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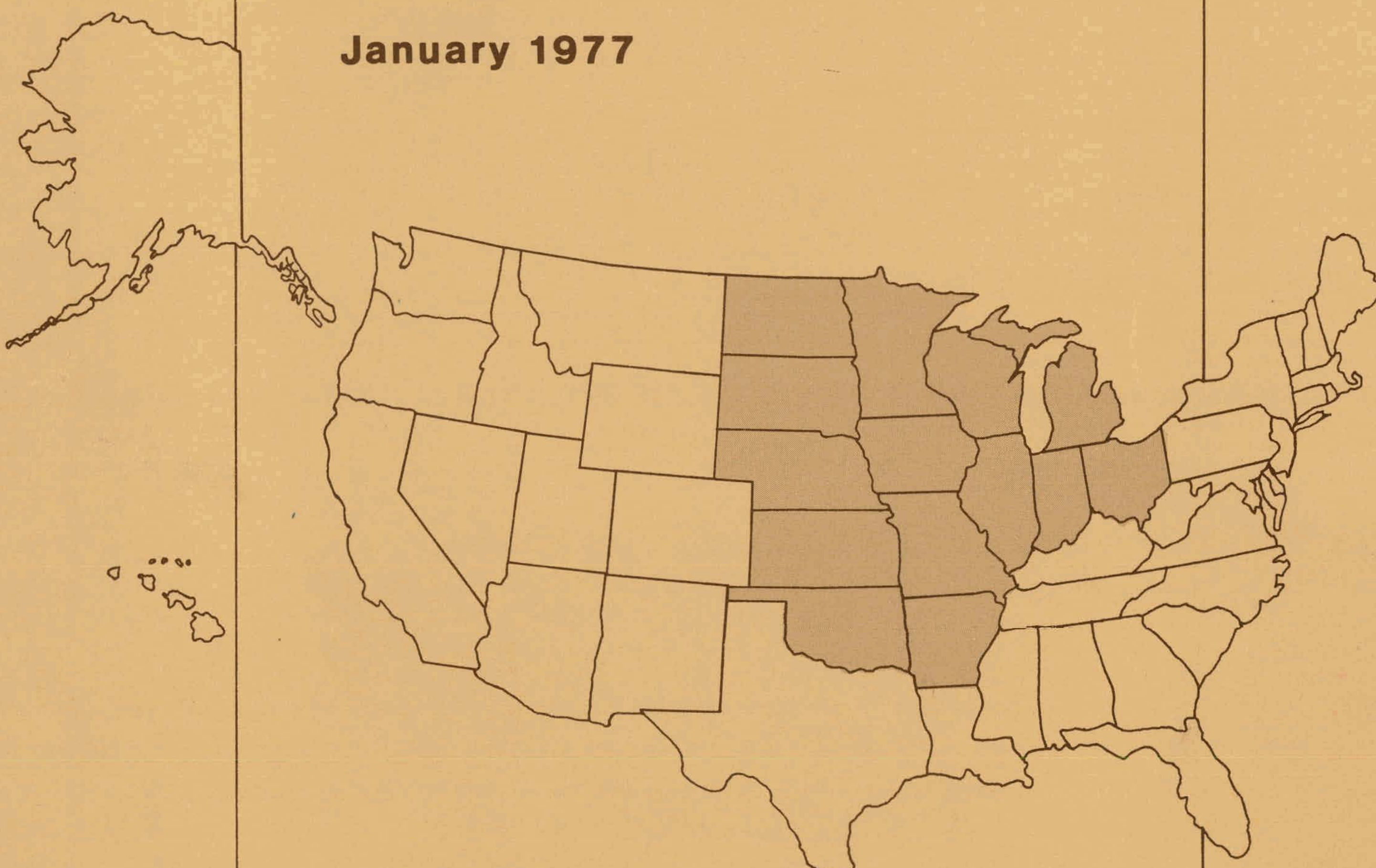
ANL/AA-6 Vol. I

NATIONAL COAL UTILIZATION ASSESSMENT

A Preliminary Assessment of the Health and Environmental Effects of Coal Utilization in the Midwest

Volume I

January 1977



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ANL/AA-6 Vol. I

NATIONAL COAL UTILIZATION ASSESSMENT

A Preliminary Assessment of the Health and Environmental Effects of Coal Utilization in the Midwest

Volume I

Energy Scenarios, Technology Characterizations, Air and Water Resource Impacts, and Health Effects

January 1977

Regional Studies Program
Argonne National Laboratory
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Argonne, Illinois 60439

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PREFACE

This study was performed as a part of the Argonne National Laboratory Regional Studies Program, which is sponsored by the Assistant Administrator for Environment and Safety of the U.S. Energy Research and Development Administration.

The purpose of the Regional Studies Program is to assess the impacts and consequences associated with alternative energy options on a regional basis, and to identify and analyze alternative mitigation and solution strategies for increasing the acceptability of these options. Program leadership is provided by Argonne's Energy and Environmental Systems (EES) Division. The assessments are conducted primarily by staff from three ANL Divisions: EES, Environmental Impact Studies (EIS), and Biological and Medical Research (BIM). Other research institutions and consultants also contribute.

The National Coal Utilization Assessment (NCUA), being conducted as a part of the Regional Studies Program, focuses on impacts and constraints on increased coal utilization. In addition, a major focal point for the NCUA is the identification and analysis of alternative solution strategies applicable to these constraints and problems.

This report, which is an integral part of the NCUA, presents an initial assessment of the potential for impacts on health and environment from coal utilization in the Midwestern states of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. Volume I includes (1) a characterization of the energy demand and siting scenarios, coal-related technologies, and coal resources; and (2) the related impacts on air quality, water availability, water quality, and human health. Volume II includes (1) background information on the native ecosystems, climate, soils, and agricultural land use for the six midwestern states; and (2) a description of the ecological impacts expected from coal utilization in Southern Illinois, which has ecosystems representative of a large segment of the six-state area.

The contributors and their responsibilities for conducting this study are designated on the following page.

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ABSTRACT

This report presents an initial evaluation of the major health and environmental issues associated with increased coal use in the six midwestern states of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. Using an integrated assessment approach, the evaluation proceeds from a base-line scenario of energy demand and facility siting for 1975-2020. Emphasis is placed on impacts from coal extraction, land reclamation, coal combustion for electrical generation, and coal gasification. The range of potential impacts and constraints is illustrated by a second scenario that represents an expected upper limit for coal utilization in Illinois.

The following are among the more significant issues identified and evaluated in this study:

- If environmental and related issues can be resolved, coal will continue to be a major source of energy for the Midwest, even with a transition of dependence to other energy forms.
- Existing sulfur emission constraints will increase use of western coal.
- The resource requirements and environmental impacts of coal utilization will require major significant environmental and economic tradeoffs in site selection.
- Short-term (24-hr) ambient standards for sulfur dioxide will limit the sizes of coal facilities or require advanced control technologies.
- An impact on public health may result from long-range transport of airborne sulfur emissions from coal facilities in the Midwest.
- Inadequately controlled effluents from coal gasification may cause violations of water-quality standards.
- The major ecological effects of coal extraction are from pre-mining and post-reclamation land use.
- Sulfur dioxide is the major potential contributor to effects on vegetation of atmospheric emissions from coal facilities.

EXECUTIVE SUMMARY

This report presents an initial identification of the region-specific impacts and constraints associated with coal utilization in the Midwest from now to the year 2020. The report is part of a series of iterative analyses leading to final assessments within the National Coal Utilization Assessment program sponsored by the Assistant Administrator for Environment and Safety of the U.S. Energy Research and Development Administration. This initial assessment was limited to Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. The following is a brief summary of a limited number of the more significant issues identified and evaluated in this study.

If environmental and related issues can be resolved, coal will continue to be a major source of energy for the Midwest.

Even with a transition of dependence to other energy forms, coal can be expected to be important in the Midwest for electrical generation and as a substitute for dwindling supplies of oil and natural gas. A projected moderate increase in total electrical generation of 5% per year over the 1975-2020 period implies a 3-4% annual increase in coal consumption for the region, even though the fraction of generation from coal decreases from 80% to 50% during that period. This projection also assumes that industrial coal demand will continue and that more than a third of the regional methane demand may be supplied by coal gasification by 2020. Recent historical patterns by comparison indicate a 6-7% annual increase in electrical demand and a more modest 1.5% annual increase in coal demand.

Existing sulfur emission limitations will increase use of western coal.

Without significantly improved sulfur removal, western low-sulfur coals will capture an increasing portion of the midwestern coal market. The demand for Western coal by utilities in the six-state Midwest study area for 1975-2020 may increase more than tenfold. Potential problems with the capacity of coal transportation systems must be determined. The acceptance of impacts of coal extraction and related impacts in the West will also be an important factor in determining level of western coal in the Midwest.

The resource requirements and environmental impacts of coal-utilization facilities will require environmental and economic tradeoffs in site selection.

Available sites for large energy facilities that are near load centers, coal resources, and water resources are nearly exhausted. Total regional water supplies are adequate, but water-resource management may increasingly require construction of reservoirs, use of dry cooling towers, or other water-conservation methods in some subareas. Much of the six-state area is prime agricultural land; thus land use issues may restrict construction of large reservoirs. These energy demands will also result in increasing pressure to use the Great Lakes water resources; such use is constrained by heavy competition for shoreline sites. Also, about half of the counties in the region with coal resources were projected to potentially be faced in the next 40 - 50 years with some level of constraint on further siting of coal facilities because of background concentrations of air pollutants.

Short-term (24-hr maximum) standards for sulfur dioxide will limit the sizes of coal facilities or will require advanced control technologies.

With sulfur dioxide (SO_2) emissions at the rate allowable by New Source Performance Standards (NSPS), 3000 MW is about the maximum facility size possible without violation of National Ambient Air Quality Standards. The designation of Class I areas under the proposed Prevention of Significant Deterioration Regulations would further limit facility size, or would require a reduction in emissions through advanced control technology or a combination of low-sulfur coal and flue-gas desulfurization. Even with a limitation in emissions equivalent to 300 MW with NSPS, new generation facilities may be excluded from buffer zones of 30 miles or more surrounding the Class I areas. Particulate emissions also are a constraint, but less severe than SO_2 constraints. Current standards for annual average air quality will not be a major constraint on coal utilization.

An impact on public health may result from long-range transport of airborne sulfur emissions from coal facilities in the Midwest.

There is increasing evidence that sulfur emissions that have been transformed to a sulfate aerosol can have an adverse effect on the exposed population. Furthermore, the effect of sulfate may be widespread because of its long residence time in the atmosphere. From an initial model, it is estimated that the sulfur emissions from an accelerated coal use rate in Illinois could increase annual sulfate concentrations by 1.0 $\mu g/m^3$ as far away as the northeastern U.S. Models for quantifying the health impacts associated with this increase are being reevaluated. Preliminary indications are that, with current pollutant levels in the populous Northeast and other areas, an increment of 1.0 $\mu g/m^3$ in sulfates may have a significant health impact.

Effluents from coal gasification may cause violations of water-quality standards.

In sample study areas, a significant effect on water quality was found; it was due in part to the low flow volume of the river and, in part, to the assumed high effluent loading from the gasification plants. Although the actual impacts are uncertain because of lack of data for effluents, the results indicate the importance of further studies. Drainage from mining areas and seepage from waste-disposal sites and holding ponds could also pollute both surface and ground water. Coal-burning power plants will probably not cause a serious impact on water quality if (1) the discharges comply with the New Source Performance Standards (NSPS); and (2) receiving waters have a relatively high stream flow.

The major ecological effects of coal extraction are related to pre-mining and post-reclamation land use.

Because of the larger acreages disturbed, the ecological effects of surface mining are more extensive than those of deep mining. Wildlife species associated with deciduous forests are expected to be more permanently affected by surface mining than are species which inhabit prairies and agricultural land, partly because of the much longer time (50-100 years) required to reestablish these forests; also, under current reclamation practices in Illinois, most of the reclaimed land is returned to agricultural use. The reclamation of strip-mined land to use in row-crop agriculture may require 10 years. If done properly, the creation of impoundments and final cut reservoirs on surface-mined land provides new habitat for fish and wildlife.

Sulfur dioxide is the major potential contributor to effects on vegetation of coal-related atmospheric emissions.

For a 3000-MW plant meeting NSPS emissions, acute visible injury to sensitive vegetation may occur to an area of over 600 acres under extreme conditions of 24-hr maximum concentrations coinciding with critical growth stages of the vegetation. Regional agricultural species sensitive to SO_2 include alfalfa, barley, oats, rye, wheat, and soybeans. Impacts on vegetation from trace elements is uncertain; however, potential impacts have been indicated for arsenic, fluoride, and cadmium.

1 OVERVIEW

1.1 OBJECTIVES AND SCOPE

As part of the Regional Studies Program being sponsored by the Assistant Administrator for Environment and Safety of the U.S. Energy Research and Development Administration, Argonne National Laboratory is contributing to a National Coal Utilization Assessment (NCUA). The NCUA, a two-year program, is to:

(1) Identify the region-specific impacts of, and constraints on, coal utilization from now to the year 2020.

(2) Analyze mitigation strategies (options for siting, environmental controls, research and development programs, etc.).

Argonne's role in this study is to conduct the above analyses in the Midwest and to integrate the regional results of the several participating national laboratories into a national perspective.

This report, an integral part of the NCUA, presents an initial assessment of the potential impacts on health and environment of coal utilization in Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. A primary objective was to identify the major region-specific impacts of, and constraints on, increased coal mining and use of coal at a level required to satisfy a major portion of the future energy demands of the region. This report is part of a series of iterative analyses leading to final assessments. A second related objective of the study was thus to identify topics to be emphasized and to develop a framework and analytical tools for subsequent analyses. These analyses will also extend the scope to other Midwestern states; quantify in more detail certain aspects, such as health effects; and include additional categories, such as local socioeconomic effects. Because the assessment process is iterative, we wish to obtain the input of a wide audience; the reader is invited to comment on the report and the need for additional analysis.

This study focuses primarily on the extraction of coal, electrical generation from it, and coal gasification; and their impact on air quality, public health, water availability, water quality, and terrestrial and aquatic ecosystems.

The evaluation in Volume I proceeds from a baseline scenario of energy demand for 1975-2020 derived from an evaluation of current problems and trends. A second scenario that represents an expected upper limit for coal utilization in Illinois is included to illustrate the range of potential impacts and constraints. To establish a reference point for future studies, the impacts of the facilities for generating electricity from coal or for coal gasification were based on effluent levels and resource requirements for existing or demonstrated technology, characterized in the report. A county-level siting pattern is developed for use in the area-specific evaluation of the impacts on the air and water quality and the consumption of water and coal attributable to the coal scenarios.

In Volume II the native ecosystems, climate, soils, and agricultural land use within the six-state area are described. An initial assessment of the impacts on these ecosystems from coal utilization is presented; the assessment is based on a case study in southern Illinois, which has ecosystems representive of a large segment of the six-state area and a projected intense coal development.

The major trends, impacts, and constraints identified by the study are summarized in the remainder of this section, along with suggested directions for future studies.

1.2 *ENERGY SUPPLY AND DEMAND*

A characterization of energy supply and demand for the six-state study region was used in conjunction with an econometric analysis to develop scenarios for 1985, 2000, and 2020. The regional electricity demand in these scenarios increases from 0.37×10^9 MWh in 1975 to 1.3×10^9 MWh in 2000, and 3.2×10^9 MWh in 2020. (The growth of electricity demand for each of the six states is shown in Fig. 1.1). A base-case scenario derived from recent trends and projections of energy patterns assumes that 60% of this regional demand is generated from coal in 2000 and 50% in 2020. A second scenario for Illinois, assuming a higher level of use of the abundant high-sulfur Illinois coals in lieu of increased nuclear generation, is based on 60% and 79% of the Illinois demand being generated from coal in 2000 and 2020, respectively. The latter scenario represents a reasonable upper bound for coal-based energy generation in Illinois, and thus an upper bound on coal-related impacts.

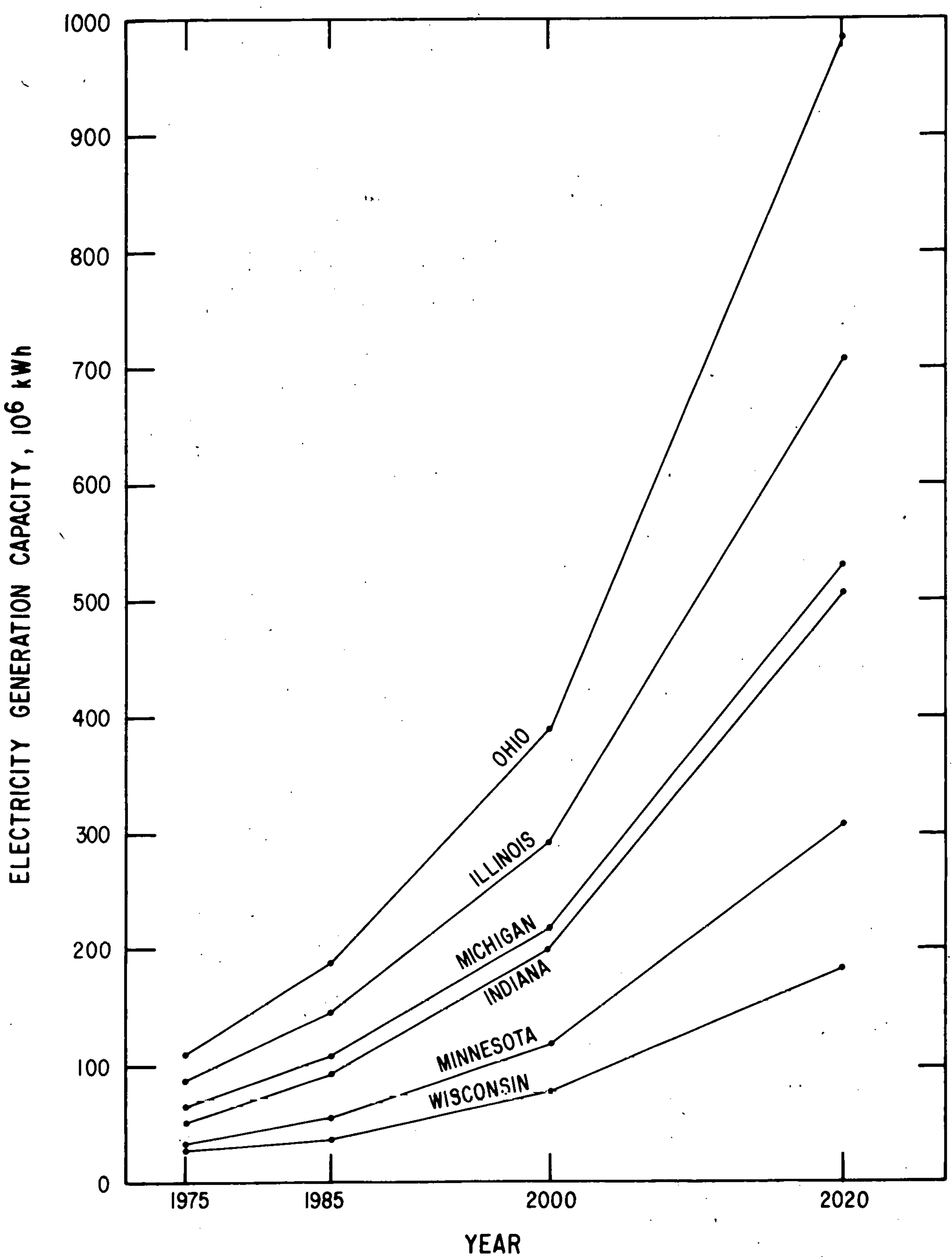

Fig. 1.1 Baseline Scenarios for State Generation of Electricity

It was projected additionally that, in the Interior Coal Province states of Illinois and Indiana, there would be plants for producing high-Btu gas with a capacity totaling 1750 x 10^6 scf/day in 2000 and 4750 x 10^6 scf/day in 2020.

The salient features of current problems and future trends in energy supply for the region are summarized below.

- While Illinois, Indiana, and Ohio are relatively rich in coal, the Midwest region, particularly Minnesota and Wisconsin, depends heavily on fossil fuels from outside the region.
- Natural-gas shortages will force considerable conversion from use of gas to use of electricity and coal. Installations of electric space heating are growing at record rates in Ohio. Even with increasing numbers of customers for electric space heating and water heating switching from gas, electricity demand is forecast to decline from its historic growth rates of 6.0–7.5% to about 4.0 or 5% by 1985 and even lower thereafter. This general decrease in demand growth will be somewhat greater for Ohio and Michigan, for which relatively slower increases in population and economic activity are forecast.
- Some states in the region may slow capacity growth by load-management programs. Wisconsin is a leader in this area. Electric generating capacity is forecast to grow at about the same rate as demand, at least until the turn of the century. The growth in capacity by type is shown in Fig. 1.2.
- Although coal is now the dominant source of fuel for electrical generation in all states in the region, several states (Illinois, Ohio, and Michigan) have made heavy commitments to the development of nuclear power. Illinois is the leading state in the use of nuclear power, with about a fourth of its electricity generated from nuclear plants. This fraction may rise to nearly half by 1985. Depletion of coal resources and potential air-pollution problems are likely to cause significant declines in the use of coal-generated electricity after 2000. Figure 1.3 (b) shows a projected mix of utility fuels for power generation in 2020. In the projection nuclear power captures about half of the generation mix in every state.
- The sources of this coal for 2020 are shown in Fig. 1.4. Illinois is the only state with most of its coal requirements produced in the state. Ohio and Indiana are the only other states with a significant fraction of their utility coal needs produced locally. Much of the imported coal will be from low-sulfur Western coal. Imports of high-sulfur coal

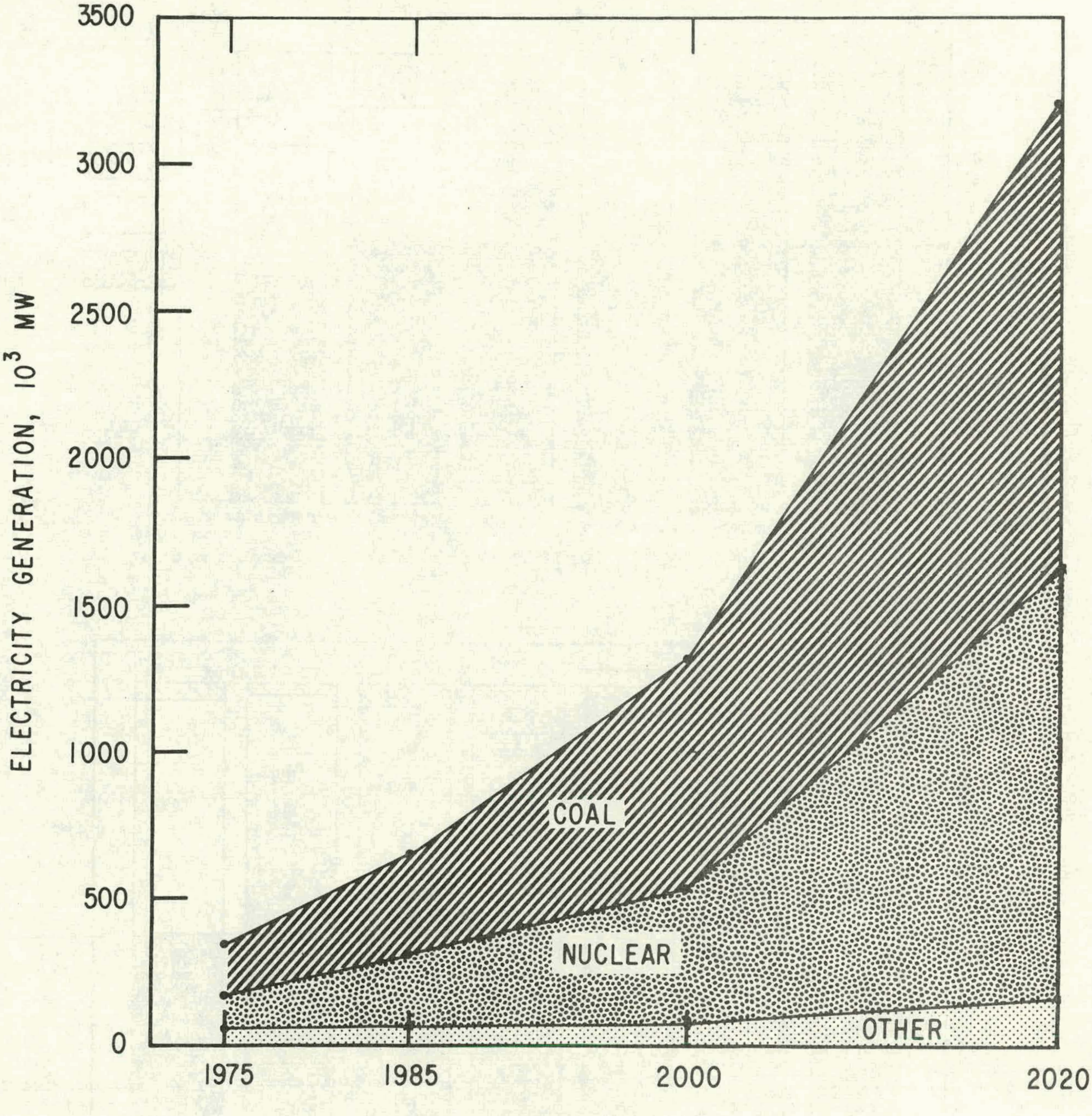

Fig. 1.2 Baseline Scenarios for 6-State Total Electrical Generation Capacity

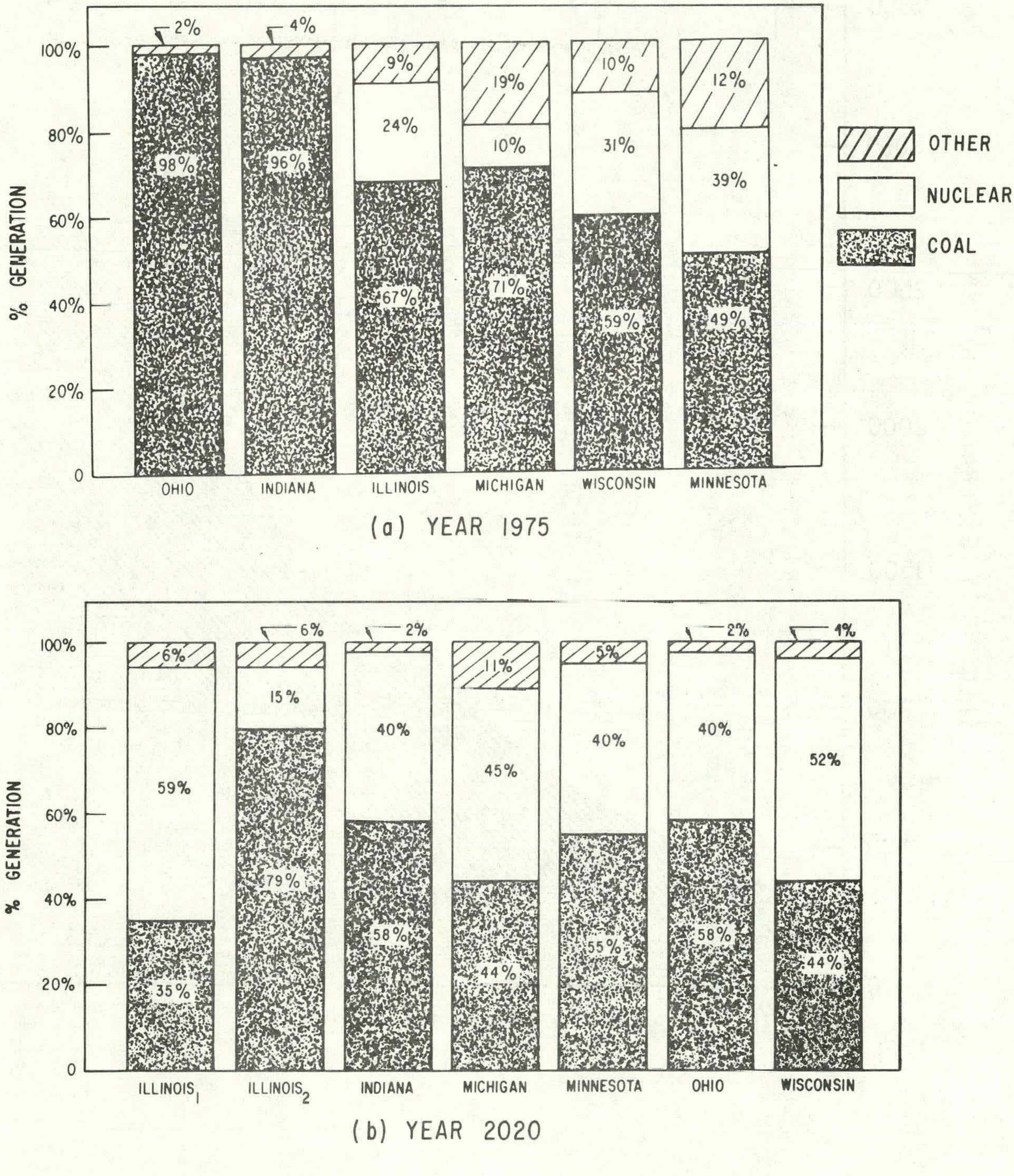

Fig. 1.3 Fuel-Mix Scenarios for Electrical Generation
(% kWh Generated by Fuel Type)

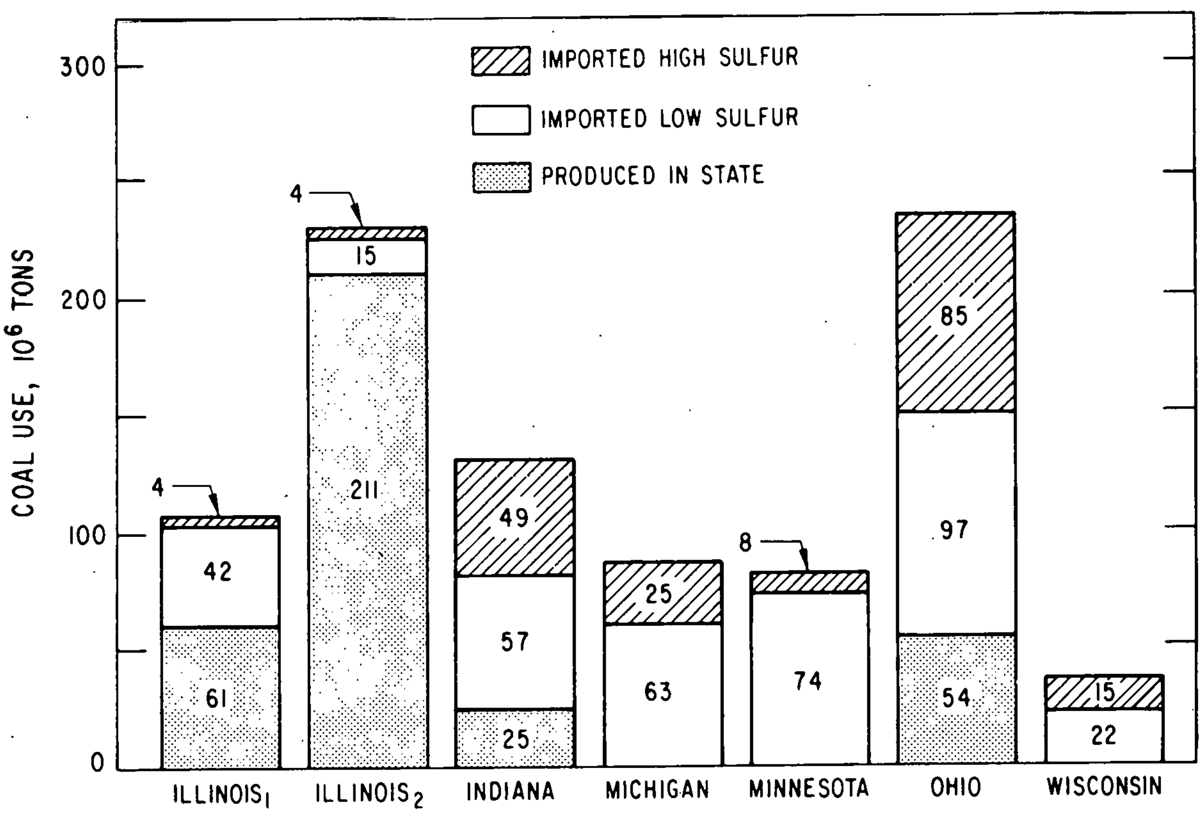

Fig. 1.4 Coal-Use Scenarios for Electrical Generation in the Year 2020

are minimal in all states but Ohio, which is close to significant deposits of such coal in Appalachia.

- Coal gasification may provide a significant source for production of synthetic natural gas (SNG). Although demand for gas (methane) is expected to grow very little, declining domestic production may create significant markets for SNG by 2000. Figure 1.5 projects the total demand for methane in the Midwest and the proportion of this demand supplied by coal gas. It shows the market for coal gas growing from 2% in 1985 to 38% by 2020.

1.3 SITING

Siting patterns for the required facilities were based on a county-level screening, which considered: (a) proximity to water, coal resources, and load centers; and (b) exclusion of areas with high population density, conservation preserves, and existing moderate to high levels of air pollution.

Electrical generation facilities of 3000-MW capacity and coal-gasification plants (high-Btu gas) of 250 million scf/day capacity (which are nearly equal in energy output at the plant) were used as standard capacities for new sites. The assumed 3000-MW capacity for electrical generation is consistent with current trends in projected baseload capacity additions. The assumed size for the gasification facilities conforms to most engineering design and environmental impact studies of coal gasification. Constraints on site availability may reverse this trend toward large facilities; however, the uniform assumption of large plants in this initial study was used to determine importance of those potential constraints.

The principal constraints and issues related to siting can be summarized as follows:

- Choice sites for large energy facilities that are near load centers, coal resources, and water resources are nearly exhausted and future siting will require a trade-off between these factors.
- The aggregate water supplies of the Mississippi and Ohio rivers and the Great Lakes are sufficient to supply energy needs. However, use of these water resources is constrained by heavy competition for shoreline sites and by the distance of these rivers from many of the large load centers.

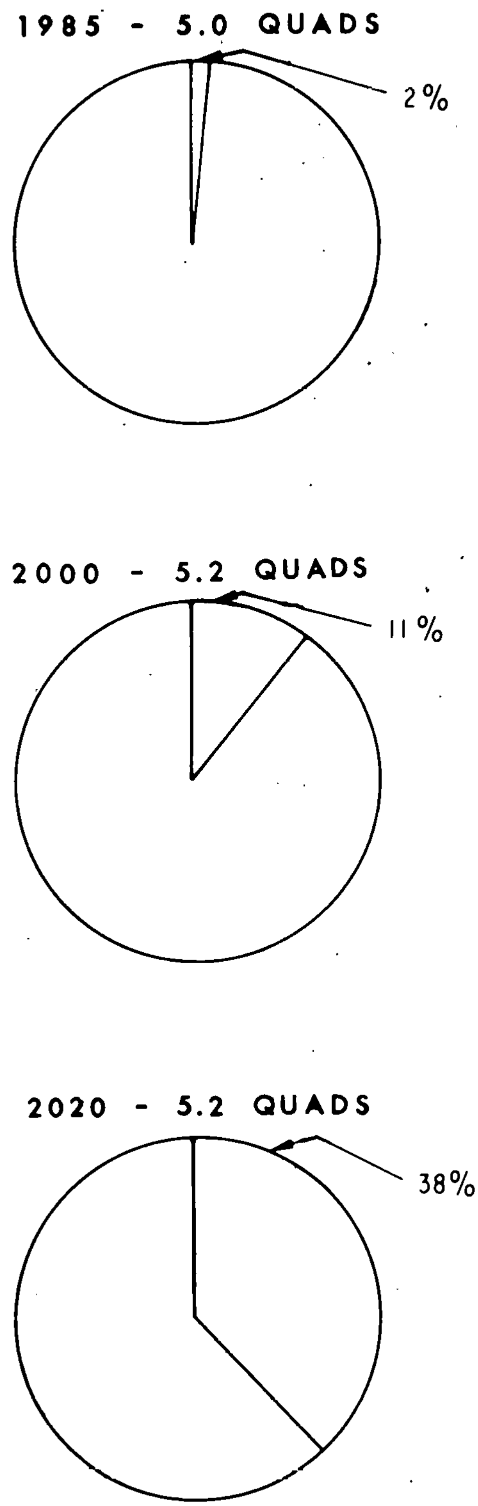

Fig. 1.5 Total Methane Demand in Midwest and Proportion Supplied by Coal Feedstock

- Separation of the available coal and water from the load centers will increase transmission requirements.

- The constraints on use of water from the major rivers and Great Lakes will make construction of reservoirs on smaller streams more attractive. The advantages of energy facilities near coal resources, many of which are far from water supplies, also encourage development of reservoirs. However, much of the six-state area is prime agricultural land; this fact must be considered in the decision on construction of the large reservoirs required.

- Most coal resources in the region are in areas of good air quality and thus pollutant concentration can be increased without violating standards. Exceptions are parts of eastern Ohio; and the Springfield, Peoria, and East St. Louis, areas in central Illinois, in which more active air-quality management is required.

- Comparison of the 1985 utility projections with the 2020 siting patterns indicates that the trends in siting implied by the above issues and constraints are, to some extent, already occurring.

We emphasize that the results of this analysis partly depend on the siting criteria and procedures used. The constraints of 7-day/10-year low flow were the most restrictive because of the assumption that new plants were 3000 MW and would primarily use wet cooling towers, which consume large volumes of water.

The analysis did not deal with site-specific issues at the subcounty level. The occurrence of sensitive ecosystems such as aquatic spawning grounds is one such issue. Others are the amenability of the subsurface soil conditions to facility construction or existence of flood plains along river shorelines. Nor were the socioeconomic impacts of facilities considered. State-to-state energy transfers may also be significant in determining siting patterns.

1.4 AIR-QUALITY STANDARDS

Evaluation of potential constraints on coal utilization imposed by air-quality standards includes first, consideration of current and projected ambient background concentrations; and second, an analysis of increments of air pollutants attributable to the coal-related processes.

Ambient background concentrations were characterized qualitatively by designating each county in the region as belonging to one of the following categories. (The categories are listed in order of decreasing constraint on coal-related energy developments. If more than one category applies to a county the most severe constraint is assumed):

- Air quality Maintenance Areas (AQMAs)
- Monitored Ambient Standard Violation
- High Projected Emission Density
- Moderately High Projected Emission Density.

A county in one of the above categories is not necessarily eliminated as a site for coal conversion or electrical generation, but finding acceptable sites would be increasingly difficult in counties with more severe constraints.

Of the 111 counties in Illinois, Indiana, and Ohio with coal resources, 12 have been designated as AQMAs by the U.S. Environmental Protection Agency. This designation indicates that these counties either now have problems in meeting National Ambient Air Quality Standards (NAAQS) or expect problems in maintaining them because of projected growth or development.

An additional 12 counties not designated as AQMAs have had monitored violations of NAAQS and were thus placed in the second category. In each county there had been violations of the standards for total suspended particulate (TSP). Some violations of the standard for sulfur dioxide occurred, but only at sites where TSP standards had also been violated.

By using a simplifying assumption that background emissions will increase in proportion to population, an additional 32 counties in the coal resource regions were projected by 2020 to be in the third and fourth category with moderate to high emission densities (defined as approximately equal to or greater than emission densities in AQMA counties or counties having standards violations).

Thus, in half of the counties in the region with coal deposits, air pollution may be a limiting factor for siting coal facilities in the next 40-50 years.

The evaluation of increments in air pollution included an analysis of (1) impacts from single facilities, (2) impacts from a cluster of electrical generation facilities, and (3) cumulative impacts from all facilities in the region. All electrical generation facilities were assumed to emit pollutants at the rate allowed by current New Source Performance Standards (NSPS). The results for TSP and SO_2 are compared with standards in Tables 1.1 and 1.2. These results indicate that, even with the upper emission level of the scenario for Illinois High Coal Use, the estimated increments in ambient pollutant levels from the coal-based energy generation will not cause violations of the annual average NAAQS if areas with existing high concentrations are avoided in siting. Similarly, annual average increments from coal facilities in areas designated as Class II under proposed regulations for the Prevention of Significant Deterioration (PSD)* do not constrain coal use, with the possible exception of large clusters of facility sites. However, the 3000-MW facilities may violate standards on the annual average increment of sulfur dioxide in areas designated as Class I according to proposed PSD regulations.

More constraining than the annual average standards are the short-term (3-hr, 24-hr) maximum standards. The 24-hr maximum NAAQS for sulfur dioxide (not to be exceeded more than once per year) are within the range of uncertainty for the impact from the single 3000-MW coal-fired facility.

The most severe constraints result from designation of Class I areas for the proposed PSD regulations. Even with reduction by a factor of 10 in emissions (and maximum concentration), electrical generation facilities may be excluded from buffer zones of 30 miles or more surrounding the Class I areas. This constraint implies use of smaller reduced facilities or development of more advanced control methods.

The percentage of the allowable increments in TSP levels from coal facilities is smaller than the percentage for sulfur dioxide. However, because existing background levels for TSP are generally nearer to those allowed by the standards, sites must be selected to minimize impacts of this pollutant. There is no short-term standard for nitrogen oxides, and the

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*PSD regulations were included in the Clean Air Act Amendments of 1977. The PSD evaluation in this report was based on information available at the time of analysis and represents the potential constraint to siting resulting from numerous Class I PSD areas.

Table 1.1. Comparison of Air Quality Standards for SO_2 with Concentrations Resulting from Coal Utilization

	Maximum Concentration, μg/m³		
	24-hr Max	3-hr Max	Annual Average
NAAQS	365	1300	80.0
PSD Class I Increment	5	25	2.0
PSD Class II Increment	100	700	15.0
3000 MW at NSPS	250-490	380-760	2.4[a]
12 x 3000 MW Cluster at NSPS	450-900	690-1360	19.0[a]
250 x 10^6 scf/day Gasification	21-25	32-38	0.2
Illinois High Coal Use Scenario (2020)			5.9

[a]60% Load Factor.

Table 1.2. Comparison of Air Quality Standards for Particulates with Concentrations Resulting from Coal Utilization

	Maximum Concentration, μg/m³	
	24-hr Max	Annual Average
NAAQS	260 (150[a])	75 (60[a])
PSD Class I Increment	10	5
PSD Class II Increment	30	10
3000 MW at NSPS	21-41	0.2[b]
12 x 3000 MW Cluster at NSPS	37-74	1.6[b]
250 x 10^6 scf/day HYGAS	1.8-2.1	0.02
Illinois High Coal Use Scenario (2020)	-	0.5

[a]Secondary Standard.

[b]60% Load Factor.

annual standard would have minimal effect. Nitrogen oxides and other constituents of power-plant stack gas may affect the generation of photochemical oxidants, but results are too inconclusive to allow assessment of future constraints. Coal facilities produce carbon monoxide pollution, but the levels are insignificant when compared with that allowed by the standard. Current air-quality regulations put fewer restraints on siting of gasification plants than on power plants. Full assessment of the impact on air quality from coal-gasification emissions will require further evaluation of other potentially hazardous emissions.

1.5 HEALTH EFFECTS

There is increasing evidence that sulfate aerosols formed from sulfur emissions endanger the health of the exposed population. Furthermore, sulfates may have widespread impact because they remain in the atmosphere five days or more before removal by natural processes. For example, Fig. 1.6 illustrates emissions resulting from the scenario for Illinois high coal use in 2020. Although the relationship between dose rate and mortality for human exposure to sulfates has not been firmly established, a preliminary model estimates that the approximate 1.0 $\mu g/m^3$ increment in Fig. 1.6 for the populous Northeastern U.S. would increase the mortality rate by 0.25%.

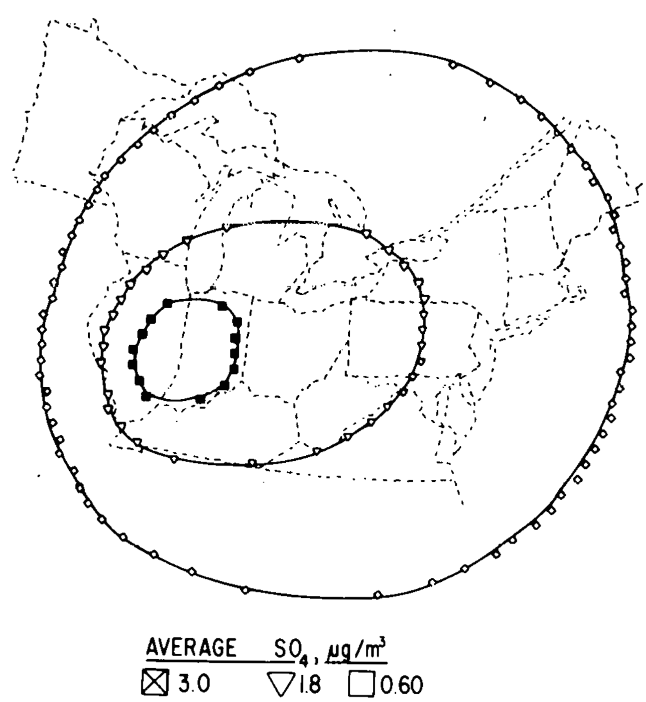

Fig. 1.6 Cumulative Long-Range Sulfate Concentrations for Illinois High Coal Use Scenario

Emissions from coal-conversion facilities contain many other pollutants, which, at high enough concentrations, cause adverse health effects either individually or in combination with other environmental conditions. However, information is insufficient to evaluate the impact of these pollutants at the low concentrations produced from coal use. A brief qualitative discussion of these potential health impacts is presented in this study report.

1.6 IMPACTS OF WATER CONSUMPTION

For each major river basin in the six-state area, water availability for future energy development was evaluated. The evaluation included a calculation of direct water requirements for the projected facilities for steam power generation and for coal gasification and a comparison of requirements with natural availability. Wet cooling towers and moderate water-conservation practices for coal gasification were assumed. For the initial analysis, the 7-day/10-year low flow at the mouth of each basin was used to represent the natural availability. The results of the analysis are summarized in Table 1.3 for the major regional hydrological basins. These results show that the aggregate water resources of the Great Lakes and Ohio and Mississippi Rivers are adequate to supply the overall energy-production requirements. However, a more detailed evaluation of subareas reveals potential conflicts with other water users and, as discussed in Sec. 1.3, natural flows are deficient in regions that are attractive for energy facilities because coal resources or load centers are near.

To illustrate the potential areas of specific conflicts in water use, more detailed evaluations were conducted for the Rock, Illinois, and Kaskaskia River Basins in Illinois. (These evaluations were for the Illinois High Coal Use Scenario to emphasize the relationships to coal use.) The results are shown in Table 1.4.

Water supply will be sufficient to support the projected energy developments on the Illinois and Rock Rivers in 2020, mainly because of abundant surface and ground water in these basins and development of potential reservoirs. However, increasing uses could reduce stream flow enough to cause conflicts in demand.

