off-peak power to pump the water from a lower reservoir to a higher reservoir during off-peak hours. During peak periods of power usage the flow of water from the higher reservoir to the lower is used to generate electricity. Cost benefits to utilities result from the ability to run the power system's nuclear and coal plants, which have a high capital cost, at a continuous full load.⁸⁷ In areas where conventional pumped storage is not possible, such as in flat terrain, an underground reservoir can be excavated into which water can flow from a surface reservoir, lake, or river. Pumped-storage hydroelectric plants currently provide 10,000 MW of electricity in the United States.⁸⁷

Conventional and pumped-storage hydroelectric plants typically require storage reservoirs, except in those cases where the "run-of-river" water flow is sufficient to contribute a base load. Impoundments typically inundate large areas (often 10,000 to 20,000 acres) and remove those areas from other use. The displacement of families, the loss of productive farmland or wildlife habitat, and the destruction of scenic areas are common causes of conflict when new hydropower facilities are proposed. The reservoirs generally fill in with silt after some years of operation, thereby causing permanent change to the landscape.

Large hydroelectric projects do, however, have several positive aspects. In addition to providing electric power, the projects often play an important role in water supply and flood control and provide significant recreational opportunities. Thus, unlike most of the other energy-related facilities discussed in this report, hydroelectric development provides a different range of multiple uses for the land rather than limiting the area to a single use. Some of these new uses may cause additional land impact, however. For example, recreational activities can damage adjacent land by direct damage to vegetation, or by indirect damage such as increased erosion.⁷

4.3.1 Facility Size

The size of the reservoir created by a dam is extremely variable and depends on the physical characteristics of the area, the capacity of the facility, etc. Though it would be desirable for the purposes of this report to present an algorithm for predicting reservoir area, no correlation could be found between reservoir characteristics such as maximum storage, dam height, or gross static head^{86,89} and actual reservoir size. Valley shape or excavation configurations seem to be the determining factor.

4.3.2 Past and Future Land Use

Hydroelectric plants are concentrated in selected regions of the country, and, generally, reflect both physical and social influences. The largest amount of hydroelectric generating capacity in the United States is found in the Pacific Northwest (Fig. 4.6). The greatest number and density of small-scale hydroelectric plants are in the Northeast and the Lake Central regions (Fig. 4.7). These three regions also have the greatest potential for developing new small-scale hydropower.

Fig. 4.6 National Hydroelectric Power Resources, All Sites (Source: Ref. 86)

An energy scenario (NEP-II) currently under study by the national laboratories projects a 34% increase in hydroelectric capacity between 1975 and 1990. Most of this increase is projected for the Pacific Northwest. Major increases are also expected in Arizona, California, Colorado, Montana, and New Mexico (Fig. 4.8). The amount of land that may be affected by these additions and the nature of the impact can be estimated only after evaluation of specific sites.

Fig. 4.8 Projected Additional Hydroelectric Generating Capacity, 1990

5 SOLID WASTE DISPOSAL

This section briefly describes the sources and characteristics of solid wastes generated from energy industries considered in this study. Because of the significant volume involved, solid wastes generated from combustion of coal and oil will be emphasized. The generation and disposal of solid wastes from other energy resource activities, such as coal cleaning, uranium milling, and oil shale development, were addressed in previous sections.

5.1 SOLID WASTES GENERATED BY COAL COMBUSTION

Practically all coal-fired combustion facilities require land for disposal of solid wastes, including bottom ash, fly ash, scrubber waste, and sludge from water treatment. The amount of waste from water-treatment processes is much smaller than the wastes from the other three sources. Therefore, only solid wastes from bottom ash and fly ash removal and flue-gas scrubbers are discussed here.

Coal ash is the noncombustible solid residue of coal. In a coal-fired boiler some of the ash remains inside the boiler and is known as bottom ash. Fly ash is the fraction that is too small to settle out in the combustion chamber; it becomes suspended in the high-velocity flue gas. Air-pollution regulations require electric utility and industrial boilers to be equipped with particulate control devices to prevent fly ash from entering the ambient air.

The chemical makeup of coal ash depends largely on geologic and geographic factors related to the origin of the coal. Coal is enriched in many elements in comparison to their concentration in the earth's crust, and when the coal is burned, the ash is further enriched in some of these elements. As a result, some potentially toxic heavy metals exist in coal ash in concentrations much greater than are found in either the input coal or the earth's crust.

The major constituents of coal ash, including silicon, aluminum, iron, and calcium, make up 95-99% of the total composition. Minor constituents, such as magnesium, titanium, sodium, potassium, sulfur, and phosphorous, generally compose 0.5-3.5%. Coal ash also often contains trace concentrations of from 20 to 50 other elements, including antimony, arsenic, barium, beryllium, boron, copper, fluorine, lead, manganese, mercury, molybdenum, nickel, selenium, tellurium, thallium, tin, uranium, vanadium, and zinc.

The control of sulfur-dioxide emissions from stationary sources required under the Clean Air Act has led to the installation of flue-gas desulfurization (FGD) systems at many electric power and industrial plants. At present, a large majority of FGD units in the country are of the lime/limestone wet scrubbing type, which produces solid waste in the form of sludge. The lime/limestone scrubber wastes contain calcium sulfite and calcium sulfate and/or fly ash, but the proportions of the solids vary widely. FGD sludge also contains a myriad of trace elements originating in the coal. Available data indicate that the concentrations of several trace elements (arsenic, boron, cadmium, chromium, lead, mercury, and selenium) in scrubber liquor

exceed the water-quality criteria, in some cases by more than an order of magnitude. The chemical oxygen demand, total dissolved solids, and high concentrations of sulfate, chloride, calcium, and magnesium are additional sources of potential pollution.⁹⁰ According to a recent announcement, EPA proposed to classify coal ash and FGD sludge as nonhazardous wastes under the Resource Conservation and Recovery Act.⁹¹

5.2 OPTIONS FOR DISPOSAL OF SOLID WASTE

This section discusses the technical aspects of waste disposal by ponding, landfilling, and filling old mines. Other options, such as disposal in oceans or reuse as construction material, are beyond the scope of this study.

5.2.1 Ponding

The principal means of coal-ash disposal involves dumping the ashes into shallow ponds or lagoons, usually on the site of the facility where the ashes are produced. At present, the most common disposal method for FGD sludge is also by ponding. The sludge (normally untreated) is usually mixed with the ash and sluiced or carried by trucks to on-site disposal ponds.

In the past, ash and untreated FGD sludges have been dumped in unlined ponds with very little control. Under the RCRA however, depending on the final designation of ash and sludge, controls may be required. These will probably take the form of ensuring that any runoff is collected and treated prior to release, lining of ponds, and, possibly, sludge fixation.

5.2.2 Landfilling

Landfilling is the most likely disposal method for the majority of wastes generated from fossil-fuel energy industries. This method involves disposal of solid waste on land with provisions for minimizing environmental contamination. Landfill operations range from open dumping of debris to controlled disposal in "secure" or "sanitary" landfills. Open dumps, in which wastes are piled on the surface of the terrain, are prohibited in most states and are to be totally phased out under the provisions of RCRA even for non-hazardous waste. In landfills, the wastes are usually compacted to confine them to the smallest practical area, and then are covered with a layer of soil at regular intervals. To minimize the potential for the contamination of groundwater and surface water, landfills must be located in areas where the subsurface formation is relatively impervious to infiltration (e.g., dense clays) and where the distance to the groundwater table is significantly large. The landfill surface area should also be properly contoured to divert surface runoff from the site. When the subsurface formations do not provide an adequate barrier against leachate infiltration, the use of artificial barriers such as plastic, asphalt, concrete, or clay materials for lining the landfill may be necessary. The intercepted leachate would be pumped to a surface facility for treatment. Observation wells should also be installed downstream of the landfill site (in the direction of groundwater flow) to detect

leachate migration. Provided that such measures are taken and that the public nuisance aspects of landfill operations are minimized, landfilling can be an environmentally acceptable and a cost-effective method for solid waste disposal.

5.2.3 Mine Disposal

Mine disposal consists of returning wastes to surface and underground mines. Disposal in surface mines is essentially a form of landfilling; the operation is subject to the same restrictions cited in the paragraph on landfills. For the disposal of solid wastes at surface mines, mines in the interior and western regions are considered much more promising than eastern contour mines. Contour mines have a relatively low capacity for solid waste disposal and, in many cases, waste placement would be difficult in contour mining areas.^{92,93}

Disposal in underground mines involves a greater delay before the waste can be deposited. Moreover, the physical operation of returning the waste to underground mining is more difficult, requiring certain changes in mine design and operation to accommodate the space and equipment for returning the waste.

Placement and handling techniques for solid waste disposal in both surface and underground mines are available and have been demonstrated for disposal of other materials (e.g., coal refuse), although the techniques may require modification for application to coal ash and FGD. The FGD wastes will have to be dewatered to the extent necessary for landfill operations.

5.2.4 Impact of Solid Waste Disposal

The land used to dispose of solid wastes generated by utility and industrial fuel combustion is lost to other commercial or agricultural purposes while the disposal site is in operation. The exact nature of the commercial or agricultural losses resulting from solid waste disposal is site specific, but virtually all flora and fauna are removed from such land. Whether these losses can be confined to just the acreage used for disposal is a site-specific problem that depends on many factors in the ambient environment, on management of the disposal site, and on the presence of ecologically sensitive areas such as animal migration paths or nesting grounds. Many of the negative ecological effects resulting from solid waste disposal can be minimized if proper consideration is given to ecology and regional planning in site selection, and if good site-management plans and reclamation plans are adopted.

A potential impact of coal-ash and FGD sludges is contamination of the surrounding water, for example, through leaching and percolation of soluble components of the solid waste into the groundwater system. Little documentation is available to determine whether leachate from operating ash-disposal sites is a potential source of pollution. However, this lack of documentation does not mean that a pollution problem does not exist. The composition of fly ash, the concentration of soluble constituents, the liquor pH, the solubility of trace metals, attenuation of solids, and/or the lateral water movement in underlying aquifers may be such that the problem area has not been identified.

Runoff or overflow from waste disposal sites could carry contaminants directly to surface waters. This impact, however, is receiving less emphasis than groundwater contamination because of a smaller probability of occurrence. Only in the event of unusually heavy rainfall or flooding would surface runoff become a significant problem, because present regulations would prevent the discharge of contaminated runoff from any storm smaller than the 10-year, 24-hour maximum storm.

Reclamation of disposal sites has not been practiced much in the past, but with increasing concern for the environment and regulations governing disposal practices, functional and aesthetic restoration of disposal sites is likely to be undertaken. Vegetation can generally be established on coal-ash or FGD disposal areas if care is taken to correct problems such as lack of necessary plant nutrients and the presence of inhibiting elements (e.g., boron). Sludge fixation and a two- to three-foot layer of top soil, however, will usually suffice for the establishment of vegetation.

The reclaimed disposal sites may be available for a variety of uses, but not without concerns. One concern with the agricultural use of the reclaimed disposal sites is possible contamination of food grown on the site by such potentially toxic substances as lead, nickel, cadmium, chromium, arsenic, mercury, and selenium that exist in energy-related solid wastes.⁹⁴

5.3 LAND REQUIREMENTS AND SITING CONSIDERATIONS

The quantity of ash generated from a coal-fired facility depends primarily upon the amount of coal used, its ash content and heat value, and the type of pollution-control technology used. The quantity of FGD scrubber waste produced is a function of the sulfur content of the coal, the proportion of the sulfur that remains in the bottom ash, the permissible emission rates of sulfur dioxide, and the quantity of unused sorbent, as well as the specific reactions that take place to convert sulfur dioxide to a solid sulfate salt. Quantities of solid wastes generated per 10^{12} Btu of output energy are presented in Table 5.1.

There is little uniformity in the acreage of land required for sludge and ash disposal, because of variability in disposal practices, topography, and climate. Available figures are mostly based on theoretical calculations rather than actual experience. According to a study by the U.S. Fish and Wildlife Service,⁹⁶ land requirements for waste disposal from a utility plant per 10^{12} Btu of output varied from 12.8 acres for eastern coal to 5.9 acres for western coal.

For a 1000-MWe coal-fired power plant equipped with lime/limestone FGD systems, the average production of solid waste was estimated at 0.406×10^6 ton/yr (dry weight), including 0.273×10^6 ton/yr of ash and 0.133×10^6 ton/yr of sludge. Assuming all solid wastes are to be disposed of on land, the lifetime (30 years) land requirement for solid waste disposal for the average 1000-MWe power plant was estimated at 310 acres, of which 158 acres are for ash disposal and 152 acres for sludge disposal.⁹³

Oil-fired generating plants also require FGD systems to desulfurize flue gases. The major difference between oil- and coal-fired boilers is that

Table 5.1 Solid Wastes from Coal-Fired Utilities

Waste	Tons per 10 ¹² Btu Output Energy			
	Eastern Coal ^a		Western Coal ^b	
	Without Scrubber	With Lime Scrubber	Without Scrubber	With Lime Scrubber
Bottom Ash	2,201.4	2,201.4	2,441.1	2,441.1
Fly Ash	8,676.4	8,676.4	8,735.2	8,735.2
Scrubber Sludge	0	15,247.0	0	2,511.0

^aBased on a North Central Appalachian coal with a heat content of 11,500 Btu per pound, 2.3% sulfur, and 9.2% ash, assuming 34.13% thermal efficiency.

^bBased on a Western Rocky Mountain Province coal with a heat content of 10,000 Btu per pound, 0.6% sulfur, and 7.7% ash, assuming 34.13% thermal efficiency.