Table 1.3. Energy Facilities and Related Water Consumption for Major Regional Basins

WRC Aggregated Subareas	Basin	Total Electrical Generating Capacity, MW[a] 1980	2020	Coal Gasification Capacity in 2020, 10^6 scf/day	Related Water Consumption in 2020 cfs	% 7day/10yr low flow	7day/10yr low flow[b]
401	Lake Superior	2,522	14,136	-	178	-	-
402-404	Lake Michigan	22,520	73,006	-	919	-	-
405	Lake Huron	3,682	25,696	-	324	-	-
406-407	Lake Erie	19,574	92,209	-	1,162	-	-
502,503 506,507	Ohio River	43,594	207,398	2,500	2,625	5.8%	45,000
701-705	Upper Mississippi River	50,114	167,693	2,250	2,211	4.6%	48,500

[a]Does not include portions of basins outside study area.

[b]Represents low flows of cumulative basin discharge, i.e., the low flow of the Ohio and Mississippi Rivers at their confluence near Cairo, Illinois.

Table 1.4. Water Requirements and Availability (cfs) in Selected River Basins for Illinois High Coal Use Scenario (2020)

	Illinois	Rock	Kaskaskia
Consumption			
Municipal and Industrial	1,908	178	203
Agricultural	420	1,056	436
Mining	23	3	6
Electrical Generation and Coal Gasification	815	202	45
TOTAL	3,166	1,439	690
Instream Uses			
Hydroelectric Power	9,366	14,210	0
Commercial Navigation	3,140	0	337
Recreation, Fish, and Wildlife	10,680	3,452	542
Water Quality Management	510	1,594	25
Water Availability			
Stream Flow			
7-day/10-yr Low Flow	3,600	1,440	120
Median Flow	21,870	4,300	1,460
Lakes and Reservoirs	3,232	0	193
Ground Water	5,750	3,495	428

The Kaskaskia River Basin has a smaller water supply than the Illinois and Rock River Basins and higher water demand. If the water demand of the energy scenario for the year 2020 is to be met, serious conflicts in water use could arise. Thus, alternative technologies, siting restrictions and/or increase in water resources (e.g., importation from other basins or regulation of stream flows by reservoirs) should be sought.

In summary, for the siting requirements of the energy scenario beyond the year 2000, total water supplies are adequate but water-resource management in the region may increasingly require construction of reservoirs, use of dry cooling towers, or other water-conservation methods in selected subareas.

These energy demands will also increase pressure to use Great Lakes water; doing so would require more emphasis on sound management of coastal zones. The impacts and constraints associated with use of the Great Lakes water were not considered in detail in the study.

1.7 IMPACTS ON WATER QUALITY

In coal facilities, waste streams result from cleaning of stack gases; softening, neutralization, and demineralization of boiler water; blowdown from plant processes; cooling and cleaning of raw gases; quenching of gasifier ash and removal of slurry; runoff from coal storage piles; and other sources. Effluent concentrations were estimated for these waste streams and, as an initial indicator of potential pollution, the cumulative loadings for significant pollutants were calculated for each major river basin in the study area on the basis of the projected siting patterns. As with the effects on water use, the nature and extent of effects on water quality from these loadings is area-specific, depending on the existing water quality and the hydrologic characteristics of the receiving water.

To illustrate the impacts on water quality of these pollutant loadings, analyses were made for the Illinois and Kaskaskia Rivers in Illinois. Both rivers flow through the areas of Illinois coal resources and represent a range of high and low flow rates. The results are summarized in Table 1.5. The standards indicated are based on use of the river for aquatic life, agriculture, industry, food processing, public water supply, and primary contact uses.

We conclude from the study of the Illinois River and a similar study of the smaller Rock River in Illinois that coal-burning power plants will probably not seriously reduce water quality if (1) the discharges comply with the New Source Performance Standards (NSPS), and (2) receiving waters have a dilution capacity equivalent to these rivers. These results are strengthened by the fact that the analysis was based on the upper limit of coal use in Illinois represented by the high coal use scenario.

The NSPS for coal-conversion facilities have not been established. For this analysis, approximate pollutant loadings were used for the Kaskaskia River, where two gasification plants and one power plant would be sited in the 2020 scenario. A significant effect on water quality was found (see

Table 1.5. Impacts of Coal Conversion on Water Quality in Selected Rivers for High Coal Use Scenario (2020)

	Illinois River[a]		Kaskaskia River[b]		
	Background	Increment	Background	Increment	Standard
NH_3, mg/l	0.7-5.0[c]	0.001-0.004	0.15-3.3	1.0-2.6	1.5
Cl "	30-60	0.90-0.38	33-70	3.4-9.0	250
SO_4 "	37-100	0.21-0.81	-	1.7-4.4	250
Cyanides "	-[d]	-	-	0.014-0.135	.01
TSS "	-	0.04-0.17	-	2.7-7.2	15
Cd, μg/l	0.01-2.3	0.009-0.035	4.72	0.8-2.0	10
Cr "	0.01-130	0.5-1.9	-	0.8-4.2	50
Cu "	30-160	0.29-1.13	49	2.7-7.2	20
Fe "	630-1800	0.29-1.13	-	410-1078	300
Zn "	48-160	0.37-1.43	-	8.2-21.6	1000
Pb "	-	0.009-0.035	-	423-1118	50
Phenols "	-	-	1.4-6.0	50-130	1

[a] 37,255 MW capacity from coal at NSPS (where applicable); 70% load factor.

[b] 1858 MW capacity from coal at NSPS (where applicable); 70% load factor; 500 x 10^6 scf/d gasification.

[c] Underlined values exceed standards.

[d] Data not available.

Table 1.5); the effect is due in part to the low flow volume of the river and in part the high effluent loading, particularly from the gasification plants. The assumed effluents from these plants would contribute to violation of standards for phenols, cyanide, ammonia, copper, and lead, especially during low flow. The actual impact levels are uncertain because of lack of data for effluents from gasification facilities; thus further studies to remove those uncertainties are needed.

Drainage from mining areas and seepage from waste-disposal sites and holding ponds could seriously pollute both surface and ground water. Further assessments are required to determine their possible impacts.

1.8 IMPACTS OF COAL EXTRACTION ON TERRESTRIAL ECOSYSTEMS

Analysis of the impacts of surface and deep mines showed that deep mining in southern Illinois would have less ecological effect than would surface mining. Impacts from deep mines result primarily from the deposition of gob and slurry during coal preparation. Land used for this deposition cannot be used for other purposes, and acidic runoff from gob piles damages local vegetation and pollutes the watershed.

Unlike deep mining, surface mining disrupts large areas. From 1975 to 1985, strip mining to supply a 3000-MW coal-fired power plant was projected to require an average of 440 acres per year in seven Illinois counties. Acreage mined to supply the same plant will increase as thinner coal seams are mined.

In general, wildlife of deciduous forests are expected to be more permanently affected by surface mining than are species that inhabit prairies and agricultural pasture lands. Since most current reclamation amendments require return of mine spoils to a grassland or a mixture of agricultural pasture and grain crops, wildlife species typical of prairies are expected to recolonize the mined area once reclamation is complete. Vegetation and wildlife typical of mature, deciduous forests are not expected to become established on mine spoils for 50-100 years if secondary succession is allowed to take its course. Reducing the acreage of upland deciduous forest and forest edge will eliminate habitat for such common game species as the fox squirrel, gray squirrel, eastern cottontail, and white-tailed deer. Songbirds, such thrushes, woodpeckers, the red-eyed vireo and ovenbird will also be displaced from forested areas being mined.

The effect on agricultural land of strip mining will be less and will be more temporary than the effect on forests. Following is the projected disturbances in 2020 of agricultural land; the projections are based on the Illinois High Coal Use Scenario.

County	Total Acres in Row Crops	Total Acres Disturbed	Area Disturbed, %
Gallatin	133,550	668	0.5
Jackson	128,124	128	0.1
Madison	254,821	255	0.1
Perry	89,262	179	0.2
Randolph	156,987	314	0.2
St. Clair	244,670	245	0.1
Williamson	29,975	60	0.2

Under current Illinois reclamation laws, most of this land will be returned to some form of agriculture. Rapid establishment of high-income crops, such as corn, soybeans, and oats, will require extensive fertilization. Return of strip-mined land to row-crop agriculture may require 10 years from the time of first disturbance. Initial reclamation will be mostly to grasslands. The changes in land use and the associated ecological and economic impacts from increased strip mining are the major issues to be considered before future mine development. The changes in land use will cause the greatest impact on terrestrial ecosystems resulting from increased coal mining in southern Illinois. The entire land-use issue warrants extensive study to accurately predict the long-term impacts of surface mining.

1.9 IMPACTS ON AQUATIC ECOSYSTEMS

Impacts on specific aquatic ecosystems from development of coal mines and preparation plants depend on the location of coal reserves and types of mining. Impacts of premining activities (e.g., vegetation removal, construction of haul roads, and pit excavation) are expected to be negligible if erosion is controlled. Impacts from operations have resulted from off-site disposal of mineral-laden effluent pumped to local waterways from sumps in low areas of the mine pit. In some of southern Illinois, as in Saline County, acid mine drainage has caused pollution. These discharges are now chemically treated, the acid is neutralized, and resulting effluent is passed through settling basins to prevent damage to the local water and the aquatic biota. Thus, acidic mine drainage from future individual mines should not endanger the biota.

The analysis of impacts on aquatic ecosystems considered the possibility of atmospheric emissions from combustion being deposited and entering surface waters through runoff or leaching. The likelihood of significant increase in surface water acidity from this mechanism is considered low. A conservative (worst-case) estimate of deposition of the atmospheric pollutants indicates a possible measurable increase in trace elements, however.

No adverse impacts on aquatic biota are expected from cooling water for electrical generation. In all locations the volume of makeup water required and the size of the intake structure indicate that impacts from impingement and entrainment should be negligible. Construction of the blowdown-discharge structure may cause a temporary adverse affect on some benthic invertebrates. Localized thermal gradients will be established near the discharge structure but are not expected to adversely affect fish or most other aquatic biota. No far-field impacts on aquatic biota from trace elements in aqueous effluents, impingement, entrainment, or thermal effects are expected from a single electrical generation plant. For power plants sited on reservoirs these impacts are expected to be limited only to the reservoir.

The number of new surface mines in certain parts of the three river basins may be limited, however, by lack of enough dilution water in some headwater streams to insure that water quality standards are maintained. From typical assumptions of stream flow rates, discharge effluent standards, and mine effluents discharged into local waterways, the following number of new surface mines with 1000-gpm discharge are considered feasible within the next 50 years for the three drainage basins: Kaskaskia River, 10; Big Muddy River, 5-10; and Saline River, none.

Creation of impoundments and final-cut reservoirs on surface-mined land provides new habitat for fish and wildlife. In the Kaskaskia and Saline River drainage basins strip mining has increased the amount of aquatic habitat by more than 300%. The creation of final-cut reservoirs is not expected to greatly alter the distribution patterns of winter resident water fowl. The biological productivity and water quality of these reservoirs need further study. The potential long-range uses of the reservoirs can be determined only after considerable data on social, economic, and environmental effects are obtained and analyzed.

1.10 ECOLOGICAL IMPACT OF ATMOSPHERIC POLLUTANTS

Analysis indicated that sulfur dioxide is the only primary gaseous pollutant resulting from operation of a 3000-MW plant, sited singly or in clusters, that may have measurable ecological impacts. For a single model plant, based on 24-hour maximum emission values, the total area in which acute visible injury to sensitive vegetation may occur is about 608 acres. For twelve clustered 3000-MW plants, sensitive vegetation could be injured in more than 22,000 acres. The area in which threshold to severe injury to sensitive vegetation may occur would approach 6400 acres. In each impacted area visible injury would be in the form of leaf necrosis or chlorosis. The severity of the impact would be directly related to the percentage of area of the particular vegetation that is injured. Regional agricultural species sensitive to sulfur dioxide include alfalfa, barley, oats, rye, wheat, and soybeans. Damage by sulfur dioxide to agricultural crops would make a cluster of 12 plants environmentally unacceptable.

The impact analysis of atmospheric particulate concentration and depositions dealt only with arsenic, beryllium, cadmium, fluoride, lead, and selenium. For clustered siting, arsenic may adversely affect vegetation of low tolerance (e.g., soybeans). Impacts on vegetation are uncertain, however, because of the conservative assumptions and other uncertainties of the analysis. Beryllium deposition is not expected to damage vegetation, nor are cadmium emissions, unless endogenous soil levels are just below toxic levels or other sources of cadmium pollution are entering the region. Because cadmium is not readily excreted from mammals, possible adverse effects to the food chain should not be ruled out. Fluoride emissions are expected to result in some detectable damages to vegetation. Foliar damage to species such as sorghum, fruit trees, and conifers may result from clustered siting, but the damage is not expected to result in a major economic loss since these species are relatively uncommon. No adverse impacts on biota are anticipated from deposition of lead or selenium oxides.

1.11 *DIRECTIONS FOR FUTURE STUDIES*

Because of the broad range of complex issues related to future utilization of coal resources, this study has been limited to an initial analysis of selected health and environmental issues thought to be of primary significance. Further analysis is required for a more in-depth understanding of some aspects of those issues and an evaluation of methods to mitigate problems which have been identified. Also, other issues that may be significant have been considered only marginally, or not at all. Following is a partial list of the topics related to health and environmental effects that require additional evaluations in the region:

1. Although the projected coal requirement depletes only a small fraction of the coal reserve, additional evaluations are required to identify local, area-specific impacts of increasing rates of extraction. To be included are additional evaluations of the impacts of land-use requirements, possible flow of pollutants into surface and ground waters, and the probability of success of reclamation practices.

2. Results in this study indicate that standards for short-term ambient-air quality standards, in particular regulations for Prevention of Significant Deterioration, may limit options for future coal utilization. Further studies are required to assess the relationships between state and Federal policies for designating Class I areas, timing of new methods for reducing emissions, and availability of sites not in the vicinity of Class I areas. Improved models for evaluating short-term pollutant concentrations are also required.

3. Strategies for mitigating potential long-range impacts of sulfates should be considered.

4. The potential regional health and environmental effects of trace elements and other hazardous substances in atmospheric and water effluents must be more fully identified so that research and technology development may be started.

5. The overall regional water quality will apparently not be significantly affected by coal utilization, if available pollution control methods are used. However, further evaluation is required for possible local effects from intense development in limited areas, reduced capacity to assimilate municipal and industrial wastes because of energy related water consumption, and runoff from waste disposal sites.

6. Because of the limitations on water supply in the regional river basins, development of alternative water resources or use of water-conservation measures need consideration. Included would be possible roles of once-through cooling, dry cooling towers, reservoirs, and increased use of Great Lakes water.

7. Not considered in this study are the possible impacts in the Midwest of the increased coal transportation by rail, barge, and possibly slurry pipelines. Also, impacts from development of right of ways for electrical transmission lines and gas pipelines were not evaluated.

8. Further consideration of the regional impacts of synthetic-fuel plants on terrestrial and aquatic ecosystems is required before widespread plant construction. However, the current incomplete knowledge of the effluent characteristics and their health and environmental impacts would limit these studies.

9. Ground-water pollution by disposal of solid waste (e.g., fly ash and bottom ash) and the impact of contaminated ground water on surface water should be considered.

10. Studies of the ecology, sociology, and economics of final-cut reservoirs should be conducted to evaluate the impacts of these reservoirs before their development from new strip mining.

11. Studies on the immediate and ultimate land use of strip-mined lands should consider the economic and ecological costs and benefits of the various potential reclamation alternatives for the region.

12. Industrial uses are a significant fraction of the total coal consumption in several industrial states, such as Ohio and Illinois. Further evaluation is required of the potential future extent of this consumption and the environmental acceptability of coal processes available, or under development, for industrial application.

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2 CHARACTERIZATION OF COAL TECHNOLOGIES

2.1 INTRODUCTION

The coal fuel cycle is generally considered to have five distinct phases -- extraction, transport of coal, conversion, transmission of conversion products, and end use. Of course, in any given path of energy delivery, all phases need not be distinctly considered. (For example, conversion may occur at the point of extraction, or end use at the point of conversion.) This preliminary assessment focuses on extraction and conversion, from which the major impacts on health and environment result.

The discussion in this section is limited to characterization of the conversion technology, including electrical generation and synfuel production. Extraction as it relates to surface-water contamination is discussed in Sec. 6 and in Vol. 2.

Data for the characterizations were obtained from many sources. Although many values are similar to those produced for use in the DOE-sponsored National Coal Utilization Assessment, they are not identical.

Where the technology characterizations required specification of single coal parameters, it was assumed that these parameters were representative of the Central Interior Province coal. See Table 2.1, which also includes, for comparison, parameters for Northern Great Plains coal and solvent-refined coal (SRC) referenced in this section.

Coal conversion can be grouped into two categories; combustion, usually involving boilers, and synfuel production, in which coal is destructively hydrogenated to produce cleaner fuels. Combustion methods are considered as they are used in electric power production and as auxiliary energy sources for synfuel production. Figure 2.1 shows the general paths of this production. Production of SNG (high-Btu gas) and coal liquid will be considered; production of fuel gas (low Btu) and solvent refining of coal will be described briefly as they relate to electric power production.

The technology assumed to be used is generally that which represents the current state of the art and that reasonably expected to be commercially available in the next fifteen years--processes for which sufficient design and test data are available. Many unique methods for producing synfuels and

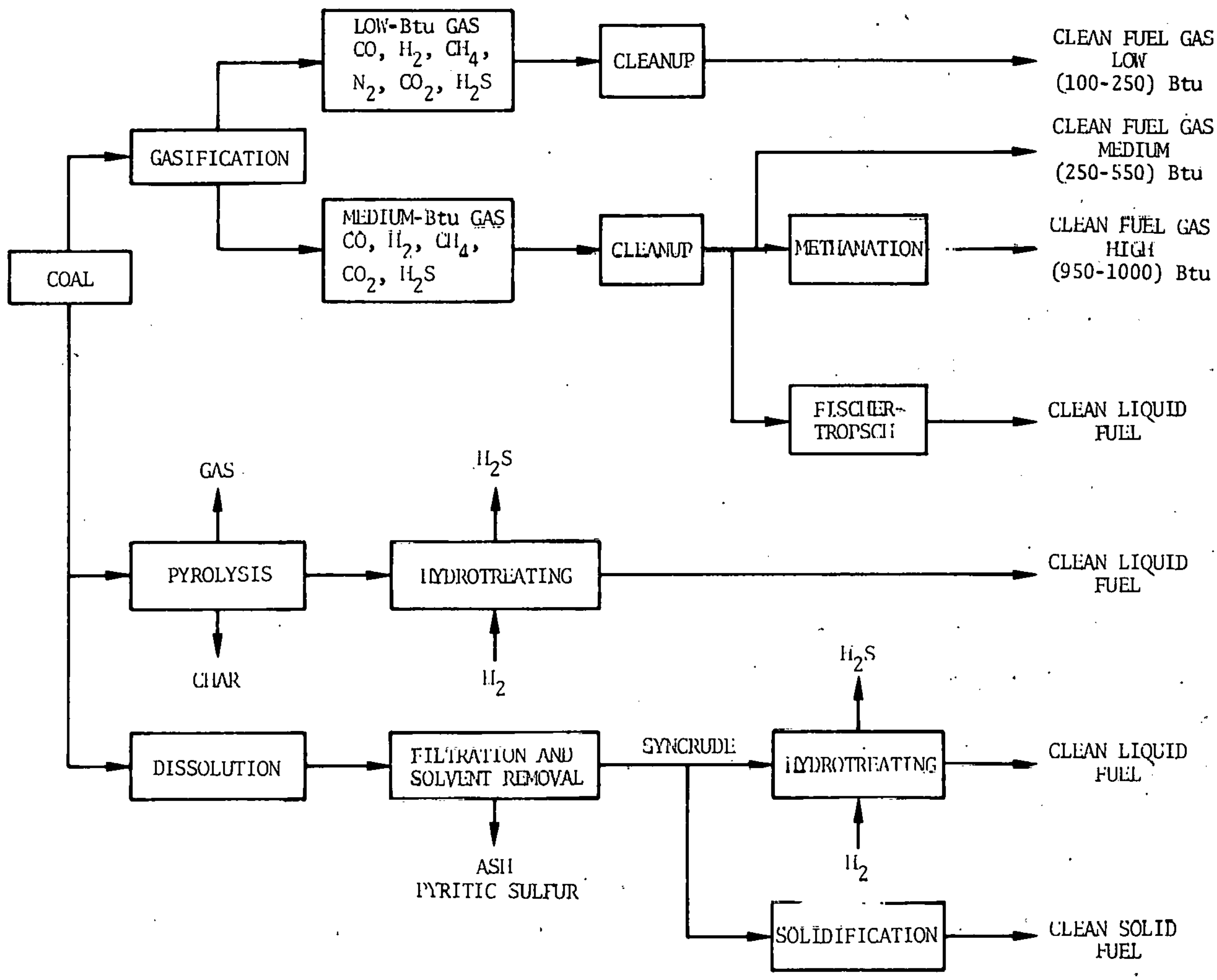

Fig. 2.1 Paths for Synfuel Production

Table 2.1. Characteristics of Regional Coals and SRC: Proximate and Ultimate Analyses (wt %)

(Regional coal data are geometric means of many samples)

	Coals		
	Central Interior	Northern Great Plains	SRC
Moisture	5.9	26.4	10.8
Volatile Matter	30.9	28.9	63.2
Fixed Carbon	46.3	35.6	25.8
Ash	10.7	9.1	0.2
Hydrogen	4.9	6.4	5.9
Carbon	64.3	49.0	87.9
Nitrogen	1.2	0.7	2.2
Oxygen	10.7	34.3	3.1
Sulfur	3.0	0.5	0.7
Btu/lb	11,440	8,440	16,250
(J/gm)	(26,607)	(19,630)	(37,795)

Data from Ref. 1.

electric power now in the conceptual stage are not included. Potential benefits and impacts of more advanced technologies will be assessed in later studies. All conversion processes require two key natural resources -- coal and water. (In some processes, control of sulfur emissions requires, in addition, limestone, dolomite, or lime). The quantity of coal required obviously is related directly to how much output energy is required and the overall plant efficiency. The efficiency of conversion varies significantly among the conversion processes; generally, the higher the quality of the product energy, the lower the overall efficiency.

Electric power production is the least efficient because of the inherent (by the second law of thermodynamics) limitations on the efficiency of a condensing steam (Rankine) power cycle. Thus, although the efficiency of energy conversion from coal to heated steam is high (90% or better), and a steam turbogenerator is very efficient (95%), the overall plant efficiency never exceeds 40%. More advanced, noncondensing power cycles, such as combustion turbines or magnetohydrodynamics (MHD), may raise this efficiency to as high as 50%. Conversion of coal to synfuels, on the other hand, is more efficient; the less severe the temperature and pressure in processing, the higher in general is the conversion efficiency. Production of synthetic natural gas can be thought of as the most extreme or thorough processing of coal into a very clean synfuel with a high energy density; efficiencies of various conversion processes vary with design details but are usually 55-65%. If less hydrogen is used in the synfuel process, heavier liquid or solid products result; but the benefit of making these less refined products is an overall process efficiency of 65-75% or, possibly, slightly better. Manufacture of fuel gases of low energy density (low-Btu gas) has similar efficiency advantages. The simplest and most efficient processing of coal is chemical washing to remove only pyritic sulfur; the overall conversion efficiency is just over 80%.

Water is a critical environmental factor for all coal-conversion processes; all use water to make either electric power or synfuels, and they all require cooling of process streams, usually (at least in part) by evaporative cooling. The water used in the process may be the makeup used in a boiler steam circuit, or it may be used directly in synfuel production. Boiler feedwater must be treated to obtain a very high purity, and the blowdown from a boiler circuit is relatively clean water, except, perhaps, for corrosion inhibitors and traces of metals eroded from tube walls. On the other hand, water that has contacted the coal, ash, or any coal-derived products is a potentially serious hazard to the environment. Process cooling may be by evaporative cooling towers, recirculating cooling ponds, or once-through cooling systems. Once-through, or run-of-the-river, cooling does not consume water by evaporation; ponds and evaporative cooling towers do. Thus, they require a continuous blowdown stream to prevent buildup of solids.

There is, in every coal-conversion process, a hierarchy of water use. Boiler feed water is the cleanest water in the plant and the blowdown from a steam circuit is used to supply some of the makeup cooling water. The blowdown from the cooling circuit is frequently used to sluice ash or sludge to a disposal pond. Water used in synfuel production must be treated before it is suitable for any reuse within the facility; this water is subsequently used in the cooling circuit or for ash handling. The amount of water consumed in coal conversion depends mainly on how much evaporative cooling is required, since the quantity consumed within the conversion process or elsewhere in the plant is small by comparison.

Some of the environmental pollution problems of conversion are common to all coal utilization: the results of storing and handling coal, treating water, and disposing of solid wastes. Coal storage piles must be carefully constructed so as to capture all water runoff (to prevent the many toxic leachable materials in raw coal from reaching ground or surface water). For synfuel plants, control of runoff should extend to the whole plant because leaks and spills of toxic substances are possible. Coal handling causes dust that must be controlled, by either wetting it or removing it by filters. Such preventive measures are common at modern coal-conversion facilities. The coal is crushed to a size suitable for combustion or other conversion is in grinding machines that are sealed because the crushed coal is usually conveyed from them pneumatically. Synfuel conversion frequently requires that the coal be dried before use; the flue gas from coal drying must be filtered for particulate removal; and, if coal combustion is the source of heat for drying, sulfur removal may also be necessary.

Many similar problems in ash disposal arise. Fly ash recovered from the flue gases of combustion boilers is usually conveyed pneumatically to a pond or taken from the plant site for use in paving and construction materials. Bottom ash from boilers and gasification processes is usually quenched with water and sluiced to a storage pond. In coal-liquefaction processes, most of the coal ash is in the form of a filter cake or sludge that is also sluiced to a storage pond. The ponds of ash represent a potential long-term environmental hazard, because toxic substances leach out and seep into ground and surface waters. Although the ash has less leachable, harmful elements than raw coal, the ultimate hazard is probably far more serious because the hazardous material is leached more easily from ash. For conversion facilities near a supplying mine much of this problem can be avoided by burying the ash. Disposing of sludges from water treatment has problems similar to those in ash disposal. Disposal problems result from the use of limestone scrubbers for flue gas to remove sulfur. These scrubbers generate enormous volumes of thixotropic sludge. However, in processes under development, filtration of the sludge, followed by chemical stabilization, can decrease the water content and permeability enough that the sludge could be used for land fill.

All coal-utilization processes reject large amounts of heat to the environment. In power production from steam, or any other steam cycle, this heat rejection is thermodynamically essential. In synfuel production, heat rejection is required not only in the auxiliary steam power plant but also in processing the product gases and liquids. The key to synfuel process efficiency is, in large part, minimizing this loss of processing heat. Heat is not generally considered a pollutant, except when it is discharged to a body of surface water; thus, only in steam electric power plants using once-through cooling is the heat discharge analyzed for environmental effects. All closed-cooling circuits using towers or ponds have blowdown, necessary to control solids buildup. This blowdown stream must be disposed of by return to the environment -- either directly from the cooling circuit or after other use within the plant and subsequent treatment. With current technology, cleaning and recycling this stream, with its high solids content, are not feasible.

2.2 ELECTRIC GENERATION

For this assessment, production of electric power from coal is considered to be represented by a boiler burning pulverized coal, with an electrostatic precipitator and a flue gas desulfurization (FGD) unit, if high-sulfur coal is used. Details of the boiler design are not important in this assessment; it would be essentially a state-of-the-art, tangentially fired boiler with a 1000°F, 2500-psi single-reheat steam cycle. The unencumbered plant efficiency (without FGD or closed-cycle cooling) is about 38% (8970 Btu/kWh, or 2520 kcal/kWh) during the hottest summer days. At less than full rated power output, the plant efficiency would drop another percentage point or two. With FGD and a closed cooling system, the plant would have an annual average overall efficiency of about 35% (9650 Btu/kWh, or 2432 kcal/kWh) in base-load service.

The nominal size of a new coal-fired power plant could be 500-1000 MW, the size depending primarily on the total size of the utility system in which it is placed; for this assessment we assume 1000 MW per unit and three units per site, for a total site capacity of 3000 MW. The size and the efficiency together determine the rate of coal and cooling-water consumption. The rate at which particulate matter and sulfur oxides enter the flue gas is directly proportional to the rate of coal feed to the furnace, since 90% of the ash in the coal and essentially all of the sulfur leave with the flue gas in this type of boiler. The fly ash is collected by the precipitator operating at better than 99% (by weight) efficiency and then conveyed pneumatically to storage. The smaller amount of bottom ash is quenched and sluiced to a storage pond; the same pond is used to contain sludges from process-water treatment. The coal sulfur, released as sulfur dioxide, can be collected by an FGD or a scrubber system. The remaining criteria pollutants, oxides of nitrogen, can be controlled only by modification to the burners and combustion zone of the boiler; there are no demonstrated techniques for removing nitrogen oxides from the flue gas of coal-fired boilers. It is assumed that federal NSPS (listed in Table 2.2) are met for nitrogen oxides and that no more stringent control is feasible.

Pollution by sulfur compounds has been the focal point for measuring environmental damage from coal-fired power plants. There are three options to reduce sulfur emissions in burning coal: remove SO_2 from the flue gas, remove it from coal before combustion, or use a coal naturally low in sulfur. Burning low-sulfur coal is currently, and will be in the near future, the likely approach. In the area covered by this assessment, the only source of low-sulfur coal for steam production is the Northern Great Plains Province. The salient characteristics of this coal are shown in Table 2.1. The low heat content of this coal increases all the potential environmental hazards of coal handling and solid-waste disposal, because it must be fired at a higher rate to maintain the nominal output. Besides many operational difficulties in burning this low-quality, low-sulfur coal, the fly ash is not collected efficiently enough on conventional precipitators. We have assumed that any power plant designed to use this coal will have high-temperature precipitators to maintain a collection efficiency of 99%, or better (by weight). As shown in Table 2.2, use of this coal allows a power plant to meet, or to improve slightly on, the NSPS for sulfur emissions.

The second option for sulfur control is to use a scrubber that washes the flue gas with a solution that chemically combines with the sulfur. The general division of scrubbers into regenerable and throwaway types follows from the processing of the scrubbing liquid; in regenerable processes sulfur is removed as an acid or a solid and most of the scrubbing liquid is recycled.

Table 2.2. Air-Pollutant Emissions from Uncontrolled and Controlled Combustion ($lb/10^6$ Btu)[a]

Pollutant	NSPS	Central Interior Province Coal[b]		Northern Great Plains Coal[c]		Solvent Refined Coal, Controlled[d]
		Uncontrolled	Controlled	Uncontrolled	Controlled	
SO_2	1.2	5.2	0.8	1.2	1.2	0.9
NO_x	0.7	>1.0	0.7	>1.0	0.7	0.7
Particulates	0.1	8.4	0.1	9.7	0.1	0.1

[a] To convert $lb/10^6$ Btu to g/kcal, multiply by 1.8×10^{-3}.

[b] Assumes FGD with 85% sulfur-removal efficiency, ESP with 99% removal efficiency, and state-of-art furnace for NO_x control.

[c] Assumes high-temperature ESP with 99% particulate collection and state-of-art furnace for NO_x control.

[d] Assumes state-of-art furnace for NO_x control.

In throwaway processes, lime or limestone combines with the sulfur and sludge is disposed of. Flue-gas-desulfurization systems require parasitic energy for their operation; they reduce plant efficiency; they are, at present, less reliable than the rest of the power plant; they are expensive; and they cause problems in disposal of solid and liquid waste from their own operation. They do, however, remove 85-90% of the sulfur in the flue gas, and they may have a beneficial side effect of reducing emissions of fine particulates, although it has not yet been demonstrated. In this assessment it is assumed that a limestone, throwaway FGD device represents a near-term control method and a regenerable process represents a more advanced method. The effect on sulfur emissions is the same for both; only the solid-waste effluent varies for purposes of this study. Beyond the scope of this interim assessment, but clearly an environmental impact, is the quarrying of the large quantities of limestone needed; since about 3.3 lbs of limestone is needed per pound of sulfur removed. a 1000-MW power plant burning the 3% sulfur central interior coal of Table 2.1 will require about 2.3×10^5 tons (2.1×10^5 metric tons) per year of limestone if that type of scrubber is utilized.

Sulfur also can be controlled by limestone scrubbing in fluidized-bed combustion, in which limestone or dolomite is mixed with the coal in the fluidized bed to react with the sulfur. Although still in the developmental stage, fluidized-bed combustion may have advantages in construction costs and operating efficiencies. The result may be effective control of sulfur at the expense of a large volume of solid waste; regenerating the sulfur sorbent is not yet economically feasible. This combustion method is one of many potential future processes here considered for controlling some or several environmental pollutants at better efficiency and lower cost than FGD.

The third option for reducing the sulfur content of the coal by precombustion processing includes physical or chemical washing, solvent refining (SRC), or conversion to low-Btu fuel gas.[1] Coal washing is widely used to remove excessive sulfur and ash before combustion and may be continued in conjunction with other fuel processing or with less efficient, but cheaper, FGD units. However, in the region of this assessment, this process will not bring much coal into compliance with federal NSPS.

Solvent refining is a very mild hydrogenation of coal to produce a low-ash, low-sulfur product, SRC, which is usually a soft, low-melting solid. As shown in Tables 2.1 and 2.2, combustion of SRC results in sulfur emissions that are well within the NSPS; nor should undue problems arise with emissions of particulates or nitrogen oxides. There are some minor problems in handling SRC at a power plant, but they should present no problem for new facilities. Combustion of SRC to produce electric power should be at least as efficient a conversion process as the use of untreated coal and perhaps slightly better. Of course, the cost and energy losses incurred in production of SRC reduce the total benefits to where they are approximately competitive with first-generation flue-gas desulfurization. The future primary use of SRC may be in existing, older boilers in preference to retrofit of FGD systems or conversion to low-sulfur coal. But the use of clean boiler fuels derived from coal -- represented by SRC -- cannot be ruled out for new power plants, especially where the only economically attractive resource is high-sulfur coal.

The most extensive processing of coal before electric power production is the manufacture of a fuel gas in an air-blown (rather than oxygen) gasification process. This processing is the most complex of the options and is still in the developmental stage; but, for environmental control, it is promising in that most atmospheric pollutants can be reduced to a very low level. Because the energy density of the fuel gas is very low, it cannot be economically stored or transported. Also, because of the need for overall energy efficiency in producing electric power, it is desirable to utilize the sensible as well as chemical energy of the fuel gas in a combined cycle, a combustion turbine followed by a waste-heat-recovery steam boiler. Therefore, the production facility for fuel gas must be integrated into the power plant and have the same degree of load following. In contrast, coal washing or liquefaction can be remote from the power plant and operate smoothly without following variations in the demand for electricity. In spite of the added complexity, the potential gains in process efficiency make an integrated facility and combined cycles viable.

The fuel gas is manufactured by a process similar to those for making SNG, except that using air for combustion instead of pure oxygen dilutes the synthesis gas with nitrogen gas (but with considerable savings in cost and efficiency). The processes best suited for fuel-gas production differ from those for SNG because production of methane in the gasifier is of no importance. Therefore, more thermally efficient gasifiers can be used. But, since SNG gasifier designs are more fully developed, the first gasifiers used for power production will probably be similar; second-generation fuel-gas producers should provide more efficient, higher-temperature processes. Cleaning of the fuel gas is similar to that in making SNG, with the important exception that carbon dioxide should not be removed from the gas stream. There would be advantages in cost and efficiency in performing all the cleanup steps on the fuel gas without lowering the gas temperature, so that the sensible heat of the gas could be used in the combined cycle. Removal of sulfur compounds and nitrogen compounds (ammonia) at high temperatures is not now feasible, but procedures are under development to remove sulfur and particulates at high temperatures. The result is that near-future gasification with combined-cycle power production will use first-generation gasifiers and low-temperature cleanup, resulting in a power production facility that produces electricity at somewhat higher cost than for alternatives such as FGD but gives better environmental control. More advanced gasification processes and higher-temperature turbines may, by the end of the century, produce power from coal more cheaply than can the alternative control techniques, but with a risk of some serious problems with emissions of nitrogen oxides.

Many effluents other than oxides of sulfur and nitrogen are emitted with flue gases from combustion, especially those identified as being toxic. Fine (respirable) particles are neither well characterized nor regulated. Probably about 15% by weight of the total particulate emissions remaining after the use of an efficient electrostatic precipitator (ESP) are less than 2 μ; the distribution by size below 3 μ is not well-documented. The only methods that may be effective in controlling these fine particles are fabric filters in the flue gas or fuel-gas conversion followed by a wet gas scrubber. Whether wet scrubbers for sulfur removal from the flue gas reduce emissions of fine particulates is not clear. If regulatory standards for fine particulates were developed, other techniques and improved ESPs might be necessary for combustion processes.

The release of the many trace elements found in coal is another source of environmental hazards and data uncertainty. Table 2.3 shows the trace elements and their concentration in the representative coals of this assessment.

Table 2.3. Trace Elements in Representative Coals (Average values from many samples of whole coal)[1]

Element	Central Interior Coal	Northern Great Plains Coal	Estimated Volatility, %
Si	1.4%	1.1%	--[a]
Al	0.77%	0.59%	--
Ca	0.50%	0.92%	--
Mg	0.063%	0.245%	--
Na	0.026%	0.100%	10
K	0.11%	0.037%	30
Fe	2.3%	0.45%	10
Mn	72 ppm	34 ppm	10
Ti	0.040%	0.037%	10
As	12 ppm	2 ppm	50
Cd	0.12 ppm	0.2 ppm	60
Cu	16.3 ppm	7.4 ppm	10
F	58 ppm	37 ppm	90-100
Hg	0.10 ppm	0.06 ppm	90
Li	7.0 ppm	4.3 ppm	--
Pb	19 ppm	4.3 ppm	50
Sb	0.8 ppm	0.4 ppm	50
Se	2.8 ppm	0.5 ppm	50
Th	1.6 ppm	2.4 ppm	10
U	1.4 ppm	0.7 ppm	--
Zn	58 ppm	12.8 ppm	20
B	50 ppm	70 ppm	10
Ba	30 ppm	300 ppm	--
Be	1.5 ppm	0.3 ppm	10
Co	7 ppm	1.5 ppm	10
Cr	10 ppm	3 ppm	20
Ga	3 ppm	2 ppm	10
Mo	2 ppm	1.5 ppm	50
Nb	0.7 ppm	3 ppm	--
Ni	18 ppm	2 ppm	20
Sc	3 ppm	1.5 ppm	10
Sr	30 ppm	100 ppm	--
V	20 ppm	7 ppm	20
Y	7 ppm	3 ppm	--
Yb	0.7 ppm	0.3 ppm	--
Zr	10 ppm	15 ppm	--

[a]Nonvolatile at furnace conditions.

The concentration of these elements varies considerably between mine sources and within the supply from any one mine. Many of these trace elements are known, or believed to be, not volatile during conversion but to remain with the coal ash. But some ash does enter the flue gas and the ash that is electrostatically precipitated may be stored for long periods, during which it is subject to leaching and erosion. For all these trace elements, little firm information is available on their fate during storage or conversion of the coal or their form as they leave the process with various waste streams.

For this assessment, a 3000-MW standard facility was assumed (see Table 2.4.* The emission rates used for modeling atmospheric dispersion were chosen to be consistent with those used by the General Electric Co. in their study for the National Science Foundation (see Table 2.5). The trace-element emissions reflect the volatility estimates shown in Table 2.3, and thus are an upper limit on emissions, since precipitator capture is ignored.

Table 2.4. Plant Characteristics

Total rated capacity	3000 MW
Heat rate	8970 Btu/kWh(2260 kcal/kWh)
Stack height	244 m
Stack diameter	11.3 m
Exhaust velocity	14.2 m/s
Exhaust temperature	394 K
Load factor	60%
Ambient air temperature	293 K

*Impacts of alternative parameter values on air quality are discussed in Sec. 7.

Table 2.5. Emission Rates for the Standard 3000-MW Plant at 60% Capacity Using Interior Province Coal

Pollutant	Emission Rate $lb/10^6$ Btu input[b]	Baseline Plant Emission Rate, g/sec
SO_2	1.2[a]	2.45×10^3
NO_x	0.7[a]	1.42×10^3
Particulates	0.1[a]	2.03×10^2
CO	0.038	7.31×10^1
As	5.25×10^{-4}	1.07×10^0
Be	1.31×10^{-5}	2.66×10^{-2}
Cd	6.3×10^{-6}	1.28×10^{-2}
F	4.56×10^{-3}	9.28×10^0
Hg	7.87×10^{-6}	1.60×10^{-2}
Pb	8.3×10^{-4}	1.69×10^0
Se	1.23×10^{-4}	2.50×10^{-1}

[a]New Federal Source Performance Standards as of Jan. 1977.

[b]To convert from $lb/10^6$ Btu to g/kcal, multiply by 1.8×10^{-3}.

In coal conversion to produce electricity, water is used primarily for steam and evaporative cooling. The consumption for cooling varies greatly with cooling-system design. Once-through systems and cooling ponds are similar in that water consumed by the heat rejected by the power plant is very dependent on the surface area of the water body and local climatic conditions. The cooling pond here is assumed to cover about one acre per MW. Evaporative cooling towers are the systems most likely to be used in new power stations. Natural-draft and mechanical (forced-draft) towers both consume water at about the same rate, and are not as sensitive to variations in climatic conditions as are cooling ponds. Water consumption rates at 70% of rated capacity (see Table 2.6) are consistent with values reported by General Electric.[3]

Treatment of intake water for boiler use creates waste streams of sludge and wash water. The boiler and cooling-water circuits must have continuous blowdown streams to prevent solids buildup. Waste-water streams also flow from ash handling, FGD systems, boiler-tube cleaning, and floor drain

Table 2.6. Water Consumption by Coal-Fired Electric Power Generating Facilities[6]

Cooling Systems	Water Consumption[a] cfs
Once-Through	13
Cooling Pond	23
Wet Towers	18
Dry Towers	0.28

[a]Consumption is annual average total for a 1000-MW plant operating at an annual capacity factor of 100%.

in the plant area. For this assessment, rough estimates were made[4] of the pollutants that would contaminate waste water streams in a power plant (Table 2.7).[5] Plant sanitary sewage was not included. It was assumed that the FGD system had a closed-water circuit, except for the occluded water discharged to a holding pond. The fly ash is assumed to be handled pneumatically as specified by New Source Performance Standards (NSPS).[4] The estimates in Table 2.7 combine the pollutant loadings from the following waste streams:

- Boiler blowdown,
- Metal-cleaning wastes,
- Cooling-system blowdown,
- Ash-handling overflow, and
- Miscellaneous low-volume wastes.

Where the NSPS are applicable, the pollutant loadings have been adjusted to reflect the allowable levels of discharge.

One other main category of pollutants, discharged from fossil-fuel, steam-generated electric power plants, is thermal.[1] Waste heat is rejected during burning of coal, to the cooling water passing through the condenser. The amount of heat rejected, which depends on several parameters, averages about 6000 Btu(1512 kcal)/kWh. This increases cooling water temperature about 8.5°C with once-through cooling or 12°C with cooling towers.[4]

Current effluent guidelines restrict the discharge of heated effluents to the environment; therefore, treatment is necessary. Treatment devices for cooling, such as towers, sometimes generate chemical pollutants. To evaluate

Table 2.7. Estimated Loadings of Water Pollutants from Coal-Fired Power Generation Plants

Pollutant	Uncontrolled lb/day/MW[a]	Controlled (NSPS), lb/day/MW[a]
TSS	0.3649[b]	0.328 max 0.099 avg
Oil and Grease	--	0.0656 max 0.0491 avg
Ammonia	2.39×10^{-3}	--[c]
Nitrate	2.0×10^{-3}	--
Chloride	0.22	--
Free Available Chlorine[d]	0.031	0.0156 max 0.0062 avg
Sulfate	0.466	--
Fe	0.218[e]	6.5×10^{-4}
Cu	0.0089[e]	6.5×10^{-4}
Zn	0.657	8.2×10^{-4}
Cr	0.376	1.07×10^{-3}
P	0.164	8.35×10^{-3}
Na	0.248	--
Ni[f]	8.42×10^{-3}	--
Mg[f]	0.201	--
Al[f]	2.0×10^{-3}	--
Mn[f]	7.0×10^{-5}	--
Cd[f]	2.0×10^{-5}	--
Se[f]	7.0×10^{-5}	--
As[f]	2.0×10^{-5}	--
B[f]	8.3×10^{-4}	--
Pb[f]	2.0×10^{-5}	--
Ba[f]	1.2×10^{-4}	--

Note: pH of all discharge is 6.0 - 9.0 by NSPS.

[a] To convert lb/dayMW to kg/day/MW multiply by 0.4536.

[b] TSS discharge should, in addition, be increased by concentration factor of 3.7 applied to cooling. Intake water multiplied by 3744 gal/day/MW (14.2 cu m^3/day/MW).

[c] Not given.

[d] Free available chlorine residual will be reduced to near zero if cooling blowdown goes to ash-handling system.

[e] Data not available for all waste streams.

[f] Discharge values based on ash-handling data only.

Data based primarily on ref. 5.

the impact of thermal discharges, it will be assumed that no heated effluents warmer than allowed by the EPA standards will be discharged and that cooling towers, spray ponds, or other mechanical cooling facilities will be used to treat the heated waste.

2.3 COAL GASIFICATION

Coal gasification, in this assessment, covers processes that make a clean, methane-rich gas from coal by destructive hydrogenation at high temperature and pressure. This preliminary assessment does not attempt to differentiate between specific process designs, but, rather, uses a generalized process for inputs and effluents. The unit facility site is based on a production of 250×10^6 scf/day (7.08×10^6 m^3/day) of SNG. The technology is approximately that of a "second-generation," fluidized-bed gasifier followed by the usual cooling, shift conversion, water quench, acid-gas removal, and catalytic methanation. Since the environmentally significant effluents come from the gas-cleanup train and not the gasifier chamber, specific gasification designs will differ more in costs and efficiencies related to coal feed than in the residuals to the environment. The major exceptions are effluents from the on-site production of auxiliary steam and electric power, for which the amount of auxiliary energy needed varies with the design and efficiency of the process.

Figure 2.2 shows the process stages and streams of inputs and effluents for coal gasification. The nature and location of each basic process block within the diagram will vary between processes. Likewise, not all of the effluents noted may be present for all processes; some gasifiers favor production of certain products more than do others. Coal is prepared by crushing to size and drying; the degree of drying (if any) depends on the operating economics of each process. The flue gas from drying is treated to remove particles and then vented to the atmosphere. The prepared coal is fed to the gasifier either in batches, through a lock hopper, or continuously, by mechanical feeders or in a pumped slurry. Any gases released during the feeding are assumed to be recovered and reinjected into the gas stream; thus, there are no effluents to the atmosphere at this point. In the gasification chamber the coal is hydrogasified at 700-1150°C and 10-100 atm to form a synthesis gas consisting mainly of carbon monoxide and hydrogen, with lesser amounts of carbon dioxide and methane. The shift-conversion unit adjusts the ratio of CO

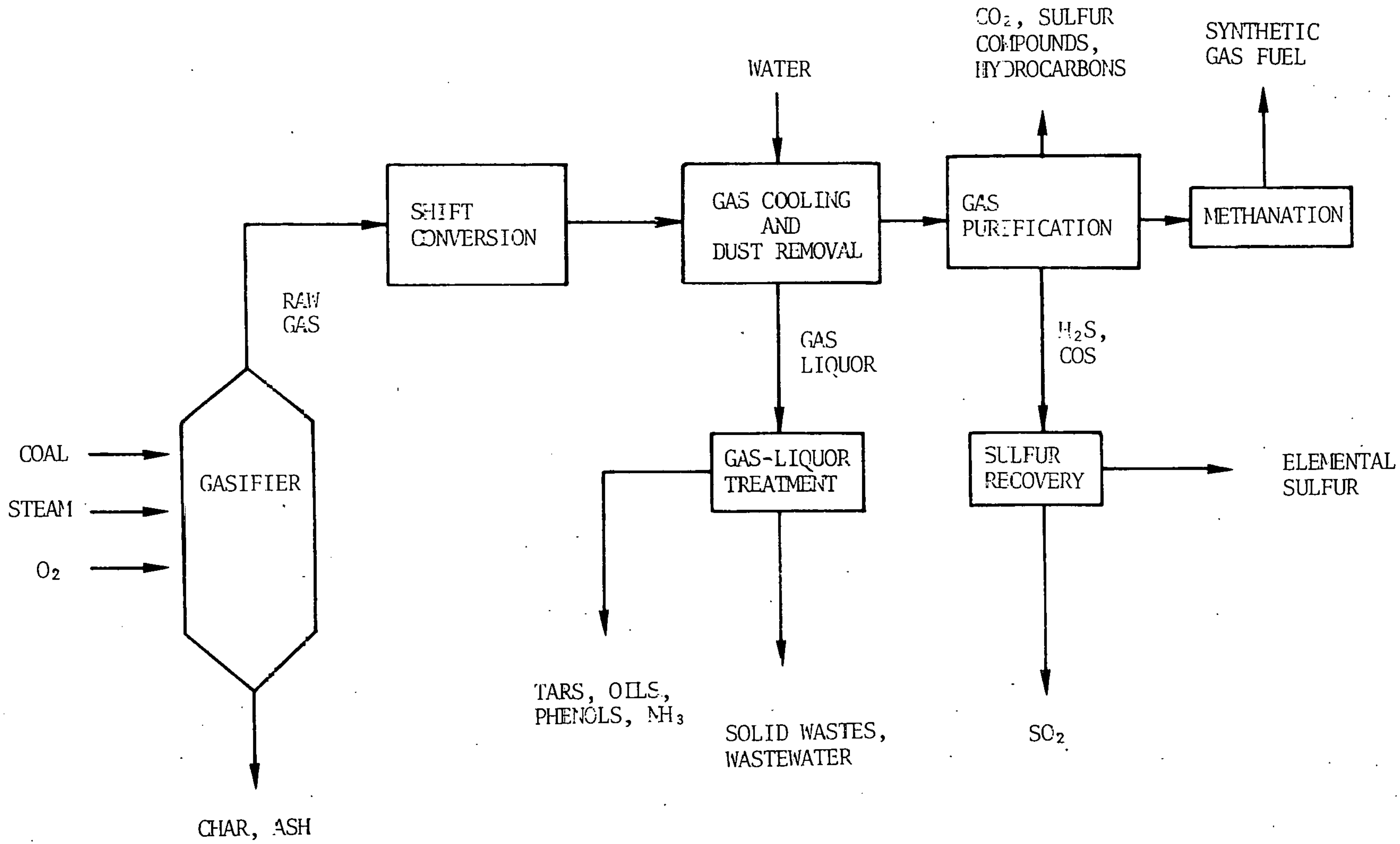

Fig. 2.2 Basic Coal Gasification Process Diagram

and H_2 using steam and catalysts, but no effluents normally arise from this stage.

In gas cooling and cleaning, most of the environmental pollutants in the coal are separated from the product gases. Gas cleaning must be very effective, both to protect the methanation catalysts and to produce SNG acceptable for mixing with natural gas. The synthesis gas is cooled by heat exchangers and then is further cooled and scrubbed by a direct water-spray wash. The liquid effluent (gas liquor) consists of the wash water and water condensed from the synthesis gas; it requires considerable treatment before reuse or release to the environment. The aqueous effluents (see Table 2.8) show the effects of levels of possible treatment before a waste stream is sent to the cooling-water circuit and then released to the surroundings through blowdown.

The first step in treating gas liquor is reduction of pressure to release dissolved gases, which are sent to the sulfur-recovery section. Next, tars and oils are separated by mechanical skimming and phenols by chemical solvents.

Table 2.8. Representative Pollutant Concentrations in Gas-Liquor Condensate from Coal Gasification

Substance	Untreated	Treated
TSS	600 mg/ℓ	20 mg/ℓ
pH	8.6	8.5
Phenols	2,600 ppm	0.01-20 ppm
Oil/Grease	$\geq$ 500 ppm	0.1-10.0 ppm
COD	15,000 mg/ℓ	80-100 mg/ℓ
NH_3	8,000 ppm	5-10 ppm
CN	0.6 ppm	0.1 ppm
Total Solids	1,400 ppm	12 ppm
SCN^-	150 ppm	70 ppm
Phosphates as P	2.5 ppm	0.3 ppm
Chloride	550 ppm	25 ppm
Fluoride	56 ppm	6 ppm

Data based primarily on Refs. 4-7.

If these hydrocarbons are present in large quantities, they may be recovered as by-products or reinjected into the gasifier. Processes for gasification at very high temperature produce little or none of these heavier hydrocarbons. Ammonia, formed in the gasifier from the nitrogen in the coal, is removed from the gas stream with the gas liquor. Distillation by steam stripping is used to recover the ammonia as a salable by-product.

The synthesis gas leaves the gas wash and is further cooled by heat exchangers in preparation for acid-gas removal which, with current methods, must be at from 50°C to 45°C, depending on the cleaning process used. The gas stream is washed with a solvent that removes sulfur compounds and carbon dioxide, leaving the synthesis gas at the high purity required of the SNG product. The solvent is regenerated to release the carbon dioxide and sulfur compounds selectively; the carbon dioxide is vented to the atmosphere and the sulfur compounds are sent to a recovery system to recover elemental sulfur. The very large volume of carbon dioxide carries small quantities of gaseous pollutants with it. In the sulfur recovery, Claus or Stretford processes are followed by incineration and flue-gas scrubbing; small quantities of sulfur in the form of SO_2 or COS escape to the atmosphere.

The very clean product-gas stream is passed over a catalyst to raise the methane content to the required level for mixing with natural gas. This process releases only large amounts of heat and some water, which is recovered for reuse in the plant.

Emission of airborne pollutants from the gasification train (with the possible exception of some trace elements whose ultimate fates are not completely known) are not expected to be a significant problem. Particulate emissions from the gasification train will be virtually nonexistent. Except for small quantities released, if the off gas is incinerated, NO_x is not produced in the gasification plant. The removal efficiencies of the acid-gas processes and the sulfur-recovery and FGD units will determine the composition and volumes of the sulfur compounds emitted. Some processes remove COS or H_2S more effectively than others. Estimates for sulfur emissions differ widely among designs. As an example, one statement is that a commercial Synthane plant operating on central Interior Province coal would emit about 900 lb/hr (408 kg/hr) of SO_2 but would not emit COS. An equivalent HYGAS plant might emit only about 100 lb/hr (45 kg/hr) of SO_2, but it would also emit 400-500 lb/...

(180-225kg/hr) of COS. In general, sulfur emissions might be expected to be between these limits

In addition to its primary process use, coal is used to produce the energy required by the gasification process for such purposes as generating steam, oxygen production, compressing gases, and pumping liquids and cooling water. The coal may be burned in a boiler or be processed into a liquid or gas. The levels of environmental control parallel those in electric-power production. This auxiliary power production may contribute more pollutants than the main gasification process, but this need not be so. The residuals shown in Table 2.9[8,9] reflect the high and low levels of control that may be imposed on this source. For this assessment, the data available from the EMDB were used for the HYGAS process to represent gasification processes.[10,11] These atmospheric emission rates are shown in Table 2.10.

Table 2.9. Environmental Residuals for High and Low Control for Auxiliary Facilities for SNG Plant[8,9]

(Units of $lb/10^6$ Btu input as coal to auxiliary power plant)

Emission	Low Control[a]	High Control[b]
SO_2	1.2 $lb/10^6$ Btu (3500-6000 lb/hr)	0.1 $lb/10^6$ Btu (300-500 lb/hr)
NO_x	0.7 $lb/10^6$ Btu (2000-3000 lb/hr)	0.2 $lb/10^6$ Btu (600-900 lb/hr)
Particulates	0.1 $lb/10^6$ Btu (300-500 lb/hr)	0 $lb/10^6$ Btu (0 lb/hr)
Cooling Tower Evaporation	6×10^6 gal/day	2.8×10^6 gal/day
Blowdowns	2×10^6 gal/day	0.9×10^6 gal/day

[a]Coal-fired auxiliary power plant with FGD. Moderate water usage, low discharge.

[b]Fuel gas-fired auxiliary power plant. Low water usage, no discharge.

Note:

Auxiliary power plant - 300-500 MW at 10,000 Btu/kWh(2520 kcal/kWh).
To convert from $lb/10^6$ Btu to g/kcal, multiply by 1.8×10^{-3}.
To convert from lb/hr to kg/hr, multiply by 0.4536.
To convert from gal/day to m^3/day, multiply by 3.78×10^{-3}.

Table 2.10. Atmospheric Emission Rates for the Standard 250×10^6 scf/day SNG Plant[10,11]

(90% annual load factor)

Pollutant	Emission Rate, lb/10^6 Btu Input	Baseline Plant Emission Rate, g/sec
SO_2	0.126	2.02×10^2
NO_x	0.136	2.42×10^2
Particulates	0.014	2.49×10^1
CO	6.7×10^{-3}	1.19×10^1
Total HC	1.79×10^{-3}	3.10×10^0

Note:

Btu input is total to entire facility -- process plus auxiliaries.
To convert from lb/10^6 Btu to g/kcal, multiply by 1.8×10^{-3}.

Very little information is available on quality or quantity of waste water from coal-conversion processes, and only crude estimates can be made of water pollutants. Because the plants designed to date are for dry regions, no discharge of waste water is planned; and there is no exact specification for water treatment or of residual water contamination. For an area rich in water, whether it would be more economical to treat waste water for release or to partially clean it for reuse is not certain.

About 10-15% of the water consumed by an SNG facility is used in the gasification itself. Most of the rest ($\geq$ 60%) is used for cooling, both of the gas stream and of steam-driven pumps and compressors. The volume of water used for cooling can be reduced greatly by air cooling and heat recovery within the process. Cooling-water makeup usually will come from treated process water. Blowdown will be used to sluice ash and then be stored in a pond, evaporated, or discharged. Detailed estimates of water consumption are available only for Lurgi process facilities at a few specific sites. The rate of water consumption can be varied by design over a wide range to correspond to the availability, quality, and cost of water and the options for waste-water disposal at a site. Table 2.11 gives ranges of water consumption for a 250×10^3 scf/day SNG plant based on design data, estimations of minimal water use, and simple thermodynamic balances.

Table 2.11. Water Consumption (cfs) by a Unit SNG Facility

Upper Limits	17.05 - 20.15
Lower Limits	6.2 - 11.6

The lower limits would apply to SNG facilities in areas where water is scarce or discharge of waste water could cause difficulty. Water-consumption limits and waste-disposal restrictions were assumed to be stout; a consumption rate of 10.8 cfs was used for unit SNG plants (250 x 10^6scf/day).

Two approaches were used to estimate the type and amount of pollutants to be expected from coal gasification and liquefaction. The first is to determine the amounts of pollutants carried by process liquid wastes. This information will show the absolute upper bound on how much pollutant could be released. Information on treatment processes could be superimposed on these raw data to estimate more realistic levels of possible effluents. The second approach is based on analogy with other, somewhat similar, process facilities. New Source Performance Standards (NSPS) are based on the technology available for waste-water treatment, not on amounts of pollutants resulting from a process. The NSPS for coal-gasification facilities will specify process effluent rates that will be based on the same treatment technology as that for "similar" plants. Thus, appropriate scaling of process size permits one to estimate the future maximum allowable levels of discharge.

Table 2.12 lists the approximate loading rates for various compounds in treated and untreated waste streams from coal-gasification processes. These rates are based on 250 x 10^3 scf/day of gas production using Illinois No. 6 coal. Recovery of certain by-products before discharge was *not* assumed in data under *untreated* option. A volume of 3.3 x 10^6gal(1.25 x 10^4 M^3)/day of waste water is assumed.

2.4 COAL LIQUEFACTION

"Coal liquefaction" is used to describe a wide range of processes that convert coal to clean liquid fuel. The primary product may be equivalent to refined petroleum products, unrefined crude oil, or a heavy boiler fuel that might be a solid at ambient temperatures. Most liquefaction processes produce a range of gaseous, liquid, or solid byproducts besides the primary

Table 2.12. Representative Water Pollutant Loading from a 250×10^3 scf/day SNG Plant Using Illinois No. 6 Coal

	Untreated		Treated	
	Conc., mg/l	Loading, lb/day	Conc., mg/l	Loading, lb/day
TSS	600	16,500	0.20	550
pH	8.6	-	8.5	-
Phenols	2,600	71,500	0.4	10
Oil	7,500	13,800	5	138
COD	15,000	413,000	90	2,500
BOD	2,300	62,400	14	375
NH_3	8,000	220,000	7.5	206
Cyanide	0.6	16.5	0.1	2.75
Total Solids	1,400	38,500	12	330
Thiocyanate	150	4,130	45	1,239
Phosphate as P	2.5	69	0.3	8.3
Chloride	500	13,800	25	688
Fluoride	56	1,540	6	165
SO_4	-	39,000	-	334
Fe	3	82.5	-	-
Pb	3	82.5	-	-
Mg	2	55	-	-
Zn	0.06	1.65	-	-
As	0.03	0.83	-	-
Cu	0.02	0.55	-	-
Cr	0.006	0.16	-	-
Cd	0.006	0.16	-	-
Mn	0.04	1.1	-	-
Ni	0.03	0.83	-	-
Al	0.8	22	-	-
Se	0.36	9.9	-	-
Ba	0.13	3.6	-	-

Note:

To convert lb/day to kg/day, multiply by 0.4536.

environmental impact from the alternative synfuel processes. These differences may become sharper as pilot plants make available data on startup and transient effluents, system leaks and spills, problems in product and byproduct storage, and the exact composition of all effluent streams.

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3 PROBLEMS AND FUTURE TRENDS IN ENERGY SUPPLY

3.1 INTRODUCTION

This section analyzes present problems and future trends in energy supply for Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin. These states form a relatively cohesive region with many economic and social characteristics in common. They also share environmental concerns associated with energy development, such as pollution of the Great Lakes, pollution of the air by power plants, and disruption of prime agricultural land by coal extraction.

A key feature that unites the region is a shared need to develop new energy sources to replace dwindling supplies of oil and natural gas. The former substantial oil and gas production within the states of Illinois, Ohio, and Michigan has been reduced to a small fraction of the region's needs.* The steady decline in the regional production of these fuels has been followed by declining rates of production in key supply areas outside the region. Moreover, the Canadian government has begun a gradual phaseout of oil shipments to the U.S. This policy is especially troublesome to the border states of Minnesota and Michigan, which have several refineries relying on Canadian crude oil.

Shortfalls in natural-gas supplies have resulted in varying degrees of disruption within all consuming sectors in Midwestern states. Table 3.1 shows that only Michigan escaped the need to curtail use by "firm" customers during the 1975-76 heating season. Yet, even in Michigan the gas supply was insufficient to meet all potential demand.

Thus far, the hardest-hit sectors have been industrial and utility users of gas, particularly in the eastern parts of the region. Residential and firm commercial users are just beginning to feel the effects of the shortage. In many parts of the region, gas utilities are prohibited by regulatory agencies from adding new residential or commercial accounts. Where new gas is available, it is being reserved for use by small residential and commercial users. This curtailment has resulted in record numbers of new electrically heated buildings, which increase electricity demand further. The supply restrictions are likely to spread.

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*Total oil and gas production for 1975 within the region was equivalent to about 98.4 million barrels of oil; the total 1975 demand was 1678 million barrels.

Table 3.1. End-Use Winter Gas Requirements for November 1975 through March 1976[a] (billion cf)

State	Requirement	Shortage	Increase in Shortage over Previous Winter
Illinois	741.7	14.7	8.7
Indiana	280.2	13.2	3.9
Michigan	532.9	—	—
Minnesota	166.9	15.8	0.6
Ohio	679.5	94.9	37.1
Wisconsin	239.6	25.8	21.9

[a]American Gas Association, *Gas Supply Review* (Oct. 1975).

These problems with traditional sources of primary energy will profoundly affect energy patterns within the region in three ways. First, electricity will constitute a larger share of total energy consumed. Even though growth in electricity demand is expected to drop off from its historic growth rate of 6-7% per year (see Table 3.2), electricity's share of total energy will grow mainly because its price has increased less than that of other fuels* and natural-gas shortages have become worse. Second, the direct combustion of coal for industrial uses may reverse its recent decline and begin to grow modestly. The growth of industrial demand largely depends on the availability of low-sulfur coal or small-scale control methods, such as fluidized-bed combustion. Third, in the intermediate to long term, converting coal to synthetic fuels may help to replace declining supplies of natural gas.

*Annual growth rates (%) for real energy prices in the East North Central census region (1974-1985) as projected by the U.S. Federal Energy Administration (National Energy Outlook, February 1976) were:

	Residential	Commercial	Industrial
Electricity	0.5	0.8	1.7
Natural Gas	4.5	5.4	4.5
Oil	1.0	1.0	0

Table 3.2. Electricity Sales, 1960-1972

State		Sales, 10^6 kWh 1960	1972	Annual Rate of Growth, %
Illinois	Total	33,140	76,572	7.23
	Residential	9,368	22,686	7.65
	Commercial	7,027	19,588	8.92
	Industrial	14,829	29,178	5.80
Indiana	Total	17,000	41,726	7.77
	Residential	6,674	13,335	7.38
	Commercial	2,275	7,333	10.24
	Industrial	8,339	20,550	7.82
Ohio	Total	57,268	96,881	4.48
	Residential	10,405	23,932	7.19
	Commercial	5,258	16,550	10.03
	Industrial	39,654	53,238	2.49
Minnesota	Total	9,033	23,044	8.12
	Residential	3,841	8,743	6.87
	Commercial	1,289	3,751	9.31
	Industrial	3,487	9,826	9.02
Michigan	Total	27,222	61,166	6.98
	Residential	8,963	19,054	6.49
	Commercial	5,136	11,907	7.26
	Industrial	12,595	28,567	7.06
Wisconsin	Total	12,458	27,952	6.97
	Residential	5,031	10,729	6.34
	Commerical	2,371	5,652	7.51
	Industrial	4,558	10,705	7.37

Source: Edison Electrical Institute, *Statistical Yearbook.*

3.2 ELECTRICAL ENERGY: DEMAND AND GENERATING CAPACITY

Studies of electricity demand have ranged from naive historical trends to more theoretically sophisticated models.[1] Until the early 1970s, the trend models performed extremely well. However, the impacts of recent events, such as the oil embargo and the imposition of stringent antipollution regulations, cannot be accounted for by the trend approach. As a result, the predictive power of these models, particularly for *turning-point errors,* has been poor. An attempt has been made to formulate a simple econometric model that explicitly takes some of these institutional and economic changes into account.

The factors used in the model are prices of electricity and natural gas population; and a measure of economic activity. Separate models were estimated for each of the three end-use sectors: industrial, commercial, and residential. Ideally, for estimation, one would like each sector to be relatively homogeneous. Unfortunately, individual users are generally classified on the basis of how much electricity they demand and not by their characteristics. As a result, the residential sector is probably the most homogeneous and the commercial sector the least.

The model specification used in this study is similar to a widely used class of econometric models.[2] It has three analytical features that have come to characterize postembargo models for electricity demand: (1) a dynamic stock-adjustment term; (2) *ex post* average electricity and gas prices; and (3) pooled cross-sectional state and annual time series data.

Each consuming sector requires a slightly different specification of independent variables to account for the particular factors influencing the sector demand. In the residential model, the independent variables are the average price of electricity and *per capita* disposable income, and consumption is estimated with total disposable income and with average prices of electricity plus natural gas. In the industrial model, total consumption is again expressed as a function of average prices of electricity and natural gas, but with value added for manufacturing. Disposable industrial prices are deflated by using the Wholesale Price Index for manufacturing, and income and all prices are expressed in real terms. Conversion to real terms in the residential and commercial sectors is achieved by using the Consumer Price Index (CPI).

In generating forecasts, the assumptions made for future values of the independent variables have a major impact on the growth rates. Standard data sources were used in formulating these future values. The OBERS (Series E)[3] forecasts of population and personal income were used. The price forecasts for electricity and natural gas are based largely on the FEA forecasts.[4]

Overall, the main driving forces associated with electricity demand are forecast to decline from their historic rates of growth. Demographic analyses suggest that lower birth rates and net migration from the Midwest will markedly lower population growth in the region. Related to the above is the fact that commercial and industrial activity will be considerably slower than in the past. The values forecast for electricity demand by state are given in Table 3.3.* Overall, the growth in demand is much slower (especially after 1985) than the historic growth rates shown earlier.

Future requirements for electrical energy were translated into the capacity additions necessary to satisfy this demand. Three general requirements arose in attempting to characterize the number and type of generating facilities to be constructed within a state. First, an estimate had to be made of the overall annual load factors within each area. Second, an appreciation of the net annual transfers of power from state to state had to be obtained, and finally, a combination of fuels used to generate power had to be projected.

Forecasting system load factors was largely judgmental. For the last few decades the rate of increase in generating capacity has outstripped the growth of demand. For a variety of reasons the annual peak demand (PD) has grown much faster than average demand (AD). If the ratio AD/PD (i.e., load factor) were to continue to decline, the growth of capacity would continue to outpace energy demand. However, utilities are having difficulty in financing and siting new baseload power plants. The marginal cost of incremental capacity to the utility (and society at large) is rising rapidly. Therefore, this historic deterioration in system load factors probably will not continue. Regulations to have users pay more of the true social cost of electrical power consumed during peak hours are likely.**

The problem of controlling the growth of peak demand is economic, not technological. Technological means now exist for controlling peak use of power. England, Wales, and West Germany have used storage techniques with appropriate tariffs to flatten system load curves within an amazingly short time.† Several U.S. utilities are experimenting with similar peak-load pricing schemes and storage devices. Both Madison Gas and Electric and Detroit

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*The model and parameter values are discussed in more detail in Appendix A.

**The Wisconsin Public Utilities Commission has been a leading agency in the introduction of "marginal cost" pricing to setting utility rates.

†J. Asbury and A. Kovalis have described recent experiences in load leveling in England, Wales, and the Federal Republic of Germany, personal communication, Argonne National Laboratory, April 28, 1976.

Table 3.3. Forecast Total Demand for Electricity

	Demand, million kWh						
State	1975	Annual Rate of Growth, %	1985	Annual Rate of Growth, %	2000	Annual Rate of Growth, %	2020
Illinois	86,960	5.4	147,597	4.7	292,672	4.5	708,675
Indiana	50,764	6.6	95,922	5.0	199,588	4.8	511,426
Michigan	67,032	5.1	109,815	4.8	220,515	4.5	527,553
Minnesota	28,251	7.4	57,851	5.0	119,784	4.8	304,217
Ohio	108,002	5.7	188,244	5.0	392,439	4.7	986,227
Wisconsin	28,365	3.4	39,535	4.5	76,843	4.4	182,681

Edison now offer special rates for customers with hot water heaters that shut off during peak load periods. It is assumed that, before 2000, Midwestern utilities generally will raise the ratio AD/PD. Therefore, the growth in generating capacity is somewhat less than the growth in energy demand given in Table 3.3.*

A general improvement in system load factors will also result in improved plant factors (fraction of potential output actually attained) for coal-fired plants and in fewer peaking units. The plant factors assumed for this study (see Table 3.4) were based upon historical operating trends for steam electric plants in each state. The high factors for nuclear plants are greater than recent experience suggests but are generally considered to be the minimums necessary for the economic operation of these plants.

For locating the above capacity, an attempt was made to classify states as to whether they were net importers or exporters of electricity. This classification was made by consulting the Electric Reliability Council Reports of MAIN, MARCA, and ECAR.[5] These sources indicated that Ohio, Minnesota, and Illinois import electricity; and Michigan and Wisconsin are net exporters. Indiana showed no significant transfers in either direction. Because these

*Improvements in plant reliability and utility interties would reduce the capacity reserve margins held by utilities. This reduction would also tend to slow the growth in generating capacity slightly.

Table 3.4. Projected Plant Factors for 2000 and 2020

Fuel	State	Plant Factor 2000	Plant Factor 2020
Coal	Illinois	0.53	0.55
	Indiana	0.57	0.59
	Michigan	0.57	0.59
	Minnesota	0.55	0.57
	Ohio	0.56	0.59
	Wisconsin	0.52	0.54
Oil	All	0.40	0.40
Nuclear	All	0.63	0.70
Other	All	0.15	0.15

transfers appeared to be small (less than 3% of any given state's total demand), no adjustments were made to capacity needs to reflect transfers.

The Reliability Council Reports of MAIN, MARCA, and ECAR were used to formulate capacity (Table 3.5) for each state in 1985. The capacity mix for 1985 was then used, in conjunction with the above assumed plant factors (Table 3.4) for each plant type, to arrive at the fuel mix for 1985. The resulting fuel mix for 1985 is given in Table 3.6, along with projections to 2020. The fuel mixes projected for 2000 and 2020 were based on a number of judgmental considerations. In the long run, the percentage of coal used in the generation of electrical power is likely to diminish in all states, due to depletion of coal resources and environmental problems of mining and combustion. The above factors will result in sharply rising prices for coal.

A detailed breakdown of capacity needs by state is given in Table 3.7. It shows Illinois leading all other states in total capacity in the near term. However, by 2020 Ohio's capacity requirement leads Illinois by a sizable margin. In fact, the generating capacity for Ohio is nearly twice the combined needs for the states of Minnesota and Wisconsin. It should be cautioned that this wide variation is based upon a continuation of historical demand relationships, both for average and peak demand. Problems with siting, resources, or the environment could easily trigger institutional changes in relationships between electricity supply and demand.

Table 3.5. Electric Utility Generation Capacity According to Fuel Type (% of total kWh generated by type)

	1975						
	Fossil Fuels						
State	Coal	Oil	Gas	Nuclear	Hydro	Other[a]	Total
Illinois	61.19	8.46	0.38	20.97	0.02	8.98	100.00
Indiana	91.42	2.43	1.53	0	0.61	4.01	100.00
Michigan	51.32	18.65	0.12	9.33	12.32	8.26	100.00
Minnesota	48.38	1.81	1.70	28.43	2.11	17.57	100.00
Ohio	88.60	2.73	0.83	0	0	7.84	100.00
Wisconsin	58.21	0.79	3.61	17.56	4.76	15.07	100.00
	1985						
Illinois	46.44	11.25	0	36.90	0.01	5.40	100.00
Indiana	84.82	1.39	0.87	10.28	0.35	2.29	100.00
Michigan	48.91	15.38	0.09	19.16	9.55	6.91	100.00
Minnesota	60.85	1.19	0.50	18.69	1.39	17.38	100.00
Ohio	69.93	1.66	0	23.02	0.11	5.28	100.00
Wisconsin	54.73	0.30	0.24	28.72	3.12	12.89	100.00

[a]Turbine, diesel and combined cycle.

Source: National Electric Reliability Council Reports, 1974.

Table 3.6. Electric Utility Generation according to Fuel Type (% of total kWh generated by type)

State	Coal	Oil/ Natural Gas	Nuclear	Other	Total %
		1975			
Illinois	60.2	11.5	28.2	0.1	100.0
Indiana	93.9	5.3	0.0	0.8	100.0
Michigan	75.7	21.6	1.0	1.7	100.0
Minnesota	54.6	18.2	24.4	2.8	100.0
Ohio	94.0	5.5	0.0	0.0	100.0
Wisconsin	53.8	10.2	31.5	4.5	100.0
		1985			
Illinois	45.3	6.2	48.4	0.1	100.0
Indiana	83.9	1.6	13.7	0.8	100.0
Michigan	48.1	24.9	25.4	1.6	100.0
Minnesota	63.3	7.7	26.2	2.8	100.0
Ohio	67.4	1.7	30.8	0.1	100.0
Wisconsin	52.0	6.8	36.7	4.5	100.0
		2000			
Illinois	43.0 (60.0)[a]	8.0 (8.0)	48.0 (31.0)	1.0 (1.0)	100.0
Indiana	73.0	1.0	25.0	1.0	100.0
Michigan	53.0	10.0	32.0	5.0	100.0
Minnesota	65.0	1.0	29.0	5.0	100.0
Ohio	68.0	1.0	30.0	1.0	100.0
Wisconsin	55.0	0.0	40.0	5.0	100.0
		2020			
Illinois	35.0 (79.0)[a]	5.0 (3.5)	59.0 (15.0)	1.0 (2.5)	100.0
Indiana	58.0	1.0	40.0	1.0	100.0
Michigan	44.0	7.0	45.0	4.0	100.0
Minnesota	55.0	1.0	40.0	4.0	100.0
Ohio	58.0	1.0	40.0	1.0	100.0
Wisconsin	44.0	0.0	52.0	4.0	100.0

[a]Numbers in parentheses indicate fuel mix for Illinois in High Coal Use Scenario.

Table 3.7. Projected Capacity (MW) according to Fuel Type

State	Coal	Oil/ Natural Gas	Nuclear	Other	Total
		1985			
Illinois	21,103	4,226	16,451	--	41,780
Indiana	23,180	--	2,356	--	25,356
Michigan	12,229	4,677	4,387	1,872	23,165
Minnesota	10,159	--	1,755	--	11,914
Ohio	27,672	1,120	7,085	--	35,877
Wisconsin	6,278	--	4,248	512	11,038
		2000			
Illinois	27,106	6,681	25,451	2,228	61,466
Indiana	29,180	569	9,041	1,519	40,309
Michigan	23,406	6,293	12,786	8,391	50,876
Minnesota	16,160	342	6,294	4,558	27,354
Ohio	54,399	1,120	21,333	2,986	79,838
Wisconsin	9,278	--	5,570	2,924	17,772
		2020			
Illinois	51,481	10,112	68,186	5,393	135,172
Indiana	57,392	1,459	33,361	3,829	96,041
Michigan	44,163	10,539	38,715	16,059	109,476
Minnesota	33,509	868	19,845	9,261	63,483
Ohio	110,675	2,814	64,333	7,505	185,327
Wisconsin	16,992	--	15,491	5,561	38,044

Wisconsin, Michigan, and Minnesota have almost no fossil fuel resources and may have to import expensive fossil energy or nuclear power. This problem is not quite as difficult in Minnesota, because of its relatively easy access to the Northern Great Plains coal, which has strong long-term supply potential. Since Illinois has the largest coal reserves of any single state, utilities in Illinois and Southern Indiana will have ready access to long-term supplies and are assumed to maintain a high level of coal usage.

Natural gas, hydroelectric power, and oil are not competitive energy sources in the Midwest and should decrease in relative importance. Shortages of natural gas have already occurred. These shortages have placed institutional and economic impediments in the way of further use of natural gas by utilities. The Federal Power Commission and many states have effectively prohibited expansion of natural gas use for steam boilers; its future use will be almost exclusively for fueling turbine generators.

Oil is too expensive for extensive use in the Midwest. It will continue to be used as a fuel for peaking plants and as a backup for coal but not as a primary fuel for baseload plants.

Hydroelectric power is economically attractive, but its potential is limited in the Midwest (see Table 3.8). Environmental and recreational interests can be expected to muster significant opposition to the further development of hydroelectric projects. Hydroelectric capacity is expected to reach its maximum by 1985 and will diminish in relative importance.

Table 3.8. Hydroelectric Generation Capacity

State	Developed Capacity	Developed Capacity, MW	Potential Developed, %
Illinois	35	206	14.6
Indiana	94	315	22.9
Michigan	387	278	58.1
Minnesota	169	136	55.4
Ohio	3	317	0.8
Wisconsin	426	188	69.4

Source: Federal Power Commission, *Hydroelectric Power* (Jan. 1972).

All of these factors suggest that nuclear power will become, almost by default, an increasingly important source of electricity.* Table 3.9 contains recent information on existing and planned nuclear power plants for each state in the Midwest. Although Illinois has been a leading state in the use of nuclear power, other Midwestern states may have to equal or exceed Illinois in terms of nuclear dependence. This development will occur because of the increasing cost of coal due to the depletion of coal reserves and added environmental controls.

Projections for 2000 and 2020 (see Table 3.6) were obtained by assessing the above trends in power generation and the relative costs of fuels. However, the widely different growth patterns for nuclear power cannot be explained by economic factors alone. For example, nuclear power additions in Ohio greatly exceed those of Indiana, two states in which fossil energy costs are nearly equal. Presumably capital and construction costs would also be similar. Why then, are utilities in Cincinnati, Toledo, and Cleveland projected to expand their use of nuclear power so rapidly? Apparently, intangible political and social factors strongly affect a utility's choice of plant type as well as the relative economics. The degree of reliability of these projections is greatest for 1985 (for which known industry plans are used) and become more conjectural as they are extended from the industry planning horizon.

Also shown in Table 3.6 is an alternative scenario for Illinois for 2000 and 2020 in which a significantly high percentage of Interior Province coal is used for electrical generation instead of nuclear or low-sulfur Western coal. This scenario represents a maximum credible upper bound in the possible use of in state-produced coal for Illinois. The limited growth in nuclear power could be interpreted as the result of a nuclear moratorium after 1985.

The scenario has various environmental implications, resulting from higher sulfur levels of the Illinois coal, which are discussed in subsequent

*In the long term, technology based on renewable resources, such as solar energy, or untapped sources of energy, such as peat or solid waste, may begin to add an alternative to the nuclear-coal tradeoff. However, utility resistance to unproven sources and the somewhat uncertain economics of these energy sources will limit their growth during the rest of this century. Moreover, since this study focuses on the impacts of increased coal development, exclusion of other "advanced" sources was appropriate.

Table 3.9. Existing and Planned Nuclear Power Plants in Midwest

State/Site	Capacity, Net kilowatts	Commercial Operation
ILLINOIS		
Morris	200,000	1960
Morris	809,000	1970
Morris	809,000	1971
Zion	1,050,000	1973
Zion	1,050,000	1974
Cordova	800,000	1972
Cordova	800,000	1972
Seneca	1,078,000	1978
Seneca	1,078,000	1979
Byron	1,120,000	1980
Byron	1,120,000	1982
Braidwood	1,120,000	1981
Braidwood	1,120,000	1982
Clinton	933,400	1981
Clinton	933,400	1984
INDIANA		
Westchester	645,300	-
Madison	1,130,000	1982
Madison	1,130,000	1984
MICHIGAN		
Big Rock Point	75,000	1965
South Haven	700,000	1971
Lagonna Beach	1,093,000	1980
Bridgman	1,060,000	1975
Bridgman	1,060,000	1978
Midland	458,000	1982
Midland	808,000	1981
St. Clair Co.	1,200,000	1984
St. Clair Co.	1,200,000	1986
MINNESOTA		
Monticello	545,000	1971
Red Wing	530,000	1973
Red Wing	530,000	1974
OHIO		
Oak Harbor	906,000	1977
Oak Harbor	906,000	1983
Oak Harbor	906,000	1985
Perry	1,205,000	1980
Perry	1,205,000	1982
Moscow	810,000	1979
Moscow	1,170,000	1986
WISCONSIN		
Genoa	50,000	1971
Two Creeks	497,000	1970
Two Creeks	497,000	1972
Carlton	541,000	1974
Ft. Atkinson	900,000	1983
Ft. Atkinson	900,000	1984
Durand	1,150,000	1985

Source: Energy Research and Development Administration, June 30, 1976.

sections of this report. The two Illinois scenarios represent sharply contrasting situations that highlight some of the impacts of coal conversion for electrical generation.

3.3 COAL DEMAND BY UTILITIES: COAL SOURCES

The previous sections have discussed expected growth in electricity demand and utility fuel mixes. These variables are the primary determinants of the utility demand for coal. Even though the percentage share of coal used in the fuel mix should decline, the exponential growth in demand for electricity is expected to overwhelm this decline and prompt substantial absolute growth in demand for coal by electric utilities This growth is illustrated by contrasting the historical levels of utility coal consumption in Table 3.10 with the projected patterns for consumption in Table 3.11.

Recently enacted air-pollution standards have strongly affected the electric utility demand for coal. The choice of coal type strongly influences the environmental, economic, and land use-impacts of coal use in generation of electricity. Newly constructed 100-MW power plants must meet Federal limits of 1.2 lb SO_2 per 10^6 Btu of fuel burned. In most plants, the limit can be met by using either low-sulfur coal alone or high-sulfur coal with control devices.

However, some state standards are so stringent that utilities will have to either scrub the flue gas or wash even western coal to obtain compliance.

Table 3.10. 1975 Interregional Coal Flows for Electric Utilities[a] (10^3 tons per year)

State	Appalachian	Interior	Gulf	Northern Great Plains	Rocky Mountains
Ohio	44.1	2.1	0	0.6	0.4
Indiana	0.4	25.0	0	3.2	0.1
Illinois	0.2	21.2	0	9.0	0.1
Michigan	21.8	2.5	0	1.0	0.2
Wisconsin	0.8	6.8	0	3.0	0
Minnesota	0	1.6	0	7.9	0.1

[a]These flows have been modified from U.S. Bureau of Mines, *Bituminous Coal and Lignite Distribution for 1975*, Washington, D.C., pp. 14-20 and p. 49 (April 12, 1976). They are approximate because in many cases end use was not specified precisely for coal from a given supply region.

Table 3.11. Annual Coal Consumption for Electrical Generation[a]
(10^6 tons per year)

Year	Interior Coal Province: Illinois	Interior Coal Province: Indiana	Interior Coal Province: W. Ky.	Eastern Coal Province: Ohio	Eastern Coal Province: Other, High S.	Eastern Coal Province: Other, Low S.	Western Coal
1985							
Ill.	19.34	-	0.97	-	-	-	13.54
Ind.	6.91	18.76	-	-	-	-	14.81
Mich.	-	-	-	-	16.25	-	8.82
Minn.	2.16	-	-	-	-	-	18.39
Ohio	-	-	-	29.27	9.76	10.64	7.09
Wisc.	5.31	-	-	-	-	-	5.31
Total	33.72	18.76	0.97	29.27	26.01	10.64	67.96
2000							
Ill.a	32.48 (59.14)	-	2.00	-	-	-	20.57 (12.96)
Ind.	18.12	26.37	-	-	-	-	18.22
Mich.	-	-	-	-	31.93	-	16.02
Minn.	4.25	-	-	-	-	-	33.60
Ohio	-	-	-	48.78	27.15	10.78	16.33
Wisc.	9.32	-	-	-	-	-	9.67
Total	64.17 (90.83)	26.37	2.00	48.78	59.08	10.78	116.41 (108.60)
2020							
Ill.	60.88 (211.45)	-	4.04	-	-	-	42.25 (15.43)
Ind.	49.46	24.79	-	-	-	-	57.06
Mich.	-	-	-	-	62.81	-	24.67
Minn.	7.98	-	-	-	-	-	73.62
Ohio	-	-	-	54.11	84.94	13.59	85.23
Wisc.	14.71	-	-	-	-	-	22.07
Total	133.03 (283.60)	24.79	4.04	54.11	147.75	13.59	302.90 (276.06)

[a]Numbers in parentheses indicate coal consumption for Illinois High Coal Electric Scenario. Assumes 33% thermal efficiency for 1985 and 38% for 2000 and 2020. Coal heat content assumed to be 22×10^6 Btu/ton for Interior Province, 23.8×10^6 for Eastern Province, and 18×10^6 for Western coals.

Furthermore, flue gas from low-sulfur lignite must be scrubbed to meet even Federal standards because of lignite's very low heat content.

In general, the most important factors affecting the use of low-sulfur coal are what electric utilities will do to comply with regulations and the relative transportation costs to sources of high- and low-sulfur coal. Most utilities in the Midwest are now burning low-sulfur coal rather than applying control methods to burning of high-sulfur coal.[6] The proportion out of compliance is expected to diminish and the ratio of control usage to low-sulfur coal is expected to increase because of technological improvements. Coal-consumption projections in Table 3.10 are based on an overall regional use for 1985, about 35% low sulfur and 65% high sulfur.*

These percentages have been established with the aid of a formal model of coal markets. The model minimized the delivered cost of obtaining coal at various demand centers. Each center is allocated low-sulfur coal, intermediate sulfur coal with washing, or high-sulfur coal with scrubbers for flue gas.

Within the Midwest, utility companies differ in how they control sulfur, with no systematic pattern by state. As methods to control sulfur pollution receive more industry acceptance, differences in transportation costs for western low-sulfur coal and for high-sulfur coal will primarily determine the market share of each.[7] For this reason, Ohio and Michigan will use the most high-sulfur coal and Minnesota will burn low-sulfur coal almost exclusively because the lignite fields of the Dakotas and the subbituminous coal of the Powder River are close. Annual coal consumption for electric generation by source is given in Table 3.11.

Although the proportion of low-sulfur coal used in each state will remain about constant from 1985 to 2020, it is a substantial increase over that in 1975, especially in Ohio, Indiana, and Michigan, as can be seen by comparing Table 3.10 with Table 3.11. The other significant change is that consumption of high-sulfur coal is being slightly more localized. Therefore, Ohio and

*This ratio has been retained generally for 2000 and 2020 because of uncertainty about the values to be assigned to the relevant variables. For instance, environmental policy is uncertain, and how much the cost of control technology will decrease is also in doubt.

Indiana, for example, are projected to cease shipping coal to each other. It was decided that, since their coal reserves were of about equal sulfur content, little justification existed for importing each other's coal. This rationale was also applied to the other states in the region so that they obtain their high-sulfur coal entirely from the closest coal source.

The estimates of coal production in Table 3.11 show that all significant regional production will occur in Ohio, Indiana, and Illinois, and the coal will be relatively high in sulfur.[8] Intrastate production for industrial consumption (in direct combustion) should decline, given that industrial boilers will require use of low-sulfur coal as the only practical control technology and that negligible low-sulfur reserves exist in these states. The low-sulfur coal is expected to be bid away from the electric utilities by industry, which can be assumed to have a more inelastic demand for such coal. Yet, consumption by electric utilities of intrastate high-sulfur coal is not expected to increase greatly from present amounts in Indiana and Ohio, because of reserve depletion and the high costs of expanding production in these areas. Higher costs can be expected because of increasing use of thinner seams and deep mining. Illinois has the most abundant minable reserves of any state. In addition, more coal should be available by strip mining at competitive prices in Illinois than in Indiana or Ohio.[8] Therefore, total production within Illinois for utility markets should increase considerably in absolute terms.

3.4 COAL GASIFICATION

The size of a synthetic-fuels industry in the U.S. will be limited for the next ten years. The lead times necessary for bringing first-generation conversion plants on line is at least five years and is even longer for more advanced processes. Two first-generation commercial-scale gasification plants may come on line by 1985, one in North Dakota, and the other in New Mexico. No commercial plants are now scheduled for the Midwest. Beyond 2000, possible synthetic-fuel output is large. Several studies have estimated U.S. production at 5-20 quadrillion Btu by 2020.

Illinois and Indiana, particularly Illinois, are likely to capture a significant share of the U.S. synfuels industry. Illinois already has three major ERDA-sponsored demonstration projects for coal conversion. Illinois has significant coal reserves and relatively plentiful water supplies to support a mature industry. Many of the development problems are mitigated by the Illinois tradition of coal extraction and sizable labor force in and around coal-mining areas. A well-developed transportation network connected to nearby demand centers completes the set of favorable conditions in Illinois for a potential synfuels industry.

Most of these factors are also present in eastern Ohio, but coal reserves there are fairly depleted. After 2000, there may not be enough locally concentrated coal reserves in Ohio to supply the 150 million tons required over the life of a 250×10^6 cf/day plant. Therefore, this report focuses on the long-term potential for a gasification industry in Indiana and Illinois.

The tenuous near-term-future of the synfuels industry leads us to consider that synfuel conversion might reach significant levels within 50 years. Because of the currently unfavorable economics of synfuels, no commercial plants were expected to be in operation by 1985. We assumed that, by 2000, Illinois could contain six standard size (250×10^6 cf/day) second-generation gasification plants, and 14 plants by 2020. It was further assumed that Indiana would contain one standard gasification plant in 2000 and five in 2020 respectively. These plants would all be near feed-supplying mines and would supply in turn their gas products to markets in the Midwest. Likely sites for these plants were largely drawn from an earlier study of gasification potential for Illinois[9] as well as recently announced industry plants.[10] The projected number of plants and associated coal consumption are summarized in Table 3.12.

The impact of the above level of gasification on supplies of gaseous fuels is shown in Fig. 1.5, which shows the total Midwest demand for methane and the proportion obtained from coal gasification. The total demand has a slow growth, attributable to price increases and population stabilization; thus, the assumed level of coal gasification accounts for almost half of total supplies of gaseous fuel by the year 2020.

Table 3.12. Annual Coal Consumption Scenarios for Coal Synfuel Conversion in the Midwest

Year	Number of Commercial Plants	Coal Consumption, 10^6 tons/year[a]
1985		
Illinois	0	0
Indiana	0	0
2000		
Illinois	6	30
Indiana	1	5
2020		
Illinois	14	70
Indiana	5	25

[a]Based on a standard 250 x 10^6 scf/day (950 Btu/scf) facility with 70% thermal efficiency, 330 days/year, 22 x 10^6 Btu/ton coal, or approximately 5 x 10^6 tons/year per facility.

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4 SITING PATTERNS

Full assessment of impacts and constraints related to coal gasification requires a description of the geographical distribution of the processes that are part of the coal energy cycle. This siting pattern is necessary to consider area-specific impacts related to these processes and the cumulative impacts of the entire coal-related energy system within a region.

Future siting patterns, including the characteristics of the facilities at each site, cannot be predicted. However, it is possible to construct a plausible set of *a priori* assumptions for siting criteria and procedures that will result in the straightforward projection of a pattern for siting and technology consistent with those assumptions. An evaluation of the impacts and constraints for that pattern can then be used to guide definition of siting and technology options that can be analyzed to determine associated trade-offs.