Source: Ref. 95.

the oil-fired boilers produce insignificant amounts of ash and generally burn a lower-sulfur fuel. A residual oil-fired boiler produces about half as much solid waste (ash-free) as a boiler fired with high-sulfur eastern coal, and 2.5 times as much as a boiler using western coal.⁹⁷

Most utility plants have been and will continue to be sited in nonurban areas. As a result, availability of land for waste disposal may not be a problem in most areas of the country, according to a study by Brookhaven National Laboratory (BNL).⁹⁰ To confirm this finding at a national level, BNL conducted a national survey of utilities that plan to add coal-fired units in the early 1980s. All of the utilities surveyed indicated that they had adequate acreage to accommodate on-site waste disposal at the planned facilities. Even in the Northeast, where one might expect the greatest difficulties in site selection because of high population densities, the utilities have been able to acquire 1000 to 3000 acres to accommodate solid waste disposal on sites where planned units will be built. These results indicate acquiring large land areas for coal-burning plants is well within the capabilities of the utilities. BNL researchers concluded, therefore, that availability of waste disposal sites will be unlikely to constrain increased coal utilization in the electric utility sector.

In addition to the quantities of land needed, the RCRA has specified where landfills and ponds may be situated, even for nonhazardous wastes. Landfills and ponds are not to be located in certain environmentally sensitive areas unless the disposal facility is designed, constructed, and operated so that it does not pose a threat to the environment or to public health. Environmentally sensitive areas include

- Active fault zones,
- Regulatory flood ways,

- Coastal high-hazard areas,
- 100-year floodplains,
- Wet lands,
- Critical habitat areas, and
- Recharge zones of sole-source aquifers.

Most of these criteria will not in themselves affect utilities, because generating plants cannot be located in such areas. The restriction on disposal in 100-year floodplains, however, may constrain utilities, because floodplains are favored for siting inland generating plants.

5.4 PAST AND FUTURE LAND USE

In the assessment of the effect of energy-related solid waste disposal on land use, the following assumptions were made:

- Future coal- and residual oil-fired utilities will be located in the counties specified in the energy scenario being analyzed by the national laboratories (RIIA-II).
- All solid waste will be disposed of on land.
- For coal-fired utility boilers, electrostatic precipitators with 99.5% particulate-removal efficiency are used for both 1975 and 1990. FGD systems are used by 2.8% of the boilers in 1975 (Ref. 98) and all of the boilers in 1990 to desulfurize flue gases. All FGD systems are of lime/limestone type. The assumed rate of solid waste generation and the disposal site land requirements are given, by state, in Table 5.2.
- All residual oil-fired utility boilers in 1990 will be equipped with lime/limestone-type FGD systems. FGD sludge generation and lifetime (30 years) disposal area requirement are, respectively, 0.16×10^6 ton/yr, and 184 acres per 1000 MW.

The resulting estimates of solid waste generation and disposal area requirements are listed in Table 5.3. These estimates indicate that utilities will generate more than 162×10^6 tons of solid waste in 1990. This quantity is of the same order of magnitude as the amount of municipal wastes that may be generated in that year (see Table 5.4).

Total land commitments for utility waste disposal (i.e., over the 30-year lifetime of all coal- and oil-fired plants) may increase from 30,850 acres in 1975 to 134,100 acres in 1990 -- 0.0059% of the total U.S. land area. Most of the growth indicated in Table 5.3 reflects the combined effects of greater reliance on coal and an increase in FGD sludge resulting from the Clean Air Act requirements. Florida, Illinois, Indiana, Kentucky, Missouri, New York, Ohio, Pennsylvania, and Texas will encounter the largest increase (greater than 1000 acres) of land required for utility waste disposal.

Table 5.2 Rates of Solid Waste Generation and Disposal Area Requirements of the Utility Sector^a

Region and State	Ash (10 ⁶ ton/yr/GW)	Land Required for Ash Disposal (acres/yr/GW)	FGD Sludge (10 ⁶ ton/yr/GW)	Land Required for Sludge Disposal (acres/yr/GW)
Region 1				
Connecticut	0.114	2.18	0.200	7.65
Maine	0.114	2.18	0.200	7.65
Massachusetts	0.114	2.18	0.200	7.65
New Hampshire	0.114	2.18	0.200	7.65
Rhode Island	0.114	2.18	0.200	7.65
Vermont	0.114	2.18	0.200	7.65
Region 2				
New Jersey	0.188	3.59	0.200	7.65
New York	0.28	5.35	0.180	6.88
Region 3				
Delaware	0.327	6.25	0.167	6.38
Wash., D.C.	0.286	5.46	0.167	6.38
Maryland	0.233	4.45	0.132	5.05
Pennsylvania	0.315	6.02	0.195	7.45
Virginia	0.247	4.72	0.167	6.38
West Virginia	0.307	5.86	0.175	6.69
Region 4				
Alabama	0.306	5.84	0.200	7.65
Florida	0.233	4.45	0.231	8.83
Georgia	0.229	4.37	0.191	7.30
Kentucky	0.322	6.15	0.321	12.27
Mississippi	0.232	4.43	0.191	7.30
North Carolina	0.267	5.10	0.092	3.52
South Carolina	0.228	4.35	0.112	4.28
Tennessee	0.326	6.23	0.191	3.52
Region 5				
Illinois	0.210	4.01	0.231	8.14
Indiana	0.219	4.18	0.270	10.32
Michigan	0.194	3.71	0.215	8.22
Minnesota	0.231	4.41	0.126	4.82
Ohio	0.264	5.04	0.250	9.56
Wisconsin	0.190	3.63	0.215	8.22
Region 6				
Arkansas	0.281	5.37	0.145	5.54
Louisiana	0.281	5.37	0.145	5.54
New Mexico	0.452	8.63	0.068	2.60
Oklahoma	0.135	2.58	0.043	1.64
Texas	0.380	7.26	0.081	3.10
Region 7				
Iowa	0.236	4.51	0.320	12.23
Kansas	0.418	7.98	0.327	12.50
Missouri	0.283	5.41	0.313	11.96
Nebraska	0.180	3.44	0.320	12.23

Table 5.2 (Cont'd)

Region and State	Ash (10 ⁶ ton/yr/GW)	Land Required for Ash Disposal (acres/yr/GW)	FGD Sludge (10 ⁶ ton/yr/GW)	Land Required for Sludge Disposal (acres/yr/GW)
Region 8				
Colorado	0.221	4.22	0.060	2.30
Montana	0.273	5.21	0.066	2.52
North Dakota	0.278	5.31	0.081	3.10
South Dakota	0.293	5.60	0.066	2.52
Utah	0.290	5.54	0.050	1.91
Wyoming	0.289	5.52	0.070	2.67
Region 9				
Arizona	0.297	5.67	0.057	2.18
California	0.274	5.23	0.053	2.03
Hawaii	0.252	4.80	0.055	2.10
Nevada	0.184	3.51	0.055	2.10
Region 10				
Alaska	0.550	10.50	0.083	3.17
Idaho	0.551	10.52	0.083	3.17
Oregon	0.536	10.24	0.083	3.17
Washington	0.541	10.33	0.082	3.17

^aDerived from data given in Ref. 93.

**Table 5.3 Estimated Solid Waste Generation and Disposal
Area Requirements of the Utility Sector**

State	1975		1990		Ratio of Areas, 1990/1975
	Solid Waste (10 ⁶ tons)	Lifetime Disposal Area Requirement (acres)	Solid Waste (10 ⁶ tons)	Lifetime Disposal Area Requirement (acres)	
Region 1					
Connecticut	0	0	0.79	837	-
Maine	0	0	0.41	453	-
Massachusetts	0.20	125	1.54	1,613	12.9
New Hampshire	0.055	33	0.25	254	7.7
Rhode Island	0	0	0.05	57	-
Vermont	0.003	2	0.01	9	4.5
Subtotal	0.258	160	3.07	3,233	20.1
Region 2					
New Jersey	0.38	224	1.28	1,285	5.7
New York	0.76	442	4.88	4,630	10.5
Subtotal	1.14	666	6.16	5,913	8.9
Region 3					
Delaware	1.16	66	0.53	447	6.8
Wash., D.C.	0	0	0.02	23	-
Maryland	0.67	392	1.73	1,353	3.5
Pennsylvania	4.90	2,854	10.56	8,608	3.0
Virginia	0.71	415	1.38	1,225	3.0
West Virginia	3.62	2,106	5.89	4,596	2.2
Subtotal	11.06	5,833	20.11	16,252	2.8
Region 4					
Alabama	2.74	1,655	5.45	4,393	2.6
Florida	0.92	542	6.05	5,791	10.7
Georgia	1.76	1,032	4.55	3,809	3.7
Kentucky	3.68	2,167	11.16	9,597	4.4
Mississippi	0.41	151	1.75	1,564	10.4
North Carolina	3.13	1,815	5.52	3,252	1.8
South Carolina	0.74	432	1.20	1,047	2.4
Tennessee	3.06	1,754	4.28	2,437	1.4
Subtotal	16.44	9,548	39.98	31,890	3.3
Region 5					
Illinois	3.18	1,873	7.23	6,418	3.4
Indiana	2.75	1,628	9.71	8,686	5.3
Michigan	2.02	1,193	4.89	4,430	3.7
Minnesota	0.70	406	2.15	1,685	4.2
Ohio	5.87	3,450	11.00	9,395	2.7
Wisconsin	1.00	590	2.87	2,524	4.3
Subtotal	15.52	9,140	37.85	33,138	3.6

Table 5.3 (Cont'd)

State	1975		1990		Ratio of Areas, 1990/1975
	Solid Waste (10 ⁶ tons)	Lifetime Disposal Area Requirement (acres)	Solid Waste (10 ⁶ tons)	Lifetime Disposal Area Requirement (acres)	
Region 6					
Arkansas	0.04	21	2.74	2,155	102.6
Louisiana	0	0	2.53	2,287	-
New Mexico	1.14	650	2.41	1,593	2.5
Oklahoma	0	0	1.56	1,338	-
Texas	0.89	512	12.11	9,221	18.0
Subtotal	2.07	1,183	21.35	16,594	14.0
Region 7					
Iowa	0.82	448	5.14	2,842	6.3
Kansas	0.85	497	4.49	3,733	7.5
Missouri	2.26	1,332	7.09	6,215	4.7
Nebraska	0.23	140	1.57	1,476	10.5
Subtotal	4.16	2,457	18.29	14,266	5.8
Region 8					
Colorado	0.53	309	2.13	1,502	4.9
Montana	0.15	88	0.78	542	6.2
North Dakota	0.36	207	2.56	2,333	11.3
South Dakota	0.17	98	0.18	130	1.3
Utah	0.26	148	1.66	1,093	7.4
Wyoming	0.73	422	1.99	1,362	3.2
Subtotal	2.21	976	9.30	6,962	7.1
Region 9					
Arizona	0.48	278	2.00	1,450	5.2
California	0	0	2.30	2,640	-
Hawaii	0	0	0.25	287	-
Nevada	0.33	192	1.02	733	3.8
Subtotal	0.81	470	5.75	5,110	10.9
Region 10					
Alaska	0	0	0.01	12	-
Idaho	0	0	0	0	0
Oregon	0	0	0.34	234	-
Washington	0.73	417	0.81	525	1.3
Subtotal	0.73	417	1.16	771	1.8
National Total	54.38	30,850	162.84	134,121	Avg. = 4.3

Table 5.4 Estimated Generation of
Selected Wastes

Category	Quantity (10 ⁶ ton)
Food Wastes (1990) ^a	24
Yard Wastes (1990) ^a	33
Municipal Wastes (1990) ^a	211
Non-Food Wastes (1990) ^{a,b}	298
Phosphate Rock Slime (1970) ^c	760
Taconite Tailing (1971) ^c	1100

^aRef. 99.

^bIncluding concrete, masonry, aluminum, copper, ferrous metal, glass, lead, leather, paper, plastics, rubber, textiles, wood, tin, paper-board.

^cRef. 100.

6 REGULATORY ISSUES

Comprehensive power-plant siting regulation has never been undertaken at the federal level, and comprehensive land-use legislation has never been passed. Instead, individual laws designed to protect specific sectors of the environment (e.g., air quality, water quality) often regulate the indirect off-site impact of energy development. Other laws, designed to protect or preserve fragile lands such as wetlands or floodplains, prohibit development in certain areas. The goal of the myriad federal laws is to allow economic and energy development to proceed while ensuring adequate environmental protection. A number of these laws are pertinent to the problem of potential conflicts between energy and land use.

The effect of these laws on energy development is the subject of this section. The first part describes briefly the major federal laws that can influence the selection of energy sites, and discusses the kinds of state and local laws that may also apply. The second part describes in more detail the importance of air quality, water quality, and water rights legislation and of federal land-management programs to future energy development.

6.1 SELECTED REGULATIONS AFFECTING SITING OF ENERGY FACILITIES

6.1.1 Federal

Many of the federal laws that can affect selection of an energy-facility site are summarized below.

6.1.1.1 Clean Air Act

Air-quality management is of particular importance in power-plant siting decisions. Under the Clean Air Act, as amended in 1972, each state is required to include in its State Implementation Plan (SIP) a strategy to control power-plant emissions so that National Ambient Air Quality Standards (NAAQS) are attained and maintained. This maintenance effort is concerned with designated Air Quality Maintenance Areas (AQMAS), which generally encompass urban areas. As of 1977, there were approximately 546 counties containing parts of AQMAS that had been established to control particulates and sulfur dioxide.¹⁶

Section III of the Clean Air Act most affects energy siting: it authorizes EPA to set performance standards for new sources of emissions. These standards are implemented by the states through a preconstruction review process. The regulations established to prevent the significant deterioration of air quality (PSD regulations) will also affect the siting of fossil-fueled power plants and some fuel processing or mining facilities. Air quality regulations and their effect on the siting of energy facilities are discussed in more detail in Sec. 6.2.1.

6.1.1.2 Federal Water Pollution Control Act (Clean Water Act)

The Clean Water Act, as amended in 1972, sought to eliminate high levels of pollution in certain waterways through a regulatory program that is technologically and economically feasible. Energy-facility siting is most affected by the Act through sections that require permits to be obtained as part of the National Pollutant Discharge Elimination System (NPDES). In this procedure, EPA issues an NPDES permit for any pollutant discharge, provided the source meets the "best technology" or other effluent-related criteria. Section 316, dealing with thermal pollution, and Section 404, relating to the discharge of dredge or fill material, are also important to energy-facility siting. In general, this act requires states to regulate land use practices that will control pollution from nonpoint sources. Water quality legislation and its impact on energy-related land use are discussed in greater depth in Sec. 6.2.2.