In this study a baseline siting pattern for the six-state region and a second siting pattern in Illinois incorporating high use of Illinois coal have been developed from the criteria and procedures described below. The resulting siting patterns are shown in Figs. 4.1 and 4.2.

4.1 CAPACITY REQUIREMENTS

The electrical-generation capacity needed by each of the six states according to type of fuel (coal, nuclear, oil, other) are given in Sec. 3. Generation from coal is further classified by type of coal (produced in state, imported low-sulfur, imported high-sulfur). Although the impacts on health and environment of power generation of fuels other than coal were not considered, all major facilities for all fuel types had to be sited to obtain a consistent pattern that takes into account competition for water, land, and other resources by facilities using fuels other than coal.

Because of the long lead times necessary to put baseload power plants in operation, the sites of most plants that will be in operation (or decomissioned) by 1985 are already planned; this information can be obtained from the Federal Power Commission.[1] Locations of the existing or planned facilities in the six-state area are shown in Appendix B.

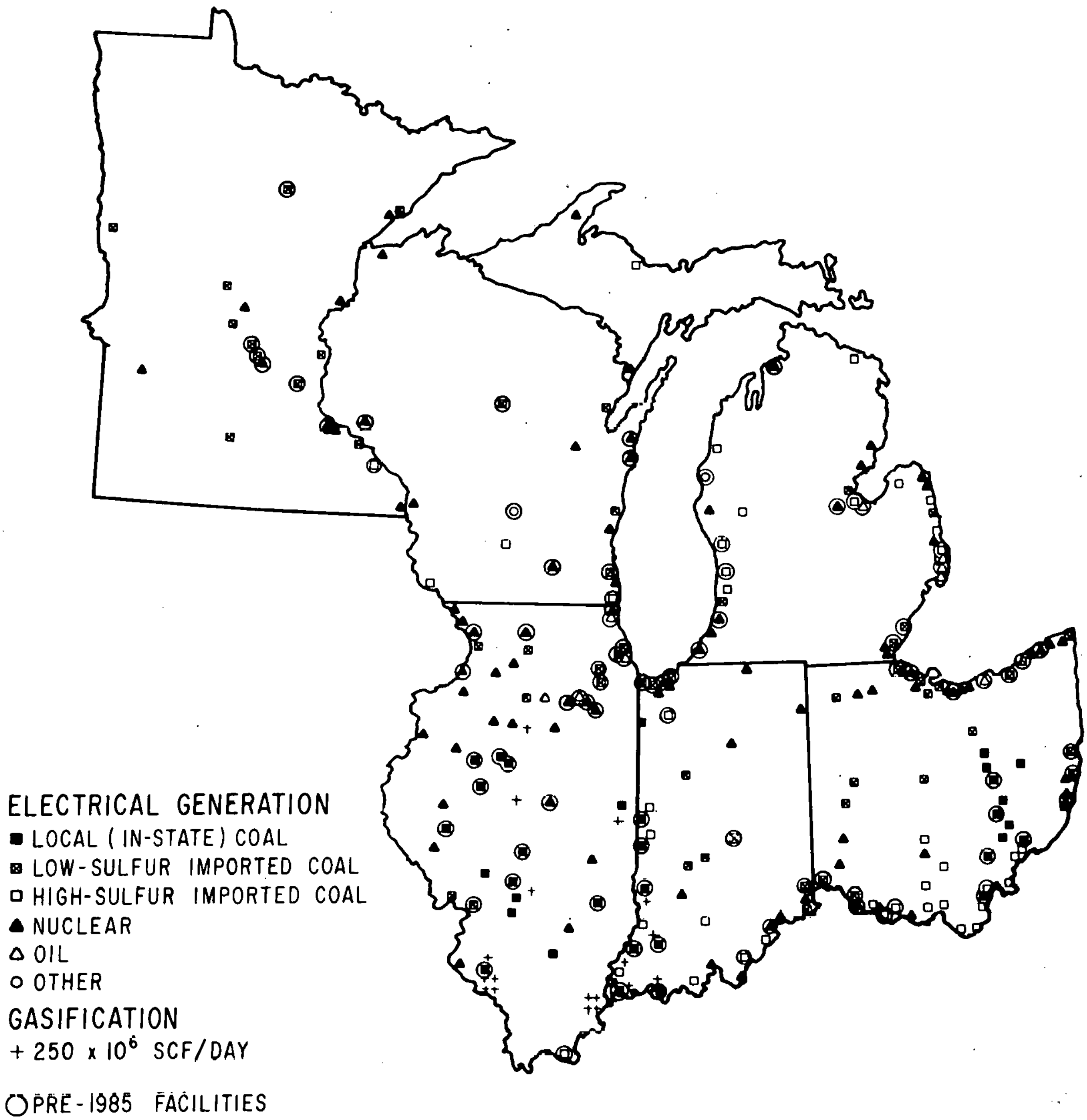

Fig. 4.1 Energy Facility Siting for Baseline Scenario (2020)

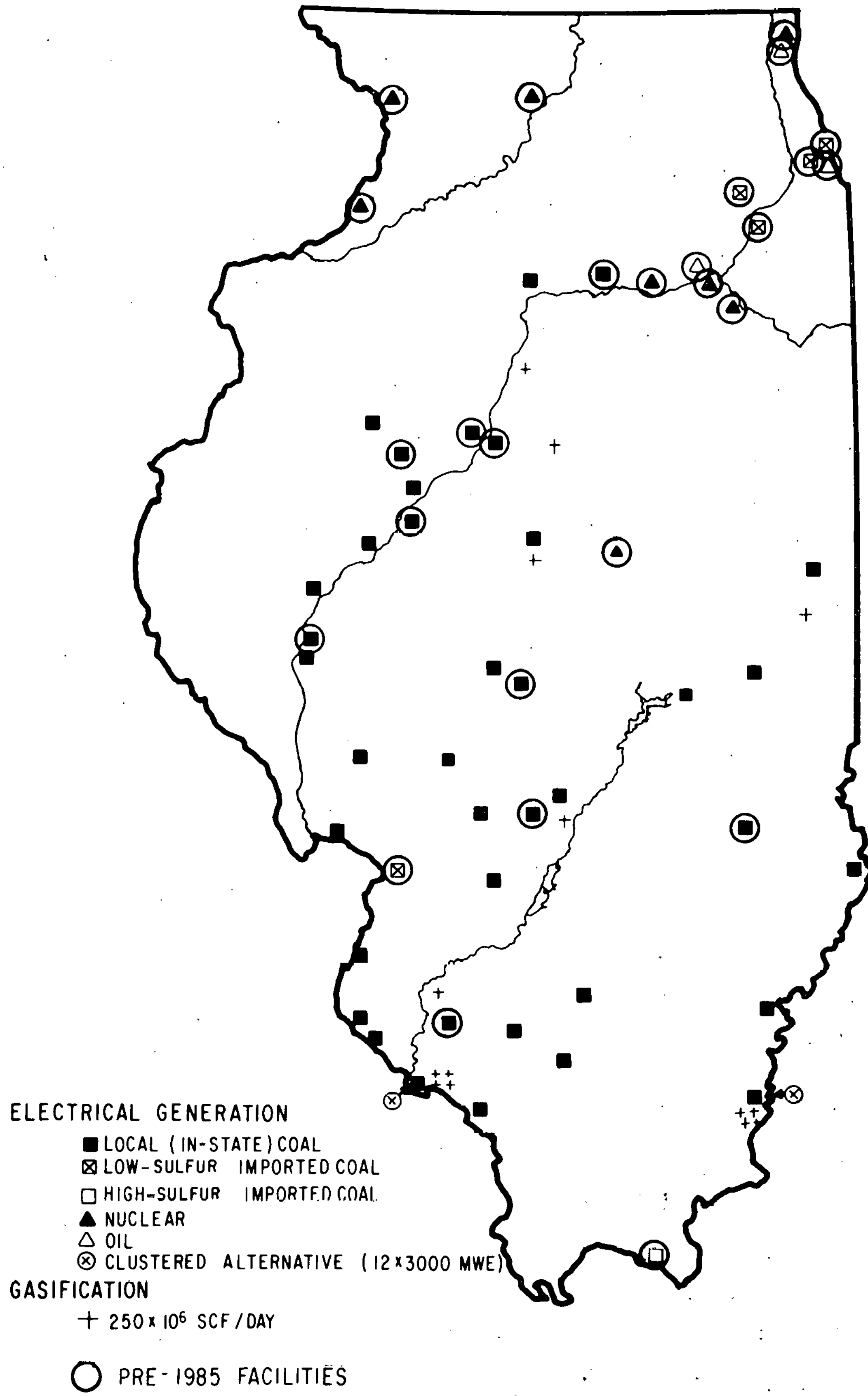

Fig. 4.2 Energy Facility Siting for Illinois High Coal Use Scenario (2020)

Although most existing power plants will not be in operation in 2020, it was assumed that all plants existing in 1985 will exist in 2000 and 2020. This assumption is not unreasonable, because the utility probably would build a similar (or larger) plant on the same site after retirement of the present plant. The only exceptions to this assumption were plants for which capacity will be less than 200 MW in 2000 and those with capacities less than 500 MW in 2020. They were excepted because they would be either retired or converted to peaking plants and thus not included in this study. The plants that continue in existence would maintain their present fuel. However, the source of coal for the coal plants was not restricted to that now used. Each plant was assigned one source of coal after consideration of air quality, proximity of coal reserves, and assumed coal mix for each state.

In addition to electrical-generation facilities, the coal-gasification plants described in Sec. 2 for the energy-development scenarios for Illinois and Indiana were sited by similar procedures. The siting projection for these facilities was identical for both Illinois scenarios.

Projected new facilities were assumed to have uniform total site capacities of 3000 MW for electrical generation and 250 x 10^6 scf/day for gasification to produce high-Btu gas. The 3000-MW capacity for electrical generation is consistent with current trends in projected additions to baseload capacity. These utility projections include many sites that each contain multiple 500 to 1000 MW units. The largest is the coal-fired Sherburne facility in Minnesota, which is projected to have two 680-MW and two 800-MW units when completed in 1984, or a total of 2960 MW. Constraints on site availability may reverse this trend toward large facilities; however, the uniform assumption of large plants emphasizes the importance of those constraints. The assumed sizes for the gasification facilities are consistent with most studies on engineering design and environmental impacts for coal gasification. A further advantage of these unit sizes is that 3000 MW is nearly equivalent to 250 x 10^6 scf/day at 1000 Btu/scf, thus facilitating comparison of gasification and electrical generation.

An alternative to dispersing coal-fired electrical-generation facilities throughout the region is to cluster them in areas with large water and coal resources and thus take advantage of possible geographical and technological economies of large-scale construction.[2] To evaluate the relative environmental impact of clustering, two potential sites for clusters of electrical generation facilities[3] are indicated in Fig. 4.2.

4.2 *SITING CRITERIA*

The objective of the siting procedure was to place the plants close to the load center, subject to the following criteria:

<u>Water</u>

1. Total water consumption for energy production from rivers in the Upper Mississippi and Ohio River Basins must be less than 2% of the annual runoff in these basins.

2. If all new power plants upstream from any point on a river obtain their water directly from the river (i.e., do not have reservoirs or cooling ponds), the total water consumption rate by these plants cannot exceed 20% of the 7-day/10-year low flow at that point.

3. If all new power plants upstream from any point on a river use reservoirs or closed cooling lakes, the total water consumption rate by these plants can be as high as 40% of the 7-day/10-year low flow, because these lakes or reservoirs are less affected by short periods of low flow. For Illinois, a more detailed evaluation of potential reservoirs was made possible by using the results of an analysis conducted by the Illinois Water Survey.[4] This information gives the yield of potential reservoirs throughout the state defined as one-half the reservoir capacity during a drought that recurs once each 40 years.

A more detailed discussion of constraints of water availability and low-flow is presented in Sec. 6.

<u>Air</u>

1. New coal plants cannot be sited in Air Quality Maintenance Areas (AQMAs).

2. Existing coal plants in AQMAs burn low-sulfur coal, which, in combination with a removal technology such as flue-gas desulfurization, represents best available control technology.

3. When possible, siting coal plants in counties that have a monitored violation of National Ambient Air Quality Standards must be avoided.

4. There must be a minimum of ten miles between the 3000-MW plants.

The relationship of siting and air quality is discussed in more detail in Sec. 7.

Population

1. 3000-MW plants cannot be sited within ten miles of cities with populations greater than 25,000.

Transportation

1. New plants burning instate coal must be near an adequate coal resource (coal resources are discussed in Sec. 5).

2. All plants using imported fuels must be near navigable waterways or adequate rail networks.

Public Lands

1. Conversion facilities cannot be on publicly owned lands.

4.3 SITING PROCEDURES

For the 3000-MW plants, the first step was siting the plants burning in-state coal as close to the mines as possible. For the baseline scenario, all new mine openings in Illinois between 1985 and 2000 were projected to be 67% deep mines and 33% surface mines, with all mines after 2000 being deep mines. In Indiana and Ohio, all mines opened after 1985 are expected to be deep mines. Alternatively, for the Illinois High Coal Use Scenario, it was assumed that strip mines would compose 50% of all new mine openings between 1985 and 2000, and 43% of new openings between 2000 and 2020. These percentages are based on the belief that the ratio of strip mines to deep mines will be higher than that assumed in the nominal case, because previously marginal strip mines become profitable as coal prices increase in response to higher demand. All the counties within these states were then ranked in terms of deep and surface reserves. Proceeding through the rankings, sites were selected if adequate water was available and if there was no existing exclusionary constraint (Air Quality Maintenance Area, high population density, lack of transportation, public land). The plants burning in-state coal are expected to serve the nearest load centers.

By using the criterion of water availability, the remaining plants (those using out-of-state coal, nuclear power, or other sources) are located as close to the load centers as possible. These potential sites are, however, first screened for exclusionary areas, as above. Final selection of the sites and plant fuels was based on air quality and transportation facilities. The resolution for site selection was at the county level.

The coastal zones of the Great Lakes were projected as sites for plants using imported coal (there are no coal resources in the coastal zone) if the following conditions were met:

1. The site was nearest the load center and did not violate the constraints considered; or

2. There were no remaining unconstrained sites on inland waterways within the state.

4.4 CONSTRAINTS

Applying the siting criteria and procedures to obtain the siting patterns in Figs. 4.1 and 4.2 identifies factors that are expected to constrain future siting options. The principal constraints can be summarized as follows:

1. Choice sites for large energy facilities that are near load centers, coal resources, and water resources are nearly exhausted; and future siting will require a trade-off between these factors.

2. The aggregate water supplies of the Mississippi and Ohio Rivers and the Great Lakes are sufficient to supply energy needs. However, use of these water resources is limited by heavy competition for shoreline sites and by the distance of the major rivers from many of the large load centers.

3. Separation of the available coal and water resources from the load centers will increase transmission requirements.

4. Limits on use of the water resources in the major rivers and Great Lakes will make the construction of reservoirs on smaller streams more attractive. The advantages of energy facilities near coal deposits, many of which are far from water supplies, also encourage development of reservoirs. Much of the six-state area is prime agricultural land, which emphasizes land-use issues related to construction of the large reservoirs required.

5. The coal resources in the study region are in general located in areas of good air quality (see Sec. 7.1) and thus pollutant concentration can be increased without violating standards. Exceptions are parts of eastern Ohio and the Springfield, Peoria, and East St. Louis areas in central Illinois, in which more active management of air quality is required.

6. Comparison of the 1985 utility projections and the 2020 siting patterns indicates that the trends in siting implied by the above issues and constraints are to some extent already occurring.

It is emphasized that the results of this siting analysis partly depend on the criteria and procedures described previously. The 7-day/10-year low-flow constraints were the most restrictive because of the assumption that new plants were 3000 MW and would primarily use wet cooling towers, which consume approximately 33 cfs for a 60% plant load factor. If the power plant is built on a reservoir or lake, the additional evaporative loss from the plant heat addition is only 20 cfs when the lake is used for all cooling requirements. However, the total evaporative losses, including normal lake evaporation, approaches 35 cfs or more, depending on the water surface area and the climate.

The analysis did not deal with site-specific issues important at the subcounty level of analysis -- e.g., occurrence of sensitive ecosystems such as aquatic spawning grounds. Others are the amenability of the subsurface soil conditions to facility construction or existence of flood plains along river shorelines. Nor were the socioeconomic impacts of facilities considered. State-to-state energy transfers may also be important in determining siting patterns.

The following is a discussion of the above issues and constraints as they relate more specifically to each state.

Illinois. The demand for energy is dominated by the northeastern metropolitan Chicago area, whereas the major coal resources are in the central and southern areas. The criteria for siting facilities using in-state coal near the supplying mine places a heavy demand on the water supplies of central and southern Illinois, where the only major river is the Illinois. These water constraints were alleviated by assuming reliance on construction of potential reservoirs that were identified by an Illinois Water Survey Study.[4] Conflicts in land use can be expected to occur from development of energy facilities in the central Illinois coal fields because of the high quality of the land for agricultural uses. Except for the southern reach, the Mississippi River is not near either Illinois coal or the Chicago load center. A shift from nuclear power to use in-state coal, as indicated in Fig. 4.2, accelerates the trend toward the development of energy facilities in the southern and central areas.

Indiana. Although the largest load center in Indiana is in the northwest, the Ohio River on the southern border is the major water resource for energy development. More than a third of the 3000-MW plants had to be sited on the Ohio River. Use of the limited Lake Michigan shoreline in Indiana is constrained by competition from urban, industrial, and recreational uses. The Wabash River and its tributaries flow through the coal resource region of Indiana and can be expected to be used for development of those resources, but available flows are much below those of the Ohio River. Nearly all sited new plants that are not on the Ohio River or the lowest reach of the Wabash River will require reservoirs.

Michigan. Because of the lack of major inland rivers, nearly all new energy facilities in Michigan were sited along the extensive Great Lakes shorelines. Since Michigan has virtually no coal, this coastal siting also has the potential advantage of permitting coal transportation by Great Lakes barges. Coastal-zone management would become important under this siting scenario, especially in view of the emphasis placed on conservation and wilderness preservation in Michigan.

Minnesota. The Mississippi and St. Croix Rivers near the major Minneapolis-St. Paul load center in Minnesota allow siting of energy facilities to supply needs of that state without serious constraints. Possible coal-related siting issues in this state requiring evaluation are use of Lake Superior shoreline sites for: (1) a deep harbor in a transportation link for eastward shipment of coal from the Great Plains; or (2) construction of energy facilities burning Great Plains coal to produce electricity for transmission to Midwestern markets.

Ohio. The greatest discrepancy between required and potential sites are in Ohio. These difficulties resulted from a combination of (1) a high projected demand; (2) existing heavy development along the Ohio River and Lake Erie shores; (3) an absence of large rivers in the state interior; and (4) Air Quality Maintenance Areas in the eastern portion and near the coal fields in the southeast. To circumvent these siting problems, facilities were sited on the Maumee, Miami, Scioto, and Muskingum Rivers beyond the capacity allowable with the low-flow constraint if wet cooling towers are used; that is, reservoirs to enhance water supplies, or alternative cooling methods that consume less water, would be required. Construction of large cooling ponds or reservoirs would result in conflicts in use of prime agricultural land as in Illinois and Indiana.

Wisconsin. The constraints on power-plant siting in Wisconsin are not as severe as in Illinois, Indiana, and Ohio. Adequate water supplies are available in this state from major rivers and the Great Lakes; although, as in Michigan and Minnesota, sound coastal-zone management in currently undeveloped areas is a primary concern. Because of the adequate water resources, generation and export of electrical energy may become an issue.

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5 REGIONAL COAL RESERVE BASE AND EXTRACTION REQUIREMENTS

5.1 COAL RESERVE BASE

The major coal resources within the six-state study area, as shown in Fig. 5.1, are in the Interior Coal Province, which includes the Illinois and Indiana coal fields, and the Appalachian Coal Region in the Eastern Province, which includes the coal fields in southeastern Ohio. In addition, there are Interior Province fields with significantly smaller resources in lower Michigan. The state total reserve base, 1974 production, and 1975-1985 planned capacity additions classified by deep vs strip mining are shown in Table 5.1. The reserve base for Illinois, Indiana, Michigan, and Ohio are 15, 2, 0.03, and 5%, respectively, of the U.S. total of 437 billion tons.[1]* The reserves in these states are primarily bituminous coal.

Of the states considered, Illinois has the largest reserve base and also the largest 1974 production of coal, for which there was a rather even balance between strip- and deep-mine production. However, the planned additions through 1985 indicate a trend toward extraction of deep reserves by a two-to-one ratio.

The minor coal reserves in Michigan are not now being exploited and there are no announced intentions to do so soon.

Current production of Ohio coal from strip mines is over twice that from deep mines. However, the planned additions of new mining capacity are almost totally from deep mines, indicating a possible depletion in economically attractive strippable reserves. The planned additions in total capacity, relative to current production, are also smaller for Ohio than for Illinois and Indiana.

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*Coal resources in this section refer to the "reserve base" category. As defined by U.S. Bureau of Mines,[2] the reserve base includes: beds of bituminous coal and anthracity 28 in. or more in thickness and beds of subbituminous coal 60 in. or more in thickness that occur at depths to 1000 ft; thinner or deeper beds now being mined or for which there is evidence that they could be mined commercially now; and beds of lignite 60 in. or more thick that can be surface mined -- generally those no deeper than 120 ft. It includes only coal from measured and indicated categories of reliability. For comparison, the total quantity of coal estimated to exist in the U.S. including both identified and hypothetical deposits, is 4 trillion tons.[1]

Table 5.1. Reserve Base, 1974 Production, and 1975-1985 Planned Additions by Mining Method (10^6 tons)

State	Mining Method	Reserve Base[a]	1974 Production[b]	1975-1985 Planned Additions[c]
Illinois	Deep	53,400	31.3	22.6
	Strip	12,200	27.0	10.7
	Total	65,600	58.3	33.3
Indiana	Deep	8,950	0.14	0.5
	Strip	1,670	23.6	9.6
	Total	10,620	23.7	10.1
Michigan	Deep	118	--	--
	Strip	0	--	--
	Total	118	--	--
Ohio	Deep	17,400	14.4	10.95
	Strip	3,650	31.0	0.70
	Total	21,050	45.4	11.65

[a]Ref. 2.

[b]Ref. 3.

[c]Annual capacity, Ref. 3.

The county-by-county distribution of the coal reserve base is shown in Fig. 5.2, and in Appendix C along with 1974 county production levels.

The fraction of the reserve base that can be recovered depends on whether the coal bed is suited for underground or surface mining. Average recovery by underground mining would be about 50%, owing primarily to coal left unmined to support the surface. Extraneous circumstances that may increase the portion of the reserve base that may be lost to any mining are: coal under urban areas; deep-minable coal reserves beneath airports, parks, recreation areas, public institutions, or major waterways; and coal in areas of active mining where there are multiple coal beds, and beds overlying or underlying worked-out beds that are hazardous and expensive to mine.

Recovery of coal by strip mining depends primarily on the ratio of the thickness of the overburden to that of the coal bed. Basically, a ratio of 15 ft of overburden per foot of coal thickness was used in calculating the strippable reserve base, but there are exceptions, as noted in Table 5.2.

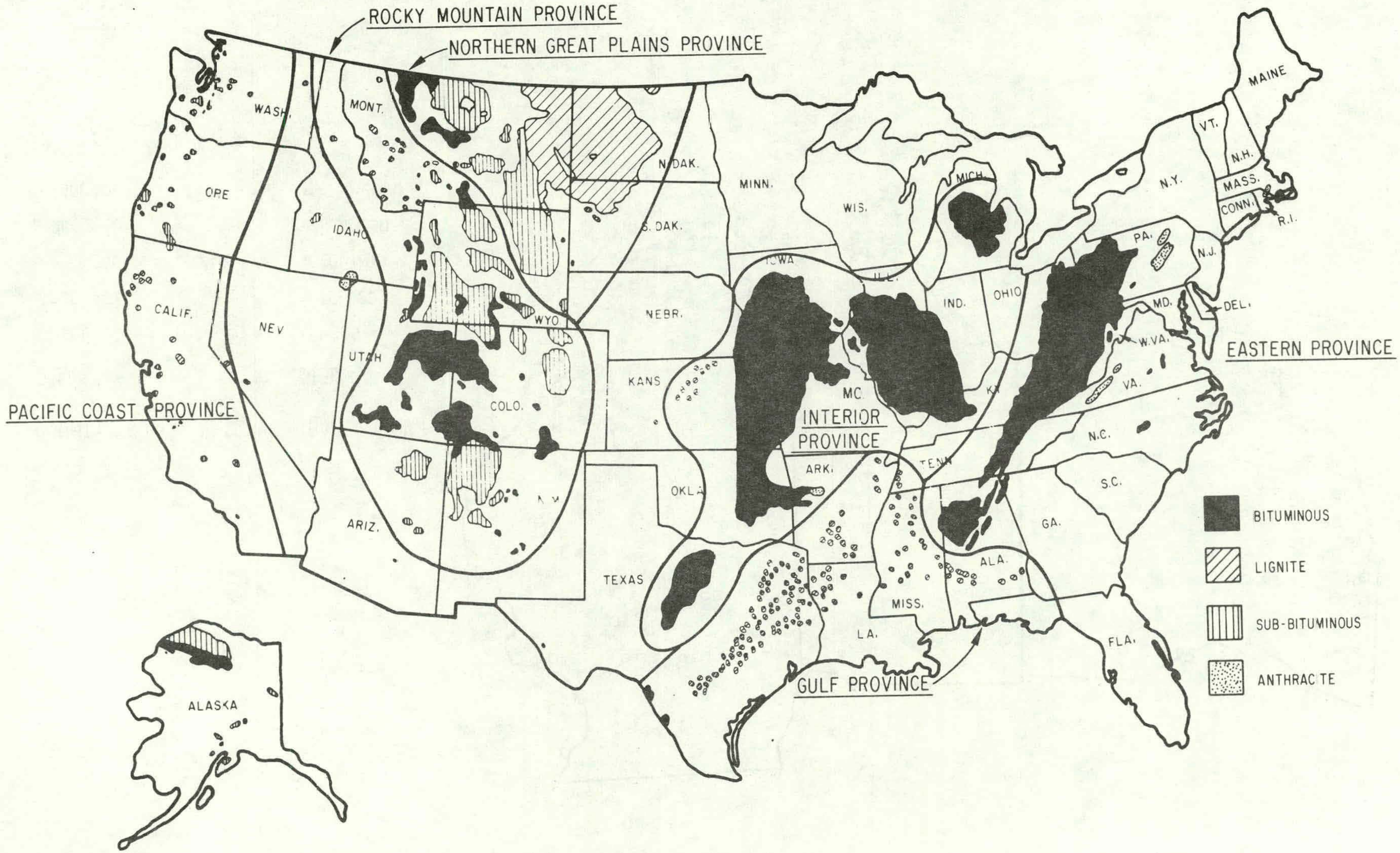

Fig. 5.1 Bituminous and Subbituminous Coal and Lignite Fields of the United States

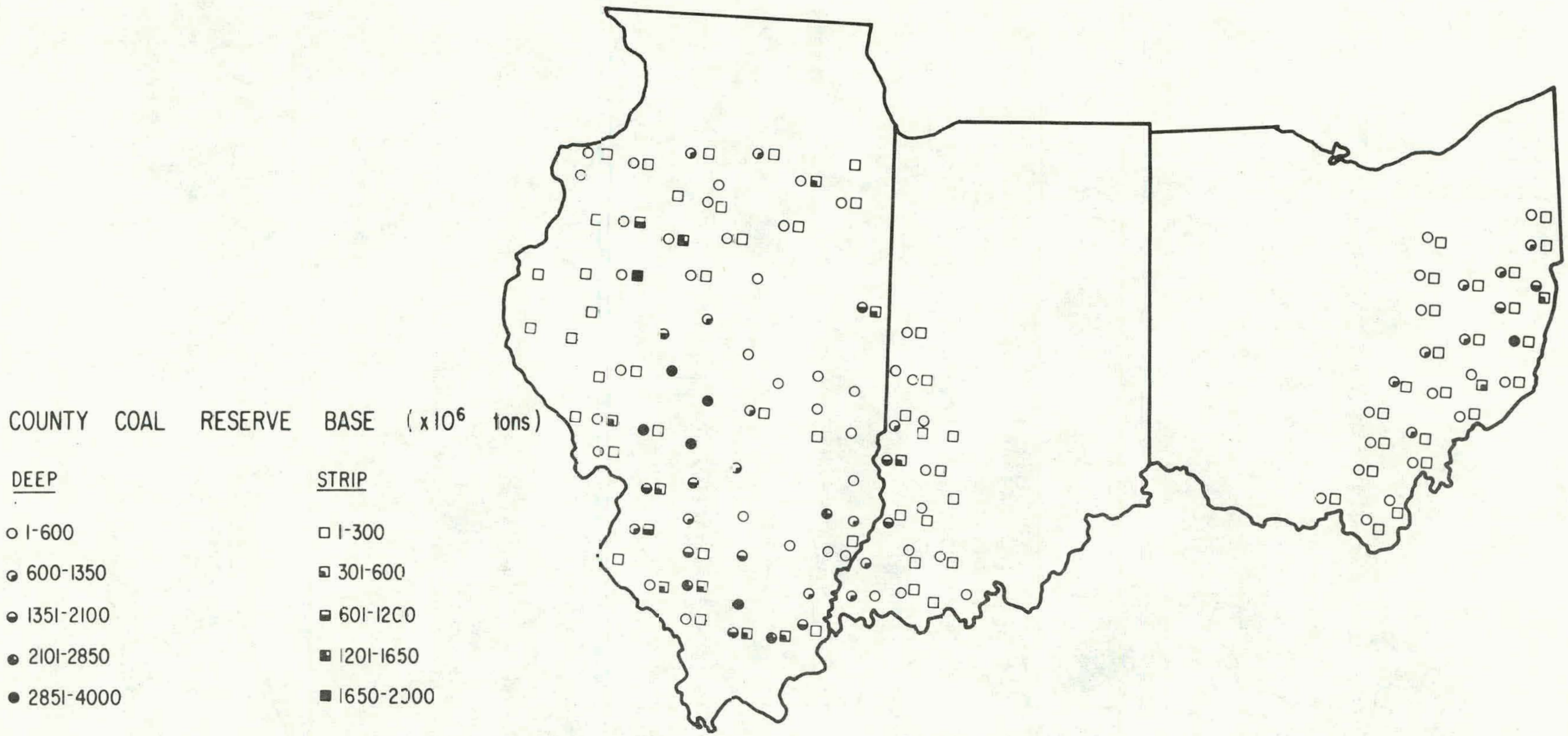

Fig. 5.2 County Coal Reserve Base Recoverable by Deep and Strip Mining

Table 5.2. Criteria Used in Estimating Strippable Reserve Base of Bituminous Coal and Lignite[2]

State	Minimum Coal-bed Thickness, in.	Maximum Overburden Thickness for Computing Reserves, ft	Stripping Ratio,[a] ft
Illinois	18	150	18:1
Indiana	14	90	20:1
Michigan	28	100	20:1
Ohio	28	120	15:1

[a]Based on maximum feet of overburden thickness at the high wall per foot of coal-bed thickness.

Another factor affecting the recoverability of coal is topography. Recovery will vary depending on the type of mining (contour stripping or area stripping), ranging from about 80% to over 90%.

Standards for air quality and emissions from plants have resulted in increased attention to sulfur content of coal. New Source Performance Standards (NSPS) for SO_2 are given in terms of allowable emissions per unit heat input (1.2 lbs $SO_2/10^6$ Btu) and thus the ratio of sulfur content and heating value becomes important in considering suitability of coal on the basis of these standards. Table 5.3 lists the average heating value of coal resources in the U.S. and the fraction of these resources in given categories of the sulfur content/heating value ratios. As shown in Table 5.3, only a very small fraction of the coal from the Midwestern states considered in this study can be used without sulfur removal in the flue gas or by preprocessing of coals, whereas much of the Western coal will meet the NSPS without sulfur control.

5.2 *EXTRACTION REQUIREMENTS FOR ELECTRICAL GENERATION AND GASIFICATION*

The annual coal consumption for the electrical generation and coal gasification projected by the scenarios are in Tables 3.11 and 3.12 for 1985, 2000, and 2020. By assuming a linear rate of growth in consumption for the periods between these years, a rough estimate of the total coal demand by these facilities in the 1985-2020 period can be obtained, as shown in Table 5.4.

Comparing Tables 5.1 and 5.4 shows that the combined coal consumption for energy generation in Illinois is 6% of the reserve base for the Baseline

Table 5.3. Coal Reserves Averaged by State[4]

State[b]	Average Heating Value, 10^3 Btu/lb	Fraction of State Reserves[a]							
		Sulfur Content/Heating Value (%S/10^3 Btu/lb)							
		0.021	0.042	0.050	0.063[c]	0.100	0.210	0.246	0.316
Alabama	13.0	0	0	0.01	0.27	0.70	1	1	1
Arizona	10.5	0	0	0	0	0.94	1	1	1
Arkansas	13.5	0	0	0.03	0.04	0.68	1	1	1
Colorado	11.5	0.01	0.54	0.63	0.71	0.93	1	1	1
Illinois	11.0	0	0	0	0	0.08	0.16	0.19	0.35
Indiana	11.5	0	0	0	0.08	0.23	0.38	0.44	0.78
Iowa	10.0	0	0	0	0	0	0	0	0.28
Kansas	12.0	0	0	0	0	0	0.21	0.36	0.56
Kentucky	12.5	0	0.07	0.07	0.30	0.44	0.50	0.51	0.84
Maryland	13.5	0	0	0	0	0.41	0.77	0.93	1
Michigan	11.5	0	0	0	0	0	0.77	0.95	1
Missouri	11.0	0	0	0	0	0	0	0.11	0.11
Montana	8.5	0	0.68	0.72	0.97	0.99	1	1	1
New Mexico	12.0	0	0.40	0.40	0.98	0.99	1	1	1
North Dakota	6.5	0	0.04	0.05	0.05	0.48	0.99	0.99	1
Ohio	12.0	0	0	0	0	0	0.21	0.49	0.78
Oklahoma	13.0	0	0.08	0.08	0.32	0.42	0.72	0.72	0.93
Pennsylvania	13.0	0	0	0.02	0.02	0.11	0.80	0.92	0.99
South Dakota	6.5	0	0	0	0	0.65	1	1	1
Tennessee	13.0	0	0.02	0.02	0.20	0.45	0.75	0.92	1
Texas	8.5	0	0	0	0	0	1	1	1
Utah	12.0	0	0.76	0.76	0.76	0.79	1	1	1
Virginia	13.5	0	0.32	0.48	0.71	0.92	1	1	1
Washington	8.5	0	0.16	0.16	0.18	0.84	1	1	1
West Virginia	13.5	0	0.16	0.26	0.44	0.55	0.83	0.88	0.96
Wyoming	9.0	0	0.37	0.37	0.45	0.96	1	1	1

[a]Entries give fraction of reserves with ratio less than or equal to the indicated values and hence are cumulative in any row.

[b]Only those states having coal reserves are listed.

[c]Meets federal New Source Performance Standards (NSPS) without coal preprocessing or flue-gas desulfurization.

Table 5.4. Total Coal Consumption for Energy Scenarios in the Midwest, 1985-2020[a] (10^6 tons)

Coal Source	Electrical Generation[b] Baseline	High Coal	Gasification
Interior			
Illinois	2706	4678	1225.0
Indiana	850	-	337.5
W. Kentucky	83	-	-
Eastern			
Ohio	1614	-	-
Other, High Sulfur	2704	-	-
Other, Low Sulfur	404	-	-
Western	5576	5171	-

[a]Based on linear interpolation of annual coal consumption in Tables 3.11 and 3.12.

[b]Indicates variation resulting from high rate of use of Illinois coal for electrical generation in that state.

scenario, and 9% for the High-Coal Electric Scenario. For Indiana, the scenario requires 11% of the reserve base and for Ohio, 8%. Thus, these high levels of coal production do not significantly deplete the total reserve base. Yet the coal extracted probably will be significantly less attractive economically than that now being mined. Also, these extraction levels could cause significant local environmental and socioeconomic impacts in areas with intense mining activities.

Figure 5.3 presents the siting pattern for the Illinois High-Coal Use Scenario, with the additional projection of which facilities use strip-mined coal and the general area in which the supplying strip mine is located. County location of strip mines was based on a ranking of the strippable reserves as given in Appendix C, plus additional siting factors discussed in Sec. 4.

It was assumed in this scenario that strip mines would comprise 50% of all new mine openings between 1985 and 2000, and 43% of new openings between 2000 and 2020. This assumption is based on the belief that the ratio of strip to deep mining will be higher than that used in the baseline case, because previously marginal strip mines will become profitable as coal prices rise with higher demand.

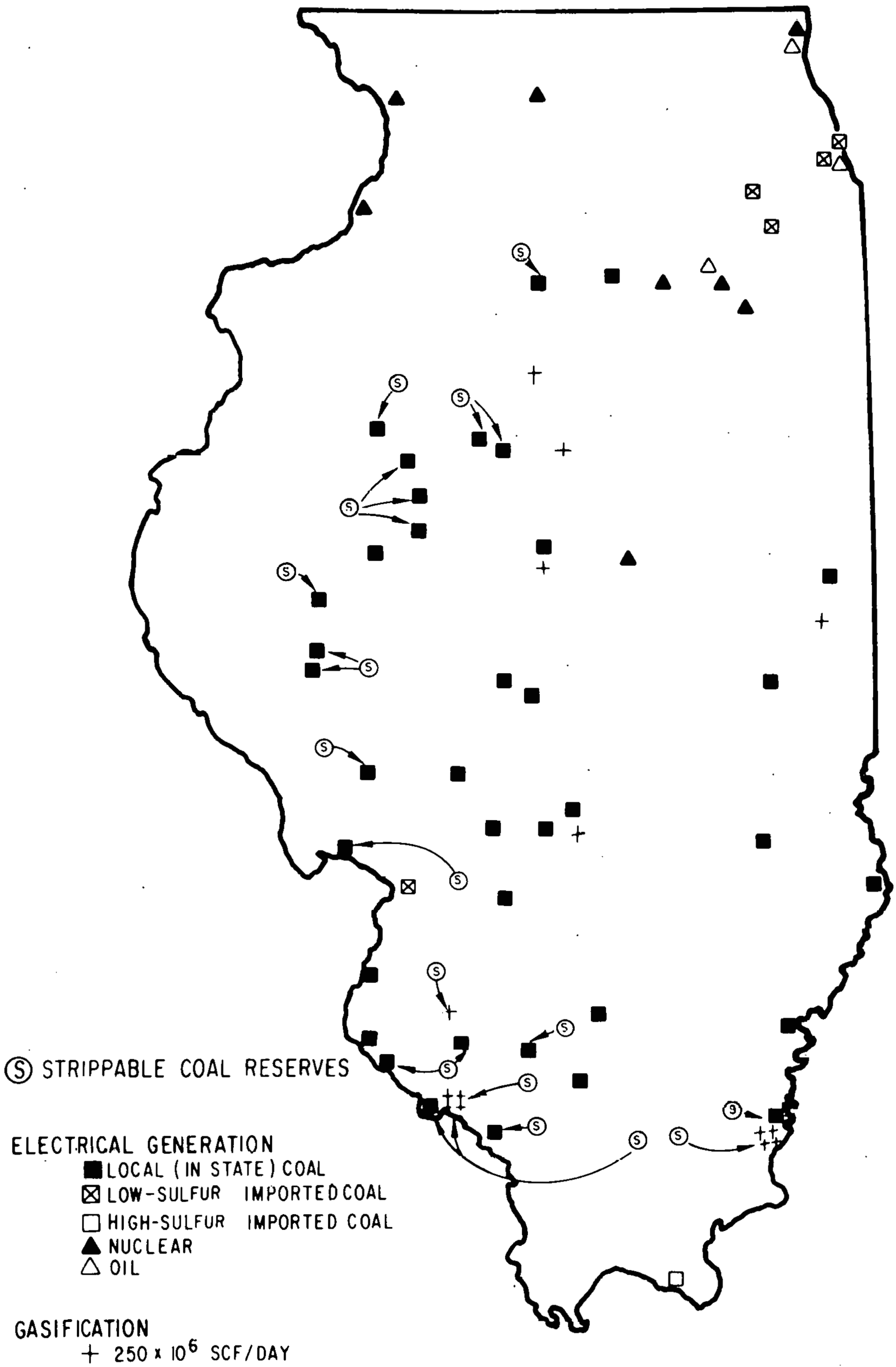

Fig. 5.3 Strippable Coal Reserves in the Vicinity of Sites for Illinois High Coal Use Scenario

There are two important points for the start-up dates in Table 5.5. First, only existing or planned plants with power above 500 MW are included in this study, and they are assumed to last until after 2020. This projection is based on the fact that plants with power above 500 MW are already on "good" sites, as far as the utilities are concerned and would, therefore, be good candidate sites for new plants of the same size when the existing plants shut down. The argument does not apply to smaller coal plants, which are expected to decrease in numbers. Not considering the smaller plants may cause land disturbance in 1975-1985 to be underestimated.

Table 5.5. Cumulative Electrical Generation (1975-2020) for Facilities Using Strip-Mined Coal in Illinois: High Coal Use Scenario

County	Startup Date	Capacity, MW	Generation, 10^6 MW-hr 1975-1984	1985-1999	2000-2020
Peoria	1975	1786	62.6	117.3	197.1
	1975	1279	44.8	84.0	141.2
Fulton	1978	685	16.8	45.0	75.6
	1976	1400	44.2	92.0	154.5
	1987	3000	--	170.8	331.1
St. Clair	1993	3000	--	92.0	331.1
Williamson	1996	3000	--	52.6	331.1
Madison	1999	3000	--	13.1	331.1
Bureau	2002	3000	--	--	299.6
Knox	2005	3000	--	--	252.3
Randolph	1975	1858	65.1	122.1	205.1
	2008	3000	--	--	205.0
Schuyler	2011	3000	--	--	157.7
Jackson	2013	3000	--	--	126.1
Morgan	1975	500	17.5	32.9	55.2
	2015	3000	--	--	94.6
Gallatin	2017	3000	--	--	63.1
Green	2019	3000	--	--	31.5
Perry	2020	3000	--	--	15.8

The second point relates to the assumptions of constant fuel mix and strip/deep ratio. The proposed strip mines might open earlier than shown here, due to the "lower" costs of strip mining. If they should do so, the total land disturbed by 2020 will be greater.

The distance to load centers was the only factor considered in selecting which plant starts up in a given year. It is beyond the scope of this report to attempt to quantify the many additional factors that may affect this decision.

The electrical generation from these plants was calculated as listed in Table 5.5 and the coal consumptions necessary to supply this generation are listed in Table 5.6.

5.3 IMPACTS ON LAND USE

Although the more detailed evaluation required to identify the magnitude and nature of the impacts associated with this level of extraction was not conducted in this study, an attempt was made to determine the potential total area disturbed by strip mining, which is of major concern. An upper limit for the area disturbed in Illinois, given by the High Coal Use Scenario, was used as the basis for evaluation.

To obtain a value for total acreage disturbed the extraction level for all years must be specified, not only for target years of 1975, 1985, 2000, and 2020. The coarse projections as described below are not expected to be accurate projections of future conditions; nevertheless, they do give an upper limit for evaluation.

To estimate the land disturbance, in each county, associated with the above production figures, estimating an average seam thickness for each county was necessary. A recent study[5] of the coal and water resources of Illinois included maps of the generalized thicknesses of the Nos. 5 and 6 coal seams, and the distance between the seams. From these maps, an average seam thickness for each seam and county was estimated. If the distance between the seams was greater than 30 ft, it was assumed that only the No. 6 seam would be mined. If the seams were less than 30 ft apart, it was expected that both seams would be mined, and the average thicknesses were summed. The final average seam thickness for each county is also listed in Table 5.6.

Table 5.6. Cumulative Coal Consumption (1975-2020) for Facilities Using Strip-Mined Coal in Illinois: High Coal Use Scenario

County	Coal Consumption, 10^6 tons				Strippable Reserve Base, 10^6 tons	Average Seam Depth, ft
	1975-1984	1985-1999	2000-2020	Total		
Peoria	28.2	45.9	77.3	151.4	1422	4
	20.2	32.9	55.4	108.5		
Fulton	7.6	17.6	29.7	54.9	1810	4
	19.9	36.1	60.5	116.5		
	-	66.9	129.8	196.7		
St. Clair	-	36.1	129.8	165.9	1163	7
Williamson	-	20.7	129.8	150.5	530	7
Madison	-	5.1	129.8	134.9	509	7
Bureau	-	-	117.5	117.5	222	4
Knox	-	-	98.9	98.9	605	4
Randolph	29.4	47.8	80.5	157.7	417	7
	-	-	80.3	80.3		
Schuyler	-	-	61.8	61.8	202	3
Jackson	-	-	49.4	49.4	299	9
Morgan	7.8	12.9	21.6	42.3	251	6
	-	-	37.1	37.1		
Gallatin	-	-	24.8	24.8	230	4
Green	-	-	12.4	12.4	423	6
Perry	-	-	6.2	6.2	973	7
	113.1	332.0	1332.0	1767.7		

By using the figures for coal consumption and average seam thickness along with assumed values for coal "density" (lb/ft^3) and coal recovery factor, a value for area of disturbed land was derived for each county and period. These numbers and their totals are listed in Table 5.7. The assumptions used in the calculations are summarized in Table 5.8.

Table 5.7. Cumulative Land Disturbed (1975-2020) from Strip Mining of Coal for Electrical Generation for Illinois: High Coal Use Scenario

County	Disturbed Land, mile^2 1975-1984	1985-1999	2000-2020	Total	Total Area in County, mile^2
Peoria	7.95	12.9	21.80	42.70	623
	5.70	9.28	15.62	30.60	
Fulton	2.14	4.96	8.38	15.48	877
	5.61	10.18	17.06	32.85	
	-	18.86	36.61	55.48	
St. Clair	-	5.81	20.91	26.73	673
Williamson	-	3.34	20.91	24.25	429
Madison	-	0.82	20.91	21.74	733
Bureau	-		33.14	33.14	866
Knox	-		27.9	27.9	728
Randolph	4.73	7.70	12.97	25.41	594
			12.93	12.93	
Schmyler	-		23.23	23.23	434
Jackson	-		6.19	6.19	605
Morgan	1.46	2.42	4.06	7.95	561
			6.97	6.97	
Gallatin	-		6.99	6.99	328
Green	-		2.33	2.33	543
Perry	-		1.00	1.00	439
State Total	27.59	76.27	292.93	403.87	

Table 5.8. Assumptions Used for Computing Land Disturbed for Electrical Generation for Illinois: High Coal Use Scenario

Efficiency (1975-1985)	33% (10.33 x 10^6 Btu/MW-hr)
(1985-2020)	38% (8.97 x 10^6 Btu/MW-hr)
Coal Heating Value	11,440 Btu/lb
Coal Density	82.64 lb/ft^3
Coal Recovery Factor	80%

With a somewhat similar procedure, four high-Btu gasification plants were projected as using strip-mined coal and the most plausible sources of this coal identified as shown in Fig. 5.2. The results in terms of coal consumption and land disturbed is given in Table 5.9.