6.1.1.3 Surface Mining Control and Reclamation Act

In the past, coal mining and the reclamation of surface-mined lands had been regulated solely by the states. In 1977 a federal surface mining act was passed -- the Surface Mining Control and Reclamation Act of 1977 (SMCRA) -- to minimize the adverse environmental effects of past and future mining. Each state is to formulate a permanent regulatory program that incorporates standards at least as stringent as those in the federal law.

Some of the stated purposes of SMCRA are cited below:

- To establish a national program to protect society and the environment from the adverse effects of coal mining;
- To prohibit mining where reclamation as required by the Act is not feasible;
- To assure that reclamation occurs as contemporaneously as possible with the mining;
- To strike a balance between protection of the environment, agricultural productivity, and the assurance of adequate coal production;
- To assist the states in developing, administering, and enforcing regulatory programs which achieve the purposes of the Act;
- To achieve reclamation of areas previously mined; [and]
- To provide appropriate procedures for public participation in the development of regulations, standards, and programs under SMCRA. [Ref. 101, p. AII-2]

Title V of the Act specifies minimum performance standards that apply to surface coal mining and reclamation operations, underground coal operations insofar as they may affect the surface, and coal-waste disposal. Special performance standards are set for surface mining in specific areas, such as on prime farmland, in alluvial valley floors, or in steeply sloped areas, and a procedure for designating certain lands as unsuitable for all or certain

types of surface mining is established. The requirements of the Act were put in regulatory form by the federal Office of Surface Mining Reclamation and Enforcement, an agency created by SMCRA. The interim regulations (30 CFR, Ch. VII., Parts 700-988) will remain in effect until a state's program has been approved.

6.1.1.4 Coastal Zone Management Act

The Coastal Zone Management Act of 1973 creates a national policy dedicated to preserve, protect, develop, and, where possible, improve coastal resources. Coastal resources (which include both seacoast and Great Lakes shoreline) are generally defined as adjacent dry lands that directly affect or are affected by the coastal waters. Thirty states are included in this program, but their participation is strictly voluntary. Participating states may use federal funds to formulate a long-range management program for their coastal zones. Any utility that applies for a federal permit for a proposed facility in the coastal zone must demonstrate compliance with the state management plan. Approximately 20 states now regulate development in certain coastal areas, especially in environmentally sensitive wetlands and estuaries. California, for example, has essentially banned all new power plants in coastal zones.¹⁶

6.1.1.5 Endangered Species Act

The Endangered Species Act of 1973 outlines a comprehensive program for the protection of endangered species and prohibits federal agencies from funding or authorizing a project that may jeopardize the survival of any endangered species. The Tellico Dam controversy is an example of the impact this law can have on siting decisions. Construction of the dam was halted when an endangered fish, the snail darter, was found downstream. The problem was finally resolved by removing the fish to another site in order that the dam could be completed. The outcomes of future conflicts of this sort are impossible to predict.

6.1.1.6 Atomic Energy Act and Energy Reorganization Act

The Atomic Energy Act established the Nuclear Regulatory Commission (NRC) to license and promulgate guidelines for siting nuclear power plants. The Energy Reorganization Act gave the NRC sole responsibility for regulating the nuclear energy industry. It requires a two-step licensing procedure for nuclear power plants, consisting of a construction permit and an operating license, both to be obtained through the NRC.

6.1.1.7 National Environmental Policy Act (NEPA)

The National Environmental Policy Act (NEPA), which became law in 1970, is considered landmark legislation because it has introduced environmental questions into the governmental decision-making process. One of the many mandates of this far-reaching law is the preparation and review of environmental impact statements (EIS) for all proposed projects that will utilize

federal funds. The EIS must assess all aspects of the proposed action, including¹⁶

- Environmental characteristics of the site,
- Description of the facilities,
- Environmental impact of the activity,
- Socioeconomic impact,
- Alternatives, and
- Unavoidable adverse impact.

The draft EIS must be reviewed by several state and federal agencies and approved through a series of hearings. Through the EIS process, NEPA has provided a statutory basis for opposition to the development of energy facilities. It also affects the facility-siting process by enjoining a proposed project until all requirements of the Act have been fulfilled. These requirements include an analysis of the impact on land resources and identification and discussion of an environmentally preferable alternative.

6.1.1.8 Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA), enacted in 1976, provides for the regulation and management of solid and hazardous-waste disposal. It mandates the EPA to promulgate standards relating to the generation, transportation, treatment, storage, and disposal of hazardous wastes in order to protect health and the environment.

Recently, the EPA classified as nonhazardous fly ash, bottom ash, slag, and flue gas emission-control wastes resulting from the combustion of fossil fuels. Utility wastes, therefore, are currently exempt from RCRA regulations.⁹¹ In light of the criteria for identifying hazardous wastes, however, this nonhazardous classification of utility waste may be subject to change.

RCRA specifies four criteria for identifying hazardous waste: ⁹¹ignitability, corrosiveness, reactivity, and toxicity. Some portions of utility solid wastes may exhibit one or more of these characteristics -- in particular, toxicity. If the classification of these wastes is changed to hazardous, they will be subject to the provisions relating to disposal facilities for hazardous waste. Included in these provisions are requirements that

- They be located on land with a low alternative-use value.
- They not be too close to public roads (less than 200 ft).
- They not be located in "critical habitat areas" of endangered species, unless it can be ascertained that the species will not be further endangered.¹⁰²

RCRA seems to have a contradictory influence on energy siting decisions. Remote sites (especially those in the semi-arid West) look attractive in view of the criteria listed above. However, to satisfy Section 5003, which

deals with the recovery of waste materials, disposal facilities must be located near their potential markets, because major waste products are expensive to transport but bring a small return in dollars.¹⁰³ RCRA may increase the cost of siting energy facilities on sandy soils as opposed to those on or near clay soils, because of the potential migration of leachates from waste facilities. RCRA may also increase the attractiveness of western coal, which has lower sulfur and ash contents, and thus less waste-handling problems.

6.1.1.9 Development on Federal Lands

The federal government owns and administers one-third of the land area of the United States. The siting of energy activities and the availability of energy resources on these lands can be limited by the land management policies of the administering agency. Some federally owned land, such as national parks and monuments and wilderness areas, are not available for any kind of intensive development. The impact of federal land-use policy on energy availability is discussed in Sec. 6.2.3. Some of the relevant legislation is listed below.

Wild and Scenic Rivers Act. The Wild and Scenic Rivers Act vests in Congress the authority to designate certain rivers as wild and scenic. Once a portion of a river is so designated, it must be preserved in its natural state. Section 1278(a) prohibits the Federal Power Commission from licensing any hydroelectric facility that would affect such a river. Construction in or near a designated river, or activities that could adversely affect the quality or quantity of water, are also prohibited.

National Wilderness Preservation System Act. The National Wilderness Preservation System Act designated areas of federally-owned land as wilderness areas, to be preserved in their undisturbed state. No development that would adversely affect the pristine qualities of these areas is permitted. The Forest Service and the Bureau of Land Management are currently nominating lands within their jurisdiction for inclusion in the Wilderness System (see Sec. 6.2.3).

Mineral Leasing Laws. Permits for the exploration and extraction of fuel and nonfuel minerals are issued under the authority of the Mining Law of 1872, the Mineral Land Leasing Act of 1920, the Mining and Minerals Policy Act of 1970, and the Outer Continental Shelf Lands Act of 1975. The Federal Coal Leasing Program, administered by the Department of Interior, is discussed in Sec. 6.2.3.

6.1.1.10 Other Federal Legislation

Other federal legislation that can affect the siting of energy facilities includes the following:

- The Safe Drinking Water Act - gives the Environmental Protection Agency power to veto any federal agency or licensee projects that might contaminate the watershed of a municipality's source of drinking water.
- The Federal Power Act of 1920 - gives the Federal Power Commission authority to grant permits and licenses for siting nonfederal hydroelectric power projects and for constructing interstate pipelines.
- The Rivers and Harbors Act of 1899 - Section 10 of this act requires the Army Corps of Engineers to issue a permit for any construction taking place in a navigable waterway. Utilities generally need such a permit to construct circulating water intake or discharge structures.
- The Floodplain Management Executive Order - prohibits federal agencies and businesses from building in a 100-year floodplain unless alternatives are unavailable.
- The Protection of Wetlands Executive Order - requires federal agencies to avoid construction activities on wetlands.

6.1.2 State

6.1.2.1 State Power-Plant Siting Laws

A legal framework for decision making concerning the location of energy facilities has been provided at the state level only within the last decade. Since 1970, 25 states have adopted some form of power-plant siting legislation.¹⁰⁴ These efforts have generally been limited to coal-fired electric generating and transmission facilities.

In most states, the private sector still makes all siting decisions, with only incremental review by governmental authorities. State environmental and natural resource agencies review proposed coal-fired electric generating facilities for violations of state environmental protection regulations. These regulations relate to such federal acts as the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act. Thus, state reviews tend to be directed toward separate considerations of air quality, water quality, and waste disposal rather than to overall compatibility and suitability of the development.

Organizational mechanisms used for utility siting can be broken into three categories:¹⁰⁴

1. Siting authority rests exclusively with the commission that regulates public utilities. This approach capitalizes on the expertise of an existing regulatory entity. State review of siting decisions is primarily needed only to certify public convenience and necessity and thus to provide the construction permit. This state review may be concerned only with energy needs, as in Virginia and West Virginia, or it may also include an environmental assessment, as in Illinois.

2. Siting authority is vested in environmental and energy agencies. In these states, an environmental protection agency is mandated to participate or consult in the review of site permit applications. Generally, then, two certificates are required: a construction permit, and a certificate attesting environmental compatibility. This structure exists in Kentucky, where the state environmental agency consults with the utility regulatory agency, which issues both of the necessary certificates.
3. An independent utility siting agency or an energy planning agency has siting authority. This agency theoretically exercises total jurisdiction over utility siting and construction within the state. Normally, however, an interdisciplinary commission, consisting of members from public and state commerce, environmental, health, and energy agencies, certifies the site. Such an organizational structure exists in Ohio.

The provisions of state power-plant siting laws are summarized in Table 6.1. As the table illustrates, all but one of the states that have adopted a power-plant siting law use a one-stop provision. That is, these states have one agency with final authority to approve power plant sites and to issue construction permits.¹⁶ Most of the states with siting legislation also require that each utility annually forecast the future power needs of its customers. Identification of potential power-plant sites must be included in the forecast.

Seventeen states require an investigation of alternatives, ranging from sites and routes to equipment and technologies. Minnesota and North Dakota, for example, require that alternative primary corridor options, as well as transmission line routes, be considered. Montana requires an assessment of alternative energy sources and uses (including joint industrial use) of the proposed site. California and Wisconsin are among the states that require conservation plans to be considered as reasonable alternatives to capacity expansion.¹⁰⁴

6.1.2.2 State Mined-Land Reclamation Laws

State mined-land reclamation programs are being reworked so as to comply with SMCRA (see Sec. 6.1.1.3). Under the Act, each state is to formulate a permanent regulatory program that incorporates standards at least as stringent as those in the federal law. Existing state laws are, in most cases, less stringent than SMCRA. Twenty-four of the 27 coal-producing states have submitted proposed programs to the Department of the Interior; Alaska, Georgia, and Washington, states that do not now produce significant amounts of coal, did not submit programs. The programs should be approved by January 3, 1981. Interim regulations promulgated by OSM will remain in effect until a state's program has been approved.

Table 6.1 Provisions of State Laws for Power Plant Siting

State	Siting Law	Provision	Site Certification Authority	Size and Composition of Site Panel	Method of Acquisition	Utility Forecast	State Approval of Forecast	Consideration of Alternative Sites Required	State Inventory of Sites
Arizona	Yes	1-stop	Arizona Power Plant Siting Committee	11 state officials, 7 others	Certification of environmental compatibility	10-yr	No	No	No
Arkansas	Yes	2-stop	Public Service Commission	Size of P.S.C.	Eminent domain	2-yr	No	Yes	No
California	Yes	1-stop	Energy Resources Conservation and Development Commission	5 Governor appointments	Application to site authority	5-, 10-, 20-yr	Yes	Yes	Yes
Connecticut	Yes	1-stop	Power Facility Evaluation Council	9 Governor appointments	Eminent domain	10-, 20-yr	No	No	No
Florida	Yes	1-stop	Department of Pollution Control	5 Governor appointments	Certification by environmental capability	10-yr	Yes	Yes	No
Illinois	No	-	Illinois Commerce Commission	Size of I.C.C.	Certification of public convenience and necessity	-	-	Yes	-
Kentucky	Yes	1-stop	Public Service Commission	Size of P.S.C.	Certification of environmental compatibility	None	N/A	No	No
Maine	No	-	Public Service Commission and Environmental Improvement Commission	-	Certification of public convenience and necessity	-	-	-	-
Maryland	Yes	1-stop	Public Service Commission	Size of P.S.C.	Environmental trust fund	10-yr	No	Yes	Yes
Massachusetts	Yes	1-stop	Electric Power Siting Council	9 Governor appointments	Eminent domain	10-yr	Yes	Yes	Yes
Minnesota	Yes	1-stop	Environmental Quality Council	Size of council	Eminent domain	15-yr	No	Yes	Yes

Table 6.1 (Cont'd)

State	Siting Law	Provision	Site Certification Authority	Size and Composition of Site Panel	Method of Acquisition	Utility Forecast	State Approval of Forecast	Consideration of Alternative Sites Required	State Inventory of Sites
Missouri	No	-	Public Power Districts	-	-	-	-	-	-
Montana	Yes	1-stop	Board of Natural Resources and Conservation	Size of board	Application to site authority	10-yr	Yes	Yes	No
Nevada	Yes	1-stop	Public Service Commission	Size of P.S.C.	Permit	None	N/A	Yes	No
New Hampshire	Yes	1-stop	Public Utilities Commission	13 Governor appointments	Eminent domain	None	N/A	Yes	No
New Jersey	Coastal Facility Review (coastal zone only)	None	Commissioner of Environmental Protection	Coastal area review board	Permit	None, 4-yr state plan	No	Yes	No
New Mexico	Yes	1-stop	Public Utilities Commission	Size of P.U.C.	Eminent domain	None	N/A	No	No
New York	Yes	1-stop	Power Siting Board	5 Governor appointments	Certification by siting board	10-yr	No	Yes	No
Ohio	Yes	1-stop	Power Siting Commission	5 Governor appointments	Eminent domain	10-yr	No	Yes	No
Oregon	Yes	1-stop	Governor	Nuclear and thermal energy council, 9 Governor appointments	Eminent domain	10-yr	No	Yes	Yes
South Carolina	Yes	1-stop	Public Service Commission	Size of P.U.C.	Eminent domain	10-yr	No	No	No
Washington	Yes	1-stop	Governor	Thermal power site evaluation council, 16 Governor appointments	Eminent domain	None	N/A	Yes	No
Wyoming	Yes	1-stop	Industrial Siting Commission	9 Governor appointments	Certification of environmental compatibility	20-yr	No	Yes	No

Source: Ref. 16, pp. 21-23.