The total land strip mined (Table 5.8 and 5.9) is over 300 square miles for this upper limit projection. The implication of this level of surface extraction are discussed in Volume II, *Ecological Effects*.

Table 5.9. Cumulative Coal Consumption and Land Disturbed (1975-2020) from Strip Mining of Coal for Gasification in Illinois[a]

		Coal Consumption, 10^6 tons			Land Disturbed, Miles^2			Reserve
Startup Date	County	1985-2000	2000-2020	Total	1985-2000	2000-2020	Total	Base, 10^6 tons
1986	St. Clair	70.	100.	170.	10.85	15.50	26.35	1163
1993	Perry	35.	100.	135.	5.43	15.50	20.93	973
2000	Williamson	-	100.	100.	-	15.50	15.50	530
2006	Saline	-	70	70	-	15.19	15.19	431
Total					16.28	61.69	77.97	

[a]Assumptions: 250 x 10^6 scf/day capacity per plant; 950 Btu/scf; 70% thermal efficiency; 90% load factor; 11,000 Btu/lb coal heating value.

REFERENCES FOR SECTION 5

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6 IMPACTS ON WATER RESOURCES

6.1 INTRODUCTION

Water is required for all phases of the coal fuel cycle. In some areas, water may be insufficient for the requirements of coal utilization, and conflicts may arise because of competing users in agriculture, industry, recreation, and other areas. In addition, waste discharges from coal utilization cause additional pollution that may degrade existing water quality and affect use by man and propagation of aquatic life.

This section presents an initial analysis of water availability in the six-state area and the effects of water consumption and pollution due to coal developments.

The overall objectives of this analysis are:

1. To assess the effects of coal-related activities on water resources regarding the quantity of available water and present and projected competitive withdrawal uses and instream uses.

2. To determine the impacts on water quality of pollutant discharges from coal extraction and utilization.

For each major river basin in the six-state area, availability for future energy development was evaluated. The evaluation includes a calculation of requirements for direct water consumption for the projected power generation and gasification facilities and a comparison of requirements with natural availability. For initial analysis, the 7-day/10-year low flow at river gauging stations was used to represent the natural availability.

In addition, cumulative loading for significant pollutants from coal utilization was calculated for each major river basin in the study area. Loadings were calculated on the basis of future siting development (Sec. 4) and the characterization of effluent discharges of coal utilization facilities, including coal-fired power plants and synfuel production plants (Sec. 2).

Impacts of water use and pollutant discharges on the quantity and quality of water are specific to areas and facilities. In this initial analysis, three river basins in Illinois, the Illinois, Rock, and Kaskaskia, were chosen as example areas. These basins were selected because an intensive energy development was projected for each and a large amount of water-related information was available for these areas. Water-use impacts were evaluated by comparing the quantity of surface and ground-water resources with the projected requirements of future energy development; the projected consumptive needs of competing users, including municipal, industrial, agricultural, and mining uses; and as instream uses by hydroelectric power generation, navigation, recreation, fish and wildlife, and water-quality management.

Impacts on the water quality of the selected rivers were represented by increments of pollutant concentration resulting from effluent discharges of projected facilities. Concentration increments were subsequently compared with existing quality levels and applicable quality standards to identify areas of adverse impacts.

The water requirements for energy production beyond the year 2000 will increase pressure to use Great Lakes water and to construct more reservoirs. Impacts and constraints of use of Great Lakes water and impoundment of water in reservoirs are not considered here.

Drainage and runoff from coal mines and seepage from waste-disposal sites and holding ponds, created for coal utilization and extraction, could cause serious pollution in surface and ground water. Qualitative discussions of these impacts are included in this section. Further assessments are required to evaluate their possible impacts on the water resources of the study area.

6.2 *REGIONAL WATER PROFILE*

The six-state study area includes three Water Resource Council (WRC)[1] regions: the Ohio River basin, the Upper Mississippi River basin, and the Great Lakes basin. The regional boundary and surface waters included in the region are shown in Fig. 6.1.

6.2.1 *Geographic Description of the Region*

Ohio Region

The Ohio River basin covers 203,910 square miles of drainage area. Most of the basin is within three major physiographic provinces, the Appalachian Plateau, the Interior Low Plateau, and the Central Lowlands.

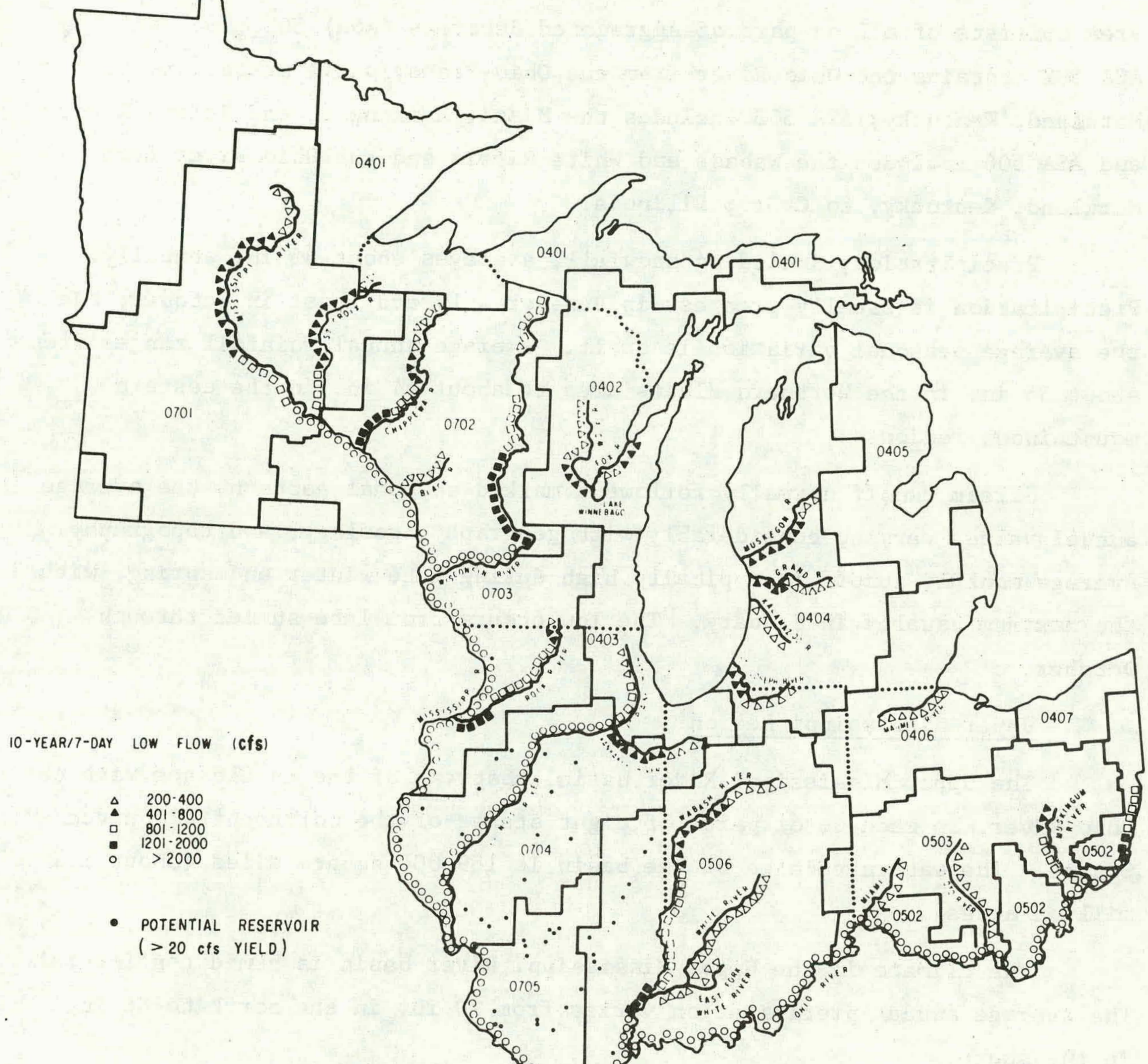

Fig. 6.1 Regional Water Resources Represented by 10-year/7-day Low Flows in Major Rivers

The section of the Ohio River basin WRC Region in the six-state study area consists of all or part of Aggregated Subareas (ASA) 502, 503, and 506: ASA 502 contains the Ohio River from the Ohio-Pennsylvania state line to Markland, Kentucky; ASA 503 includes the Miami, Muskingum, and Scioto Rivers; and ASA 506 includes the Wabash and White Rivers and the Ohio River from Markland, Kentucky, to Cairo, Illinois.

Precipitation, including snowfall, averages about 45 in. annually. Precipitation is usually greatest in June or July and least in October; and the average seasonal variation is small. Average annual rainfall ranges from about 36 in. in the Northern Plains area to about 44 in. in the eastern mountainous regions.

Stream runoff normally follows a marked seasonal pattern, the average annual values varying considerably with geography, geology, and topography. Average monthly runoff is typically high during late winter and spring, with the maximum usually in January. The low occurs from late summer through October.

Upper Mississippi Region

The Upper Mississippi River basin, upstream of the confluence with the Ohio River, is made up of parts of eight states of the northcentral United States. The watershed area of the basin is 189,000 square miles (about 121 million acres).

The climate in the Upper Mississippi River basin is humid continental. The average annual precipitation varies from 20 in. in the north to 48 in. in the south.

The basin extends in a north-south direction for about 700 air miles, from the mouth of the Ohio River to the United States-Canadian border. The east-west extension is 500 miles, from near South Bend, Indiana, to Big Stone Lake, South Dakota.

In the six-state region, the Upper Mississippi Region contains five ASAs, each containing the rivers listed: ASA 701, the Minnesota and St. Croix Rivers plus the Mississippi from its source to Minneapolis; ASA 702, the Chippewa and Wisconsin Rivers and the Mississippi from Minneapolis to Wyalusing, Wisconsin; ASA 703, the Rock River and the Mississippi from Wyalusing, Wisconsin to Burlington, Iowa; ASA 704, the Illinois River and the Mississippi from Burlington, Iowa to Alton, Illinois; and ASA 705, the Kaskaskia River and the Mississippi from Alton, Illinois to Cairo, Illinois.

Great Lakes Region Basin

The major water bodies in the study area in the Basin include Lakes Superior, Michigan, Huron, and Erie, and many inland lakes and streams. The Great Lakes contain a huge volume of water. Most of the rivers in the Great Lakes Region of the Midwest study area drain into Lake Michigan, the only exceptions being the Saginaw, which flows into Lake Huron, and the Maumee, which flows into Lake Erie.

Four ASAs of the Great Lakes Region are included in the study area: ASA 402, the Fox and Wolf Rivers of Wisconsin; ASA 404, the St. Joseph, the Kalamazoo, the Grand, and Muskegon Rivers; the Saginaw River drains ASA 405; and the Maumee River drains ASA 406.

6.2.2 Availability of Surface and Ground Water

The amount of flow and the seasonal, annual, and long-term fluctuations in flow in a river are important in assessing sites for energy facilities. Stream and ground water; water quality and availability; type and quantity of aquatic and terrestial biota; and potentials for assessing sites for river use are all affected by river flow.

For this study, the flow measurement used for characterization and projection is the 7-day/10-year low flow. This parameter provides: a measure of worst-case flow conditions for coal-conversion facilities, and also a maximum boundary for siting considerations. Table D-1 in Appendix D contains, for each WRC aggregated subarea, information on the 7-day/10-year low flow at designated river miles. This information is also summarized in Fig. 6.1. These data were gathered from published reports available from federal and state agencies, including the U.S. Geological Survey, Corps of Engineers, EPA, and State Water Resources Boards.

Compared with surface water, ground water has been rather insignificant as a source of water to energy development in the study region. Ground water is, however, a potential long-term or supplemental source of water required for energy-generation facilities. Availability and quality of ground water vary considerably between and within river basins. Ground water availability depends on recharge rates, types of substrata that convey and contain the water, and degree of development of the aquifer. Availability and quality are site-specific, but generalizations can be made for large areas.

In the Ohio River Basin, moderate to plentiful supplies of ground water are available throughout most of the areas of glacial till and the alluvial valleys. The unconsolidated deposits north of the Ohio River contain large ground-water storage reservoirs in buried flow channels formed by preglacial drainage systems. For the most part, ground-water reserves of the glacial till and the small area of the Gulf Coastal Plain in the lower portion of the Ohio River Basin are plentiful and adequate except for the needs of large concentrated municipal and industrial water supplies. However, the effect on stream flow of ground-water withdrawal may restrain its use.

The mineral content of ground water is generally higher than that of surface water. Chloride is excessive in several areas. Also excessive in some areas are mineral concentration and hardness. High iron content is common throughout the basin.[2]

In the upper Mississippi River basin, the most widespread consolidated aquifers are of sandstone, which provides poor to medium yields of ground water. There are also large areas of limestone and dolomite aquifers of extremely variable yield. Unconsolidated aquifers of good to excellent yield line most present river systems and are also in ancient river-bed systems. Ground-water availability is generally good, except in areas of large municipal and industrial locations, where use exceeds recharge.

Water from the consolidated aquifers of sandstone, limestone, and dolomite and unconsolidated aquifers of sand and gravel is generally hard, due to excessive calcium and magnesium in the aquifer-bearing rock, although the degree of hardness varies significantly. Other ground-water quality problems include dissolved solids and iron.[3]

In the Lake Michigan area of the Great Lakes basin, ground water occurs in several formations. Probably more than one aquifer will be available at any well site. Although the Lake Michigan basin has the largest ground-water supplies in the Great Lakes Basin, it includes areas where natural or man-made conditions create problems. In some places the ground-water supply is inadequate for other than domestic and rural use although this problem is often due to improper well locations or outmoded supply and distribution systems. A few areas have highly saline bedrock aquifers or poor unconsolidated aquifers, which prohibit major use of ground water. Extensive lowering of water levels in bedrock aquifers often occurs in metropolitan areas. This condition increases pumping costs and depletes the water available for future use. Contamination of shallow aquifers by waste disposal and of deep aquifers by leakage from water in multi-aquifer wells has also occurred.

In the Lake Huron area, the ground water varies greatly in amount and quality. Water occurs in glacial deposit aquifers, which vary considerably in permeability and potential water yield. The bedrock contains aquifers that generally yield moderate to small amounts of water. The chemical quality of some of this water is poor. Supplies adequate for industry and municipalities are restricted to the western and southern sections of the basin.

In the Lake Erie basin, major aquifers occur in unconsolidated sediments and near-surface bedrock formations. In contrast to the three upper Great Lakes basins, unconsolidated aquifers in the Lake Erie basin are relatively insignificant supply sources. Chemical quality of the ground water has limited its development. Most water from surficial sand and gravel aquifers is good to fair in quality. Iron is usually present. Some of the water is hard and contains appreciable amounts of dissolved solids. Bedrock aquifers consistently yield hard to very hard water containing dissolved solids, often above the recommended limit of 1000 mg/l. Saline water is present locally and increases with depth. Iron and sulfate contents may be high in some areas and increase treatment costs.[4]

General studies of ground water resource in Ohio,[5] Indiana, and Illinois show that, in the alluvial flood plains of rivers in these states, expected yields from individual wells can be expected to exceed 1.1 cfs. Expected yield per well drops significantly away from the flood plain to 0.2-1.0 cfs in the extreme northern areas of the river basins, which lie in glacial drift, to nder 0.01 cfs in the southern portions, where glacial deposits diminish and Devonian or Mississippi shale predominate. In Minnesota, in the Minnesota River basin, ground-water supplies are generally inadequate for needs other than domestic. The glacial drift in this area is of low permeability and thus only locally can wells of 0.7 cfs be found. No effort has been made to quantify in detail the effect of ground-water availability in the study.

6.2.3. Existing Water Quality

Throughout the region each state has developed systems of river-use classifications, which vary among states and river reaches. Typical classifications include public drinking supply, industrial use, agricultural use, fish and wildlife, and recreation. For each category, acceptable concentration levels have been developed for water-quality parameters that vary with use classification. Typical parameters are: dissolved oxygen (DO), biological oxygen demand (BOD), fecal coliform, phenols, pH, Fe, Cl, Mg, Pb, Cr, Cd, and Cu.

Figure 6.2 shows areas that now violate water-quality standards for dissolved oxygen, pH, Fe and heavy metals, including Cd, Cr, Pb, Mg, and Cu. This baseline map was compiled by calculating background river concentrations for water-quality parameters available through STORET, the data storage base for water quality of the Environmental Protection Agency. STORET contains data from field tests conducted by state and federal agencies, such as geological surveys, environmental protection agencies, departments of natural resources, and water surveys, as well as educational institutions.

For baseline characterization, each river in the region was divided into 20-40 mile reaches for which maximum, minimum, and mean concentrations for water-quality parameters were computed. The mean values for pH, Fe, and heavy metals and the minimum values for DO were then compared with standards applicable to the river reaches. As indicated in Fig. 6.2, standard violations are frequent throughout the region for these parameters.

These violations are due to both natural and human causes. However, since the standards are based on health criteria, even natural violations indicate problem areas.

High iron concentrations in many areas are due to natural sources, such as springs, ground-water interfaces, and geological substrata. However, erosion from excavations, mine tailings, and industrial effluent may also contribute to high iron concentrations in rivers.

The amount of dissolved oxygen in a stream is a function of water temperature, water depth and surface area, benthic deposits, organic loading, and type and amount of biological organisms in the water. Each may be modified

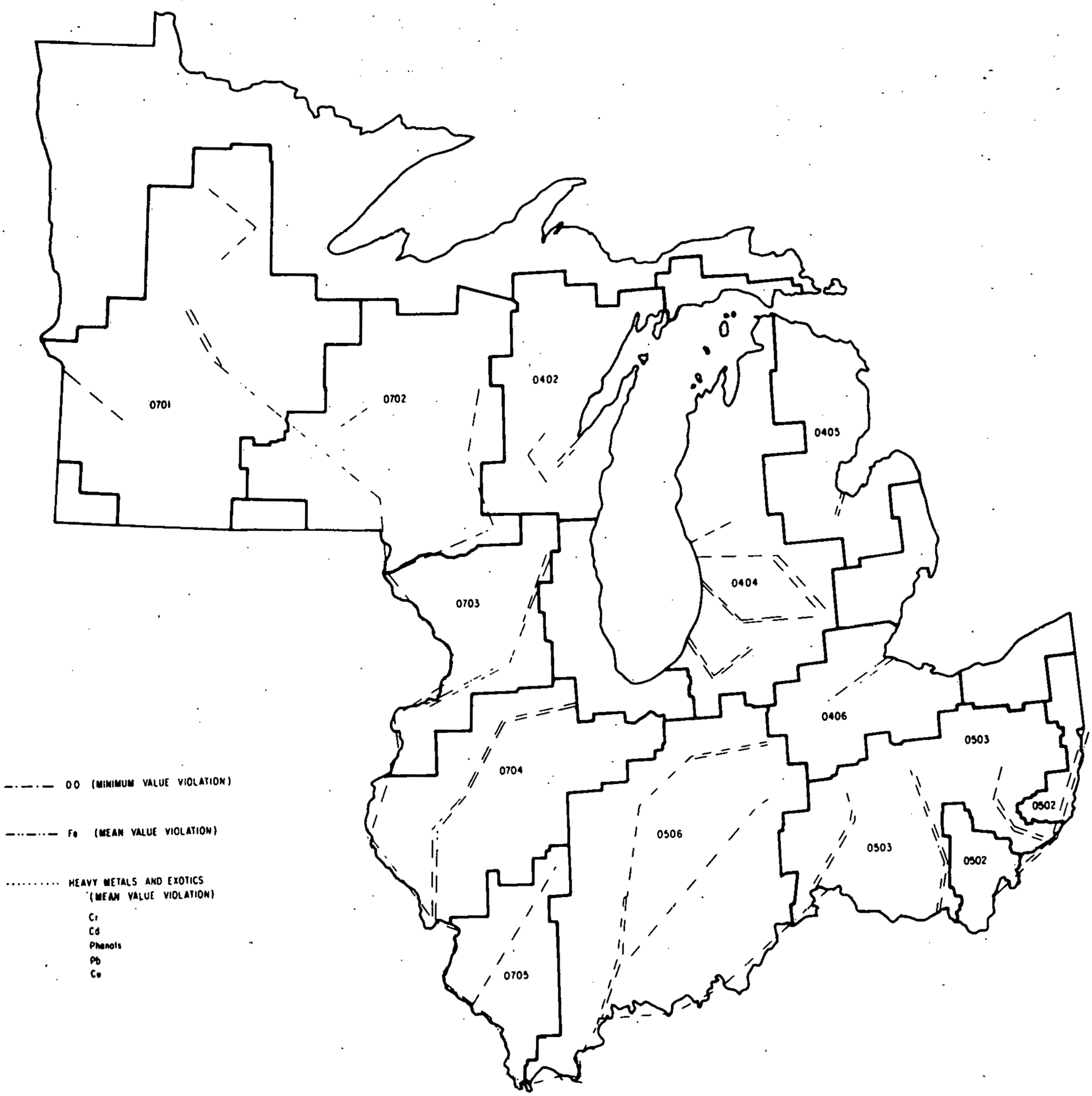

Fig. 6.2 Recorded Violations of Regional Water-Quality Standards in Major Rivers

by both natural and man-made sources. Man-induced problems most often occur in heavily populated areas and stem from increased organic loading due to municipal and industrial effluents.

Low pH can occur naturally because of springs, geological substrata, and runoff; however, such acidic water more often indicates such sources as acid mine drainage from surface tailing and deep mines, and effluent from industrial sources.

Although high concentrations of heavy metals occasionally occur naturally, they most often result from man-made pollution sources. Mining, agriculture, textiles, chemical, electrical, and refining industries can all contribute to high concentrations of heavy metals through runoff and effluent discharges.

6.3 WATER REQUIREMENTS FOR PROJECTED ENERGY DEVELOPMENT

Although energy development will result in various types of secondary domestic, industrial, municipal, mining, and reclamation water use, this section deals with the direct water requirements of energy-production facilities--coal conversion plants; and electric power plants, including nuclear plants and oil-, gas-, and coal-fired facilities.

As discussed in Sec. 2.0, it was assumed that controls on water consumption would be stringent, with a resulting consumption of 10.8 cfs for a 250 x 10^6 scf/day gasification plant. Water consumption for electrical generation based on the use of wet cooling towers was assumed to be 0.018 cfs/MW.

Power generation and water requirements for electrical generation and coal gasification for the years 1985 and 2020 have been computed (see Table 6.1) for each major water resource in each WRC aggregated subarea in the study area based on the baseline scenario. In addition, 7-day/10-year low flow and the percentage consumption of this flow by energy development in 2020 are also presented for each applicable water resource area.

Electrical power generation and coal gasification will consume enough surface water in several sections of the study area to indicate possible shortages. These industries will consume 85% of the 7-day/10-year low flow of the Maumee River in northern Ohio; about 40% of that flow of the Muskingum, Scioto, and Miami Rivers in southern Ohio, and 30% for the White River in

Table 6.1. Projected Future Energy Developments and Estimated Consumptive Water Requirements

WRC-ASA	Water Resource	1985 Total Electrical Generation Capacity, MW	2020 Electrical Generation Capacity, MW			2020 Coal Gasification Capacity, 10^6 scf/day	Estimated Water Requirements in 2020 for Electrical Generation and Coal Gasification		7 day/10-yr Low Flow, cfs
			Nuclear Oil, Gas	Coal	Total		cfs	% of 7-day/ 10-yr Low Flow	
401	Lake Superior	2,522	8,549	5,587	14,136	-	178.1	-	-
402	Lake Michigan	1,588	4,588	5,104	9,692	-	122.1	-	-
	Wolf	-	3,000	-	3,000	-	37.8	8.6	440
403	Lake Michigan	10,301	15,623	7,312	22,935	-	288.9	-	-
	Des Plaines River	3,296	-	4,530	4,530	-	57.1	3.1	1,835
404	Lake Michigan	4,147	12,076	6,000	18,076	-	227.8	-	-
	St. Joseph River	-	3,000	-	3,000	-	37.8	10.2	370
	Muskegon River	511	-	3,511	3,511	-	44.2	6.7	660
	Grand River	1,775	-	4,450	4,450	-	56.1	8.0	700
	Kalamazoo River	812	812	3,000	3,812	-	48.0	13.7	350
405	Lake Huron	2,382	14,231	10,165	24,396	-	307.4	-	-
	Saginaw River	1,300	1,300	-	1,300	-	16.4	3.8	430
406	Lake Huron	5,660	11,308	10,394	21,702	-	273.4	-	-
	Lake Erie	8,614	22,968	13,696	36,664	-	462.0	-	-
	Maumee River	-	8,848	3,000	11,848	-	149.3	85.3	175
407	Lake Erie	5,301	17,224	4,771	21,995	-	277.1	-	-
502	Ohio River	15,817	14,957	48,696	63,653	-	802.0 (1510.0)[a]	11.5 (21.6)	7,000
	Reservoir	2,966	-	2,966	2,966	-	37.4	-	-

Table 6.1. (Cont'd)

WRC-ASA	Water Resource	1985 Total Electrical Generation Capacity, MW	2020 Electrical Generation Capacity, MW			2020 Coal Gasification Capacity, 10^6scf/day	Estimated Water Requirements in 2020 for Electrical Generation and Coal Gasification		7 day/10-yr Low Flow, cfs
			Nuclear Oil, Gas	Coal	Total		cfs	% of 7-day/10-yr Low Flow	
503	Muskingum River	4,163	-	27,510	27,610	-	347.9	38.7	900
	Scioto River	-	3,000	12,000	15,000	-	189.0	48.5	390
	Miami River	-	9,000	4,712	13,712	-	172.7	40.6	425
505	Ohio River	9,143	14,676	16,780	31,456	1,500	397.2 (2440.2)	0.9 (5.4)	45,000
506	White River	5,235	4,459	13,334	17,793	250	235.0	33.5	700
	Wabash River	4,570	3,000	21,508	24,508	500	308.8 (533.0)	11.0 (19.0)	2,800
	Reservoirs	1,700	6,000	4,700	10,700	250	134.8	-	-
701	Mississippi River	8,563	3,569	14,587	18,156	-	228.8 (381.1)	11.4 (19.1)	2,000
	Minnesota River	-	3,090	3,000	6,090	-	76.7	40.4	190
	St. Croix River	-	3,000	3.000	6,000	-	75.6	7.2	1,050
702	Mississippi River	3,411	7,186	6 921	14,107	-	178.5 (646.3)	1.6 (5.9)	11,000
	Chippewa River	800	800	-	800	-	10.1	0.5	1,900
	Wisconsin River	3,079	512	5.567	6,079	-	76.6	2.9	2,660
703	Mississippi River	4,480	12,980	6,110	19,090	-	240.5 (1088.9)	1.6 (7.2)	15,000
	Rock River	4,040	13,040	3,000	16,040	-	202.1	14.0	1,440
704	Mississippi River	-	3,000	3,000	6,000	-	75.6 (1659.9)	0.4 (7.9)	21,000
	Illinois River	15,439	27,483	11,833	39,316	-	495.4 (552.5)	13.8 (15.5)	3,600
	Reservoirs	6,491	10,900	9,726	20,626	750	292.3	-	-
705	Mississippi River	650	3,000	650	3,650	1,000	89.2 (1794.1)	0.2 (3.6)	48,500
	Kaskaskia River	1,858	-	1,858	1,858	500	45.0	37.5	120
	Reservoirs	1,303	-	9,881	9,881	-	124.5	-	-

[a]Numbers in parenthesis indicate total water requirements, tributary plus mainstem.

Indiana, 40% for the Minnesota River in Minnesota; and 40% for the Kaskaskia River in Illinois. In addition, constraints may develop on the border rivers of the study area, such as the Ohio and Mississippi, when additional water is consumed from these rivers and their tributaries by states outside the study area.

For these areas, meeting the water demand will require use of less water-intensive technology, increase in available water supplies, or changes in siting patterns. Two potential methods of increasing water supplies are the use of lakes and creation of reservoirs. Though these two solutions may be available at some sites, assessment of their impacts on water availability requires further analysis. Use of ground water is a third method of water augmentation. Availability of ground water is more site-specific than availability of surface water. Ground water availability depends on thickness, depth, recharge rate, quality and type of aquifers used and the extent to which the aquifer potential is already developed by competing users. As limited by the scope of this study, only generalizations (see Sec. 6.2.2), can be made as to overall regional availability of ground water for energy as well as non-energy related users.

In this section, 7-day/10-year low flow of surface streams, a worst-case indicator, has been used to identify potential problem areas of water availability for power generation and coal conversion. In Sec. 6.5, additional water resources and effects of other competing users will be considered in evaluating the water availability problems for the sample areas in Illinois.

6.4 WATER POLLUTION FROM COAL UTILIZATION

In coal-related energy facilities, wastes result from cleaning of stack gases; softening, neutralization, and demineralization of boiler water; blowdown from plant processes; cooling and cleaning of crude gases; quenching of gasifier ash and removal of slurry; runoff from coal storage piles; and other sources. The composition amount of water pollutants possible from power-generation plants and coal-conversion facilities depend on the size and types of processes and pollution-control and water-conservation practices used in the facilities (see Sec. 2.0).

From the loading rates given in Tables 2.7 and 2.12 and siting projected in Sec. 4.0, cumulative loadings of 15 pollutants due to the 2020 baseline scenario for all major river basins in the study area, and, in addition, High Coal Use Scenario for three example areas in Illinois, were calculated. Table 6.2 summarizes data by river basins. Effluent control to meet New Source Performance Standards (NSPS) for power generation, and "controlled" option for coal gasification, were used where given; otherwise, values for uncontrolled effluents were used.

Different pollutants may influence the quality of water and of stream biota in different ways. Biological oxygen demand (BOD), has been used to indicate concentrations of oxidizable compounds; these compounds remove dissolved oxygen (DO) from water. A high BOD may use all available DO, thus converting an aerobic ecosystem to anaerobic and completely changing biological and chemical composition of the stream. The DO is a significant limiting factor in determining species composition of the biota.

Ammonia nitrogen is a specific component of BOD; and its byproducts, nitrite and nitrate, are nutrients for biological growth. Ammonia is a good indicator of stream quality because it originates primarily from human activities related to sewage and livestock operations. Synfuel facilities might discharge large amounts of ammonia in waste streams.

Chlorides occur in most surface waters and may result from natural causes or human activities, including coal processes. High concentrations of chlorides impart an unpleasant taste to water and may be hazardous to people with kidney or heart disease. Chlorides may be present as toxic salts of heavy metals.

Suspended solids cause an increased turbidity, which profoundly affects the stream biota and both increases cost and decreases effectiveness of water disinfection.

Sulfate may limit algae growth in some aquatic environments. High sulfate concentrations may have a laxative effect on humans and impart undesirable tastes to the water. Under anaerobic conditions, sulfate may be changed to sulfide, which is highly toxic to biota.

Iron compounds affect the taste of drinking water and tend to precipitate and agglomerate on pipe surfaces. Iron may, in unbuffered water,

Table 6.2. Estimated Pollutant Loadings of the Projected 2020 Coal Utilization Facilities Assuming High Effluent Control (lb/day)[a]

Pollutant	Lake Superior	Lake Michigan	Lake Huron	Lake Erie	Muskegon River	Grand River	Kalamazoo River	Maumee River
BOD	–	–	–	–	–	–	–	–
Ammonia	9.3	30.8	34.4	30.9	5.8	7.4	5.0	5.0
Chloride	860	2836	3166	2844	541	685	462	462
Sulfate	1823	6007	6706	6024	1145	1452	979	979
TSS	387	1276	1424	1280	243	308	208	208
Cyanide	–	–	–	–	–	–	–	–
Thiocyanate	–	–	–	–	–	–	–	–
Phenols	–	–	–	–	–	–	–	–
Cadmium	0.1	0.3	0.3	0.3	0.05	0.1	0.4	0.4
Chromium	4.2	13.8	15.4	13.8	2.6	3.3	2.2	2.2
Copper	2.5	8.4	9.4	8.4	1.6	2.0	1.4	1.4
Iron	2.5	8.4	9.4	8.4	1.6	2.0	1.4	1.4
Zinc	3.2	10.6	11.8	10.6	2.0	2.5	1.7	1.7
Lead	0.1	0.3	0.3	0.3	0.05	0.1	0.03	0.03
Arsenic	0.1	0.3	0.3	0.3	0.05	0.1	0.03	0.03

[a]All loadings are for the 2020 Baseline Scenario, except for the Illinois, Rock, and Kaskaskia River basins, for which data for both baseline and high coal use scenarios are presented.

Table 6.2. (Cont'd)

Pollutant	Muskingum River	Scioto River	Miami River	White River	Wabash River[b]	Ohio River[c]	St. Croix River
BOD	-	-	-	375	1125	3375	-
Ammonia	46	20	7.9	228	676	2096	5.0
Chloride	4252	1848	726	2741	7428	28462	462
Sulfate	9006	3914	1537	4684	12367	50187	979
TSS	1913	832	327	1474	4065	14974	208
Cyanide	-	-	-	2.8	8.3	24.8	-
Thiocyanate	-	-	-	1925	5775	17325	-
Phenols	-	-	-	10	30	90	-
Cadmium	0.4	0.2	0.1	0.3	1.0	3.5	0.04
Chromium	21	9.0	3.5	10	27	110	2.3
Copper	13	5.5	2.1	6.6	18	71	1.4
Iron	13	5.5	2.1	89	263	808	1.4
Zinc	16	6.8	2.7	9.3	25	98	1.7
Lead	0.4	0.2	0.1	86	257	772	0.04
Arsenic	0.4	0.2	0.1	1.0	3.0	9.5	0.04

[b] Includes loadings of the White River and Wabash River mainstem.

[c] Includes loadings of the Muskingum, Scioto, Miami, Wabash, and White Rivers and Ohio River mainstem.

Table 6.2. (Cont'd)

Pollutant	Minnesota River	Wisconsin River	Rock River[d]	Illinois River[e]	Illinois River[f]	Kaskaskia River[d]	Mississippi River[g]
BOD	-	-	-	-	-	750	2250
Ammonia	5.0	9.3	5.0	27.4	62	415	1136
Chloride	462	857	462	2520	5737	1661	13292
Sulfate	979	1816	979	5338	12152	1274	21421
TSS	208	386	208	1134	2582	1229	7425
Cyanide	-	-	-	-	-	5.5	17
Thiocyanate	-	-	-	-	-	3850	11550
Phenols	-	-	-	-	-	20	60
Cadmium	0.04	0.1	0.04	0.2	0.5	0.3	1.8
Chromium	2.3	4.2	2.2	12	28	1.7	46
Copper	1.4	2.5	1.4	7.4	17	1.9	30
Iron	1.4	2.5	1.4	7.4	17	166	522
Zinc	1.7	3.2	1.7	9.4	21	4.4	44
Lead	0.04	0.1	0.04	0.2	0.5	171	514
Arsenic	0.04	0.1	0.04	0.2	0.5	1.7	5.8

[d] Same for Baseline Scenario and High Coal Use Scenario.

[e] Represents Baseline Scenario.

[f] Represents High Coal Use Scenario.

[g] Includes loadings of the Minnesota, St. Croix, Wisconsin, Rock, Illinois, Kaskaskia Rivers and Mississippi River mainstem.

lower the pH to a toxic level. Iron precipitates may also clog fish gills and smother eggs and larvae of aquatic animals.

Copper, another effluent from power plants and gasification processes, is found in many surface waters. In small amounts it is beneficial to humans and water biota, but large doses may affect water taste, and high prolonged doses of copper may cause liver damage in humans. It presents a potential danger to high-trophic-level biota, because it concentrates through food chains. It is toxic to humans only in very high concentrations. At lower levels, it affects taste, gives a milky appearance to water, and causes a greasy surface film to develop.

Zinc reacts synergistically with copper to increase copper toxicity. It is most toxic to aquatic vertebrates, forming an insoluble compound through combination with mucous, which damages fish gills. Low levels of zinc are found in effluents from coal-utilization facilities.

Mercury, lead, chromium, and cadmium, cyanide, and phenols are all highly toxic to humans and aquatic biota, with acute and chronic effects, and all concentrate through food chains. They affect the cardiovascular, nervous, and excretory systems and have potential carcinogenic and teratogenic effects. Primary sources for environmental concentrations of all these substances are human activities, including coal mining, power generation, and coal gasification.

Impacts of pollutant loadings on quality of stream water are area-specific, depending on the nature and extent of pollutant as well as the quality and hydrologic characteristics of the receiving water.

Discharge of water heat is another main category of pollutants resulting from coal-related energy facilities. Effluent guidelines, embodied for the most part in P.L. 92-500, the Federal Water Pollution Control Act Amendment of 1972, restrict discharge of heated effluents to the aquatic environment. To evaluate the impacts of thermal discharges beyond the year 2000, use of closed-cycle cooling, such as mechanical-draft and natural-draft towers, or cooling ponds, or both, is assumed for coal facilities, with no discharged heated effluents warmer than EPA standards established for maintenance of propagation and protection for a balanced, indigeneous population of shell-fish, fish, and wildlife in or on the receiving water body.

6.5 *IMPACTS OF WATER USES AND POLLUTANT LOADING*

Three rivers in Illinois, the Illinois, Rock, and Kaskaskia, were chosen as sample areas for evaluating the impacts on the water resources of the projected 2020 baseline and High Coal Use Scenarios for 2020.

Some water-quality impacts of coal developments not quantified in this study are: (1) degradation of surface-water quality by sediment, acids, and heavy metals carried into streams by coal-mine drainage and runoff; and (2) degradation of ground water by water percolation through mined areas, spoil piles, and waste-disposal sites. These potential impacts are discussed briefly in Sections 6.5.3 and 6.5.4.

6.5.1 *Impacts of Water Use*

Impacts of water use of energy developments in 2020 were evaluated to include competing water users. Data on the projected withdrawal uses by 2020 for municipal, industrial, agricultural, mining, and instream uses for hydropower, commercial navigation, recreation, fish and wildlife, and water-quality management were obtained from the Upper Mississippi Framework Study.[7] Factors were applied to estimate consumption fractions from total withdrawal uses. These results are shown in Table 6.3, which also shows water availability in terms of 7-day/10-year low flow, median flow, yields from projected and existing lakes and reservoirs, and yields from ground water.

<u>Illinois River</u>

The Illinois is the largest tributary of the Mississippi above the mouth of the Missouri; it has a median flow of 15,480 cfs and 7-day/10-year low flow of 3600 cfs. Minimum potential available ground water, including that now being used, is 5750 cfs. The yield from lakes and reservoirs in the basin is 3232 cfs, about 2000 cfs of which is through diversion from Lake Michigan.[7,8]

By the year 2020, total water consumption by withdrawal users in the basin is expected to be 3166 cfs under the High Coal Use Scenario, and 2924 cfs under the Baseline Scenario. The primary consumers will be industrial users, which account for about 1210 cfs, or more than a third of the projected total use. Residential, commercial, agricultural, and mining users, together, account for 1117 cfs. The projected energy developments call for

Table 6.3. Summary of Water Availability and Requirements (cfs) for Energy Developments in 2020 and Competing Users

Users	Illinois	Rock	Kaskaskia
Consumptions by Withdrawal Uses			
Municipal and Industrial[a]	697.5	93.0	40.3
Industrial (self-supplied)[a]	1210.5	85.3	162.8
Agricultural[a]			
Rural Domestic	21.7	14.0	6.2
Livestock	162.8	120.9	32.6
Irrigation	235.6	920.7	396.8
Mining[a]	23.3	3.1	6.2
Energy Development (power generation and coal conversion)[b]			
High Coal Use Scenario	815	202	45
Baseline Scenario	573	202	45
Total - High Coal Use Scenario	3166.4	1439.0	689.9
- Baseline Scenario	2924.4	1439.0	689.9
Instream Uses[a]			
Hydropower	9366	14210	0
Commercial Navagation	3140	0	337
Recreation, and Fish and Wildlife	10680	3452	542
Water Quality Management	510	1594	25
Water Availability			
Stream Flow			
7-day/10-yr Low Flow[c]	3600	1440	120
Median Flow[a]	21870	4300	1460
Lakes - Reservoirs[d]	3232[e]	0	193
Ground Water[a]	5750	3495	428

[a]Estimated from data given in Ref. 7.

[b]Estimated from siting development projected in Sec. 4.0; also see Table 6.1.

[c]From Table D-1, Appendix D.

[d]From Ref. 8.

[e]Includes 2000 cfs through diversion from Lake Michigan.

power plants at 64,600 MW under the High Coal Use Scenario and 42,500 MW under the Baseline Scenario; these plants will consume 815 and 573 cfs, respectively, together less than 26% of the projected total consumption in the basin.

The data in Table 6.3 show that, apart from in-stream requirements, the water supply will be sufficient to support the projected 2020 energy development. The estimated water demand will require less than 4% of the median flow in the river. During extreme low flow, however, the demand by energy development could rise to 16% of the 7-day/10-year low flow.

For the Illinois River basin, conflicts in water use may arise between withdrawal users and instream users. The projected recreation, boating traffic, and fish and wildlife maintenance indicate a need of 10,680 cfs or more on the Illinois River by 2020. A minimum of 6500 cfs is now needed for in-stream uses in the basin, and it has been estimated that at least 25% of the time these needs will not be satisfied.[7] Furthermore, future demands of both withdrawal and instream uses will increase.

Rock River

The Rock River begins in southeastern Wisconsin, flows in a generally southwestern direction, and drains into the Mississippi below Rock Island, Illinois. The total drainage area of the river basin is 10,710 square miles.

The available surface water is about 4300 cfs at median flow, and about 1480 cfs at 7-day/10-year low flow. The minimum potential available ground water, including that now being used, is 3500 cfs. Sustained yields can be expected to be greater.[7]

The projected total consumption by 2020, including that by energy and nonenergy sources, is about 1434 cfs. The primary consumers are agricultural users, who account for 73.5% of the projected total uses. More than half of agricultural water uses are (and will be) dependent on the ground-water sources.[7]

The plan for 2020 energy development, for both Baseline and High Coal Use Scenarios, includes construction of six power plants in the Rock River basin. These plants will consume about 202 cfs of water, equivalent to about 14% of the projected total consumptive use. The water demands for the power plants are less than 14% of the 7-day/10-year low flow and about 5% of the median flow in the Rock River.

Flow rates alone indicate that the water supply in the basin will meet the requirements of the energy development in 2020. As with the Illinois River, use conflicts between the withdrawal users and instream users exist in the Rock River Basin. Increasing demands by the withdrawal users in the future will further deplete the available water for instream users.

Kaskaskia River

The Kaskaskia River rises in central Illinois and flows southwest to its confluence with the Mississippi 8 miles north of Chester, Illinois. The basin has a drainage area of 5840 square miles. The total available or dependable surface water supply, in terms of 7-day/10-year low flow, is 120 cfs. The median runoff is about 1460 cfs. The amount of ground water in the basin is small; the availability varies from one location to another because of the general lack of uniformity in the distribution of water-yielding aquifers. The minimum potential available ground water, including that now being used, is estimated at 428 cfs. Yields from lakes and reservoirs in the basin amount to about 193 cfs.[7,8]

Consumption by withdrawal users is expected to be about 700 cfs in the year 2020. Agricultural and industrial users, combined, will require 600 cfs, or 85% of the projected total demand. The projected energy developments by 2020, including one power plant and two gasification plants, will require about 45 cfs of water, or less than 7% of the projected total demand.

The data in Table 6.3 show that water supply in the Kaskaskia River basin will be a problem because of high demand and low availability. During the low-flow period the projected total water consumption will be about 94% of available supplies from all known sources in the basin, including natural stream flow, lakes and reservoirs, and ground water. Obviously, serious conflicts can arise among different users.

The conflicts may be reduced somewhat by increasing use of ground water, importing of surface water from other basins, manipulation of natural flow by existing reservoirs, or building new reservoirs to ensure a constant and dependable water supply. Or, it may be required that energy production using less water or alternative siting patterns be developed for the Kaskaskia River basin.

6.5.2 *Impacts on Water Quality*

Impacts on the water quality of the Illinois, Kaskaskia, and Rock rivers in Illinois were evaluated for the projected coal utilization for 2020. The impacts are represented by the increments in pollutant concentration due to waste discharges from coal-burning power-generation plants and coal-gasification facilities. Simple material balances were performed to incorporate the pollutant loadings and stream flow of each river reach to calculate concentration increments. The 7-day/10-year low flow was used to provide a worst-case situation in which effluent loading would be least diluted. It was assumed for this study that: (1) effective controls are used at each plant; (2) added BOD loading will be oxidized within two river reaches (40-80 miles long); and (3) other pollutants, including Zn, Fe, Cu, Cr, Cd, TSS, sulfate, cyanide, thiocyanate, phenols, chlorides, and ammonia, are conservative.

Table 6.4 summarizes background water quality and the projected concentration increments due to coal developments in 2020. Results for the baseline scenario and the High Coal Use Scenario are included.

Illinois River

The major portion of the upper Illinois River system above the Kankakee River has been used heavily by man for the disposal of wastes. The river water generally has severe pollution in the form of industrial and municipal wastes: solid fecal material, oil and grease, detergent foam, sludge and odors, and bacteria of fecal origin. The river water in this area is generally high in chloride, phosphate, and nitrogen; low in dissolved oxygen content; and extremely high in coliform counts. Long reaches of the stream are devoid of fish, and various toxic metals have been detected.

Downstream from the mouth of the Kankakee River, the water quality of the Illinois River is extremely variable, depending on flow conditions, proximity to populated areas, and other factors. In general, the river has recovered some of its quality; rough fish have begun to appear, followed by some sport species in successive sectors downstream.

The entire Illinois River has been classified for aquatic life use, as well as for agricultural, industrial, food processing, public water supply, and primary-contact uses. The Illinois standards for water quality applicable for public water supply, the most stringent standards, are tabulated in Table D-2.

Data on water quality obtained from STORET indicate that mean values for iron, copper, and phenols exceed the 300, 20, and 10 μg/l standards for the entire Illinois River. Mean values for ammonia, cyanide, and chromium violate the standards, 1.5, 0.01, and 50 mg/l, respectively, for parts of the river, particularly the upper and middle reaches. The STORET data (not given in Table 6.4) also indicate violation of standards in the maximum readings of ammonia, dissolved solids, Hy, Cu, Zn, Cd, and Cr, and the minimum value of DO for the entire length (or part) of the Illinois River.

The 2020 Baseline Scenario includes construction of eleven coal-burning thermal electric power plants, on the Illinois River and its tributaries. The 2020 High Coal Use Scenario includes four more of these plants similary located.