6.1.3 Local

Zoning ordinances are used by municipalities to regulate and restrict land use. These ordinances normally pertain to types of development, size and location of buildings, use of open spaces, etc. Industrial land uses may be further regulated through building codes, permit systems, and air- and water-pollution controls. Most states, however, may use their power of eminent domain to invalidate zoning ordinances in order to construct energy facilities that are considered to be in the public's general welfare. Therefore, local land-use controls normally do not present a significant conflict in power-plant siting decisions.

6.2 REGULATORY ISSUES OF PARTICULAR CONCERN

6.2.1 Air-Quality Legislation and Energy Development

Air-quality management policies in the United States have been established by statute, beginning with the Air Pollution Act of 1955 through the most recent amendments to the Clean Air Act, passed in August 1977.¹⁰⁵ The legislation and subsequent regulations promulgated by the Environmental Protection Agency have set up a comprehensive scheme for management of national air resources. The pursuit of air quality can significantly affect industrial and utility siting patterns, energy development, and the use of land.

6.2.1.1 Air Quality Standards

In accordance with congressional statute, EPA established National Ambient Air Quality Standards (NAAQS) for seven pollutants -- sulfur dioxide (SO₂), total suspended particulates (TSP), nitrogen dioxide (NO₂), carbon monoxide (CO), photochemical oxidants or ozone (O_x, O₃), hydrocarbons (HC), and lead (Pb) (see Table 6.2). States were required to prepare State Implementation Plans (SIP) outlining proposed strategies for the attainment and maintenance of the NAAQS. Twenty states have adopted SIPs that set more stringent air-quality standards for sulfur dioxide, and 24 have set more stringent particulate standards than are federally mandated. The SIPs were to include a New Source Review program, permitting construction of new major sources only where emissions would not cause or exacerbate a violation of the NAAQS. In areas where the ambient air is dirtier than the standards (nonattainment areas), the SIPs must include regulations to clean up existing sources of emissions in order to achieve attainment, as well as restrictions on new sources. It must be noted that the designation of an area as in attainment or nonattainment is made on a pollutant-specific basis. Counties containing nonattainment areas for five designated pollutants are shown in Figs. 6.1 to 6.5.

In areas where the air is cleaner than required by the NAAQS, a set of regulations has been established to prevent the significant deterioration (PSD) of air quality. Additional loads of pollutants in these PSD areas are to be limited to specified amounts (or increments), which are calculated relative to a baseline air quality. Increments represent a total addition to

Table 6.2 National Ambient Air Quality Standards

Pollutant	Time Period	Standard ^a	Maximum Permissible Concentration ($\mu\text{g}/\text{m}^3$)
Sulfur oxides (measured as SO_2)	Annual	primary	80
	24-hour	primary	365
	3-hour	secondary	1300
Total Suspended Particulates	Annual	secondary	60
	Annual	primary	75
	24-hour	secondary	150
	24-hour	primary	260
Nitrogen dioxide	Annual	primary & secondary	100
Carbon monoxide	1-hour	primary	40
	8-hour	primary	10
Oxidants/ozone	1-hour	primary	235
Hydrocarbons ^b	3-hour	primary & secondary	235
Lead	3-month	primary & secondary	1.5

^aPrimary: to protect public health. Secondary: to protect public welfare.

^bThe hydrocarbon standard does not have to be met if the oxidant standard is met.

the pollutant load that cannot be exceeded. Increments have been established only for TSP and SO_2 (shown in Table 6.3). PSD regulations are required for the remaining criteria pollutants, but they have not yet been proposed and might not use an increment approach.

Three classes of PSD areas are defined: Class I, or "pristine," with a minimal increment allotted (counties containing Class I areas are mapped in Fig. 6.6); Class II, with increments large enough to accommodate moderate economic growth (a 1000-MW coal-fired power plant can be built in a Class II area if 85% of the SO_2 is removed from its flue gas); and Class III, with increments for maximum growth. Certain scenic areas (150 national parks and wilderness areas) are set aside as mandatory Class I, to be preserved as national treasures for future generations. (These mandatory areas are concentrated in the western third of the United States.) All other areas are designated Class II. States have the legal right to reclassify the Class II areas; Indian tribes retain the same reclassification rights for tribal lands.

In addition to protecting the air quality in Class I areas, the 1977 Clean Air Act Amendments declared the protection of visibility in such areas to be a national goal. Regulations are to be established to preserve (and restore, if necessary) visibility in Class I areas where visibility is determined to be an important value. Visibility was deemed important in 148 out

Fig. 6.1 U.S. Counties Containing Primary SO₂ Nonattainment Areas

Fig. 6.2 U.S. Counties Containing Primary TSP Nonattainment Areas

Fig. 6.3 U.S. Counties Containing Primary NO_x Nonattainment Areas

Fig. 6.4 U.S. Counties Containing Primary CO Nonattainment Areas

Fig. 6.5 U.S. Counties Containing Primary O₃ Nonattainment Areas

Table 6.3 PSD Increments Compared with NAAQS
($\mu\text{g}/\text{m}^3$)

Pollutant	Allowed PSD Increment			NAAQS
	Class I	Class II	Class III	
TSP				
Annual	5	19	37	75 ^a
24-hour	10	37	75	260 ^a
SO ₂				
Annual	2	20	40	80 ^a
24-hour	5	91	182	365 ^a
3-hour	25	512	700	1300 ^b

^aPrimary.

^bSecondary.

of 150 Class I areas; the two rejected areas are a lake in Wisconsin and a swamp in Florida.

Although the determination of the attainment status of all states has been officially promulgated in the Federal Register,¹⁰⁶ as required by the 1977 Clean Air Act Amendments, the actual air quality in much of the country is unknown. For example, in Colorado, 90% of the counties have no valid data for SO₂, and 40% lack TSP data. Even in industrialized Ohio, almost 50% of the counties are without SO₂ data, and 30% lack valid TSP values. Thus, new sources may be unaware of the air-quality status of an area chosen for a construction site.

6.2.1.2 Air-Quality Regulations and Sources of Emissions

Air-quality programs either to attain the NAAQS or to prevent significant deterioration are carried out through the review of sources of emissions of air pollutants. Regulations are written in terms of "major" sources of specific pollutants; just as areas are classified as attainment for a specific pollutant, a source is major in terms of a specific pollutant. A major source is defined in current federal regulations as one with emissions in excess of 100 tons per year, after the use of control equipment. States may adopt either the federal definition or a more stringent limit.

Existing sources of emissions are regulated by SIPs. Emission limitations are required on existing sources by federal law only if the area is in nonattainment. In areas where an NAAQS is being violated, the SIP must require such emission limitations as are necessary for attainment and maintenance of the particular standard. A state can promulgate regulations for all existing sources, or any subset, if it chooses. Some states, such as Arkansas, have a limited number of existing sources and no SIP emission limitations for fuel combustion.

Fig. 6.6 U.S. Counties Containing PSD Class I Areas

New sources are subject to the requirements set by the federal New Source Performance Standards (NSPS) if such a standard has been set for the particular source. NSPS have been promulgated for a number of major new sources. Many power plants would be subject to those that apply to utility boilers having greater than 250×10^6 Btu/hr heat input (see Table 6.4). States must either meet the federal standards or promulgate more stringent standards. For example, New Mexico, Arizona, and Wyoming have established more stringent requirements than the NSPS for SO_2 emissions from utility boilers.

In addition to the NSPS, a new major source must comply with the emission limitation and other requirements determined by the attainment status of the proposed site. In a nonattainment area, a new source must meet the lowest achievable emission rate (LAER) of the pollutant in nonattainment, as

Table 6.4 NSPS for Electric Utility Boilers
>250 x 10⁶ Btu/h^a

Pollutant	Fuel		
	Coal	Oil	Gas
Sulfur dioxide			
Emission limitation (lb/10 ⁶ Btu heat input)	1.2	0.8	0.8
Percent reduction required	90% ^b	90% ^c	90% ^c
Particulate matter			
Emission limitation (lb/10 ⁶ Btu heat input)	0.03	0.03	0.03
Percent reduction required	99%	70%	-
Nitrogen oxides			
Emission limitation (lb/10 ⁶ Btu heat input)	0.06 ^d	0.03 ^e	0.2 ^f
Percent reduction required	65%	30%	25%

^aA 30-day rolling average of continuous monitor readings is to be used to determine compliance.

^bUnless emissions are less than 0.6 lb/10⁶ Btu, in which case 70% reduction is required.

^cNo reduction required if emissions are less than 0.2 lb/10⁶ Btu.

^dSolid fuels, except subbituminous coal (0.5), coal-derived fuels (0.5), and certain lignite-containing fuels (0.8).

^eExcept shale oil (0.5) and coal-derived liquids (0.5).

^fExcept coal-derived gases (0.5).

determined by the permitting authority, and must provide an offset (an agreement from an existing source or sources to clean up emissions to more than offset the projected new emissions). In a PSD area a new source must use the best available control technology (BACT), again as determined by the permitting authority on a case-by-case basis. Moreover, the emissions from the new source must be modeled to determine whether they would result in pollution in excess of the allowable PSD increment. If the increment has been used up by previous sources, the new source either may be denied a permit to construct or may be required to provide an offset, similar to the requirement for a nonattainment area. (To date, this latter aspect of increment usage has not occurred; consequently the response by EPA or the permitting authority is conjecture.)

In principle, LAER should be more stringent than BACT and BACT more stringent than NSPS. NSPS are set at a particular time. BACT can reflect the most current control technology developments available at the time of a particular permit application, with consideration given to cost and availability. LAER is viewed as being technology-forcing, with costs to be given less weight, as is appropriate in areas where violations of health standards exist.

6.2.1.3 Air-Quality Regulations and Energy Development

Air-quality regulations will have effects on energy development in terms of the emission limitations required for new facilities and in the possible restrictions on the location of new facilities. Nonattainment will likely have minimal effects on utility siting, but more significant impact on industrial development and large fuel-burning installations. Nonattainment areas for TSP, SO₂, and NO_x, the major pollutants emitted during fossil-fuel combustion, are typically small and localized in urban areas and existing industrial areas. Establishing new industries or expanding existing plants in such areas may be difficult, depending on the ability of other sources to reduce emissions and make room for a new source of emissions. Utilities have more mobility and can more easily avoid locations in urban nonattainment areas. Many recent permit applications for utilities have been in PSD areas. (As of February 1980, 85 PSD permits had been approved for new utilities, with 74 more still being negotiated.)

PSD regulations have the potential for precluding some sites from use for energy development. A major new source could not locate within a Class I area, nor within some distance of the border of such an area without violating the permissible pollution increment. The distance depends on such factors as emission levels, wind patterns, and terrain features. Separation distances for a new 1000-MW coal-fired power plant (with emissions limited to 0.12 lb of SO₂ per 10⁶ Btu) have been estimated as 5 miles in flat terrain and 25 miles in more rugged terrain.¹⁰⁷ The size and number of Class I areas in the western United States, coupled with typical mountainous terrain, will likely limit the choice of sites for new sources in those areas.

In addition to the exclusion of some areas from new energy development (Class I and the land in close proximity), Class II increments may limit the scale and collocation of new facilities. The extent of the constraints imposed by Class II increments depends on the size of the source and on the

availability of the full increment in a specific location. PSD regulations have been in effect since 1975; thus far, no utility permit has been denied. In one case, however, a proposed power plant in Indiana needed sophisticated, multi-source modeling techniques to prove that the addition of projected emissions to the area's existing emissions would not cause a violation of the short-term SO₂ increment.

The allowed Class II increment is likely to lead to smaller facilities and more scattered siting patterns. Energy parks or individual power plants larger than 3000 MW may be precluded. Development of energy resources may also be constrained; for example, the combination of particulate matter emissions from a surface mine and a mine-mouth generation unit might exceed the available TSP increment.

PSD regulations have been described as land-use regulations in disguise,¹⁰⁸ based on a single environmental parameter. PSD may lead states to review existing siting policies and land-use management programs. For example, if a state wished to maximize development, a redesignation to Class III, with larger increments available, could be initiated. On the other hand, a state wishing to maintain more pristine air quality or a state with a large number of Class I areas would need to consider policies aimed at allocating air resources judiciously.

6.2.2 Water Legislation and Energy Development

Federal and state legislation and regulations pertaining to water quality and water use can produce conflicts with the use of land for energy-related activities and can affect the land required for such activities. Both the actual siting and the rate of land use can be influenced. Several classes of conflicts or effects are possible:

- Development may be precluded in an area; for example, development may be precluded on a stream that has been designated as a wild and scenic river.
- Development may be possible, but because of particularly strict requirements on effluents, it may be most reasonable to avoid development in an area; for example, development on streams that are protected by stringent water-quality standards may entail extra expenses or difficulties in obtaining permits.
- Development may not be constrained, but regulations may influence the amount of land required for certain activities; for example, land may be required for waste-disposal areas or for cooling structures.