Data in Table 6.4 indicate a relatively insignificant impact of coal developments in 2020 on the water quality of the Illinois River. This low impact is due mainly to relatively high stream flow, with consequent high-dilution effect on the river, and low pollutant loadings from power plants.

For both the Baseline and the High Coal Use scenarios, the estimated increments of pollutant concentrations, except for chromium, are only a small percentage of background concentrations. Thus, assessments indicate that effluent discharges from these future power plants would probably not cause variations in the status of standards violations.

For both scenarios, chromium will increase by 0.4-1.8 mg/l during low flow. Although this increment equals or exceeds background levels for all reaches except Reach 3, it is still not high enough to violate the 50 mg/l standard. The present chromium levels on Reach 3 exceed the standard. This violation will probably remain after 2020 development if other conditions stay unchanged.

Rock River

The Rock River in Illinois has been classified for aquatic-life use, as well as for agricultural, industrial, food processing, public water supply, and primary-contact use. Water-quality standards are now being violated. The STORET

Table 6.4. Background Water Quality and Impacts of 2020 Coal Utilization

Reach	Pollutants[a], mg/l													
	BOD		Ammonia		Chloride		Sulfate		TSS		Cyanide		Thiocyanate	
	B	I	B	I	B	I	B	I	B	I	B	I	B	I
Illinois River -- Baseline Scenario														
6	8.6	-	1.89	0.001	61.0	0.08	102.0	0.17	-	0.04	0.0035	-	-	-
5	5.9	-	0.97	0.001	50.8	0.13	87.2	0.28	-	0.06	0.0004	-	-	-
4	-	-	1.02	0.003	50.2	0.26	78.3	0.54	-	0.11	0.0023	-	-	-
3	43.6	-	5.25	0.002	16.8	0.22	37.7	0.46	-	0.10	0.42	-	-	-
2	-	-	0.54	0.002	39.8	0.20	87.0	0.43	-	0.09	0.007	-	-	-
1	-	-	0.67	0.002	29.5	0.23	71.6	0.48	-	0.10	0.0004	-	-	-
Illinois River -- High Coal Use Scenario														
6	8.6	-	1.89	0.001	61.0	0.10	102.0	0.21	-	0.04	0.0035	-	-	-
5	5.9	-	0.97	0.002	50.0	0.16	87.2	0.33	-	0.07	0.0004	-	-	-
4	-	-	1.02	0.003	50.2	0.29	78.3	0.62	-	0.13	0.0023	-	-	-
3	43.6	-	5.25	0.003	16.8	0.28	37.7	0.59	-	0.13	0.42	-	-	-
2	-	-	0.54	0.004	39.8	0.36	87.0	0.76	-	0.16	0.007	-	-	-
1	-	-	0.67	0.004	29.5	0.38	71.6	0.81	-	0.17	0.0004	-	-	-
Rock River -- Baseline and High Coal Use Scenario														
3	-	-	0.42	0.001	24.4	0.09	41.2	0.18	-	0.04	-	-	-	-
2	-	-	0.52	0.001	25.8	0.09	-	0.18	-	0.04	-	-	-	-
1	-	-	0.52	0.001	25.4	0.07	-	0.15	-	0.03	-	-	-	-
Kaskaskia River -- Baseline and High Coal Use Scenarios														
7	-	-	0.63	-	40.2	-	-	-	-	-	-	-	-	-
6	-	-	0.21	-	33.9	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	4.90	0.15	2.69	35.6	8.99	-	4.37	-	7.19	-	0.036	-	25.2
3	-	2.50	3.31	1.03	-	3.43	-	1.67	-	2.74	-	0.014	-	9.6
2	-	1.35	0.15	1.49	51.4	4.97	-	2.41	-	3.97	-	0.020	-	13.9
1	-	0.7	0.17	1.03	70.9	4.11	-	3.15	-	3.04	-	0.136	-	9.5

Table 6.4. (Cont'd)

	Pollutants[a], µg/l													
	Phenols		Cadmium		Chromium		Copper		Iron		Zinc		Lead	
Reach	B	I	B	I	B	I	B	I	B	I	B	I	B	I
							Illinois River -- Baseline Scenario							
6	2.5	-	1.62	0.007	0.014	0.39	54.7	0.24	636	0.24	134.1	0.30	-	0.01
5	2.14	-	-	0.012	-	0.65	103.3	0.40	722	0.40	47.9	0.50	-	0.01
4	2.76	-	0.018	0.023	0.43	1.25	107.3	0.76	747	0.76	70.0	0.96	-	0.02
3	18.7	-	-	0.020	130.00	1.06	-	0.65	988	0.65	-	0.81	-	0.02
2	2.41	-	2.3	0.018	5.20	0.99	161.0	0.60	1094	0.60	248.7	0.76	-	0.02
1	3.0	-	0.38	0.021	-	1.10	30.8	0.67	1847	0.67	160.0	0.85	-	0.02
							Illinois River -- High Coal Use Scenario							
6	2.5	-	1.62	0.009	0.014	0.48	54.7	0.29	636	0.29	134.0	0.37	-	0.01
5	2.14	-	-	0.014	-	0.76	103.3	0.46	722	0.46	47.9	0.58	-	0.01
4	2.76	-	0.018	0.027	0.43	1.42	107.3	0.86	747	0.86	70.0	1.09	-	0.03
3	18.7	-	-	0.025	130.00	1.36	-	0.83	988	0.83	-	1.04	-	0.03
2	2.41	-	2.3	0.033	5.20	1.75	161.0	1.06	1094	1.06	248.0	1.34	-	0.03
1	3.0	-	0.38	0.035	-	1.86	30.8	1.13	1847	1.13	16.0	1.43	-	0.04
							Rock River -- Baseline and High Coal Use Scenarios							
3	0.65	-	-	0.008	-	0.41	35.8	0.25	500	0.25	11.1	0.32	-	0.008
2	0.84	-	-	0.008	-	0.42	-	0.25	-	0.25	-	0.32	-	0.008
1	0.53	-	-	0.005	-	0.36	-	0.21	-	0.21	-	0.26	-	0.006
							Kaskaskia River -- Baseline and High Coal Use Scenarios							
7	5.4	-	-	-	-	-	49.1	-	-	-	-	-	-	-
6	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-
5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
4	6.0	130	-	2.09	-	2.09	-	7.2	-	1078	27.3	21.6	-	1118
3	-	50	4.72	0.80	-	0.80	-	2.7	-	412	-	8.2	-	427
2	1.4	72	-	1.16	-	1.16	-	4.0	-	596	-	11.9	-	617
1	-	49	-	0.86	-	4.23	-	4.8	-	410	-	10.8	-	423

[a]In concentrations of mean background (B) and increment due to projected coal utilization: (I).

data in Table 6.4 indicate that mean values of iron and copper exceed their respective standards. Maximum levels of ammonia, dissolved solids, Fe, Cu, Hg, and phenols as well as the minimum reading of DO, which are not listed in the table, violate standards for parts or the entire length of the river. Untreated wastes from industrial and municipal sources are the major waste loads. The many livestock and the large tonnages of applied fertilizers also degrade water quality in the basin.

Both Baseline and High Coal Use Scenarios include construction of a coal-burning power plant on the Rock River. Impacts on water quality by the waste discharge from this plant will be insignificant owing to low pollutant loadings and high stream flow.

Kaskaskia River

The Kaskaskia River is classified for aquatic-life use, as well as for agricultural and industrial supply, food processing, public water supply, and primary contact use. Although inputs from municipalities and industries are minor, water quality problems exist because of (1) high natural background loading; and (2) runoff and drainage from mine sites, croplands, and livestock facilities.[7] Surface waters are hard to very hard, containing bicarbonates of calcium and magnesium in concentrations of 16-575 mg/l in the northern part of the basin and 140-365 mg/l in the southern part. Concentrations of dissolved solids are lower during high flow than during low flow -- ranging from 350 to 1300 mg/l. Nitrate concentrations at Shelbyville and Vandalia exceed the 10 mg/l standard for food processing and public water supply. Maximum chloride readings exceed the 250 mg/l standard during summer and fall for the upper 40 miles of the river. Maximum and mean annual concentrations of mercury and phenols exceed the 2.0 μg/l and 1.0 μg/l standards for the Kaskaskia from Shelbyville to the river mouth.

The plan for 2020 coal developments in the river basin includes construction of two gasification plants and one power plant. Results of impact analysis indicate a pronounced effect of these facilities on the quality of the river water. This impact is due to the low flow volume of the river and the high effluent loadings from the facilities, particularly the gasification plants.* The most pronounced effects are from cyanide, ammonia, Pb, and Fe.

*See Sec. 2.0. The New Source Performance Standards for coal gasification have not been published. For this analysis, approximate loading values for gasification facilities were used.

The estimated concentration increments indicate that, during low flow, waste discharges from these plants will cause violation of standards for the above pollutants. Discharges from these plants may also cause problems with other pollutants, e.g., Cu, Cr, Cd, and TSS.

Although these levels are uncertain because of lack of data for effluent standards for gasification facilities, the estimated impacts show the importance of further analysis to identify the actual magnitude.

6.5.3 Pollution of Surface Water by Coal Mining

Water pollution from coal mining has been studied extensively for the eastern U.S. and relatively less for the rest of the country. Mining disturbs the earth and the balance of natural systems. The resulting physical and chemical environmental changes often lead to water pollution. Two major forms of water pollution are caused by mining -- physical and chemical. Physical pollution is the increased erosion caused by land disturbance, resulting in increased sediment load. Chemical pollution is caused by exposure of minerals to oxidation or leaching, with resulting undesirable concentrations of dissolved materials.

Pollutants from mine sites can be carried off in runoff or mine drainage. Pollutant concentrations that most frequently exceed acceptable levels in waste water from coal production facilities are: acidity, total Fe, dissolved Fe, Mn, Al, Ni, Zn, Sr, fluoride, sulfates, ammonia, total dissolved solids, and total suspended solids.[9]

A recent EPA report indicates that, from a total of 3000 active and abandoned mines in Illinois, an average of 24,000 lbs of acid (in terms of $CaCo_3$) are generated and discharged into streams daily. Sediment loading was estimated at 8700 tons/day from a total of 230,000 acres of surface mines in Illinois.[10]

Chemical characteristics of raw-mine drainage are determined by local and regional geology of coal and associated overburden. The quality of raw mine drainage ranges from severely polluted to that for drinking water. Depending upon the specific hydrological condition, drainage from a mine can vary from zero to millions of gallons per day within a geographic area or coal field, or even between adjacent mines.

Pollutants from coal mines can generally be categorized as acid or ferruginous drainage and alkaline drainage, which in turn reflect local or regional coal and overburden conditions. Alkaline drainage, most common in the Western coal fields, generally has total dissolved solids and suspended solids above acceptable levels. Acid or ferruginous drainage, typically found in the Appalachian and Eastern Interior Coal Regions, has high concentrations of all of the critical pollutants.

Apart from chemical pollutants, the next most serious problem from pollutants due to mining operation is increased sedimentation. Severity of sediment pollution is determined by local rainfall characteristics, topography, soil, and erosion-control practices.

From available historical data obtained in the past decade on quality of waste water from coal mines, EPA established waste characteristics for thirteen pollutants for both acid and alkaline drainage from underground and surface mines.[9]

The EPA study concluded that methods have been developed to abate pollution by mining waste water at reasonable costs. Methods include neutralization of acidity, with concurrent reduction of other pollutants to safe concentrations; and use of settling basins and coagulants to remove excessive total suspended solids. Acidity can usually be neutralized with lime; the neutralization is followed by aeration and sedimentation. Other neutralization reagents occasionally used include limestone, caustic soda, soda ash, and anhydrous ammonia. Neutralization of, and subsequent settling treatment of, mine drainage can remove iron, manganese, aluminum, nickel, zinc, and total suspended solids.

Control of water pollution from coal mines requires that the water-treatment methods be used in conjunction with effective mining, regrading, water diversion, erosion control, soil supplementation, and revegetation techniques.

Coal production has been included in point-source categories and is currently regulated by federal and state environmental conservation agencies. Waste discharges from these operations are controlled via NPDES (National Pollution Discharge Elimination System) permits that specify permissible quantity and quality of the effluent from a specific operation.

Furthermore, mining companies are required to monitor their effluents to ensure compliance. These requirements are expected to significantly reduce direct waste discharges to surface water from active mines.

Table 6.5 lists the New Source Performance Standards, for coal-mining operations, recommended by EPA.

6.5.4 Ground-Water Pollution by Waste Disposal

Pollutant discharges from conversion facilities to surface waters can be minimized by extensive reuse of water in these plants and evaporation of waste water in ponds. However, designing a plant to eliminate all effluent discharges would not necessarily eliminate potential impacts on water quality. All the material that would normally be carried off in the effluent would still need to be disposed of in other ways. One method, which may be chosen by many plants, is to bury the residuals, possibly at the mine site. The procedure is effective in areas where the ground-water level is deep and rainfall sparse, but it could pollute ground water where coal seams, through which contaminants could leak, compose parts of local aquifers. Little information is available on the mechanism, or the nature and extent, of ground-water pollution by waste disposal, and more research is needed.

In addition, research is required to evaluate the effectiveness, and to improve the capability of, holding ponds to evaporate waste water in preventing the discharge of effluent to surface waters. This research should include studying the potential for, and prevention of, ground-water pollution by the downward percolation of the waste water in these ponds. Among pertinent factors are: the effect of pond locations relative to aquifers, integrity of various linings, and fate and transport of pollutants through subsurface structures.

Table 6.5. EPA Recommended New Source Performance Standards[a]

Parameter	Coal Storage, Refuse Storage, and Coal Preparation Plant Ancillary Area		Bituminous, Lignite, and Anthracite Mining: Acid or Ferruginous Mine Drainage		Bituminous, Lignite, and Anthracite Mining: Alkaline Mine Drainage	
	30-Day Average	Daily Maximum	30-Day Average	Daily Maximum	30-Day Average	Daily Maximum
pH	6-9	6-9	6-9	6-9	6-9	6-9
Iron, Total	3.0	3.5	3.0	3.5	3.0	3.5
Dissolved Iron	0.30	0.60	0.30	0.60		
Manganese, Total	2.0	4.0	2.0	4.0		
Total Suspended Solids	35.0	70.0	35.0	70.0	35.0	70.0

[a]All values except pH in mg/l.

Source: ref. 9.

REFERENCES FOR SECTION 6

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7 IMPACTS ON AIR QUALITY

The impact of emissions of atmospheric pollutants from coal-utilization facilities on the ambient air quality and rate of pollutant deposition has been evaluated. On the basis of this evaluation, possible constraints on coal utilization imposed by air-quality regulations have been identified. The estimates of impacts on air quality and deposition rates are also inputs to other sections of the report dealing with evaluation of risk to human health and natural ecosystems.

The assessment considers impacts of both electrical generation and gasification; however, the primary emphasis is on impacts of electrical generation because emission rates per unit plant for the pollutants considered are much larger and there are more plants. The calculation of ambient concentrations and depositions of trace elements is based on first-order models, the objective being to establish order-of-magnitude levels that will identify potential problems for further study.

7.1 EXISTING AND PROJECTED BACKGROUND CONCENTRATIONS

The advantages of siting a coal-utilization facility in a given subregion are to a large extent determined by the existing air quality. Areas that should be automatically excluded are those in which current air pollution exceeds the local standards or is projected to exceed them because of emissions due to economic and industrial growth. Factors taken into account in this assessment included not only the present air quality and emissions, but also projected emissions from which future air quality can be estimated. The result is a designation of areas on a county-by-county basis in the six-state region in which an existing or potential air-quality problem was discovered.

7.1.1 Air Quality Maintenance Areas

Air Quality Maintenance Areas (AQMAs) have been designated by the U.S. Environmental Protection Agency (EPA) to identify areas in which the potential exists to exceed any National Ambient Air Quality Standard (NAAQS) by the year 1985. The determination of AQMAs included compilation of 1970 emissions from various state files, State Implementation Plans (SIPs), and the data bank of the National Emissions Data System (NEDS).[1] These emissions were projected to 1985 by (1) applying SIP control strategies to existing sources, including the emissions from planned power plants that would come under the new regulations; and (2) assuming increases in proportion to Bureau of Economic Analysis (BEA) growth indicators. Air quality for 1985 was estimated by using these projected emissions in a model for atmospheric dispersion. When data were available for the regions, calibrated models were the preferred method. Areas in which projections for a pollutant exceeded NAAQS were designated as AQMAs for that pollutant.[2] Additionally, a few areas in which projected air quality was not substandard were designated as part of an AQMA if they shared a common air envelope with areas having poor projected air quality.

It is logical to assume that the designation of an area as an AQMA for particulates or sulfur dioxide would restrict siting of additional facilities other than those planned through 1985. The designated AQMAs in the six-state study area are shown in Fig. 7.1, along with other designated areas.

7.1.2 EPA/SAROAD Data

In counties not designated as AQMAs, an attempt was made to assess present air quality through air-monitoring data stored on EPA's Storage and Retrieval of Aerometric Data (SAROAD) system. Summary data from 1972-1974 were consulted, and data from the most recent year were used for sites having data available for more than one year. Counties in which data from a given monitoring station were shown to be in violation of the annual and/or 24-hr primary state or federal standards for SO_2 or total suspended particulates (TSP) were identified as relatively poor siting areas. A county in which only the 24-hr secondary standard was violated was not automatically identified as a poor county, since this violation could indicate only a single bad meteorological condition or, perhaps, a single pollutant source near the station, rather than a county-wide problem. Locations of the counties with monitoring stations in which standards were violated (but not AQMAs) are also indicated in Fig. 7.1.

One difficulty with monitoring data is that they generally represent air quality at only individual sites. Unless there are several stations in a given county, an adequate estimate of the air quality of the entire county

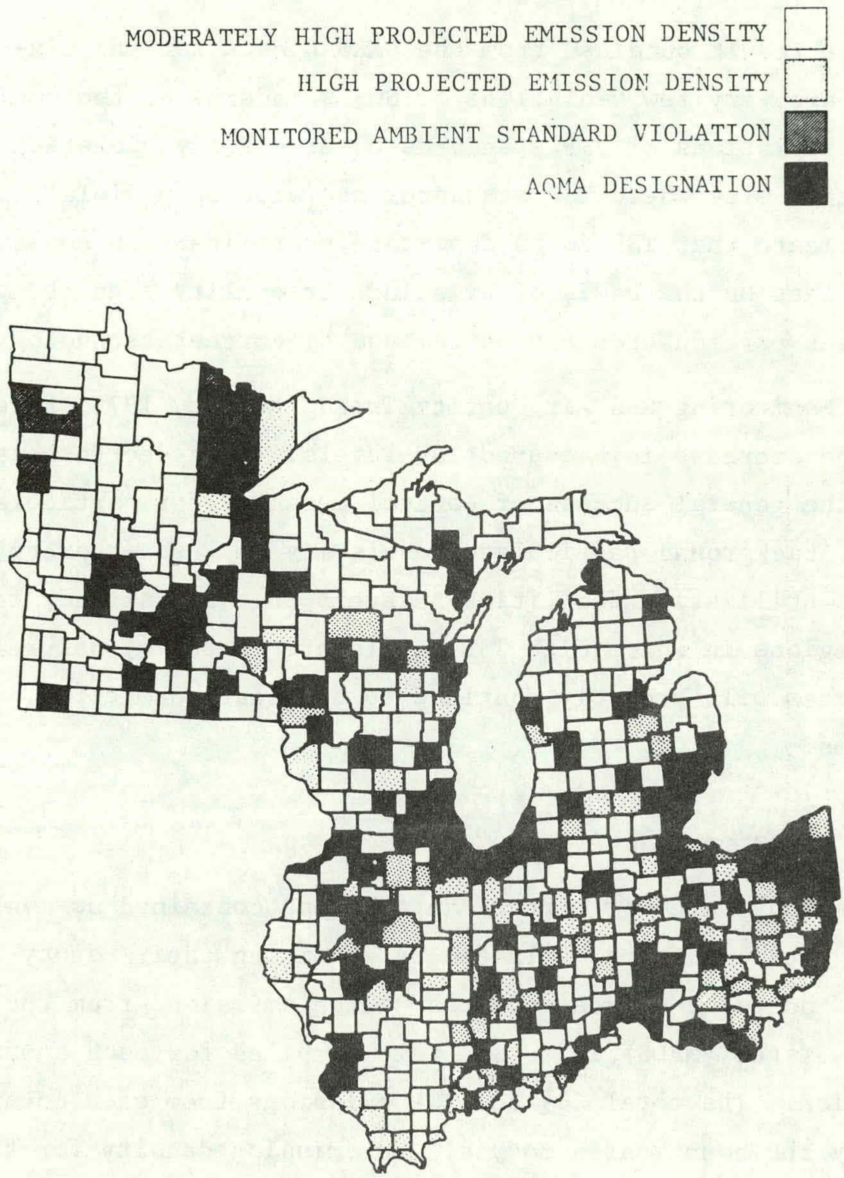


Fig. 7.1 County Classifications Based on Existing and Projected Emissions and Air Quality

is not possible. Nevertheless, a violation at a given point in a county probably shows that the background levels throughout the county are relatively high.

A notable result obtained from the SAROAD data for the six-state region is that there are very few violations of SO_2 standards at the monitoring sites, although many violations of TSP standards occur. Every violation of the SO_2 standard was at a site where TSP standards had also been violated. These coincidences indicate that TSP is an important contaminant in constraining siting of coal facilities on the basis of existing air quality even though 99% or more of flue-gas particulates can be removed by current technology.

The EPA Monitoring and Air Quality Trends Report, 1973, revealed a general nationwide decrease in measured TSP levels. This decrease is believed to represent the general success of control measures for particulates; thus, in the future, background particulate levels may be less important in constraining coal-utilization facilities in areas that are already fairly well developed. Regions in which high TSP levels are caused by natural or uncontrollable sources will probably continue to be questionable for coal-utilization facilities.

7.1.3 County Emission Densities and Projections

Counties that were not part of an AQMA and contained no monitoring sites in the SAROAD data bank were evaluated by examining their county-wide emission density. Data on point-source and area-source emissions from the National Emission Data System (NEDS) 1972 file were compiled for each county in the six-state region. The total SO_2 and TSP emissions from each county were summed and divided by the county area to yield an emission density for the two pollutants in units of (tons/yr)/mi.^{2} Future levels of particulate and sulfur emission within each county were, according to an initial estimate, assumed to be directly proportional to the county population. Population statistics by county for 1975 and projections for three other years (1985, 2000, and 2020) were taken from the Census Bureau Statistics published by the Bureau of Budget in each state.[4] The 1972 emission totals were cited with the 1975 population data and the emissions for the other three years projected by multiplying the 1972 emissions times the ratio of the population in each of the three years and the population in 1975.

The assumption that emissions will increase in proportion to population increases is a first-order approach that yields rather crude and simple estimates of future emissions. A more rigorous approach would consist of dividing the emissions into several source categories and applying more realistic growth indicators, such as projected manufacturing earnings or total personal income, to the appropriate source category to produce projections of emissions in each class. This method would appear to be an improvement, since certain classes of sources should increase more rapidly than others, depending on the type of growth in the individual counties. However, a difficulty is that using the OBERS projections of manufacturing earnings, personal income, and employment yields projected emissions that by 2020 are five times those of 1975.[5] Obviously, the problem here and the one in general with projecting emissions is in determining how much future regulations for emission control and emission-control technology will reduce emissions from new sources.

With present and projected emission densities available, it is necessary to determine approximately what densities of sulfur and particulate emissions will cause excessive pollution. An attempt was made to determine these levels by observing what values of the county-wide emission density for SO_2 and TSP produced a violation of state or federal standards at a site within that county. Of 65 counties in the six-state region in which TSP standards were violated, 52% had a TSP emission density in 1975 greater than 20 (tons/yr)/mi^2 and 75% had a TSP emission density greater than (10 tons/yr)/mi^2. The SAROAD data contains very little information for monitoring sites within counties that violate no TSP standards. Therefore, determining representative emission density for a "clean county" was difficult. Nevertheless, on the basis of available data, counties with projected TSP emission densities greater than 20 (tons/yr)/mi^2 were qualitatively designated as having "high" emission densities and those with these densities between 10-20 (tons/yr)mi^2 were designated as having "moderately high" densities.

All violations of SO_2 standards occurred in counties that had TSP violations or were designated as part of an AQMA. Thus, it was assumed unnecessary to determine a density level for sulfur dioxide emissions that would cause iolations of air-quality standards in a county. Nevertheless, SO_2 concentrations that are a significant fraction of the standards might constrain siting by providing high background concentrations. The data showed that SO_2 emission densities above 40 (tons/yr)/mi^2 resulted in average yearly SO_2 concentrations at the monitoring stations of 40 - 75 $\mu g/m^3$; the NAAQS are 80 $\mu g/m^3$. Hence, those counties not classified as having high or moderately high emission densities on the basis of the previous criteria for TSP, were declared as having moderately high emission densities if they contained an SO_2 density greater than 40 (tons/yr)/mi^2. The results of applying these qualitative descriptors are also indicated in Fig. 7.1. Designation of counties as AQMAs or as those with NAAQS violations supersedes these criteria.

7.1.4 *Sensitive Geographical Areas*

The areas in Fig. 7.1 shaded according to various criteria indicate areas having a current or projected problem with air quality. Comparison of these areas with projected siting patterns is useful in designating regions in which the demand for increased energy production might conflict with maintenance of adequate air quality. Figure 4.1 indicates a siting pattern for the baseline scenario for the year 2020. Direct comparison of Fig. 7.1 with Fig. 4.1 identifies several "sensitive areas" in the region in which siting of current or future coal facilities is in areas of poor or potentially poor air quality.

Figure 7.2, which shows the result of such a comparison, indicates that most of the sensitive areas are in Illinois and Ohio. These states have many counties with current or projected air-quality problems as well as high projected energy demand. Most of the sensitive areas are in and around the larger population centers, from which the problems with air quality due to energy demand emanate.

Counties designated as AQMAs, having violations of standards or high emission densities of SO_2 or TSP, are not necessarily excluded from possible siting. Where a violation of standards or high emission density indicates a single source or a cluster of sources rather than high emissions across the county, there are possibly several good sites in the county.

For example, coal-fired steam electric plants might be located in a county with localized high emissions or containing a local air-quality problem if the facility were situated so that plumes from it would have minimal interaction with existing plumes in the county.

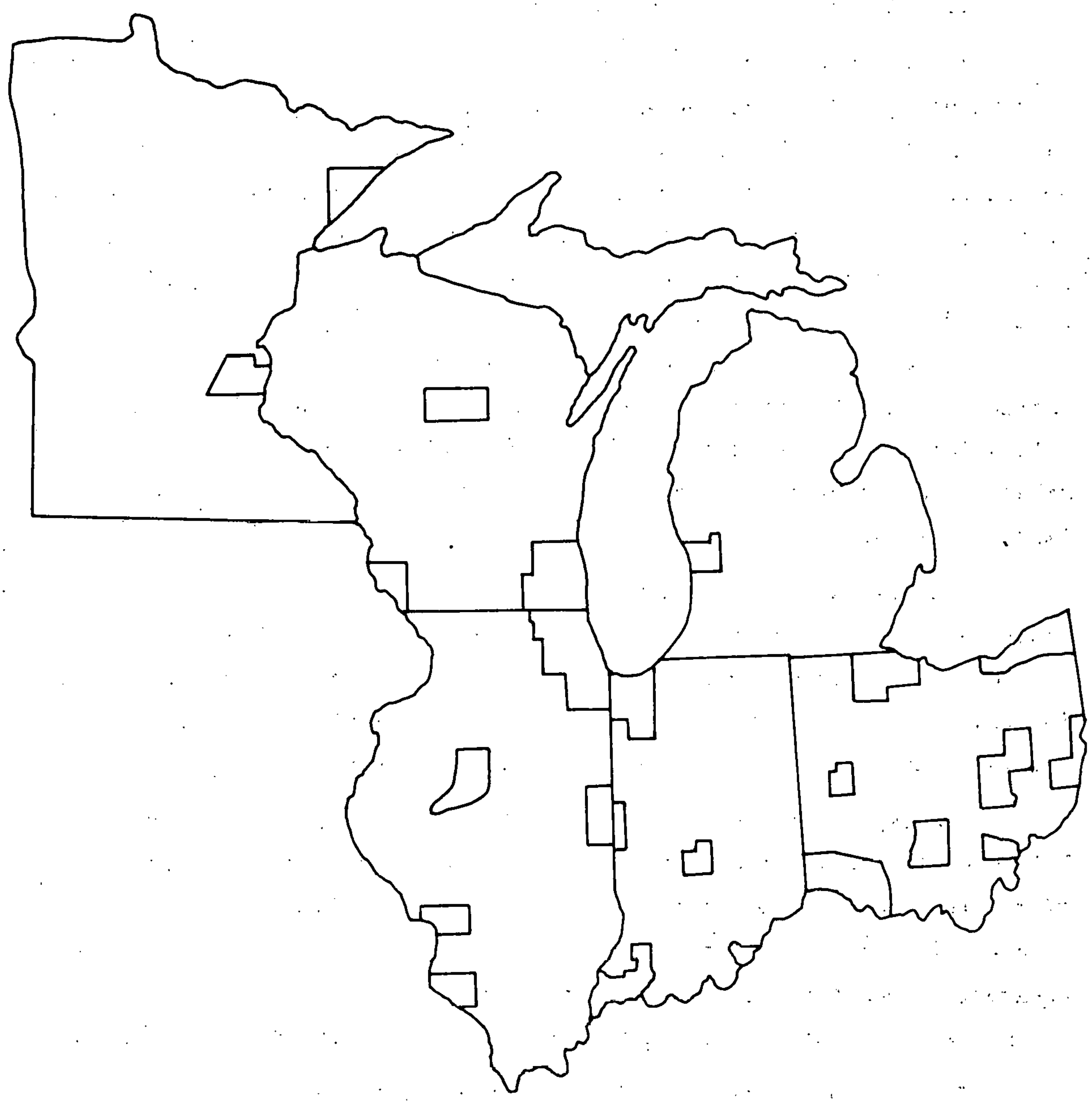


Fig. 7.2 Areas with Projected Problems of Air-Quality Maintenance Coinciding with Siting Areas for Coal Facilities: 2020 Baseline Scenario

In counties in which the emission density and air quality are fairly uniform, the dispersed configuration of smaller coal facilities would probably be more suitable because of the local emissions. Because of the uniform background concentration, the single large facility would be more likely to produce violations on the local level, regardless of its siting.

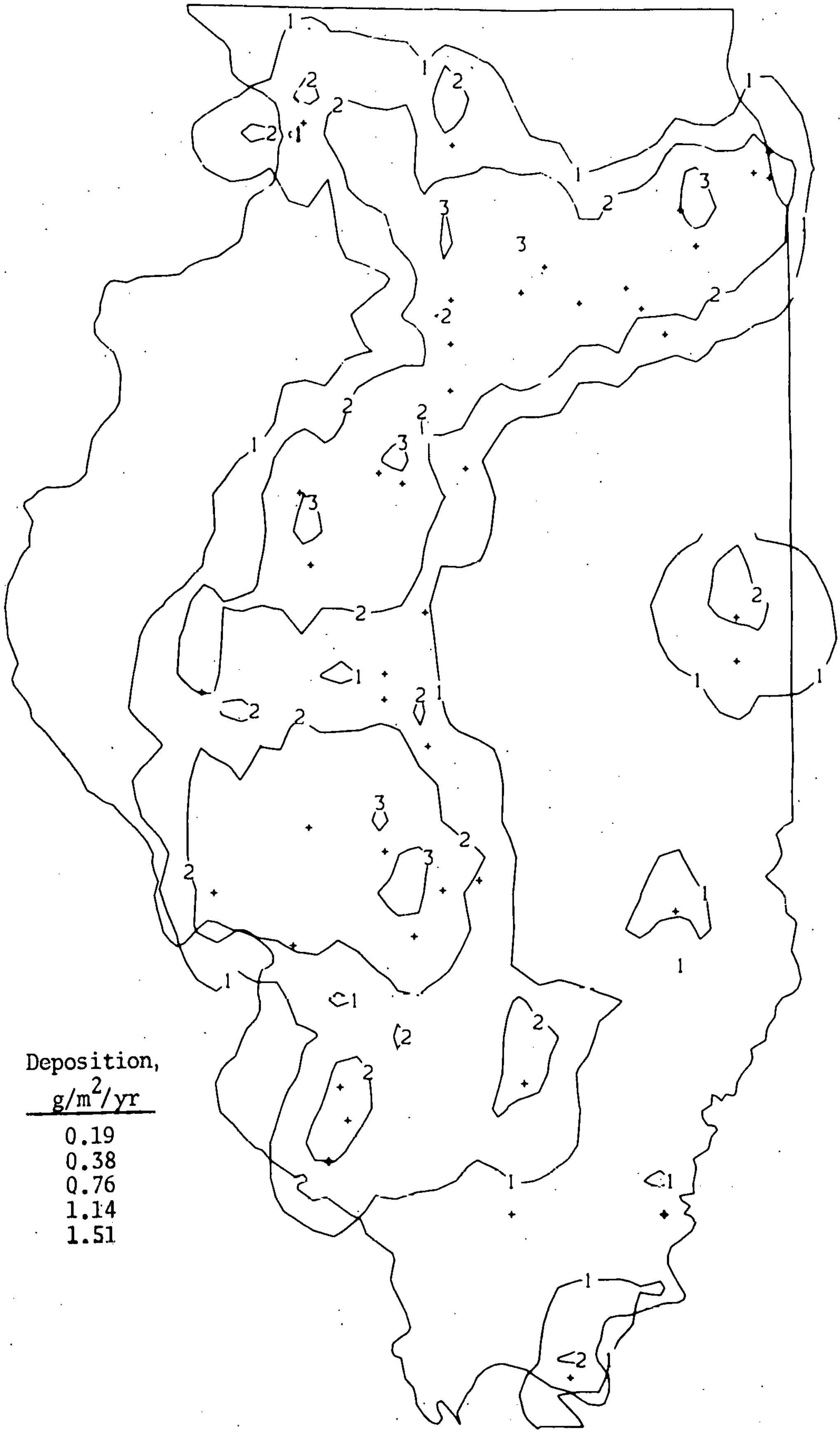
7.2 ANNUAL AVERAGE IMPACT OF COAL-USE SCENARIOS

An extensive modeling effort was carried out to identify the annual concentration and deposition impacts from coal-fired power plants and gasification plants.[6,7] The methods and detailed results of this effort are described in Appendix E. Because of the variability in meteorological conditions, this effort took into account the variation in impacts at different parts of the six-state region. The determination of the dispersion patterns from 71 different subregions within the six-state region was input to calculating the cumulative impacts of the region's scenario. In addition to characterizing impacts on air quality of individual facilities, the representative impacts of a cluster of 12 facilities, covering an area of 6 square miles, were analyzed. The configuration, described in Ref. 8, is shown in Figs. 7.3a-7.3f.

The analysis of annual average impact contains estimates of concentrations and depositions of "regulated" pollutants such as SO_2, NO_x, particulates, and CO, as well as several trace elements. Although there are no standards for ambient air quality for trace elements, the analysis was carried out to provide a coarse estimate of the magnitude of the trace-element problem.

The impacts on local air quality of the six-state scenario and the Illinois high-coal use scenario were determined by appropriate superposition of results from the reference point-source calculations described previously. Results of these calculations are shown in Figs. 7.3 and 7.4 for SO_2 with the countour values for various other pollutants as given in Table 7.1. Table 7.2 gives the estimates of annual deposition using the results in Appendix E.

The contour values are given for the sited facilities at 60% load factor, which produces enough energy on the average to meet the demand given in Sec. 3. An evaluation of impacts at 100% load, which would produce a



Conc, $\mu g/m^3$	Deposition, $g/m^2/yr$
1 - 0.60	0.19
2 - 1.20	0.38
3 - 2.40	0.76
4 - 3.60	1.14
5 - 4.80	1.51

Fig. 7.3 Cumulative Annual Average SO_2 Concentration and Deposition for Baseline Scenario (2020). (a) Illinois

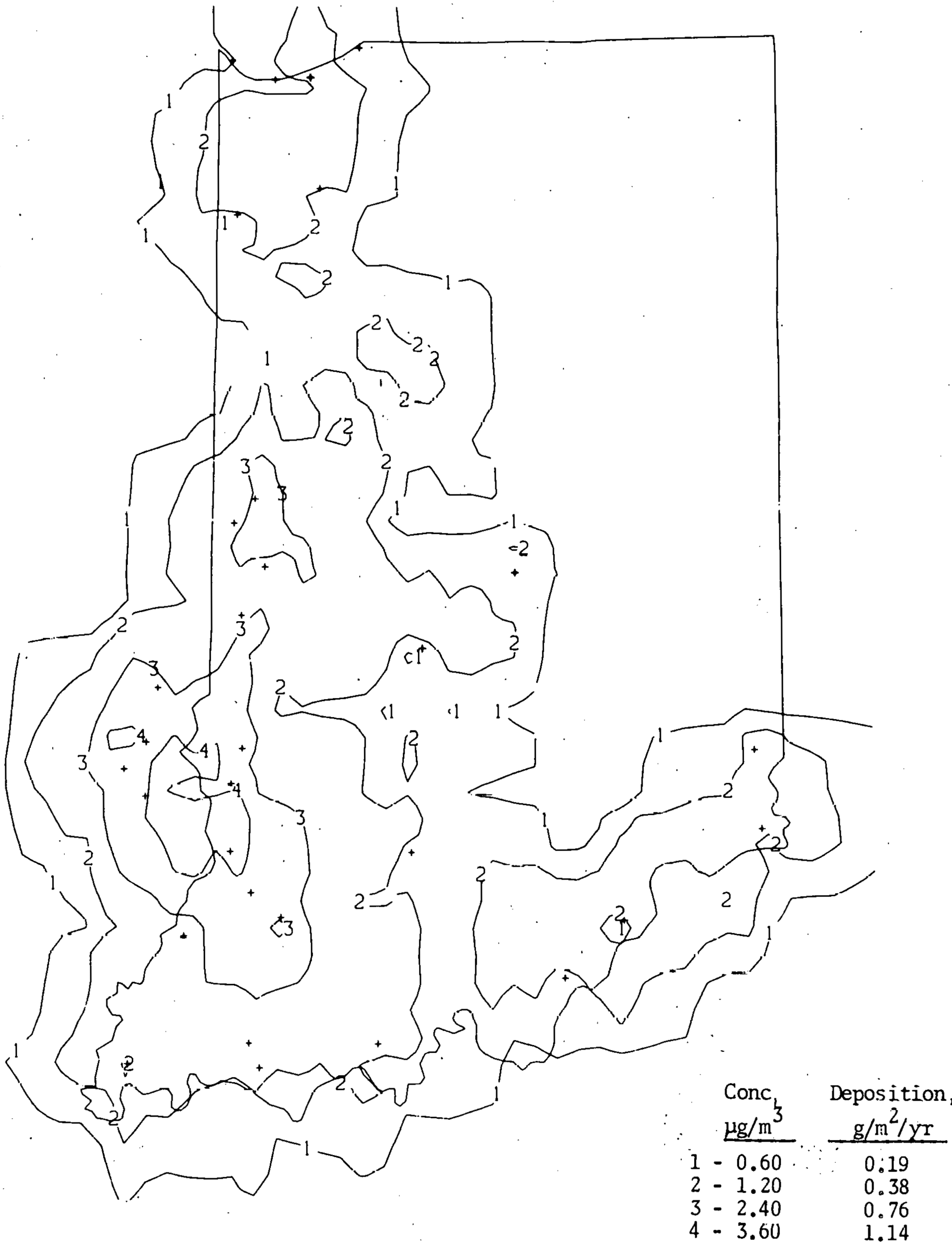


Fig. 7.3 (Cont'd) (b) Indiana

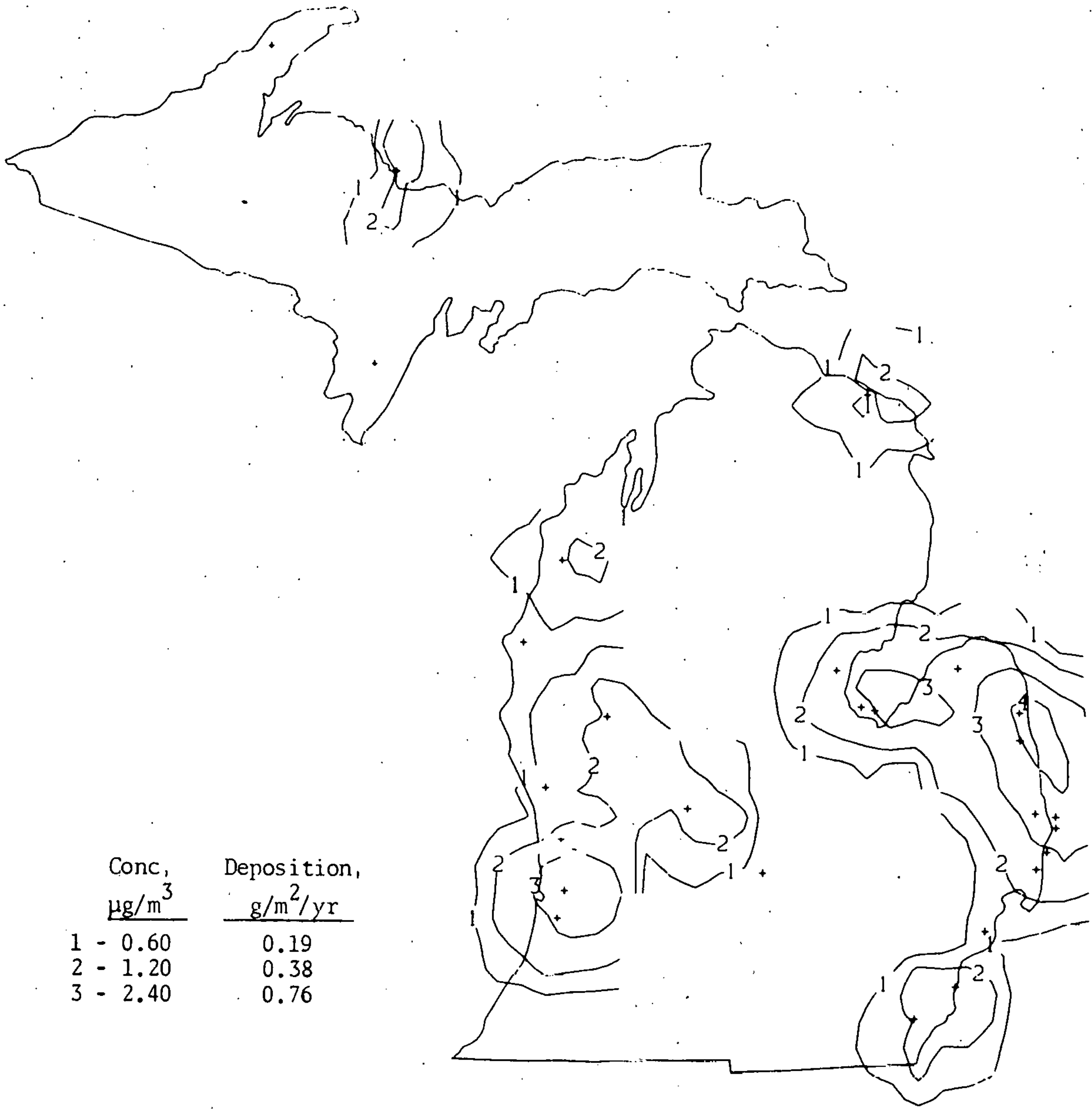


Fig. 7.3 (Cont'd) (c) Michigan

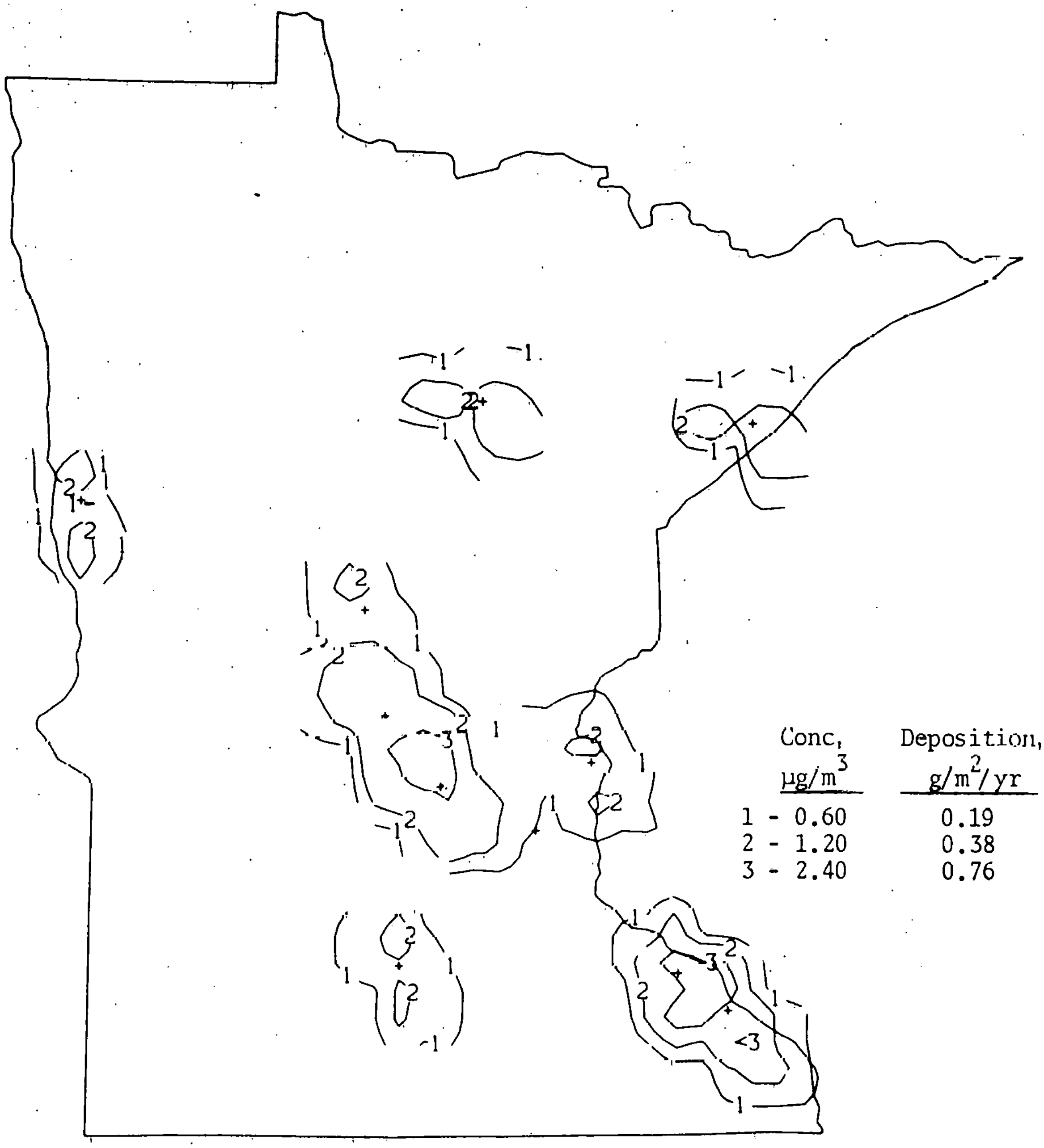


Fig. 7.3 (Cont'd) (d) Minnesota

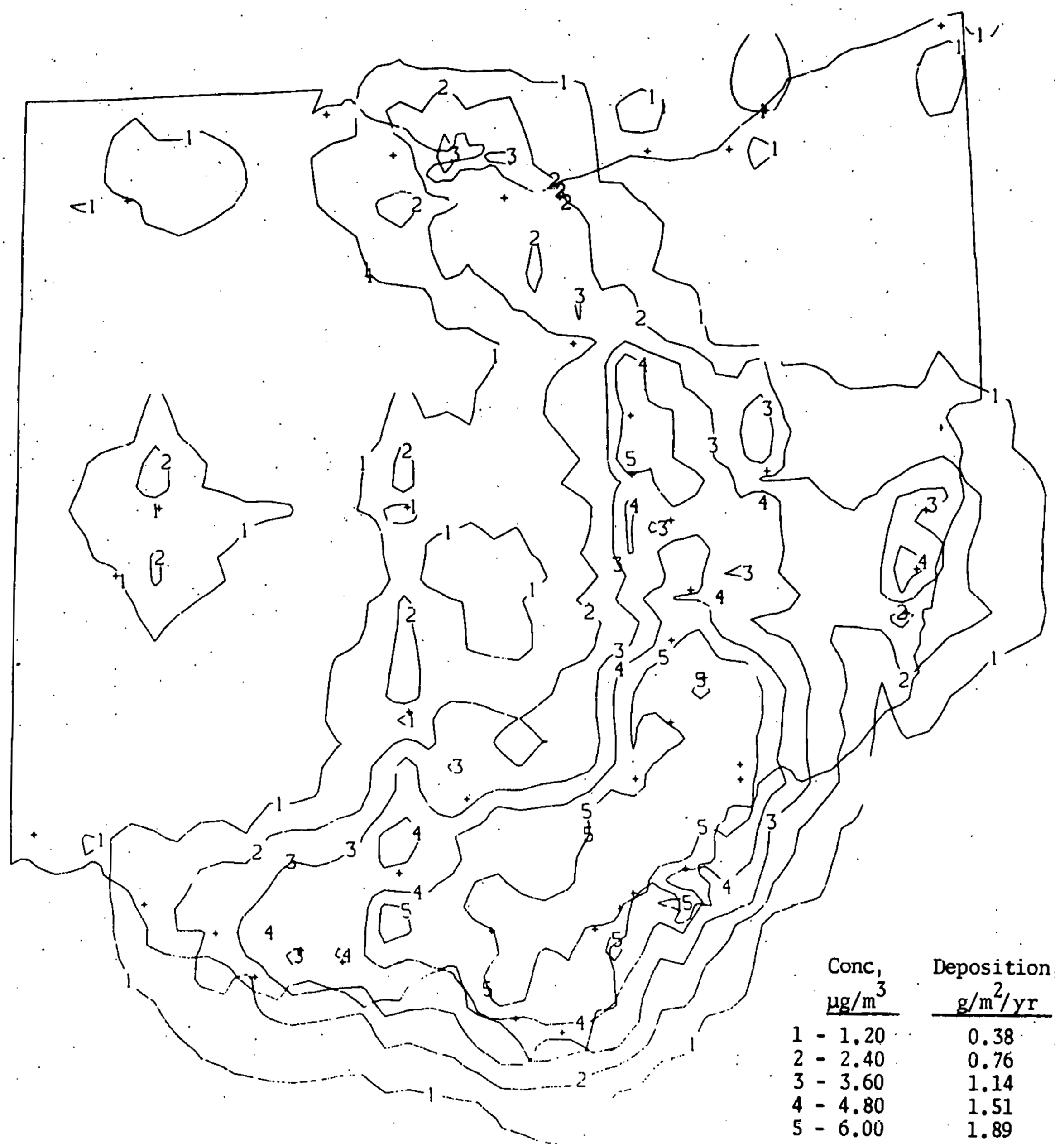


Fig. 7.3 (Cont'd) (e) Ohio

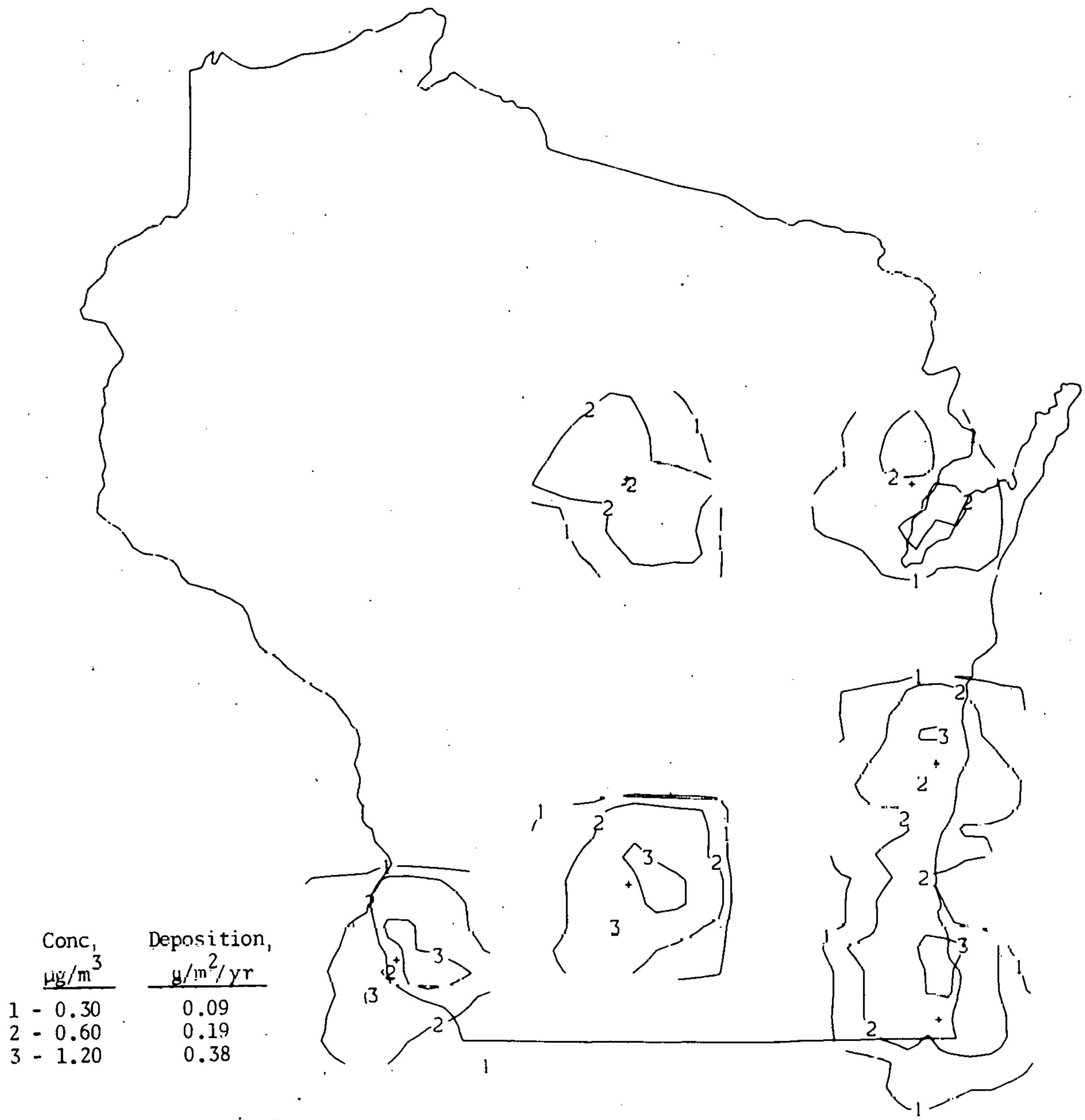
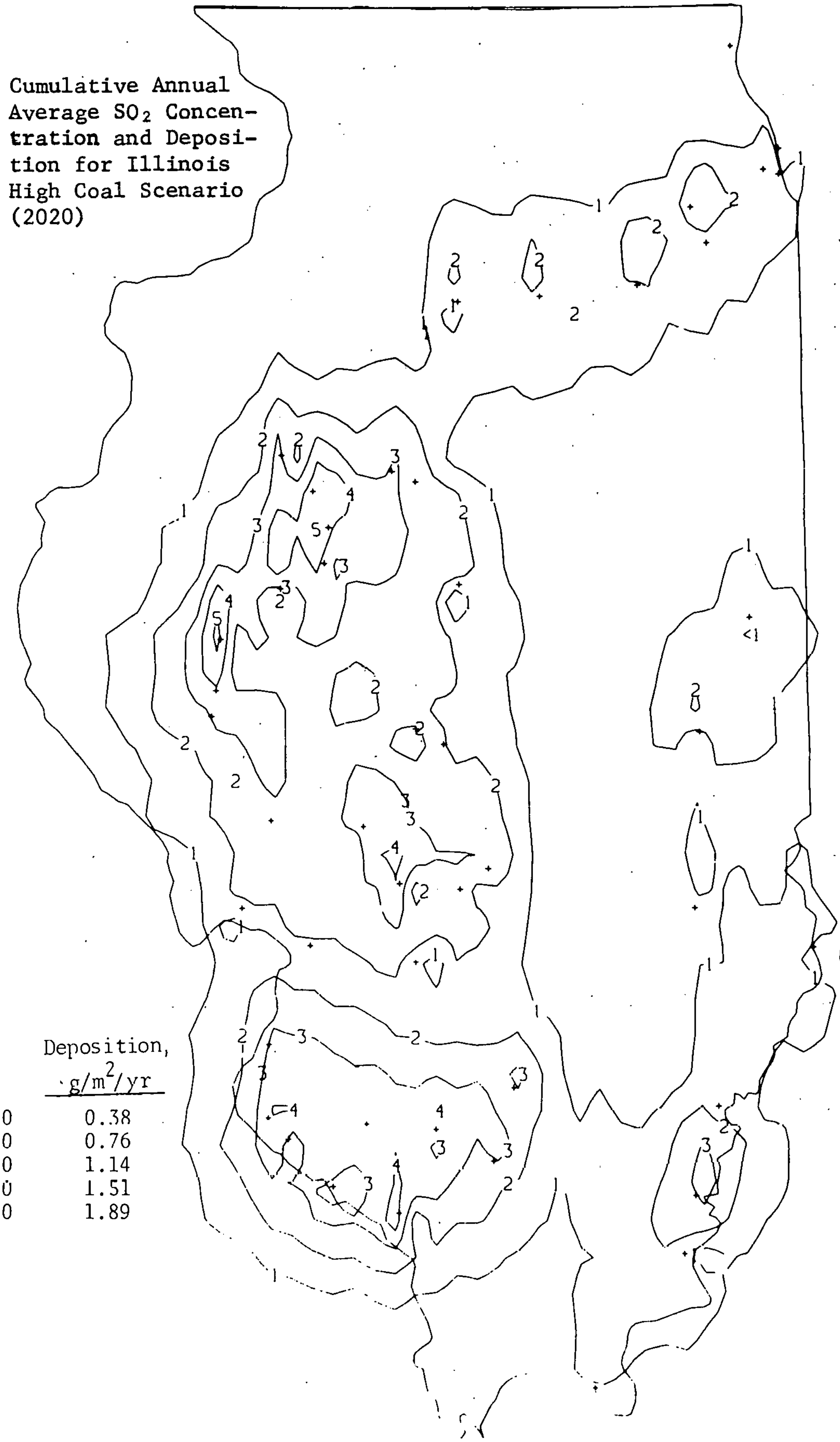


Fig. 7.3. (Cont'd) (f) Wisconsin

Fig. 7.4 Cumulative Annual Average SO_2 Concentration and Deposition for Illinois High Coal Scenario (2020)



Conc, $\mu g/m^3$	Deposition, $g/m^2/yr$
1 - 1.20	0.38
2 - 2.40	0.76
3 - 3.60	1.14
4 - 4.80	1.51
5 - 6.00	1.89

Table 7.1. Pollutant Concentrations Corresponding to SO_2 Isopleths in Figs. 7.3 and 7.4

Pollutant	Concentration, μg/m^3						
SO_2	0.30	0.60	1.20	2.40	3.60	4.80	6.00
NOx	0.18	0.35	0.70	1.40	2.10	2.80	3.50
Part.	0.03	0.05	0.10	0.20	0.30	0.40	0.50
CO	0.95(-2)[a]	1.90(-2)	3.00(-2)	7.60(-2)	1.14(-1)	1.52(-1)	1.90(-1)
As	1.31(-4)	2.63(-4)	5.25(-4)	1.05(-3)	1.58(-3)	2.10(-3)	2.63(-3)
Be	3.28(-6)	6.55(-6)	1.31(-5)	2.62(-5)	3.93(-5)	5.24(-5)	6.55(-5)
Cd	1.58(-6)	3.15(-6)	6.30(-6)	1.26(-5)	1.89(-5)	2.52(-5)	3.15(-5)
F	1.14(-3)	2.28(-3)	4.56(-3)	9.12(-3)	1.37(-2)	1.82(-2)	2.28(-2)
Hg	1.97(-6)	3.94(-6)	7.87(-6)	1.57(-5)	2.36(-5)	3.15(-5)	3.94(-5)
Pb	2.08(-4)	4.15(-4)	8.30(-4)	1.66(-3)	2.49(-5)	3.32(-3)	4.15(-3)
Se	3.08(-5)	6.15(-5)	1.23(-4)	2.46(-4)	3.69(-4)	4.92(-4)	6.15(-4)

[a](-2) denotes x 10^{-2}, etc.

Table 7.2. Pollutant Deposition Rates Corresponding to SO_2 Isopleths in Figs. 7.3 and 7.4

Pollutant	Deposition Rate, g/m^2-year						
SO_2	0.09	0.19	0.38	0.76	1.14	1.51	1.89
F	3.60(-4)[a]	7.19(-4)	1.44(-3)	2.88(-3)	4.31(-3)	5.75(-3)	7.19(-3)
Be	3.10(-7)	6.20(-7)	1.24(-6)	2.48(-6)	3.72(-6)	4.96(-6)	6.20(-6)
Pb	1.96(-5)	3.93(-5)	7.85(-5)	1.57(-4)	2.36(-4)	3.14(-4)	3.92(-4)
Se	2.92(-6)	5.84(-6)	1.17(-5)	2.33(-5)	3.50(-5)	4.67(-5)	5.84(-5)

[a](-4) denotes x 10^{-4}, etc.

conservative upper bound for these subregions that may locally have a higher load factor, can be simply obtained by multiplying the indicated results by a factor of (100/60).

The largest concentrations occur of course in those regions with the most facilities. These concentrations are in southern Ohio, where the annual SO_2 concentration is estimated to exceed 6.0 $\mu g/m^3$. In states such as Minnesota and Wisconsin, where the facilities are fewer and more widely spaced, the cumulative effects of the facilities are much smaller.

Figure 7.4 presents the cumulative impacts of the High Coal Use Scenario for Illinois. Comparison of this figure with Fig. 7.3a reveals that the dispersion patterns are similar but the magnitude of the concentrations are very different. The concentrations for this scenario are about twice those for the baseline scenario.

Comparison of Figs. 7.3a-7.3f with Fig. 7.2, which contains the sensitive areas for siting, reveals that the baseline siting pattern produces maximum impacts in many of the sensitive areas. This condition results because siting criteria, such as water availability, coal availability, and proximity to load center take precedence in these areas over air-quality criteria. A notable exception is in northeast Ohio, where most of the facilities in this sensitive area are nuclear plants.

7.3 SHORT-TERM CONCENTRATION IMPACTS

Short-term maximum concentrations were estimated primarily from the results of a GE study.[8] These results were adjusted for the emissions from the standard 3000-MW electrical generation and 250 x 10^6 scf/day gasification facilities. The results of the analysis and the methodology employed appear in Appendix E.

From the analysis, we conclude that only two controllable factors can alter the ground-level maximum concentration from a power plant. The first factor is the amount of pollutant being emitted from a stack that can be minimized by emission-control devices. The second factor is the height of the stack. A taller stack will tend to minimize the occurrences of extremely high ground-level concentrations, although high concentrations might still occur. However, decreasing the 244 m stack height used in this study by half, 122 m, would increase the estimated short-term maximum concentration by about 50%.

Meteorological factors, such as atmospheric stability, wind speed, and mixing height, also cause wide variation in short-term ground-level concentrations. The meteorology of an area for which siting of a power plant is planned should be closely studied to determine the frequency of occurrences of conditions that produce high ground-level concentrations. Areas in which such conditions are frequent are certainly less desirable as sites and probably require greater emission controls for a plant. Short-term estimated concentrations of emissions from various coal utilization facilities are compared in Sec. 7.5 with NAAQS and PSD regulations.

*7.4 POTENTIAL FOR FORMATION OF PHOTOCHEMICAL OXIDANTS IN POWER-PLANT PLUMES**

Exposures to high levels of photochemical oxidants such as ozone and peroxyacetyl nitrates (PAN) have been associated with certain ill effects in humans and various types of flora and fauna (see other sections of this report). Coal processes relate to these oxidant levels and their ill effects: because of the possible synergistic effects of the oxidants and the primary coal process emission; and because these emissions may contribute to the chemical and physical processes leading to the production of the oxidants. Following is a brief summary of how coal-derived emissions may contribute to increased oxidant levels.

Ozone (O_3), the major oxidant of smog, is formed when oxygen atoms react with oxygen in the presence of a third body, M (nitrogen molecule, N_2, or another oxygen molecule, O_2) in the reaction:

$$O + O_2 + M \rightarrow O_3 + M.$$

Once an oxygen atom is formed, this reaction is fast. Therefore, the important reaction for production of ozone is the one that produces oxygen atoms. The only reaction of atmospheric pollutants known to generate significant amounts of oxygen atoms is the photolysis of nitrogen dioxide (NO_2):

$$NO_2 + h\nu \rightarrow NO + O.$$

*Adapted from ref. 9.

In this reaction, $h\nu$ is ultraviolet sunlight, and both NO_2 and sunlight must be present to generate ozone.

This production of ozone is opposed by a removal process, also involving a nitrogen oxide:

$$NO + O_3 \rightarrow NO_2 + O_2.$$

Because of these opposing reactions, the amount of ozone that exists depends on the relative concentrations of NO_2 and NO. Of the reactions known to be important in formation of urban smog; those that drive or keep this ratio high are reactions of the peroxy radical,

$$RO_2 + NO \rightarrow NO_2 + RO,$$

where R can be hydrogen or some portion of a hydrocarbon molecule. These reactions tend to increase the ratio of NO_2 to NO, in opposition to the NO_2 photolysis reaction, which converts NO_2 to NO (and also generates oxygen atoms).

Of the components in the above reactions, coal processes may contribute significantly to the concentration of nitrogen oxides but do not emit the large quantities of reactive hydrocarbons required to increase the NO_2/NO ratio. Without background concentration of hydrocarbons, NO emissions may deplete the ozone concentrations within the plume. On the other hand, ozone increases because of the NO_x emissions if associated with high hydrocarbon levels, which might occur in an urban area. Furthermore, for power-plant plumes, some mechanism not associated with hydrocarbons might oxidize NO_2 to NO to increase the ratio, and hence ozone concentrations. Mechanisms in which chlorine and sulfur compounds participate have been proposed, but few data are available to support either mechanism. Indeed, experimental field data do not conclusively demonstrate that ozone is either produced or depleted in power-plant plumes.

The conclusions that can be drawn from this summary are that the potential for ozone production is enough to warrant further study to define more adequately the complex reactions between constituents of the power-plant plume. Also of importance is an evaluation of the impact on urban photochemical smog due to nitrogen oxide emissions from coal processes, in particular because these emissions possibly become more important due to more stringent standards on automobile emissions.

7.5 CONSTRAINTS ON COAL UTILIZATION RELATED TO AIR-QUALITY STANDARDS

7.5.1 National Ambient Air Quality Standards (NAAQS)

Under the Clean Air Act of 1970, the USEPA has promulgated air-quality standards for six pollutants: carbon monoxide, nitrogen dioxide, particulate matter, sulfur dioxide, hydrocarbons, and photochemical oxidants. The emissions of hydrocarbons from coal process are generally small and thus these pollutants were not considered further. Some levels of ozone have exceeded the 24-hr standard of 160 μg/m near power plants but there is no conclusive evidence as to what extent these levels are attributable to plant emissions alone.

The NAAQS for the remaining four pollutants are given in Table 7.3, along with estimates from previous sections of the impacts from the 3000-MW electric generation facility and the 250 x 10^6 scf/day gasification plant with emissions as given in Table 2.5 and 2.10 respectively.

Table 7.3 clearly illustrates that the coal-utilization facilities considered do not contribute a significant fraction of the allowable annual concentration; the largest increment is associated with the clustered facilities and contributes less than 25% of the annual NAAQS. The concentrations for the High Coal Electric Scenario for Illinois, which is the plausible upper bound in density of coal-conversion facilities for any state, cumulatively contribute less than 10% of the annual NAAQS in any location.

On the other hand, the short-term 24-hr standard for SO_2 will limit the size and emission rate of the electrical generation facilities. The 3000-MW facilities considered in this study appear to represent the upper limit on plant size if emissions are at the allowable New Source Performance Standard rate of 1.2 lb $SO_2/10^6$ Btu heat input. The maximum concentration estimates are given as a range of values because of the uncertainties in short-term estimates discussed in Sec. 7.4.

Emissions of TSP from electrical generation facilities contribute a significantly smaller fraction than do emissions of SO_2 to their respective 24-hr standards. However, as was indicated in Sec. 7.1.2, existing ambient TSP concentrations are generally higher relative to standards than are SO_2 concentrations; hence, careful consideration must also be given to impacts of particulate emissions in assigning priority to facility siting.

Table 7.3. Comparison of NAAQS and Estimated Maximum Concentrations from Coal Utilization Facilities

Pollutant	Type of Standard	Averaging Time	Frequency Parameter	Maximum Concentration, μg/m³				
				NAAQS	3000 MW	Cluster of 12 3000-MW Plants	HYGAS[a] Gasification 250 x 10^6 scf/day	Illinois High Coal Scenario (2020)
Sulfur dioxide	Primary	24 hr	Annual Max[b]	365	250-490	450-900	21-25	--
		1 yr	Arith. Mean	80	2.4	19	0.2	5.9
	Secondary	3 hr	Annual Max	1300	380-760	690-1360	32-38	--
Particulate matter	Primary	24 hr	Annual Max	260	21-41	37-74	1.8-2.1	—
		1 yr	Geom. Mean[c]	75	0.2	1.6	0.02	0.5
	Secondary	24 hr	Annual Max	150	21-41	37-74	1.8-2.1	--
		1 yr	Geom. Mean[c]	60	0.2	1.6	0.02	0.5
Nitrogen dioxide	Primary/ Secondary	1 yr	Arith. Mean	100	1.4	11	0.1	3.5
Carbon monoxide	Primary	1 hr	Annual Max	40,000	15-30	27-54	1.3-1.5	—
	Secondary	8 hr	Annual Max	10,000	10-20	18-35	0.8-1.0	—

[a] Ranges for short-term concentration reflect alternate wind speed and load factors as in Table 7.7. For the gasification alternate wind speeds are used with a constant load factor.

[b] Annual maximums are values not to be exceeded more than once per year.

[c] As a guide to be used in assessing plans for achieving the annual maximum 24-hour standard. Computed concentrations for facilities are arithmetic means.

The estimates in Table 7.3 show siting of gasification facilities is not to any significant degree constrained by existing NAAQS.

7.5.2 Regulations for Prevention of Significant Deterioration

Potentially more constraining in coal utilization than the NAAQS are the regulations for Prevention of Significant Deterioration (PSD) promulgated by the USEPA to prevent large increases in ambient SO_2 and particulate concentrations beyond existing levels in certain areas, even if existing levels are significantly below NAAQS. These EPA PSD regulations are summarized in Table 7.4.[10] As shown in Table 7.4, the EPA regulations would establish three classes of areas with curbs as follows:

Class I - Areas in which practically any air quality deterioration would be considered significant, thus allowing little or no major energy or industrial development.

Class II - Areas in which deterioration that would normally accompany moderate, well-controlled growth would not be considered significant.

Class III - Areas in which deterioration would be permitted to allow concentrated or very-large scale energy or industrial development, as long as the national secondary standards for ambient air quality are not exceeded.

An important aspect of the EPA regulations is that all regions are initially designated as Class II, subject to redesignation as Class I or Class III by initiative at the state and local levels.

Table 7.4. Allowable Pollutant Increments under EPA PSD Regulations

Pollutant	Averaging Time	Allowable Increments, $\mu g/m^3$ Class I	Class II	Class III
SO_2	Annual	2	15	80
	24-hr Max	5	100	365
	3-hr Max	25	700	1300
Particulates	Annual	5	10	75
	24-hr Max	10	30	150

Considerable controversy has surrounded the issue of PSD regulations, partially because the 1970 Clean Air Act does not explicitly reflect the intent of the Congress as to the desirability of such regulations. In response to this controversy, Congress is considering amendments to the Clean Air Act that provide explicit guidelines for PSD. The amendment as proposed provides for Class I and II areas with allowable increments, the same as for the EPA regulations, as indicated in Table 7.4. However, the proposal does not provide for Class III areas. Also, the proposed amendment differs substantially from the existing EPA regulations in that some areas are designated as mandatory Class I areas and others as Class II, unless they are redesignated by agreement between the States and the USEPA. Specifically, the proposed mandatory Class I areas are all areas of 1000 acres or larger that are International Parks, National Parks, National Wilderness Areas, or National Wildlife Refuges.

Following is an initial evaluation of how either the existing or proposed PSD regulations would constrain the coal-utilization scenarios considered in this report.* Allowable concentrations in EPA Class III areas are defined as being equal to the NAAQS. Thus, no additional curbs exist beyond those possibly resulting from the short-term 24-hr maximum NAAQS.

Comparing Table 7.4 with the estimated maximum concentrations in Table 7.3 shows that the allowable increments for Class II areas would not be constraining for the annual average concentrations, except for the large 36,000-MW clusters. However, the more stringent 24-hr SO_2 standard would require a 40-80% reduction in emissions from coal-fired electrical generation at individual source locations, either through reduction in plant capacity, lower use of coal with sulfur, or more efficient control equipment. Similar reductions for short-term maximums would be required for particulate emissions. The regulations proposed by Congress would require best-available control technology (BACT) as determined on a case-by-case basis; thus, in all likelihood, they would eliminate use of intermittent controls as a principal mechanism for reducing short-term maximums in lieu of other available control methods.

*PSD regulations were included in the Clean Air Act Amendments of 1977. The PSD evaluation in this report was based on information available at the time of analysis and represents the potential constraint to siting resulting from numerous Class I PSD areas.

For any foreseeable technology the large coal-utilization facilities considered in this study would be prohibited from siting in Class I areas by their very stringent constraints on allowable increments in these areas, in particular again the short-term maximum. The question remains as to how close to the Class I areas facilities can be sited without exceeding the allowable increment. Unfortunately, the available tools for estimating short-term maximums over long distances, as required for this analysis, are very imprecise. However, a "worst-case" procedure suggested by the EPA for use in similar studies can be used to obtain coarse estimates. In this approach, a long-time persistence is assumed for stability Class C, 11 mi/hr wind speed, and a 1000-m mixing height. Removal of SO_2 is included using the linear model discussed in Appendix E.

The resulting estimates of decrease in maximum 24-hr concentrations with distance are shown in Fig. 7.5 for various types of facilities.[14] The standard 3000-MW facility at full capacity with the emission rate allowed by NSPS would violate the 5-$\mu g/m^3$ PSD regulations for Class I areas to about 100 miles away, the maximum distance for which the model should be considered to have validity. Reduction of emissions to 10% of the NSPS allowable rate through a combination of use by low-sulfur coal and flue-gas desulfurization, or other advanced technologies (or equivalently, reducing the capacity to 300 MW at NSPS), would reduce the required distance from the site to the Class I area to about 30 miles, according to the model. Because of their lower rates of SO_2 emissions, gasification plants would only be excluded from the immediate vicinity of the Class I areas.

Effects of the proposed PSD regulations on the siting scenarios are shown in Figs. 7.6 and 7.7, in which the siting maps are superimposed on the proposed mandatory Class I areas and a 30-mile buffer zone surrounding these areas. According to the above analysis, large electrical-generation facilities would be virtually eliminated from these buffer zones and would require significantly reduced emission rates at the zone boundary. Obviously, the PSD regulations would cause severe limitations on available future siting options. Particularly constraining is the location of many of the mandatory Class I areas along waterways, also attractive for power plant siting.

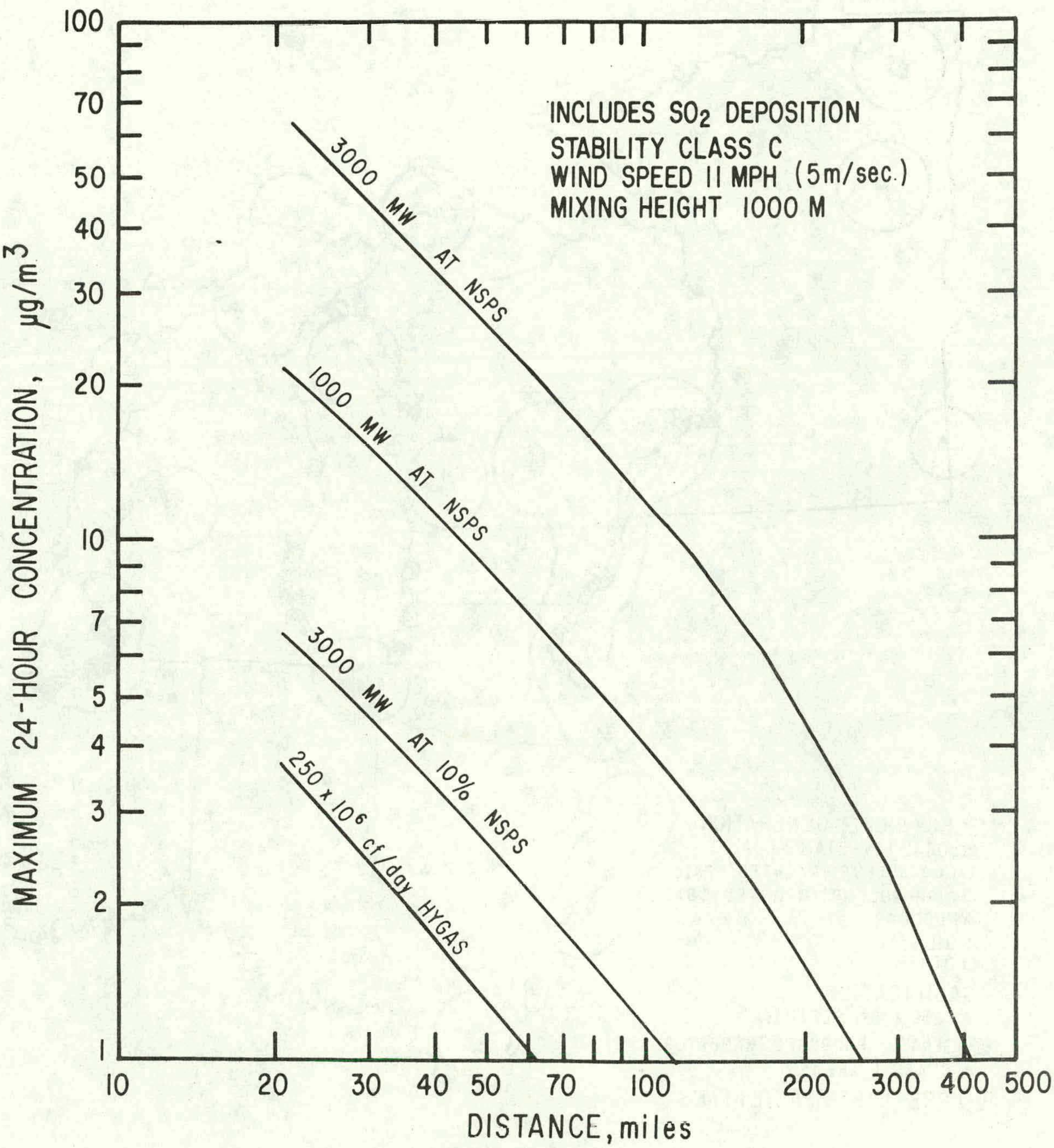


Fig. 7.5 Decrease in 24-hr SO_2 Concentration with Distance from Source

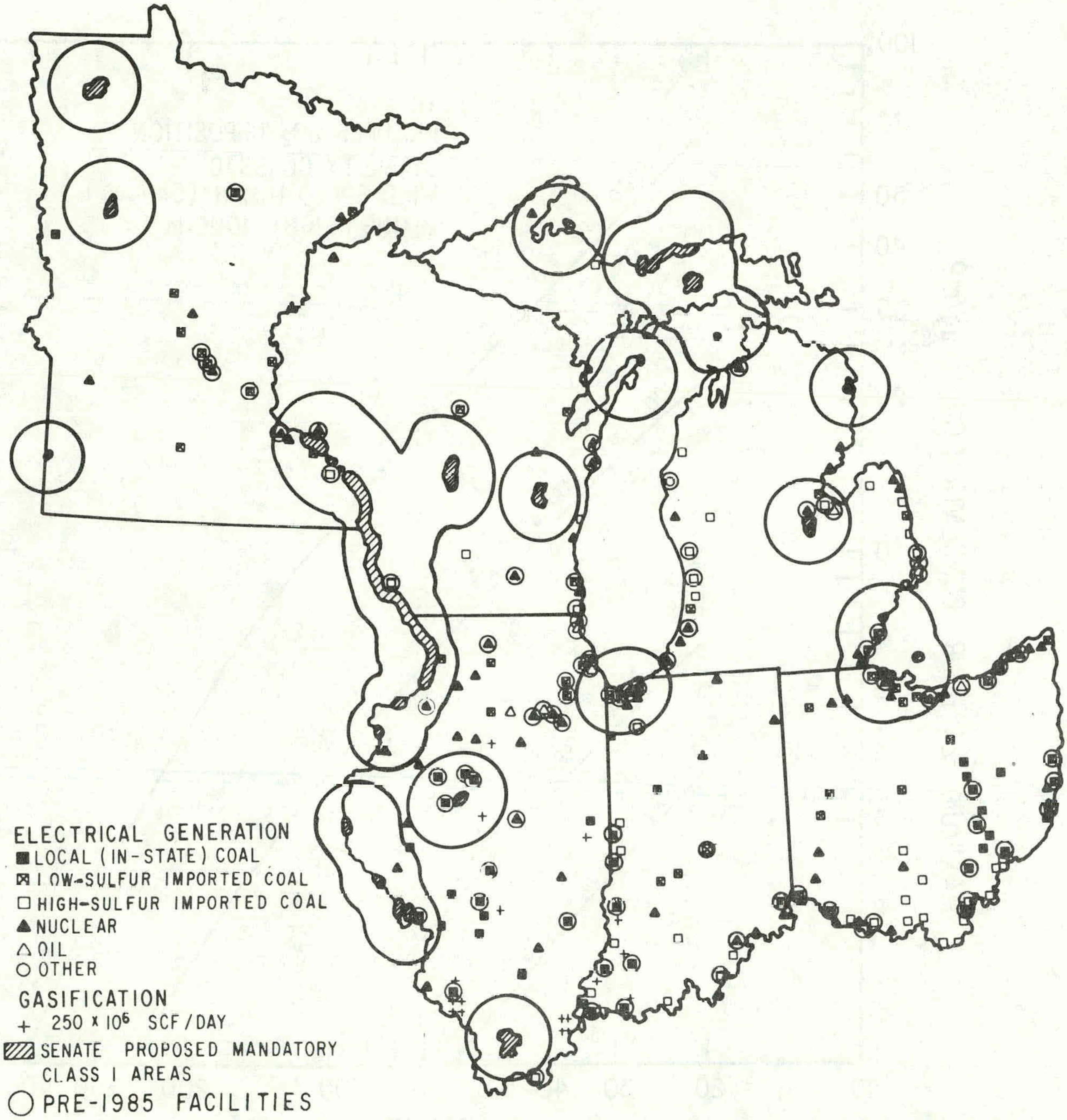


Fig. 7.6 Superposition of Baseline Siting Pattern and 30-Mile Buffer Zone for Proposed PSD Class-I Areas

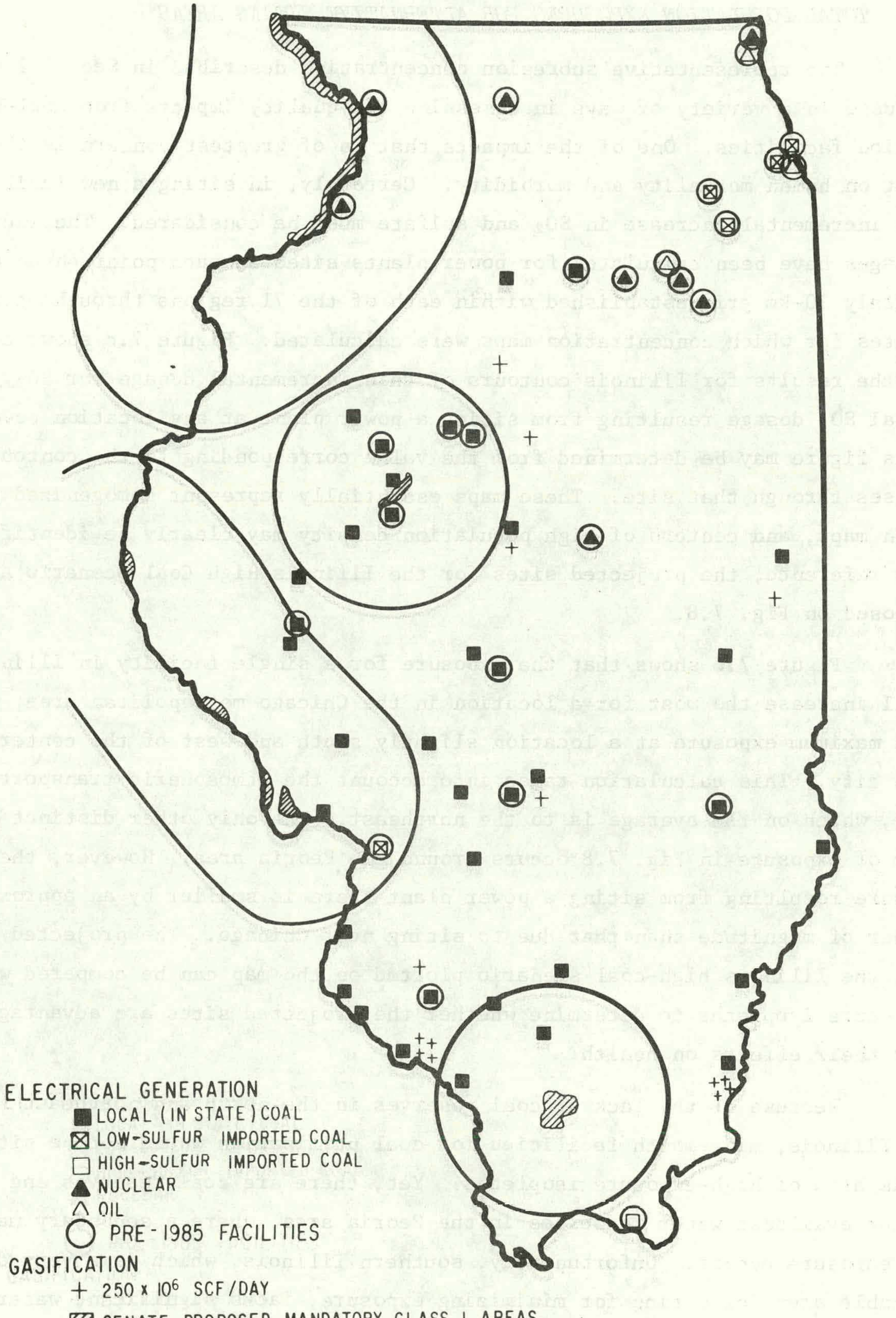


Fig. 7.7 Superposition of Siting Pattern for Illinois High Coal Use and 30-Mile Buffer Zone for Proposed PSD Class I Areas

7.6 TOTAL POPULATION EXPOSURES FOR ALTERNATIVE SITING AREAS

The representative subregion concentration described in Sec. 7.2 may be used in a variety of ways in assessing air-quality impacts from coal-utilization facilities. One of the impacts that is of greatest concern is the impact on human mortality and morbidity. Certainly, in siting a new facility, the incremental increase in SO_2 and sulfate must be considered. The incremental dosages have been calculated for power plants sited at each point on an approximately 20-km grid established within each of the 71 regions throughout the six states for which concentration maps were calculated. Figure 7.8 shows an example of the results for Illinois contours of this incremental dosage for SO_2. The total SO_2 dosage resulting from siting a power plant at any location covered by this figure may be determined from the value corresponding to the contour that passes through that site. These maps essentially represent homogenized population maps, and centers of high population density may clearly be identified. For reference, the projected sites for the Illinois High Coal Scenario are superimposed on Fig. 7.8.

Figure 7.8 shows that the exposure for a single facility in Illinois will increase the most for a location in the Chicago metropolitan area, with the maximum exposure at a location slightly south and west of the center of the city. This calculation takes into account the atmospheric transport of SO_2, which on the average is to the northeast. The only other distinct maximum of exposure in Fig. 7.8 occurs around the Peoria area. However, the exposure resulting from siting a power plant there is smaller by an approximate order of magnitude than that due to siting near Chicago. The projected sites for the Illinois high-coal scenario plotted on the map can be compared with the exposure isopleths to determine whether the projected sites are advantageous for their effects on health.

Because of the lack of coal reserves in the north and northeast sections of Illinois, mine-mouth facilities for coal utilization would not be sited in this area of high-exposure isopleths. Yet, there are coal reserves and sufficient available water resources in the Peoria area, where a secondary maximum of exposure occurs. Unfortunately, southern Illinois, which is a very desirable area for siting for minimizing exposure, lacks significant water resources. Hence, the best sites in Illinois are in the central part of the state and along most of the Mississippi River. In these regions coal and water

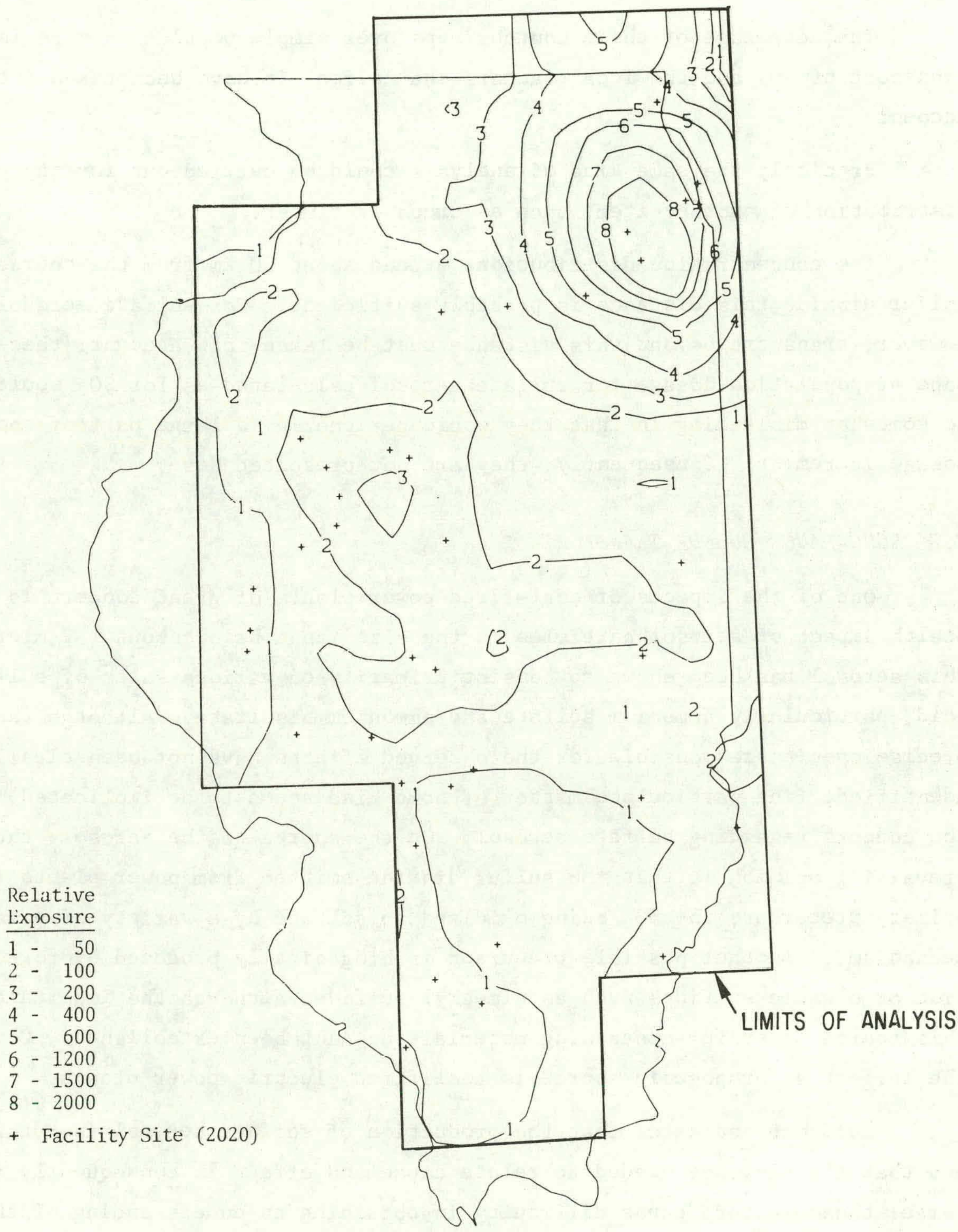


Fig. 7.8 Isopleths for Site-Dependent Integrated Population Exposures (persons × μg/m^3) from Single Coal Facilities in Illinois

resources are fairly abundant and the exposure due to coal facility siting is relatively low.

The advantage of these contour maps over simple population maps is that transport of SO_2 and the local factors that affect it have been taken into account.

Precisely the same kind of analysis could be carried out for any given distribution of another item, such as crops or timber.

The concentration distributions extend about 50 km from the source; for sulfur dioxide this distance is probably sufficient. For sulfate aerosol, however, transport beyond this distance must be taken into account; therefore, maps of population dosage for sulfate aerosol calculated as for SO_2 would be somewhat misleading in that they would be ignoring a large part of the total dosage increment. Consequently, they are not presented here.