The purpose of this section is to identify and briefly discuss the state and federal legislation and regulations that can produce such effects on energy-related land use. Water quality and water use are considered separately, and laws pertinent to land use in these areas are discussed. Specific issues in each area are then considered.

6.2.2.1 Water-Quality Conflicts

The relevant water-quality legislation is primarily federal and involves two major laws: the Federal Water Pollution Control Act, as amended, and the Safe Drinking Water Act. Both of these pieces of legislation affect, or have the potential for affecting, energy-related land use. The Federal Water Pollution Control Act Amendments (PL 92-500), as amended by the Clean Water Act of 1977 (PL 94-217), provide a comprehensive framework for water pollution control in the United States. It is by far the major piece of legislation concerning the control of water pollution. The Act prohibits discharges to public waters without a permit. The Environmental Protection Agency (EPA) originally issued all permits, but this authority has been transferred to state agencies that meet certain criteria. At present, over half of the states have control over the issuance of permits. The permits require that all discharges meet minimum technology-based criteria on the quality of effluents. These criteria can be made stricter when necessary to meet water-quality criteria. The Act also requires area-wide waste-water management planning (Sec. 208) and contains the provision that no permits will be issued for point sources in conflict with any approved plans developed under Sec. 208. Section 208 includes consideration of nonpoint sources. The Act states that it is a national goal that "the discharge of pollutants into ... navigable waters be eliminated."

The Safe Drinking Water Act (PL 93-523) of 1974, as amended by PL 95-190 (1977) and PL 96-63 (1979), provides a program for the protection of public drinking water. It requires that national drinking water standards be developed to protect health, and provides for the enforcement of such standards. The Act also provides a program to protect underground sources of drinking water by controlling underground injections of wastes. Section 1424(e) of the Act allows EPA to designate as a "sole-source aquifer" any aquifer that is the sole or principal source of drinking water for an area and which, if contaminated, would create a significant public health hazard. Following such designation, no commitment for federal financial assistance may be made for any project that may contaminate the aquifer so as to create a significant public health hazard.

Features of the Clean Water Act and the Safe Drinking Water Act that affect decisions regarding land use in the energy sector are considered below.

Restrictions on Energy Development in Water-Quality-Limited Areas.

In the past, water pollution regulations have required only a certain level of pollution control and generally have not influenced plant location. However, Section 302 of the Clean Water Act allows more stringent standards in those situations where implementation of effluent standards is inadequate to maintain in-stream water quality (i.e., in a water-quality-limited stream segment). This section may provide an obstacle to development of a facility that would discharge to a body of water for which water-quality standards are being violated. The Clean Water Act (Sec. 401) also requires certification, before a permit is granted, that a new discharge will not violate water-quality standards.

In addition, EPA has recently proposed revised permitting regulations¹⁰⁹ stating that no new-source permit shall be issued if the discharge

would violate water-quality standards. The burden of proof that no violation would result would be on the applicant. If the discharge were to a quality-limited segment of a stream, demonstration would also be required that sufficient pollutant-load allocations remain to accommodate the new discharge. Because many water-quality-limited stream segments exist, any such requirement could have considerable impact. Quarles¹¹⁰ interprets these proposals as possibly constraining the introduction of new industrial plants in areas with serious localized water pollution, as does the Clean Air Act in similar situations of air pollution.

Restrictions on Energy Development in Areas of High Water Quality.

Obstacles to development may also arise in areas having especially high water quality. Nondegradation provisions, which are part of most state water quality standards, require that existing use (for example, as drinking water supply) be maintained and protected. Areas with existing high quality (i.e., quality above the minimum required levels) are to be maintained at such levels unless a state allows limited degradation for economic or social reasons. In those cases where the water involved constitutes an outstanding national resource, existing water quality must be maintained and protected. Such outstanding resources include streams in parks, wildlife refuges, areas providing unique habitats for threatened and endangered species, or rivers protected under the Wild and Scenic Rivers Act. Although the anti-degradation provisions have not generally been used to restrict development, they could be used for that purpose. In a strict sense, these provisions do not limit new facilities because technological approaches involving zero discharges, decreased waste loads, or dilution of waste could, in principle, avoid violations of in-stream standards. Anti-degradation provisions, however, may decrease the attractiveness of an area for development or, should development occur, may result in increased consumption of land, as noted below. Quarles¹¹⁰ compares the situation involving areas of high water quality to the case of areas with pristine air quality, which are presently protected by the Prevention of Significant Deterioration program.

Increased Use of Land Needed to Meet Effluent Requirements. The Clean Water Act imposes stringent effluent requirements. These requirements result in a smaller mass of pollutants being discharged into the water from a particular type of facility than was the case in the past. The total mass of pollutants generated may remain the same. Therefore, the pollutants go elsewhere, generally to solid waste. Such waste may require storage areas, thus increasing the amount of land required for an operation. Similarly, the pollution-control operations themselves may need additional land for such purposes as evaporation ponds or sedimentation basins. Therefore, simply requiring control of water pollution results in additional land use. Thermal discharges are also regulated under the Clean Water Act. Avoiding thermal pollution results in the use of substantial areas for cooling facilities, particularly in the case of power plants.

Increased Land Use Associated with Zero-Discharge Requirements. The Clean Water Act establishes as a national goal the elimination of discharges of pollutants to the nation's water as a national goal. This goal may be difficult to attain for technical and economic reasons. Nevertheless, for a

facility with zero discharge of pollutants to a public body of water, all of the pressures for increased consumption of land noted in the preceding paragraph are present and are increased. Logically, this issue is an extreme case of the one discussed above; it has been presented separately for emphasis.

Restrictions on Development Arising from Section 208 of the Clean Water Act. Section 208 requires that area-wide waste-treatment management plans be prepared. It further requires that no discharge permits be issued for any point source that is in conflict with an approved plan. The 208 plans, in certain cases, may allocate all the assimilative capacity of a stream or may restrict development in an area. In principle, such plans could have the same impact on future development as zoning ordinances.¹¹⁰ Section 208 also requires that procedures be set forth to control nonpoint sources of pollution arising from agriculture, silviculture, mines, and construction. These sources are particularly relevant because they are associated explicitly with mining and implicitly with biomass production. In theory, then, nonpoint source controls adopted by a state or regional agency could, for example, limit biomass production, especially on marginal lands. In practice, however, the problem has to be considered on a case-by-case basis, because the Clean Water Act does not provide a clear mechanism to force submission of adequate plans.¹¹¹ It is likely that nonpoint-source control programs will be only as stringent as local agencies desire them to be, or as local conditions permit, and that there will be no severe constraints on activities such as biomass production or mining other than possibly a requirement for the use of technological controls (best management practices).

Considerations Associated with the Protection of Drinking Water Supplies. In recent years, there has been increasing concern with the protection of public drinking water supplies. This concern is expressed primarily in the Safe Drinking Water Act; however, it could also find expression in the anti-degradation provisions discussed above. The primary impact of the Safe Drinking Water Act [Sec. 1424(e)] on the location of energy developments would be through the provision in the Act for designation of sole-source aquifers. Numerous petitions are being received by EPA requesting such designations for aquifers. Development above such aquifers could be restricted if the project were federally funded and if it could result in contamination of the aquifer that would lead to a significant public health hazard. Such contamination might be the consequence of extraction activities or leaching from coal-storage or waste-storage areas. In the case of surface waters used as a water supply, the anti-degradation provisions in state water-quality standards could be used to limit discharges, and therefore to limit development. Given the present public concern over the contamination of public water supplies, further restrictions on activities that affect water supplies -- both above and below ground -- seem likely.

6.2.2.2 Water-Use Conflicts

Land-use concerns related to water use are principally a consequence of state water-allocation laws, though the federal government is also involved in conflicts over water allocation. Water laws vary from state to state, and it is beyond the scope of this discussion to review the circumstances in individual states. Only a broad outline of the subject is presented here.

Water allocation laws are generally based on either the riparian doctrine or the appropriation doctrine (or, occasionally, on some combination of the two). Each of these doctrines rests on two fundamental and different considerations. For the riparian doctrine, these considerations are as follows:

- A water right depends upon ownership of land along a body of water.
- Each owner of such land has equal right to make reasonable use of water. (It is not necessary that the right be exercised to exist.)

For the appropriation doctrine, the considerations are as follows:

- The beneficial use of water (not land ownership) is the basis of a right to water.
- Seniority of use is the basis for dividing water among users when the supply is limited: first-in-line is first-in-right.

These two doctrines developed at different times and under different climatic conditions. In the United States, most eastern states (those east of 100°W longitude) have riparian rights, while most western states follow the appropriation doctrine. The appropriation doctrine was adopted in the West in order to decrease uncertainty concerning water availability (although at the same time limiting the number of users). Appropriation rights are usually quantified in terms of specific volumes of water. In the past, the relatively water-rich areas of the East have generally not experienced water availability problems. Thus, the principle of equal rights to water has been adequate. The riparian doctrine does not ensure landowners an adequate supply of water, however, and the East may experience availability problems in the future as water use increases in areas where use is already large.

Law concerning groundwater use is less well developed than that concerning surface-water supplies. In most states, underground streams are treated in the same manner as surface streams. Most states follow the riparian doctrine for percolating groundwater; however, many western states use a permit-appropriation system.

The federal government is also involved in water allocation. Reserved water rights are created when federal and Indian lands are taken from the public domain; most such rights have not been quantified. Also, the federal government is involved with international water allocation considerations involving Mexico and Canada, with the most important area being the Colorado River Basin. Finally, federal control over navigable waters results in interstate water allocation by the federal government, either by interstate water compacts or by federal courts. The federal government also is involved in water allocation because of federal flood-control and land reclamation programs.

The use of certain streams may be limited by the Wild and Scenic Rivers Act (PL 90-542 and amendments), which designates a national system of wild and scenic rivers and provides protection for the rivers included in the system.

The Act designated 15 rivers as components of the system and an additional 58 as potential additions. The Federal Power Commission is prohibited from licensing projects that affect the rivers, and no other U.S. agencies or departments are allowed to "assist by loan, grant, license, or otherwise in the construction of any water resources project that would have a direct and adverse effect on the value for which such river(s) were established" [Sec. 7(a)].

Water-availability concerns may preclude certain developments that consume water. Physical availability of water may be the primary determinant in specific locations, but institutional or legal considerations may offer more widespread constraints on water availability. In some areas the availability of water for a project may be uncertain because of competition for the water or because of existing but unquantified water rights.

Transfer of Existing Water Rights to Energy-Related Use. In many areas of the West, water supplies are completely appropriated, and the use of water for new activities will require transfers of water rights, which may be purchased. The way in which state water law treats transfers is therefore important. Arizona, North Dakota, and South Dakota have laws that restrict or possibly prevent the transfer of water rights from irrigation to energy use.¹¹² Montana also has provisions that inhibit transfers to energy use. The North Dakota and Montana provisions were developed in reaction to possible energy development.¹¹² Generally, in the remainder of the West, water may be transferred to a new location or purpose of use, subject to the requirement that such transfer does not harm existing appropriations. This requirement can stop a transfer in some cases or reduce the quantity of water transferred in others; it also greatly complicates the whole process of transfer.¹¹² Therefore, while transfer of water rights may be necessary for new development, such transfer may be less than straightforward.

Impact of Public Interest Considerations. Most state water laws contain provisions that allow appropriation permits to be refused if the associated use is not in the public interest. In addition, many state laws contain provisions that have an effect similar to the public-interest statutes. An important example of this second type of provision involves the maintenance of minimum in-stream flows to protect aquatic habitats and recreational and aesthetic values. All western states have some regulation in one or both areas. In the past, such provisions have not been used much. Recently, however, Gould¹¹² has noted increased concern in the West over what could broadly be called the public interest:

- There is a trend toward greater administrative control over water use. Intensive public regulation will be a permanent feature of water allocation.
- Noneconomic criteria such as environmental concern are becoming more important factors in judging water use.
- "A substantial part of the legislation is a reaction to energy development." More state control is one result.

- Public interest protection will play a major role in future water allocation, possibly the greatest role of any legal principle.

Similarly, throughout the country, there is an increased administration and legislative awareness of in-stream uses. Thus new industrial users of water, such as energy developments, will be facing increasing conflicts over water use, particularly in the western states.

Uncertainties Introduced by Unquantified Reserved Federal Rights. The reserved water rights associated with federal lands such as national forests or parks or with Indian reservations are substantial in the West, where large amounts of such lands exist. The doctrine of reserved rights for such lands (the Winters doctrine) arises out of a Supreme Court decision in 1908 on water rights on Indian land. The size of the reserved right is the quantity of water needed for beneficial use of the federal or Indian land. Beneficial use is defined in terms of the purpose of the original land reservation. Because their use could have significant impact on water allocations in the West and because they are not fully quantified, these reserved rights produce uncertainties in the amount of water that can be allocated to new uses. Quantification of these rights would reduce these uncertainties and could reduce future conflicts concerning western water rights.

6.2.3 Federal Lands and Energy Resources

The federal government owns and administers 760×10^6 acres of land, one-third of the land area of the United States. Most of this land is concentrated in the western states and Alaska (see Fig. 6.7), where 30% to 90% of the area in each state is under federal control. The use of these lands is determined and managed by the federal government. The Bureau of Land Management (BLM) and the United States Forest Service (USFS) are responsible for the bulk of the federal lands, with jurisdiction over 62% and 25% of the total, respectively.¹¹³

It has been estimated that 40% of the nation's coal reserves, 50% of the oil and gas fields, 80% of the oil fields, 40% of the uranium deposits,¹¹⁴ and 60% of the geothermal fields⁷ lie beneath federal land. The recovery of these resources is directly dependent on federal land-management policies. Additional reserves are indirectly affected because of problems of access or because of inability to conduct an economically viable mining operation without the inclusion of federally owned parcels of land. These problems may be especially acute in the West. For example, in the six western states (North Dakota, Montana, Wyoming, Colorado, Utah, and New Mexico) that account for almost half of the nation's coal reserves, 72% of the coal reserves in Known Recoverable Coal Resource Areas are federally owned. By comparison, the federal government owns the coal rights to less than 3% of the coal east of the Mississippi.¹¹⁵ Ownership patterns in the West make it difficult to develop the 18% of the reserves that are nonfederal without requiring some federal land to make an efficient mining unit. In 1977, only 9% of the coal production from these six western states came from mines that involved no federal coal.¹¹⁵

Fig. 6.7 Distribution of Federal Land in the United States

In addition to the control of resources on land, the 1953 Outer Continental Shelf Lands Act and the 1978 amendments thereto grant the federal government jurisdiction over the lands in the Outer Continental Shelf (OCS) area of U.S. waters and the authority to lease those lands for resource development purposes. Thus, the federal government controls all of the resources of the OCS, which may include up to 60% of the nation's undiscovered oil and gas reserves.¹¹⁶

The large amount of energy resources effectively controlled by federal government is of concern for two reasons:

- The timetable for development of these resources is directly dependent on federal leasing schedules.
- Large amounts of federal land are being withdrawn from mineral development to preserve their wilderness values.

The potential impact of leasing programs and wilderness preservation on mid-term (pre-2000) energy production goals is discussed below.

6.2.3.1 Federal Leasing

The leasing programs of chief concern for energy development are those involving coal and OCS oil and gas. Both programs are administered by the Department of Interior (DOI). The coal leasing program has been recently (June 1979) reinstated, as the Federal Coal Management Program, after a moratorium on new long-term leasing which lasted nearly 10 years. Prior to 1970, DOI processed permit and lease requests for mineral exploration and mining (under the authority of the Mining Law of 1892 and the Minerals Leasing Act of 1920) on a case-by-case basis. Little consideration was given to the need for additional leasing or to the potential environmental effects of mining on the land to be leased.¹¹⁵ This may have been due to the historic precedent that minerals, which can only be mined where they are found, had priority over all other uses of the land.¹¹⁷ By 1970, about 788,000 acres of federal lands were leased for coal production, but less than 10% of that land was producing coal. To allow DOI to develop a comprehensive planning system to determine the size, timing, and location of future coal leasing, a moratorium on new long-term leasing was announced. The new Federal Coal Management Program allows leasing to resume in January 1981. As described in the final EIS, the decision to lease federal coal is to be

an integral part of the federal land planning process. Federal lands would be considered for leasing which have not been found unsuitable for coal mining or more valuable for resource protection or other development activities in the land planning process of the federal land management agencies. In the activity planning process, tracts would be delineated, ranked on the basis of coal quality, cost, and environmental, social, and economic effects and selected for sale by regional coal teams. Regional leasing targets, derived from production goals submitted biennially by the Department of Energy and comments received from the states, industry, and the public, would be applied during the activity planning process to ensure that sufficient tracts would be ranked and selected to meet national energy needs. [Ref. 115, pp. 1-2 to 1-3]

Selection of specific tracts of coal to be offered for lease, and the administration of the lease sales, are to be managed by BLM. Tract selection will probably proceed without the benefit of completed land-use plans until 1985 or even later,¹¹⁸ a necessary compromise if further expansion of production from federal coal leases is to continue past 1986. Because it generally takes 10-15 years of lead time to bring a mineral deposit into production,¹¹⁹ it is probable that coal from new leasing areas will not be available at least until 1990. It is expected that total planned and likely coal production from existing leases in the six major western coal-producing states would be $422.2\text{--}512.7 \times 10^6$ ton/yr by 1990; the DOE projections of demand for coal from these regions are $366.5\text{--}922.1 \times 10^6$ ton/yr,¹¹⁵ which indicates the potential, without new leasing, for a shortfall in coal availability from these regions. (It should be noted, however, that a number of sources have argued that the DOE demand projections are much too high.)^{118,120}

In timing lease sales to ensure that projected regional production goals will be met, it is assumed (1) that the regional demand/production pattern used is the most desirable alternative among the vast array of possible patterns, and (2) that a failure to meet the regional goals could result in a decrease in national coal production levels. The final EIS for the coal management program notes, however, that "on the basis of computer projection, it appears improbable that total national coal production would be greatly reduced (Ref. 115, pp. 2-58)." If western production goals are not met, more coal would be produced from other regions to meet the demand. It can be concluded, therefore, that although the Federal Coal Management Program may have local and regional effects on coal development, it will pose little constraint on achieving mid-term national energy goals related to coal.

This conclusion may not be valid, however, for OCS oil and gas development, because the opportunity to shift the pattern of demand/production away from federally controlled deposits is smaller than with coal. Because as much as 60% of the nation's undiscovered oil and gas may occur in the OCS areas, fewer domestic alternative sources are available if OCS development is curtailed. On the other hand, mid-term OCS energy production is expected to be small compared to demand.¹¹⁶ The real impact of delayed federal leasing of OCS lands is thus hard to determine.

OCS production would displace oil imports and decrease the national dependence on foreign energy sources. Thus the national policy with regard to the OCS is to expand exploration and development in an efficient and timely manner. DOI is responsible for developing five-year leasing schedules in accordance with this policy and selecting the timing and location of leasing so as to obtain a proper balance between the potential for environmental change, the potential for the discovery of oil and gas, and the potential for adverse impact in the coastal zone. As with the coal leasing program, DOE provides regional production goals as input to the lease-planning process. Planning to meet these goals, however, is made difficult by uncertainties about environmental effects, the unknown extent and location of actual reserves, the necessity of coordination among a variety of federal and state agencies and other affected parties, and the necessity of demonstrating consistency with coastal zone management plans before drilling can begin. Thus the time lag between leasing and OCS production is unpredictable and possibly substantial.¹¹⁶

6.2.3.2 Public Land Withdrawals

The large amount of land being considered for wilderness designation by USFS and BLM and the designation of 15 large new national monuments in Alaska have made the potential energy consequences of public land withdrawals an issue of great concern in the last few years. By early 1979, USFS, which already had 12.9×10^6 acres in wilderness areas,¹²¹ was nearing the end of the first stage of its review of 62×10^6 acres of RARE II (Roadless Areas Review and Evaluation) lands for possible designation as wilderness. BLM had nearly 175×10^6 acres under study for the same purpose. President Carter had just created 56×10^6 acres of new national monuments (closed to mineral development) in Alaska, and the 96th Congress was considering legislative proposals that would withdraw $100\text{--}125 \times 10^6$ acres of Alaskan land from mineral exploration and development. If all of this land had been withdrawn from development, it would have nearly doubled the amount of federal land closed to the exploration and development of energy resources. A number of reports issued at that time estimated that 60-65% of the public lands were already totally or partially closed to development.^{1,117,119,122} This estimate did not take into account the fact that the designation of several offshore sites as marine sanctuaries was also being considered, in order to protect them from OCS leasing.

By June 1980, the initial phases of the USFS and BLM studies were completed, and a large proportion of the areas originally under study were determined to be nonwilderness, thus opening those lands to mineral development. However, many acres have been recommended for wilderness designation or are still under study. The amount of land currently withdrawn from development is summarized in Table 6.5. The 282×10^6 acres indicated in this table represent 37% of the nation's public lands. The simplistic assumption that 37% of the federally controlled resources would thus be rendered unavailable leads to estimates that about 15% of the nation's coal, 19% to 30% of the oil, 15% of the uranium, and 22% of the geothermal fields are locked up on withdrawn lands. Further information about the RARE II and BLM wilderness studies and the Alaskan land withdrawals is presented in the text that follows.

Forest Service RARE II Program. In January 1979, USFS recommended that 15.5×10^6 acres of the 62×10^6 acres of RARE II lands be designated as wilderness; 10.5×10^6 acres were to be studied further for possible wilderness designation by 1985; and 36×10^6 acres were released for nonwilderness use.¹²⁴ Areas recommended as wilderness are closed to resource exploration and extraction unless those activities exist under some prior right. The 10.5×10^6 acres under further study are open to oil and gas exploration, but no resource development is permitted until the studies are completed. The impact of these withdrawals on the availability of energy resources was of particular concern in the oil- and gas-rich Rocky Mountain Overthrust Belt, where reserves of $1.5\text{--}8.8 \times 10^6$ barrels of oil and $6\text{--}51.5 \times 10^{12}$ ft³ of natural gas are estimated to occur under RARE II lands. About 95% of the entire Overthrust Belt resource area is still open for resource exploration and extraction, however.¹²⁴

BLM Wilderness Areas. By mid-1979, BLM had completed its initial inventory of more than 175×10^6 acres of roadless areas under its jurisdiction

Table 6.5 Federal Acreage Withdrawn from Mineral Uses
as of June 1, 1980 (10^6 acres)

Government facilities and installations not open to public entry	34.4 ^a
National park service lands	25.1 ^b
Fish and wildlife refuges	30.3 ^b
Wilderness areas in national forests	12.9 ^c
Wild and scenic rivers in national forests	0.3 ^{c,d}
RARE II lands recommended for designation as wilderness	15.5 ^e
RARE II lands under further study	10.5 ^e
BLM potential wilderness study areas	57.0 ^e
1978 designation of Alaskan national monuments	56.0 ^e
20-year withdrawal of Alaskan lands	40.0 ^e
Total	282.0

^aSource: Ref. 117.

^bAs of June 30, 1975. Source: Ref. 122.

^cAs of September 30, 1977. Source: Ref. 121.

^dAdditional wild and scenic river acreage can be found outside of national forest lands.

^eSee text.

and returned to multiple use 113×10^6 acres that "clearly and obviously" lack wilderness value. These decisions significantly reduced the amount of public land withdrawn from development. The remaining 62×10^6 acres have been classified as "potential wilderness study areas." A more intensive inventory of these areas is due to be completed in the western states by October 1980. As of June 1979, this second inventory stage involved 21.8×10^6 acres in Nevada, 9.3×10^6 acres in Utah, 8×10^6 acres in California (including the 6×10^6 acres of California Desert Conservation Area on which the intensive inventory has already been completed), 6.8×10^6 acres in Oregon, 5.6×10^6 acres in Arizona, 3.7×10^6 acres in Idaho, 2.7×10^6 acres in Montana, 1.9×10^6 acres in New Mexico, 1.2×10^6 acres in Colorado, 1×10^6 acres in Wyoming, and 0.14×10^6 acres in Washington.¹²⁵ These numbers represent 30% of the BLM lands and 13% of the federal lands in the seven western states with major energy resources (Arizona, California, Colorado, Montana, New Mexico, Utah, and Wyoming). Eastern land assessment has been delayed by ownership questions, particularly in the Northeast and Minnesota.¹²⁰

The management policy for the areas still under study is to "continue existing uses or allow new uses wherever possible and to conclude the period of study and uncertainty as rapidly as possible."¹²⁶ Activities causing long-lasting or permanent effects are prohibited in the study areas, although mineral uses and mining claims that existed as of October 1975 may continue even if they permanently impair wilderness suitability.¹²² Oil, gas, and mineral exploration are allowed if the areas disturbed by these activities, including access routes, are reclaimed.¹²⁶

Alaskan Lands. As of June 1975, the federal government owned 352.4×10^6 acres of land in Alaska, more than 96% of the state.¹²³ At that time most of the land was under the jurisdiction of BLM and was therefore probably open to mineral exploration and development, subject to existing native claims. Since that time, 5.2×10^6 acres were included in an emergency three-year withdrawal in late 1978, and 56×10^6 acres were withdrawn by President Carter's 1978 action creating 15 new national monuments in Alaska. The Congress has been debating legislation for two years that could withdraw $100-125 \times 10^6$ acres of Alaskan land. The House version, which was passed May 15, 1979, sets aside 110×10^6 acres of land¹²⁷ (other sources report 125×10^6 acres¹²⁰ and 127×10^6 acres¹²²), of which 67×10^6 acres would be designated wilderness. It is possible that the Senate version of the bill, which would set aside 95×10^6 acres, of which 38×10^6 would be designated as wilderness, may not be passed in 1980.¹²⁸ Anticipating this possibility, Interior Secretary Andrus extended for 20 years the withdrawal of 40×10^6 of the 52×10^6 acres removed from development in 1978; the other 12×10^6 acres are now being studied and may also be withdrawn for the 20-year period. Thus, even if the legislature fails to pass Alaskan land legislation again this year, at least $103-115 \times 10^6$ acres of land will be closed to resource development, including 7×10^6 acres of existing National Park Service land, the 56×10^6 acres withdrawn by President Carter, and the $40-52 \times 10^6$ acres withdrawn by Secretary Andrus. This is about 30% of the land area of Alaska.

The impact of these withdrawals on the availability of energy resources in Alaska was estimated by proponents of the House bill. They reported that 95% of Alaska's onshore oil and all of its offshore oil could still be developed, as well as 75% of the potential mineral resources of the state.¹²⁷

6.2.3.3 Indian Lands and Coal Resources*

The largest contiguous blocks of nonfederal coal found in the West are those owned by the Indian tribes (counties containing Indian lands are shown in Fig. 6.8). Approximately 70×10^9 tons of coal, 30×10^9 tons of which are surface-minable, are found under Indian lands. This represents one-third of the western coal reserve base, though production from Indian coal land in 1977 accounted for only 14% of total western production. Of the 22.9×10^9 tons of Indian coal mined in 1977, 80% came from the Navajo lands in Arizona and New Mexico. The remaining 20% came from the Crow and Cheyenne reservations.

The most important Indian coal owners in the West are the Navajo tribes in New Mexico and Arizona (who own 5×10^9 tons), the Crow and Cheyenne tribes in Montana (collectively owning 15×10^9 tons; ownership by individual tribes is not available), and the Three Affiliated Tribes in North Dakota (3×10^9 tons). The Southern Ute, Ute Mountain, Jicarilla, Flathead, and Blackfoot tribes control another $5-7 \times 10^9$ tons of reserves. The Navajo, Crow, and Three Affiliated Tribes have all indicated an interest in developing their coal reserves. The largest uncertainties about future development of Indian coal center on the 15×10^9 tons of reserves in Crow and Cheyenne lands. The Cheyenne do not wish to develop their coal reserves at this time, and legal battles between the Crow tribe and previous purchasers of leases and holders of prospecting permits make the future development of this coal uncertain.

*Ref. 115 is the principal source of information in this section.

Fig. 6.8 U.S. Counties Containing Indian Lands

7 CASE STUDY OF A LAND-USE CONFLICT -- COAL MINING VERSUS THE PRESERVATION OF PRIME AGRICULTURAL LAND

7.1 PRIME AGRICULTURAL LAND

Traditionally, prime agricultural lands have been defined as those soils on which row crops could be grown using a minimum of conservation practices or special equipment. This definition, embodied in the "capability classes" of the Soil Conservation Service (SCS), is being revised and expanded, both by the SCS itself and by popular usage. The SCS is redefining prime farmland using such characteristics as soil moisture, temperature, humidity, drainage, and slope. An inventory based on this definition is under way, and it is expected that 1200 high-priority counties will be finished by 1981. In the current popular usage of the term "prime agricultural land" also includes nationally or regionally unique farmlands, such as Michigan's sour-cherry orchards or California's vineyards, plus areas of historically high yield.

Prime agricultural lands are valued because of the products harvested from them; they are an important resource, and represent an important issue because the total amount of such land is dwindling, raising the (possibly unfounded) concern that the nation will lose its ability to produce enough food. Adding to this concern is the fact that the ability of farmers to increase the yield of their land seems to have reached a limit. Thus, to maintain the current level of agricultural production, land that is removed from production must be replaced by other land. However, only 24×10^6 acres of unused prime agricultural land (old SCS definition) are left, and prime lands are being increasingly replaced by bringing into production marginal lands, which require more labor and energy to farm. Some unique farmlands may be impossible to replace.

The loss of agricultural land is also important for aesthetic and environmental reasons. A rural, pastoral landscape is valued by many people on the suburban fringe. Farmlands serve important environmental functions, such as wildlife habitat and undisturbed watersheds to recharge aquifers.

The primary threat to agricultural land is urbanization. Land that is "prime" for agricultural uses is also eminently suitable for urban-industrial development. Thus prime farmlands may be preferentially removed from the national supply of agricultural land. More than 60% of the acreage removed from agriculture in the last 10 years has been converted to residential or commercial-industrial use; in the Northeast, the figure is closer to 80%. The Council on Environmental Quality (CEQ) reported that the loss of prime farmland is becoming acute in the Pacific states and in the Northeast, and that it is becoming an increasing problem in the Appalachian and Great Lakes areas.⁴⁸

A recent report¹³⁰ has identified 11 different statutory methods of farmland preservation currently in use in the United States (Table 7.1). These methods fall under three main categories of preservation techniques, described below.

Table 7.1 State Programs for Preservation of Farmland, by Type of Program^a

	Taxation Programs						Purchase Programs				
	Preferential Assessment			State Income Tax Credits	Reduced Inheritance Tax	Capital Gains Tax on Land	Zoning Programs		Land Banking	Purchase of Development Rights	Transfer of Development Rights
	Simple	With Deferred Tax	With Restrictive Agreement				Agricultural Districts	Agricultural Zoning			
Alabama	-	s	-	-	-	-	-	-	-	-	-
Alaska	-	s	-	-	-	-	-	-	-	b	s
Arizona	s	-	-	-	-	-	-	-	-	-	-
Arkansas	s	-	-	-	-	-	-	-	-	-	-
California	-	-	s	-	-	b	-	b	-	-	-
Colorado	s	-	-	-	-	-	-	-	-	-	-
Connecticut	s	-	-	-	s	-	-	-	-	s	-
Delaware	s	-	-	-	-	-	-	-	-	-	-
Florida	s	-	-	-	-	-	-	-	-	-	-
Hawaii	-	-	s	-	-	-	-	s	s	b	-
Idaho	s	-	-	-	-	-	-	-	-	-	-
Illinois	-	s	-	-	-	b	-	-	-	-	-
Indiana	s	-	-	-	-	-	-	-	-	-	-
Iowa	s	-	-	-	-	-	-	-	-	-	-
Kansas	-	s	-	-	s	-	-	-	-	-	-
Kentucky	-	s	-	-	s	-	-	-	-	-	-
Louisiana	s	-	-	-	-	-	-	-	-	-	-
Maine	-	s	-	-	-	-	-	-	-	s	-
Maryland	-	s,b	-	-	-	-	-	-	-	s	s
Massachusetts	-	-	-	-	-	-	-	-	s	s	-
Michigan	-	-	s	s	s	-	-	-	-	-	-
Minnesota	-	s	b	b	-	-	-	-	-	-	-
Missouri	s	-	-	-	-	-	-	-	-	-	-
Montana	-	s	-	-	-	b	-	-	-	-	-
Nebraska	-	s	-	-	-	-	-	-	-	-	-
Nevada	-	s	-	-	-	-	-	-	-	-	-
New Hampshire	-	-	s	-	-	-	-	-	-	b	-
New Jersey	-	s	-	-	-	-	-	-	-	s,b	-
New Mexico	s	-	-	-	-	-	-	-	-	-	-
New York	-	s	-	-	s	-	s	-	-	-	s
North Carolina	-	s	-	-	-	-	-	-	-	-	-
North Dakota	s	-	-	b	-	-	-	-	-	-	-
Ohio	-	s	-	-	-	-	b	-	-	-	-
Oklahoma	s	-	-	-	-	-	-	-	-	-	-
Oregon	-	s	-	-	-	b	-	s	-	-	-
Pennsylvania	-	s	s	-	-	-	b	-	s	-	-
Rhode Island	-	s	-	-	-	-	-	-	-	-	-
South Carolina	-	s	-	-	-	-	-	-	-	-	-
South Dakota	s	-	-	-	-	-	-	-	-	-	-
Tennessee	-	s	-	-	s	-	-	-	s	-	-
Texas	-	s	-	-	-	-	-	-	-	-	-
Utah	-	s	-	-	-	-	-	-	-	-	-
Vermont	-	s	-	-	-	s	-	-	-	-	-
Virginia	-	s	-	-	-	b	s	-	-	b	-
Washington	-	s,b	-	-	-	b	-	-	s	-	-
West Virginia	s	-	-	-	-	-	-	-	-	-	-
Wisconsin	-	-	s	s	-	-	-	s	-	-	-
Wyoming	s	-	-	-	-	-	-	-	-	-	-

^as = statute or program; b = bill. Georgia and Mississippi have no programs. Source: Ref. 130, p. 4.

Tax Breaks for Farmers. The most widespread technique used by states to slow the conversion of farmland to other uses is based on preferential tax assessment policies for farmers. The simplest such program provides preferential real property tax assessment for farmland: land used for agriculture is assessed and taxed at its agricultural value rather than at its potential value for such uses as residential subdivision or industrial development. In some states, taxes on preferentially-assessed farmland are deferred until the land is converted to a nonagricultural use. These deferred taxation programs require landowners to pay the difference between the taxes they have paid based on preferential assessment and the taxes they would have paid had the land been assessed at its market value. Some states use restrictive agreements in conjunction with their preferential taxation programs: landowners must agree to keep their land in agricultural use for a specified period of time in order to receive the tax break. Michigan and Wisconsin have statutes that provide credits against state income taxes for farmers who agree to keep their land in agriculture. (This kind of program has been referred to as a "circuit-breaker" tax credit program.) Some states reduce the amount of inheritance and estate taxes that a farmer's heirs must pay. If those heirs keep the land in agriculture, the estate is valued at its farm use value rather than its market value. Vermont, plagued by a loss not only of farmland, but of open spaces in general, has placed a tax on capital gains from the sale of land held for less than six years. This kind of law, which has been proposed in other states, could slow the sale of farmland to speculators.

Zoning for Agriculture. The creation of agricultural districts -- areas in which preferential assessment is available and governmental actions affecting the continued use of the land for agriculture are restricted -- has been authorized by several states in an attempt to preserve farmland. Exclusively agricultural zones, in which only farm-related uses and necessary support services are allowed, have also been tried in some states.

Purchase of Land or Development Rights. Some states have authorized "land banking," the direct purchase of desirable agricultural land by the state. The state then puts a restrictive clause in a lease or deed to the land, which limits the use of the land to farming, and rents or sells the land back to a farmer. Some state programs compensate a farmer who agrees to keep his land in agricultural use for the difference between the land's commercial market value and its farm value. The farmer thereby gives up the development rights to his land. A state may purchase development rights outright, or may assign development rights, independent of the basic title to the land, to land zoned for agricultural use; the farmer may then sell these development rights, and the purchasers may thereby increase the density of development allowed on land they own in a development zone.

A 1976 study prepared for CEQ concluded that few of the programs based on preferential tax assessments have been successful,¹³⁰ and that many purchase programs are stalled because of lack of sufficient funds. There is currently no federal program for farmland preservation, but bills were introduced in the House (HR 2551) and Senate (S 795) in 1979 that would require all federal agencies to consider agricultural values in decision-making. In addition, an interagency National Agricultural Lands Study was recently announced by CEQ and the Department of Agriculture (USDA). The

study, to be completed in 1981, will investigate the causes and extent of the conversion of agricultural land to nonagricultural uses, and assess the past and future role of the federal government in influencing this conversion.

Energy development can contribute to the loss of prime agricultural lands both directly and indirectly. Direct effects include the preemption of agricultural land for utility sites, cooling ponds or reservoirs, mines, fuel-processing and transportation facilities, electricity transmission corridors, and residential-commercial expansion to accommodate the new population attracted by energy jobs. The loss of agricultural lands to surface mining (especially lands devoted to row crops) is a controversial issue. The likelihood of affecting prime agricultural lands can be high in some areas of the country. For instance, 40 to 50% of the strippable coal-reserve base in many of the midwestern states may be covered by prime farmlands.¹³¹ In the West, many coal deposits and agricultural lands are found together in alluvial valleys; this conflict has yet to be resolved. In the East, this kind of conflict is less likely because much of the eastern coal is found in the mountains, well removed from the farmlands in the valleys.¹³¹

As stated in Sec. 6, the Surface Mining Control and Reclamation Act of 1978 (SMCRA) included a directive that prime agricultural land be returned to its original use and productivity after strip mining, and the regulations issued by the Office of Surface Mining pursuant to SMCRA spelled out the requirements for achieving that goal. This part of the act has caused a great deal of concern in the coal industry, and the regulations governing the treatment of stripmined farmlands are still being revised. SMCRA also authorized the designation of certain lands as unsuitable for surface coal mining. Prime farmlands were included in an initial list of criteria for unsuitable lands prepared by the Bureau of Land Management (BLM), but were later dropped in response to industry pressure. Most states have surface-mining laws which may or may not contain specific provisions for the reclamation of farmlands; state legislation is expected to be changed, where necessary, to comply with SMCRA.

Energy developments can also affect the productivity of croplands not directly removed by construction or mining. An important issue in the West is competition for limited surface and groundwater supplies between farmers, who need the water for irrigation and livestock, and energy developments, which need the water for power-plant cooling or coal washing. Coal mining can also affect water supplies by interrupting and destroying shallow aquifers which may supply irrigation or livestock water in some areas. In California and the Midwest, the possible effects on crops of sulfur dioxide (SO_2) emissions from fossil fuel-fired power plants has been of concern. Exposure to SO_2 can cause visible damage and decreased yield in many crop plants; soybeans, grains, non-citrus fruits, and many vegetable crops are particularly sensitive to SO_2 .⁷² Hydrogen sulfide emissions from geothermal developments may cause similar problems. Transmission lines through croplands may also affect their productivity. Although agricultural activities can usually continue in transmission rights-of-way, crop dusting and the use of most large farm equipment, including center-pivot irrigation systems, could be curtailed.¹³²

7.2 LOCAL SITE-SPECIFIC CHANGES IN LAND USE: THE PEABODY UNIVERSAL MINE

The Peabody Universal Mine is located in Indiana in Vermillion and Vigo counties (Fig. 7.1) approximately 10 miles north of Terre Haute. The mining operation has been one of the largest in Indiana, with an average annual production level of nearly 3×10^6 tons between 1973 and 1975. This site was selected for this report because it has been intensely studied by Argonne National Laboratory,* and because it is located in counties where 80% of the land use is agricultural. The total amount of cropland is 195,726 acres in Vermillion County and 148,328 acres in Vigo County. Corn, soybeans, and wheat were produced on about 85% of the acreage used for crops. Nearly 90% of the Universal site, prior to mining, was devoted to farmland, and over 60% of the total site was planted in crops. Pre-mining land uses at the site are given in Table 7.2.

Annual coal production at the Universal site between 1970 and 1975 ranged from nearly 10^6 tons to 3×10^6 tons (Table 7.3). During those same years, over 1,800 acres were disturbed (Table 7.4). An accurate comparison of figures on area stripped and production is difficult because the

Fig. 7.1 Location of the Universal Mine

*Most of the information in this report concerning the Universal Mine site was taken from Ref. 133.

Table 7.2 Pre-mining Uses of Areas Disturbed
by Universal Mine^a

Land Use	Acres	% of Disturbed Area
Cropland	1,138	63.4
Pasture	145	8.1
Farmstead	32	1.8
Non-Farm Residence	13	0.7
Woodland	429	23.9
Vacant and Idle	24	1.3
Disturbed (before mining)	11	0.6
Water	1	0.1

^aFrom Ref. 133.

former are reported on the basis of the permit year and the latter on the basis of the calendar year. If one does, however, compare these data, the acreage disturbed averages 145 acres per 10⁶ tons of coal with a range of 121 acres per 10⁶ tons to 159 acres per 10⁶ tons. Acreage disturbed per 10⁶ tons of coal is highly site-specific and depends upon many factors such as depth of coal, seam thickness, and mining techniques.

Table 7.3 Annual Production
of Universal Mine,
1970-1975^a

Calendar Year	Tons
1970	926,054
1971	1,300,094
1972	2,266,567
1973	3,039,321
1974	2,833,348
1975	2,761,649

^aSource: Ref. 134.

Revegetation at the Universal site between 1970-1975 has been directed toward establishing pasture, even though Peabody's reclamation plans indicated that 53% of the mined land would be planted in row crops. A comparison of pre-mining land uses in Vigo and Vermillion counties with the planned land-use objectives of reclamation at the Universal Mine indicates the role of surface mining in land-use change. Assuming short-range (six years since the beginning of mining) stability in land uses in the surrounding area, the Universal site will be characterized by a distribution of land uses differing in many respects from the unmined countryside. Pasture land will have increased from its former role (8% of the area) to more than 50% of the reclaimed area. Concurrently, the proportion of cropland will decrease from more than 60% to about 40%.

The second most common pre-mining regional land use, woodland, will no longer exist on the reclaimed land after mining, because no areas have been planted with trees. Certain minor pre-mining land uses at the Universal site, such as farmsteads and nonfarm residences, will also be eliminated. As of 1975, the area of disturbance had eliminated approximately 22 farmsteads and 9 nonfarm residences. Additional properties have been vacated on land that is controlled by Peabody, but not yet disturbed; similar pre-mining land use effects operate on crop lands and pasture. Although precise figures are not

Table 7.4 Area Disturbed by Universal Mine, 1969-1976^a

Permit Year	Acres Disturbed	% of Total ^b	Acres Disturbed, Cumulative	% Disturbed, Cumulative ^b
1969-70	148	7.8	148	7.8
1970-71	206	10.9	354	18.7
1971-72	275	14.5	629	33.2
1972-73	446	23.6	1075	56.8
1973-74	449	23.7	1524	80.5
1974-75	367	19.4	1891	99.9
1975-76	400 ^c	-	-	-

^aSource: Ref. 135.

^bPercentages do not sum to 100.0 because of rounding.

^cArea planned as indicated in permit application.

available, the process of mining will eliminate natural drainages, lakes, and farm ponds but will increase the total area covered by water.

It is unclear how SMCRA would have affected the actual revegetation at the Universal Mine. Presumably, if Peabody were to follow the law's requirements, it would return the land to the original land use and achieve 90% of the original productivity. Whether or not this end were achieved, one might argue that such a loss may be significant if "specialty" or high-value crops were grown on the mine site, or if other mining activity were planned or under way in other parts of the counties. A recent Rutgers University report (cited in Ref. 136) suggests that in order for farmers to function, there must be enough of an agricultural economy to support a viable supply, transportation, and marketing system. There exists, according to the study, a minimum requirement of agricultural acreage necessary to support an agricultural economy. These requirements ranged down to 10,000 acres in a 10-mile radius for vegetable and potato operations. Consequently, piecemeal alteration of row-crop agriculture to pasture or to some other land use could lead to an unexpected change in the local economy.

7.3 STATE AND REGIONAL CHANGES IN LAND USE: INDIANA AND FEDERAL REGION 5

Figures 7.2 and 7.3 show where coal was mined in Indiana during 1976 and the amount of land planted in row crops in Indiana mining counties, respectively. A recent survey identified pre-mining and expected post-mining land uses in Indiana counties.¹³⁷ According to the survey, 2,013 acres were in row crops prior to mining, and 2,170 acres are expected to be returned to the capability of producing row crops after mining is complete. This capability is defined by slope; under Indiana law, a post-mining land use of row crops means that the operator will return the land to a 0-8% slope. Often, this land is reclaimed to pasture instead of row crops, as shown by the Peabody Universal Mine example. In Illinois, a study conducted in 1971 by Southern Illinois University showed that of 171,000 acres disturbed by mining

Fig. 7.2 Number of Surface Mines in Indiana, Per County, 1976
(Source: Ref. 133)

(0.46% of the total land area of the state), 27% was returned to pasture and only 0.6% was returned to tilled or grain crops.¹³⁸ The success of SMCRA in causing land to be returned to its pre-mining use and productivity is still unclear but will become evident in years to come.

Other studies have estimated the amount of agricultural land that may be taken out of production by future surface mining. Argonne National Laboratory (ANL) is currently evaluating the potential effects of increased coal production on agriculture and other land uses.³ This investigation assumes that coal production from U.S. surface mines will reach 1.14×10^9 ton/yr by the year 2000. The preliminary analysis provides county, state, and regional estimates of how many acres of row crops, grains, "specialty crops" (fruits and vegetables), hay, grazing land, and forests may be affected by surface mining between 1975 and 2000. In Indiana, the 479×10^6 tons of coal projected to be produced by the year 2000 may consume 79,220 acres of land, of which 37% (or 29,378 acres) would be cropland. This represents 0.3% of

Fig. 7.3 Row Crop Acreage in Indiana Mining Counties before Surface Mining, 1976 (Source: Ref. 133)

Indiana's total cropland. To estimate acreages of land types that may be disturbed, ANL used a simple statistical procedure that assumed that land uses and coal resources are distributed randomly within the county. This random-estimation procedure was verified by ANL by comparing the estimates with actual mine-permit data from four states. The assumption of random distribution gave acceptable estimates.

Federal Region 5 is a large coal-producing area, and Illinois, Indiana, and Ohio are the leading coal-producing states in the region. According to the analysis described above, Region 5 will produce 1.7×10^9 tons of surface-mined coal by 2000, which could disturb over 280,000 acres of land. Approximately 75,000 acres of harvested cropland could be disturbed, which represents 0.1% of the total Region 5 cropland and 27% of the total land area projected to be mined. Another ANL study, based on higher coal-production levels, projected that 104,000 acres of prime agricultural land would be disturbed by surface mining between 1980 and 2000.¹³⁹

These projections give a range of 117 mi² to more than 162 mi² of cropland that may be disturbed by surface mining in EPA Region 5 by 2000. For comparison, the City of Chicago occupies 223 mi². The CEQ estimates the national loss of prime farmland due to all causes to be 10⁶ acres per year, or about 4 mi² per day.¹¹⁸ Nearly half of this loss is attributed to subdivision and other kinds of urbanization, and 10% goes to commercial and industrial development. Assuming that this rate of loss continues, surface mining in Region 5 could account for 0.3% of the farmland lost by the turn of the century.

8 CONCLUSIONS

The goal of this report was to provide information on the effects of energy development on land use and to discuss conflicts that may arise between energy development and existing uses of the land. The relationship between use of land in energy production and federal and state environmental legislation has also been discussed. The report was meant to be as quantitative as possible, and average land requirements for energy facilities in each stage of the fuel cycle were used to develop regional and national estimates of the amount of land devoted to energy uses in 1975 and by 1990. A variety of 1990 projections were used to estimate future land requirements; a summary and discussion of these estimates are presented below.

The amount of land occupied by energy-related activities in the United States in 1975 is roughly estimated at about 1.1×10^6 acres (1762 square miles), as shown in Table 8.1. This figure is probably a gross underestimate of the amount of land actually devoted to energy uses in that year, however, because it does not include abandoned surface-mined lands or those undergoing reclamation, nor the amount of land covered by hydroelectric reservoirs or devoted to transmission corridors. Adding these areas could triple the estimate given above, yielding a total area that accounts for about 0.1% to 0.2% of the land area in the continental United States, about the size of Connecticut or New Jersey. Comparing this estimate to the amount of land devoted to other uses in the United States in 1971,¹² one finds that energy-related activities occupied about the same amount of land as did airports or railroads, only one-seventh of the area occupied by highways, and only one-tenth of the area taken up by urban uses.

These kinds of comparisons can be misleading, however, because land-use impact can be much greater at the local level than national or regional comparisons might suggest. Land-use changes associated with energy development can have a significant impact on the quality of the physical, social, economic, and visual environment of the area surrounding the development. The local population incurs costs and receives benefits not shared by the larger constituency that the energy development is meant to benefit.

The worst-case estimates of potential increases in the amount of land required for energy activities by 1990 are from 18.6 to 57.7×10^6 acres, as shown in Table 8.2. Most of this acreage would be in croplands devoted to production of biomass for energy; only 1.8 - 2.0×10^6 acres would be in the more intensive uses that are more likely to cause adverse effects on land use. These estimates do not include the amount of land required for new hydroelectric facilities, because no acceptable method for calculating that value could be derived. The estimates also do not include land required for new transmission lines and transportation facilities; these activities can, in many cases, be conducted on existing rights-of-way, therefore it is possible that additional land requirements for these purposes by 1990 may be small.

To put these estimates in perspective, the amount of urban land in the United States increased from 61.1×10^6 acres¹⁴⁰ to 89.3×10^6 acres⁴⁵ between 1967 and 1977, an average rate of conversion to urban uses of about 2.8×10^6 acres per year. The estimated average rate of conversion of land to nonbiomass uses between 1975 and 2000 is less than one-twentieth of this

Table 8.1 Estimated Area Occupied by Energy Activities in 1975

Fuel Cycle Component	Estimated Area (acres)	Comments
Extraction ^a		
Coal	51,400	Disturbed by surface mining in 1975
Oil	196,700	
Natural gas	179,000	
Uranium	2,700	Disturbed in 1975
Geothermal	3,600	
Processing		
Synfuels from coal	300	Pilot plants
Oil refineries	327,400	
Uranium processing	30,700	Milling, conversion, enrichment, and fuel fabricating
Conversion/Combustion		
Coal- and oil-fired power plants	175,000	
Nuclear power plants	123,600	
Hydroelectric facilities	not estimated	
Solid Waste	30,900	Lifetime disposal area requirement for fossil-fueled power plants only
Total	1,121,300	Does not include land requiring or undergoing reclamation, land covered by hydroelectric reservoirs, or land devoted to activities not listed here

^aAssuming no land devoted to oil shale or biomass.

rate. The potential conversion of rural land to cropland for biomass production can be compared to the rate at which land is "normally" converted to cropland for food and fiber production. Between 1967 and 1975, 48.7×10^6 acres of land, mostly pasture and rangeland, were converted to cropland,⁴⁸ an average conversion rate of about 6×10^6 acres per year. Biomass production may require the conversion to cropland of $1.7\text{--}5.6 \times 10^6$ acres of land per year; the creation of energy farms, then, could possibly double the rate at which the U.S. reserve of potential croplands is depleted.

The greatest impact on land use occurs when the change is irreversible. This is most likely with industrial developments, such as power plants, oil refineries, and synfuel plants, because a conversion to an industrial use is physically or socioeconomically irreversible in most cases.

Table 8.2 Estimated Additional Area Required for Energy Activities by 1990^a

Fuel Cycle Component	Estimated Additional Area (acres)	Comments
Extraction		
Coal	1,007,400	Surface mining only; cumulative requirements, 1975-1990
Oil	23,000	
Oil shale	4,000-16,500	For shale disposal; assume 0 in 1980, with linear increase to 1990
Natural gas	-3,000	
Uranium	18,100-36,000	Cumulative requirements, 1975-1990
Geothermal	69,000-241,000	Interpolates 1990 estimate from 1985 and 2000 estimates
Biomass	6,880,000-55,740,000	Grain for ethanol, 17-state central region only
Processing		
Synfuels	24,000	Coal to gas or liquids
Oil refineries	10,330	
Oil shale retorts	1,200	
Uranium	6,800-13,500	New mills, fuel fabrication facility
Biomass--Alcohol production	21,000	Ethanol from grain; to produce 5.4×10^9 gal/yr
Conversion/Combustion		
Coal- and oil-fired power plants	110,400	
Nuclear power plants	343,000	
Hydroelectric facilities	not estimated	
Solid Waste	103,000	Lifetime disposal area requirements for fossil-fueled power plants only
Total	18,643,300-57,712,200	Worst-case estimate:
(Without biomass)	(1,763,300-1,972,200)	assumes attainment of highest projected energy production levels reported for each fuel and stage of fuel cycle

^aAssuming a high level of production in each component of the fuel cycle.

Other energy developments usually entail more temporary changes in land use, with varying degrees of reversibility. The Surface Mining Control and Reclamation Act, for instance, requires that the original land use be restored in mined areas, unless the criteria for a special variance are met. But the temporary conversion to mining use is not totally reversible -- the restoration of original productivity on reclaimed lands is still under question -- and in some areas, such as the arid West, reclamation may not be possible, in which case the change in land use would be permanent. The surface mining of uranium and oil shale will be more likely to cause permanent changes in land use because it will occur almost exclusively in the West. More than 10^6 acres could be disturbed by coal and uranium surface mining between 1975 and 2000.

Oil, gas, and steam recovery are also less disruptive uses of the land, because each well usually requires less than an acre of land. Although spacing requirements within the well field cause relatively large areas to be devoted to energy use for the life of the operation, only 10-20% of this area is actually disturbed, making the restoration of original use easier to accomplish.

Geothermal operations may be more likely to conflict with historic or cultural land-use values, because such phenomena as hot springs and fumaroles were often the site of early settlements or were endowed with religious significance by native Americans. Moreover, two of the potential geothermal sites occur within national parks, and are thus not available for exploitation. Wilderness designations and the consequent withdrawal of oil- and gas-rich lands in the Rocky Mountain Overthrust Belt have also been a matter of concern.

The use of biomass as an energy source will require that large acreages of land be devoted to crop production for energy uses. Millions of acres may be converted from other rural uses, making biomass the biggest energy-related consumer of land. The direct effect of this conversion is small, because the land surface is not covered or destroyed as it is by mining, drilling, construction of conversion or combustion facilities, or solid waste disposal. In addition, the use of common soil-conservation and soil-management practices should minimize the depletion of soil fertility, and the decision to use the land for energy purposes can be reviewed annually.

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