7.7 LONG-RANGE SULFUR TRANSPORT

One of the impacts of coal-fired power plants of great concern is the health impact of aerosol particles in the size range below about 1-2 microns. This aerosol has been shown to consist primarily of various salts of sulfuric acid, particularly ammonium sulfate and ammonium bisulfate. Although the precise species responsible for the observed effects have not been clearly identified, fine particulate matter of some kind seems to be implicated, hence the concern regarding sulfate aerosol. On the source of the aerosol, the prevailing opinion is that the sulfur dioxide emitted from power plants is a primary precursor, the SO_2 being oxidized to sulfate by a variety of possible mechanisms. Another possible precursor is biogenically produced hydrogen sulfide or organic sulfides such as dimethyl sulfide, although the importance of this source of sulfur-containing materials has not been established. Certainly the largest anthropogenic source is coal-fired electric power plants.

Evidence indicates that the production of sulfate aerosol is rather slow and that the distance needed to relate cause and effect is consequently rather large; these factors cause difficulty in obtaining an understanding of the problem. Estimates of the effective rate of conversion of SO_2 to sulfate aerosol cover a wide range, but current opinion is that the rate is 1-5%/hr.

If a typical tropospheric wind speed of 5m/sec is assumed, the relevant distance scale for the problem is 360-1800 km. This distance is enough that completely different modeling techniques are needed to predict environmental impacts. A brief discussion of the methodology used in this study is given next, followed by the results of a preliminary investigation using the model.

7.7.1 Methodology

The model used for this long-range impact study, described by Sheih,[11] is based on the work of Bolin and Persson.[12] In the model, the horizontal dispersion of an individual plume about its centerline is neglected, the assumption being that for a long-term average the statistical distribution of the centerline of the trajectories that originate at the source primarily determines the distribution of effluent from that source. The long-term average concentration at any point contains contributions from trajectories having a wide range of travel times from the source. The model first determines the distribution of the end points of trajectories ranging in age from 3-120 hr in time steps of 3 hrs. Each such distribution allows the contribution from trajectories of a particular age to be calculated; the total predicted concentration is simply the sum of all such contributions.

To calculate the pollutant concentration at a point, the vertical distribution of pollutant must be modeled as well as the horizontal. In the model used, this is done by numerically integrating the equation for one-dimensional (vertical) dispersion and thereby calculating the vertical concentration profile as a function of travel time from the source. The eddy diffusivity, K, assumed for these calculations at height z, has the following form:

$$K = \begin{bmatrix} ku_* z, & \text{at} & z \leq 85\text{m} \\ 85ku_*, & \text{at} & 85 < z < H \\ 0 & & z > H \end{bmatrix},$$

where:

k = the von Karman constant (0.4),
u* = the friction velocity (taken equal to 0.4 m/sec), and
H = an effective mixing height (taken equal to 2000 m).

The removal of pollutant at the earth's surface by dry deposition is treated by an analytically integrated form of the flux-gradient relationships for the surface layer that provides an explicit relationship between the ground-level concentration and the concentration at the top of the constant-flux layer predicted by the numerical integration. For the deposition velocity at 2-m height, the commonly accepted values of 1 cm/sec for SO_2 and 0.1 cm/sec for sulfate aerosol were used. The first-order rate constant of 1×10^{-5}/sec was used for the transformation of SO_2 to sulfate.

7.7.2 *Analysis Results*

As described above, the model makes use of the spatial distribution of the end points of trajectories of various ages in calculating the concentration of SO_2 and sulfate aerosol at any point. These distributions are obtained from trajectories initiated once every 12 hr from the source location and followed for 120 hr or until the boundary of the region in question is reached. Bolin and Persson,[12] found from studies with European data that, for a given age, the distribution was nearly isotropic and could be described to a reasonable degree by a gaussian function. The model used in this work also assumes that the distribution for a given trajectory age may be treated as gaussian with standard deviations in the east-west direction possibly different from those for the north-south direction. The only parameters that must be estimated are the coordinates of the mean position and the two standard deviations as functions of travel time.

Calculations were done for five different sites within the six-state region that were chosen to obtain information on the long-range dispersion of effluent from sources in widely-separated areas within the region. Figure 7.9 shows the locations of the five sites considered.

The dispersion of trajectories about the mean is a critical factor in the calculation of a long-term average concentration. The standard deviations in the north-south and east-west directions as a function of travel time for a site in southern Illinois are given in Table 7.5. These deviations are typical of those from the other sites also. There seems to be a trend toward higher deviations for east-west than for north-south, at least during the first 2-3 days, with the exception of the southeast Ohio site, for which the trend is in the reverse direction. The nearness of the Ohio site to the

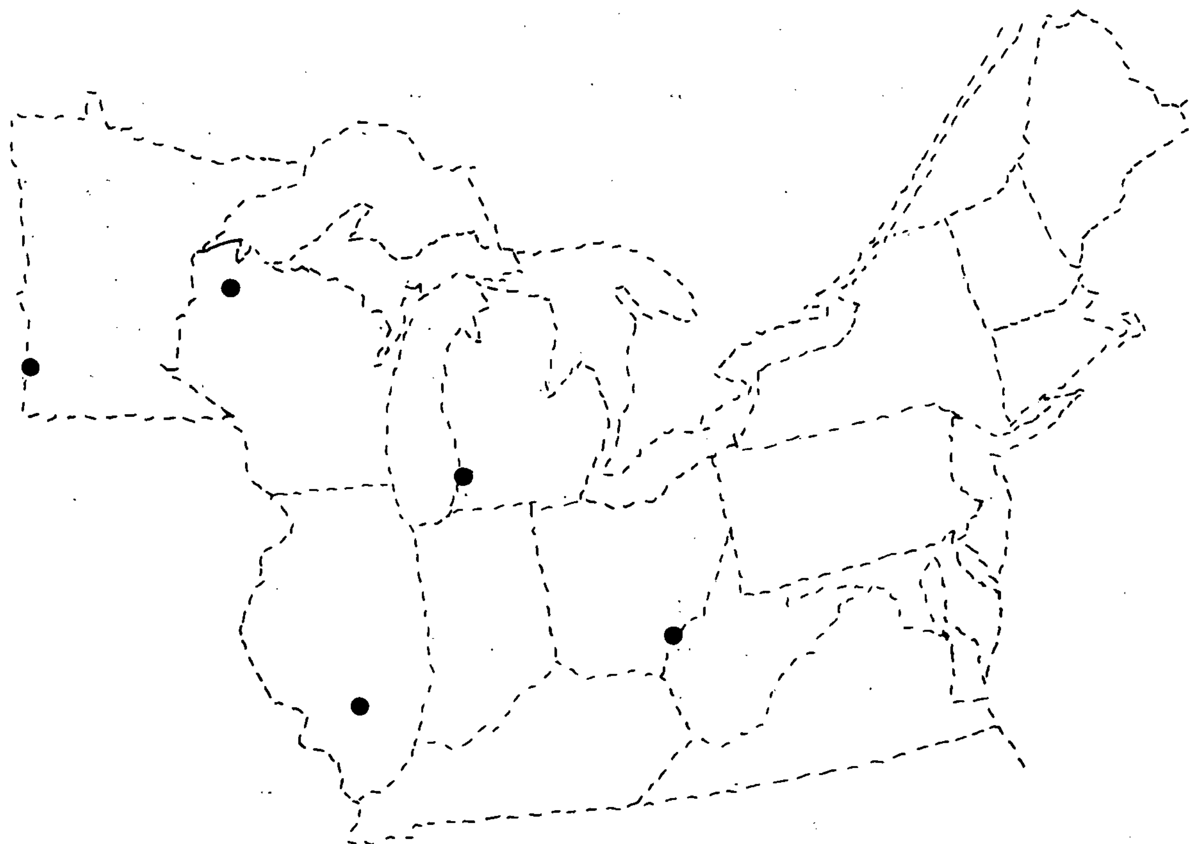


Fig. 7.9 Source Locations for Representative Calculations of Long-Range Sulfur Transport, Transformation, and Deposition

Allegheny Mountains and the generally flat terrain for several hundred kilometers about the other sites may explain the difference. After a day and a half, the standard deviations are essentially constant. This apparent constancy is undoubtedly due in part to the fact that, in the model, trajectories that leave the boundaries of the grid on which the wind data are available are no longer followed and the number of trajectories available decreases with increasing travel time, as indicated in Table 7.5.

For the concentration calculations, the standard deviations used being relatively constant after a day and a half is offset by the contribution from trajectories of a certain age being scaled by the number of trajectories of that age. This essentially means that, for the vicinity of the mean trajectory, the calculations will be relatively unaffected; while at distances on the order of the standard deviation or greater, there will be an underestimation of the concentration, the extent of the error increasing with increasing distance from the maximum.

The concentration calculations also require determining the vertical profile of SO_2 and sulfate as a function of time. The same vertical profile as a function of travel time was used for each source location, thus any variation with time of those factors such as surface roughness and solar radiation that affect the value of the eddy diffusivity was ignored. The only

Table 7.5. Standard Deviations about the Mean for Trajectories Originating in Southern Illinois

Travel Time, days	Standard Deviations, km		Number of Trajectories
	North-South	East-West	
0.5	324	357	2189
1.0	533	601	2093
1.5	644	712	1711
2.0	666	687	1134
2.5	646	678	804
3.0	625	684	596
3.5	628	672	441
4.0	624	662	325
4.5	649	638	230
5.0	641	653	168

variation in the input parameters considered was the variation of effective stack height. Figure 7.10 shows for effective emission heights of 350 and 525 m the fraction of the original emission of SO_2 that: (1) remains in the atmosphere as gaseous SO_2; (2) has been converted to sulfate aerosol but remains in the atmosphere; and (3) has been deposited on the ground as sulfate aerosol. The two sets of curves differ very little, thus the conclusion is that once the effective emission height has reached 350 m, very little is gained by increasing it, at least on average.

Figures 7.11a-7.11e show that SO_2 and sulfate aerosol maps for each of the five locations considered, for an effective emission height of 350 m. Figure 7.11a also shows the SO_2 and sulfate deposition for the southern Illinois source, which is typical of the depositions for the other sources. These figures show that the impact of large coal-fired electric power generating facilities for sulfate aerosol extends over a much longer and wider range than for sulfur dioxide. The calculations also imply that the area of maximum sulfate impact from a given source is relatively close to the source. The implications of these results in light of projected increased coal utilization are that sulfate levels in the highly populated areas around Chicago and Detroit as well as in Illinois, Indiana, Michigan, and Ohio generally can be expected to increase, and, depending on the extent of the development, might approach levels now observed in the East.

Calculations were carried out for the specific scenario corresponding to high coal usage in Illinois. Figure 7.12 shows the distributions of SO_2 and sulfate together with the maps of SO_2 and sulfate deposition resulting from this distribution of sources in Illinois. As mentioned above, the maximum impact on sulfate levels is relatively near the source; but highly populated areas in the Midwest will be affected, particularly Chicago and Indianapolis. The maximum (scaled) ground-level SO_2 and sulfate concentrations predicted for this scenario are 0.08609 and 0.04073 $\mu g/m^3$ per unit emission rate, respectively.

For comparison the existing urban and rural levels of sulfates for the U.S. are shown in Fig. 7.13.[13]

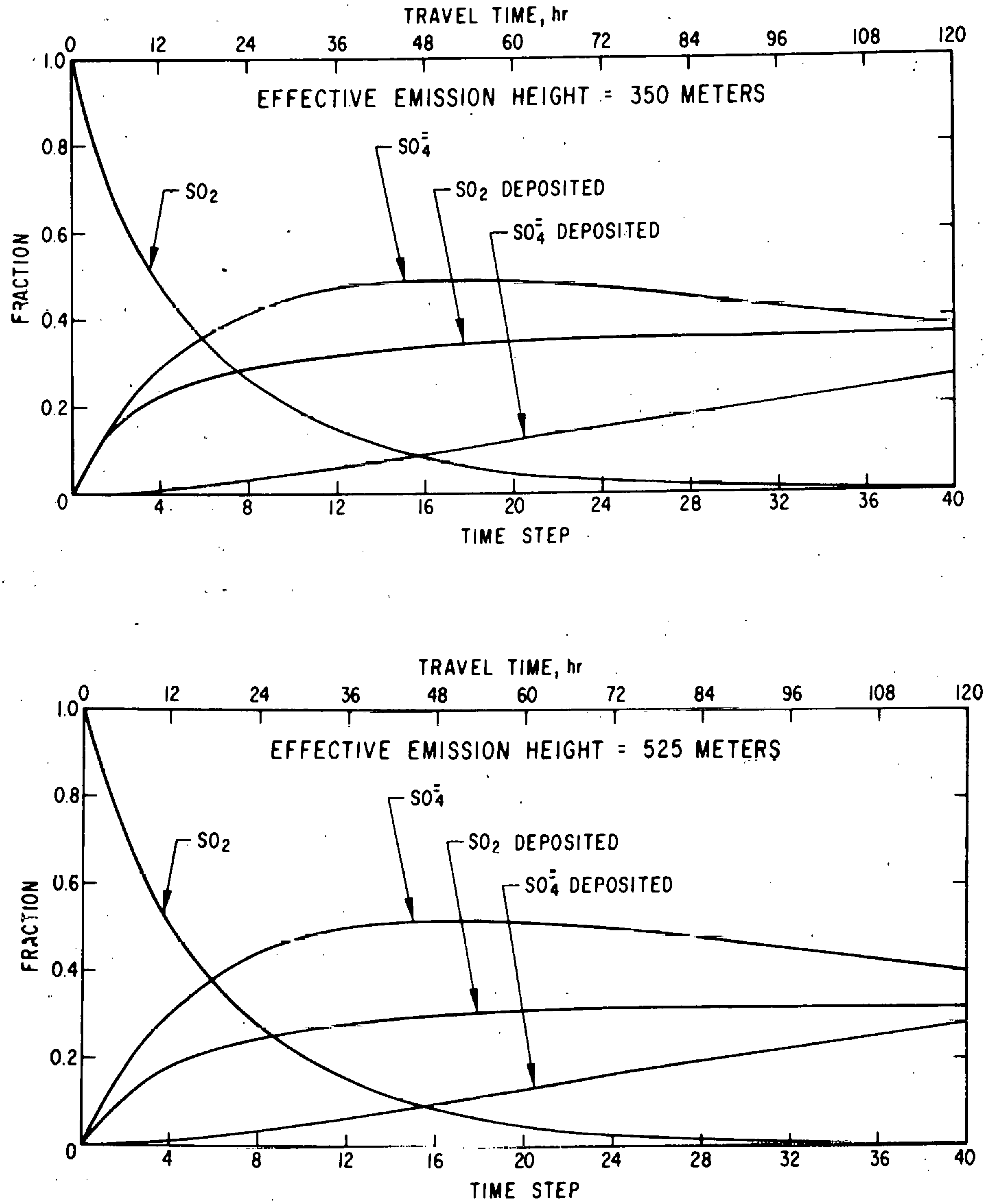


Fig. 7.10 Relative SO_2 and SO_4 Concentrations and Depositions as a Function of Time for Effective Emissions Heights of 350 and 525m

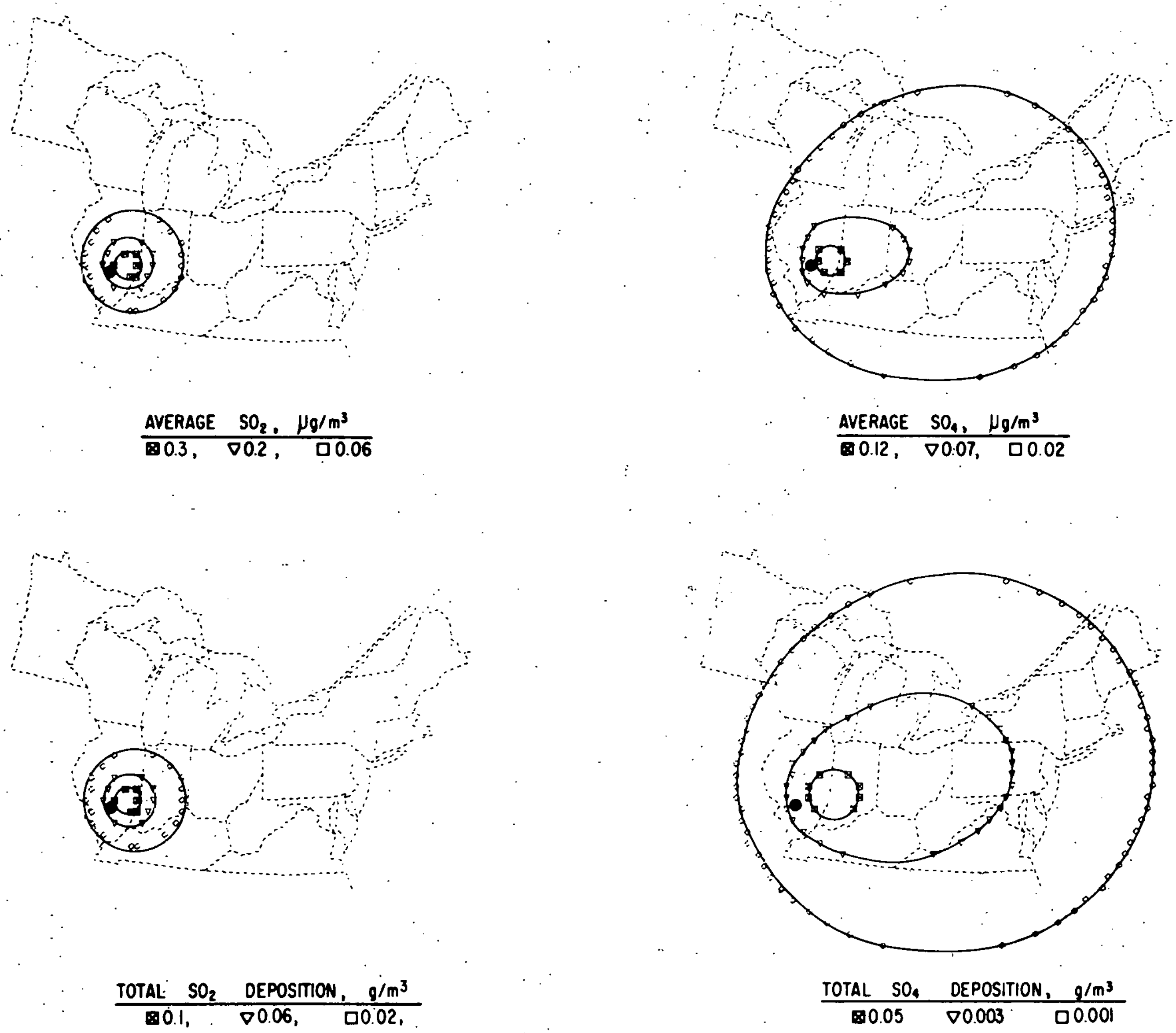


Fig. 7.11 Long-Range Sulfur Transport from 3000-MW Reference Source at 60% Load Factor (a) Southern Illinois Source

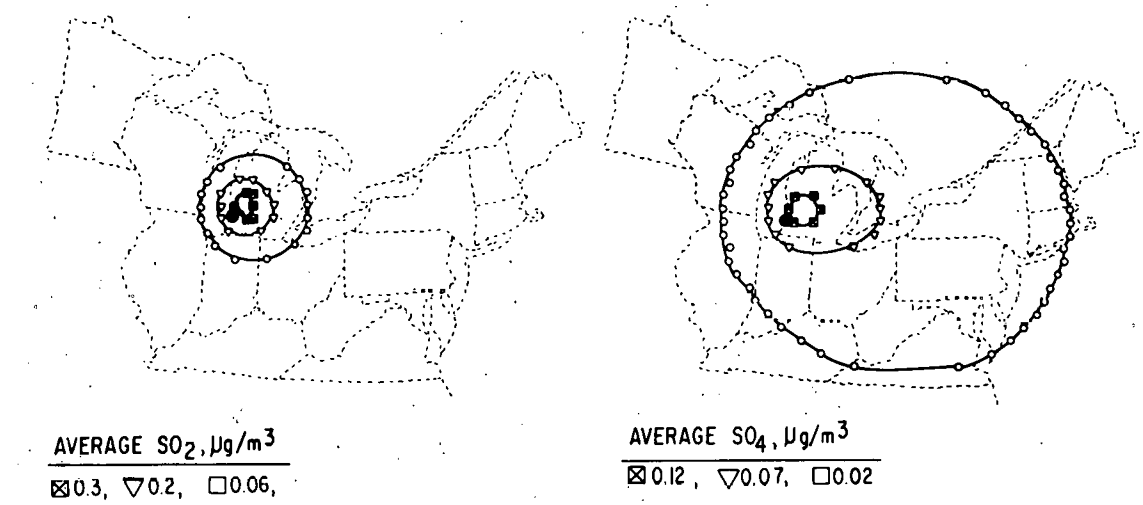


Fig. 7.11 (Cont'd) (b) Southern Michigan Source

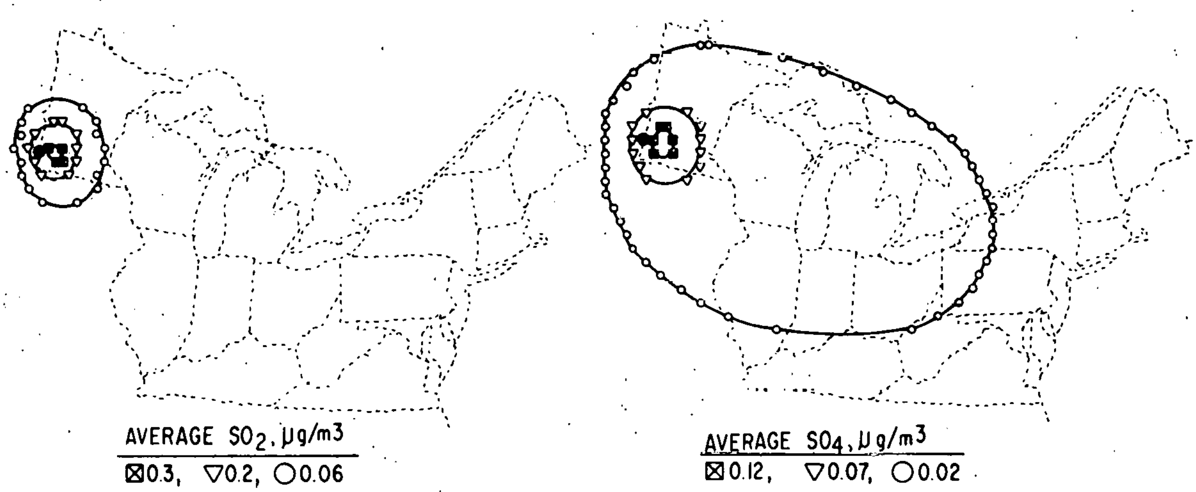


Fig. 7.11 (Cont'd) (c) Southern Minnesota Source

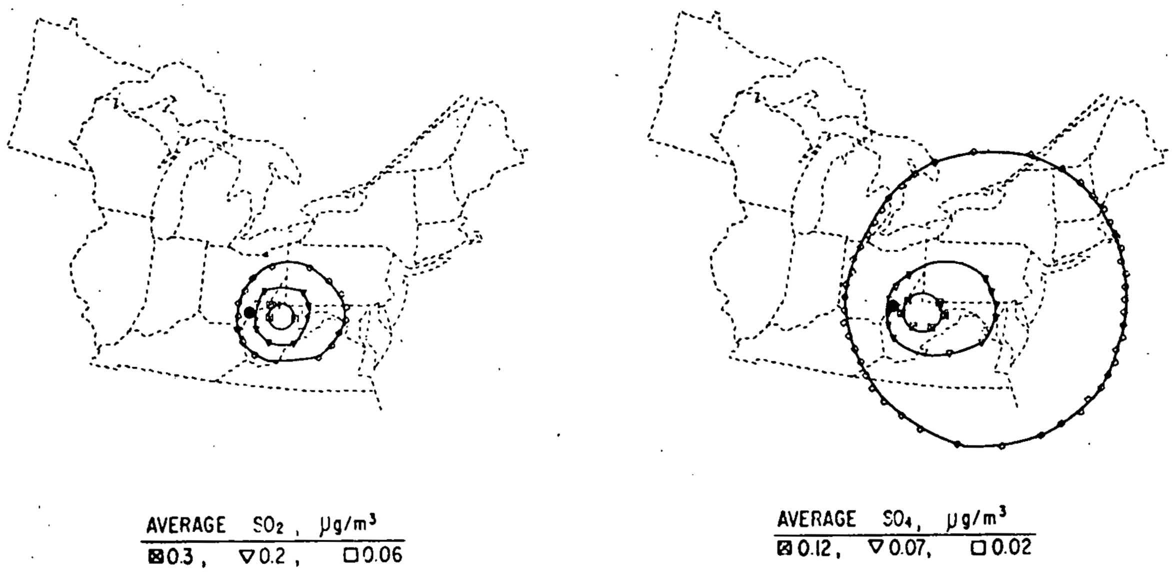


Fig. 7.11 (Cont'd) (d) Southern Ohio Source

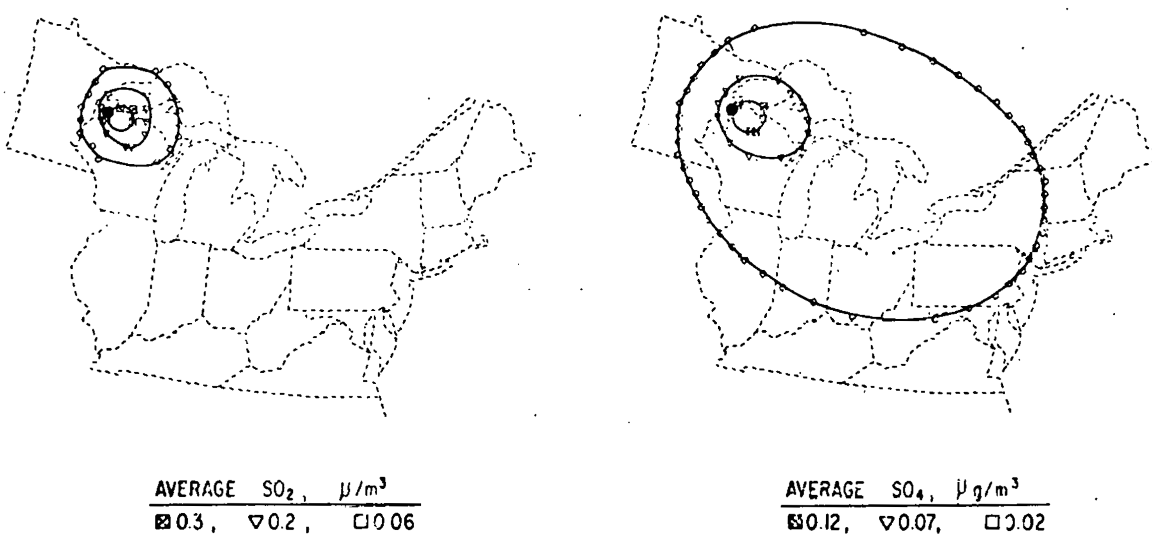


Fig. 7.11 (Cont'd) (e) Southern Wisconsin Source

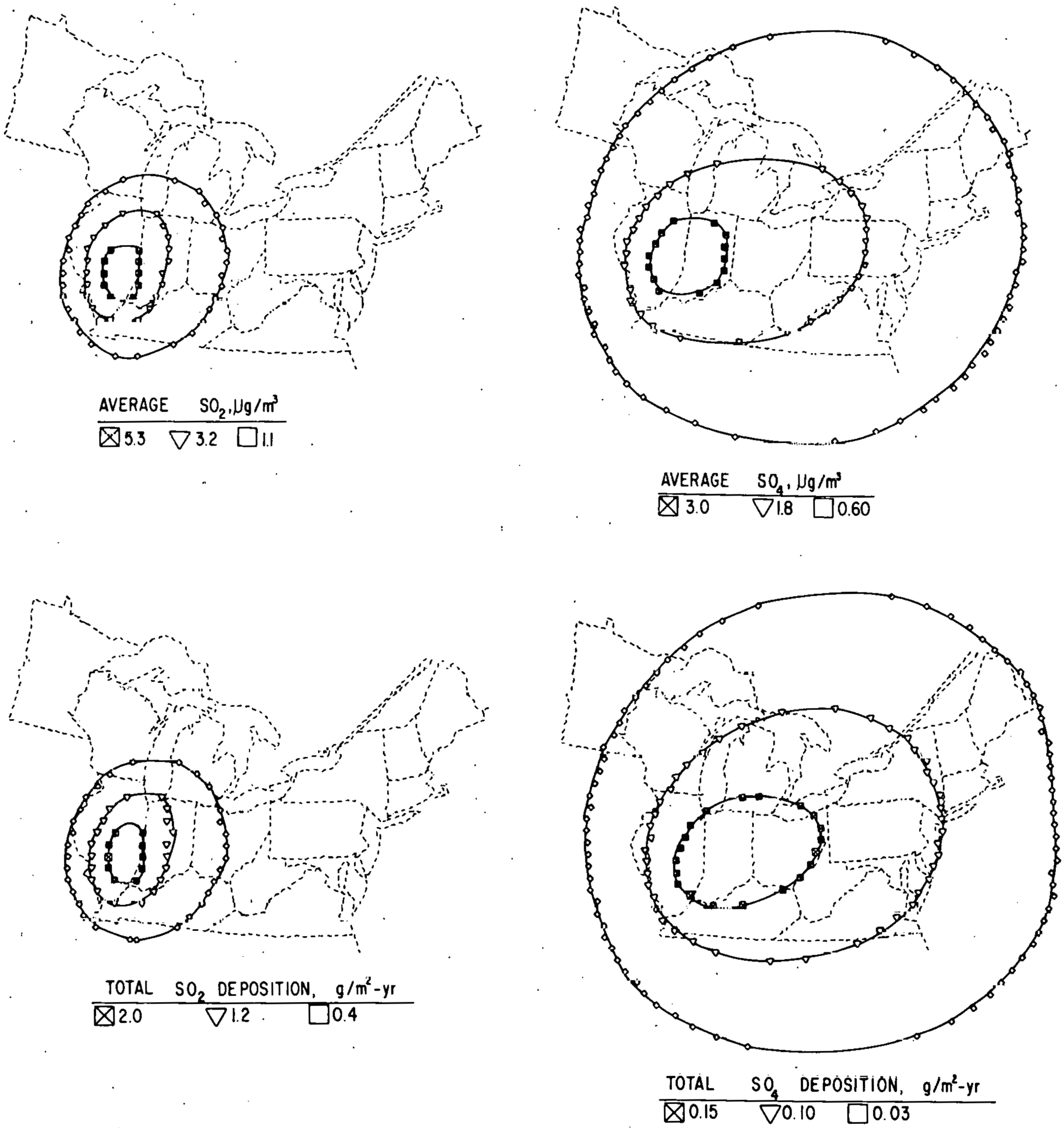


Fig. 7.12 Cumulative SO_2 and SO_4 Concentration and Deposition from Long-Range Transport for Emissions in Illinois High Coal Use Scenario

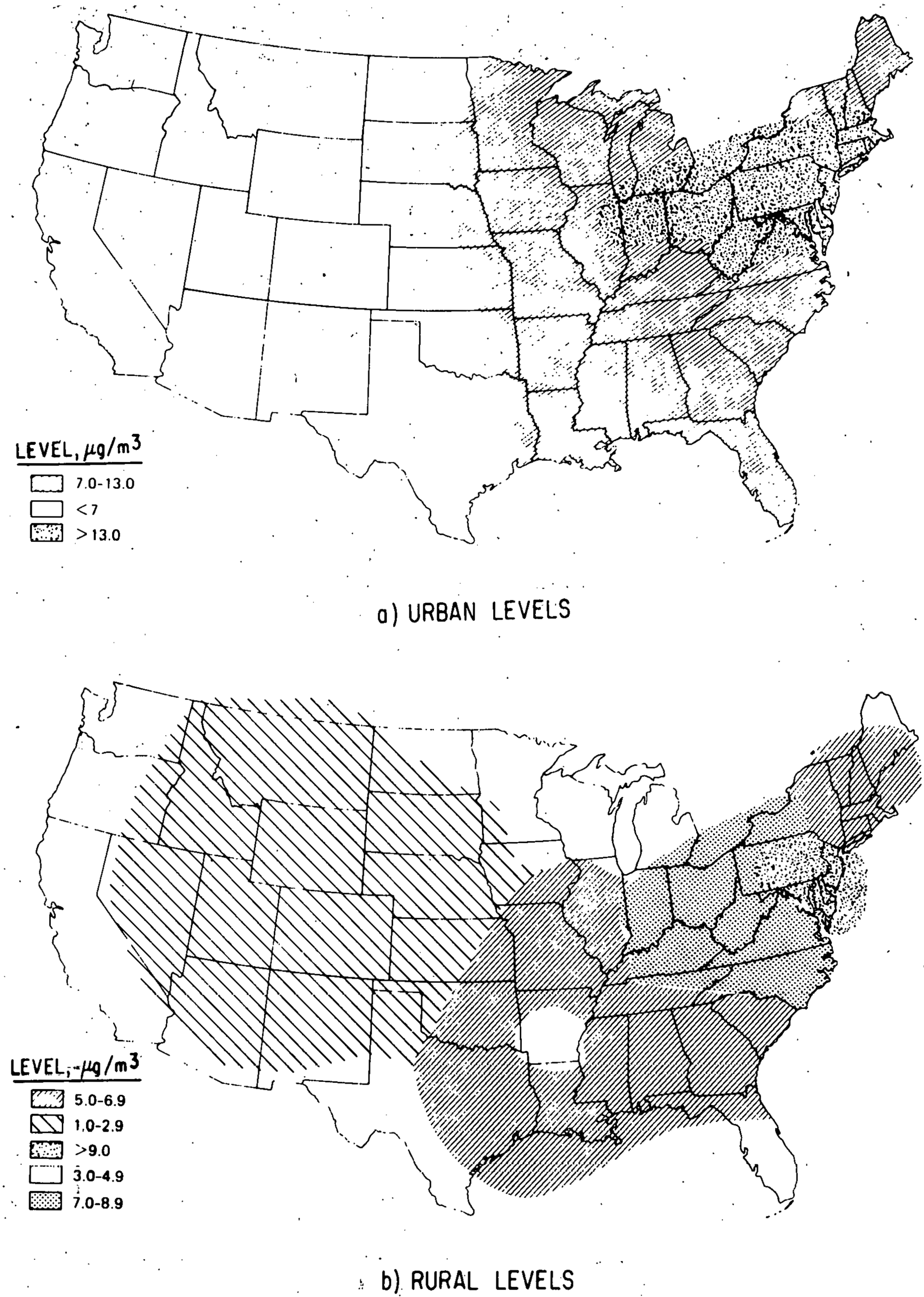


Fig. 7.13 Geographical Distribution of Typical Sulfate Levels in the United States

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8 *HEALTH EFFECTS*

8.1 *INTRODUCTION*

8.1.1 *Measurement of "Health"*

The distinction between good health and poor health is not sharp. The health of individuals can vary from perfect physical condition to moderate to severe illness to imminent death. The level of ill health which can be considered a serious economic or medical problem varies according to the age and occupation of the person considered. A case of influenza, for example, that might be considered a mild annoyance in a high school student could be cause for alarm in an elderly person with a heart ailment.

The health of a population can be measured most easily by its mortality rate. Other measurements more useful but less readily available are the incidence and prevalence of disease.

The characteristics of the population under study are important in the expected health status. The risk of death is always relatively high at birth, statistically a minimum around ages 10-15, and increases roughly exponentially thereafter. Females live longer than males, and smokers die earlier than those who abstain. A variety of social and economic factors vary markedly among easily identifiable racial and ethnic groups. Therefore, the effects of age, sex, and race must be accounted for in any scheme to measure health effects.

8.1.2 *The Study of Health Effects*

The effects on health of an environmental stress or noxious agent in humans are often hard to study. The results of animal experimentation, with all of its problems of interspecies variation, are a major source of data. Thus, we often have excellent dose-response data for substances in animals that cannot be applied directly to humans.

On the other hand, with data on human studies, we often find that they derive from cases in which the dose and duration of exposure (especially the former) and indeed the composition of the toxic substance being studied are not well-defined. Thus, while the nature of the effects may be well described for humans, quantitative dose-response relationships may remain obscure, because the circumstances of exposure may be unknown. This problem is particularly acute for long-term or latent effects in which the history of exposure over a 10-to-20-year period must be estimated.

8.2 HEALTH EFFECTS ASSOCIATED WITH AIR POLLUTION FROM COAL USE

Most of the effluents from current modes of coal use that are of direct impact on human health are in the stack emissions from coal-burning facilities; hence they appear as airborne pollutants. These characteristics have four major types of health impacts:

8.2.1 Physiological Effects

8.2.1.1 Irritation

In irritation, the challenge from the pollutant has the effect of causing an inflammatory reaction in the affected organs. Inflammation is designed as a defense mechanism, which assists the body in rejecting foreign materials. It is characteristically a local reaction, for example, around a wound, where the effect will be to wall off and later destroy invading pathogens or other foreign material that cannot be removed by any other means. Paradoxically, when an inflammatory response occurs over a wide area, it may have a deleterious effect. Because of the tissue damage it induces, inflammation may do far more damage than the challenge or foreign material that stimulated the reaction. This may interfere with other immunological mechanisms to the point where susceptibility to attack by pathogenic organisms is actually enhanced.[1]

8.2.1.2 Direct Toxicity

The pollutant causes direct damage to the cells with which it comes in contact. This damage usually results when the agent interferes with the metabolism of the cell, by either inactivating key enzymes, being metabolized into useless products, or otherwise disrupting normal cell function. In general, substances with toxic effects will also stimulate inflammation, but the response is not always in proportion to the challenge. Inflammation usually occurs at the site of contact, while toxic effects may show up anywhere in the body after absorption.

8.2.1.3 Carcinogenesis

The pollutant or its metabolic byproducts stimulate development of tumors after some latent period, which may range from a few years to several decades. This development may occur as the result of an accumulation of gene mutations or chromosome aberrations due to the biochemical reactions between the genetic material of the cell and the carcinogen.

8.2.1.4 Physical Synergism -- Lung Clearance

In the respiratory system in particular, there is a further class of effects that, while not directly harmful themselves, can enhance the effects described above. The mechanisms for clearing noxious substances from the lungs may be reduced in effectiveness, thereby increasing the residence time of effluents in the lung. This usually results either from a reduction in ciliary action in the bronchial tree; or from a thickening of the protective layer of mucus, which interferes with the ciliary action moving foreign particles out of the lung.

8.2.2 Clinical Conditions Resulting from the Physiological Effects

The responses listed above may have different outcomes, which will depend on the age and condition of the victim, the nature of the noxious agent, and the duration of exposure. The following clinical manifestations are typical among persons exposed to airborne pollutants of the kind commonly seen in coal combustion.

8.2.2.1 Acute Respiratory Disease

Inflammation of pulmonary tissue and the general debility produced by toxic effects make both the upper and lower respiratory tract more subject to infection. Thus, the incidence of influenza, pneumonia, colds, and other acute pulmonary diseases tends to be increased in exposed populations. Acute asthma attacks can be induced in susceptible persons by respired irritants, and the severity of an attack, whether pollutant-induced or not, can be markedly increased by the synergistic relationships that have been found between the body's response to histamines, which are released in the initial phase of an asthma attack, and previous exposure to other irritants.

8.2.2.2 Chronic Respiratory Disease

Prolonged exposure to irritants and toxins have been shown to lead to irreversible damage to lung tissue. Emphysema and chronic bronchitis have been shown to develop in a variety of experimental animals exposed to low levels of the common pollutants. These conditions are also the characteristic effects of chronic pulmonary injury in man and are seen, for example, after prolonged use of tobacco. Early inflammatory responses have been shown to lead to the development of various pneumonoconioses (silicosis, asbestosis, etc.) when certain kinds of irritant particles are introduced.

8.2.2.3 Aggravation of Pre-existing Conditions

A person already in poor health from, e.g., chronic respiratory or cardiovascular disease whether originally caused by the pollutants in question or not, is at much higher risk of suffering an acute or fatal episode when exposed to airborne irritants.

8.2.2.4 Neoplastic Diseases

Exposure to carcinogens of the kinds found in products of coal combustion usually leads to neoplasia or cancer in the site or organ of deposition. Cancers of the respiratory and alimentary tracts are, therefore, most likely to be associated with coal effluents. However, metabolic transport and transformation has the potential for causing cancer in other organs as well. Cancer of the bladder, central nervous system, and hematopoeitic tissues, for example, have all been associated with organic effluents having structures analogous to those in coal.

8.3 EFFECTS OF SPECIFIC POLLUTANTS ON HEALTH

The effluents produced from coal combustion are heterogeneous; this section breaks them down and tries to summarize what is known about the components of interest.

8.3.1 Sulfur Dioxide (SO_2)

Sulfur dioxide was one of the earliest suspected toxic agents in air-pollution episodes and has, therefore, been studied extensively. In the pure state, it is a colorless gas with an acrid odor. In high concentrations, it tends to be absorbed in the upper respiratory tract, so that a large proportion of it never reaches the pulmonary region, but at low concentrations most of what is inhaled reaches the terminal bronchioles and alveoli. Thus, the effective dose received by the most sensitive parts of the respiratory system does not decrease linearly with decreasing atmospheric concentration. It has not been shown to produce serious direct effects in the pure state in humans in the concentrations that would ordinarily be expected in areas of heavy coal utilization (i.e., 0.3 to 1.5 ppm), although levels above 0.25 ppm are usually associated with adverse health effects in epidemiological studies.[2]

8.3.1.1 Irritant Effects[2-5]

In humans, initial exposure at levels that might be realistically encountered produces a slight temporary vasoconstriction, which lasts about 10-20 min in a previously unexposed subject, with measurable reduction in the elasticity of the lung lasting somewhat longer. Subjects exposed over several days show slight changes in lung capacity and pulmonary resistance, levels of various enzymes, and blood chemistry. There appears to be a habituation effect, in that a person previously exposed to low levels of SO_2 does not react as severely to a given higher dose as does one who has not. In even the worst-case realistic dose range, the irritant effect is mild, and it tends to decrease with habituation.

8.3.1.2 Co-irritant Effects

In some studies, sulfur dioxide has been found to interact with other irritants to both enhance and ameliorate their effects. An experimental subject habituated to sulfur dioxide, for example, will not react as strongly to a subsequent dose of nitrogen dioxide as one without such prior exposure. Indications of a synergism have been found in studies of ozone (O_3) and histamine, wherein prior exposure to SO_2 will result in more severe reactions to those irritants.

Sulfur dioxide can be absorbed on the surfaces of otherwise benign particulates and markedly enhance the irritant effect. It is not known whether this results from the longer residence time of the SO_2 in the area of the particle deposition or from enchancement of the irritant effect of the particle itself.[14]

8.3.1.3 Carcinogenic Effects

Sulfur dioxide passes readily through cell membranes and, once in an aqueous medium, such as cell cytoplasm, can form free radicals and ions, notably sulfite, bisulfite, and SO_2^- The first two can be very toxic, but there is a well-developed enzyme system that rapidly neutralizes and removes those ions. The risk associated with these ions is, therefore, low for most people. The SO_2^- radical, however, is a relatively long-lived species with an affinity for breaking disulfide (S-S) bonds,[6] which makes it a potential cause of gene mutations and possibly a long-term carcinogen.

8.3.1.4 Co-Carcinogenic Effects

One experiment showed, in rats, that previous exposure to SO_2 facilitated the induction of lung tumors by benz(a)pyrene administered by aerosol. In fact, in this experiment benz(a)pyrene did not appear carcinogenic in the absence of SO_2.[2]

8.3.1.5 Effect on Lung Clearing

SO_2 in acute high-level doses temporarily suppresses the action of ciliated cells lining the bronchial passages. As these cells remove particulates and other debris from the lungs, the residence time for alien substances may be markedly increased. Long-term low-level doses do not have this effect. Instead, they cause thickening of the protective mucus layer over the cilia, which inhibits their ability to move the debris. Thus, in the long run, low-level doses have an effect similar to that for acute high-level doses.[2]

8.3.2 Oxides of Nitrogen

Nitrogen oxides (NO_x) are produced by both oxidation of organically bound nitrogen in coal and secondary oxidation of atmospheric nitrogen during the combustion of coal and most other hydrocarbons, especially at high temperatures or pressures. The two most important species are nitric oxide (NO) and nitrogen (NO_2). Nitric oxide oxidizes readily to NO_2.

8.3.2.1 Irritant Effect[2]

Nitrogen dioxide is a strong irritant. Rats experimentally exposed to as little as 0.5 ppm showed signs of acute inflammatory response after only four hours of exposure. Chronic exposure of experimental animals to levels insufficient to produce evidence of acute inflammation produced irreversible emphysema-like lesions. Human exposures at moderate levels have produced evidence of inflammation as measured by diminished lung compliance, but unlike SO_2 the effects seem to be delayed several hours after the onset of exposure. As with SO_2 and O_3, there is a protective habituation effect to the effects of acute inflammation. It must be emphasized, however, that the protective effects of habituation do not necessarily apply to effects other than acute inflammation. In fact, many researchers believe the reverse is true: habituation to the acute inflammatory response may be part of the effect of chronic toxicity.

8.3.2.2 Co-irritant Effect

See Sec. 8.3.1.2.

8.3.2.3 Carcinogenic Effect

Nitric oxide in aqueous solution can form nitrite (NO_2^-) ion, which in the presence of suitable organic amide bases, can form nitrosamines, highly potent carcinogens.[8] The possibility exists, therefore, of a carcinogenic effect both in the lung and the stomach as the result of swallowed particulates. Though there are suggestive relationships between stomach cancer and air pollution[9] in some localities, there is little verification available yet of this hypothesis.

8.3.2.4 Co-Carcinogenic Effect

Experiments showing enhancement of benz(a)pyrene carcinogenesis after exposure to NO_2 are in progress, but the results have not yet been published.

8.3.2.5 *Lung Clearance*

Nitrogen dioxide seems to reduce ciliary action in the same fashion as SO_2.

8.3.3 *Ozone*

Ozone may appear as the result of secondary reactions following combustion as discussed in Sec. 7.4. It is a highly reactive trimeric molecule of oxygen.

8.3.3.1 *Irritant Effect*

Ozone is among the strongest of the simple inorganic gaseous irritants.

8.3.3.2 *Co-irritant Effects*

The relationships between ozone and other irritants are many and varied. It shows a habituation effect; however, prior exposure to ozone produces <u>cross tolerances</u> to many more irritants than do most others. When exposure to ozone and other irritants is simultaneous, the effect is usually additive or synergistic. Previous exposure to substances containing disulfide groups or sulfhydryl groups tends to be protective against the acute response.

8.3.3.3 *Carcinogenic Effects*

Ozone has been shown to be carcinogenic in susceptible strains of mice. Its capacity for reacting with disulfide and sulfhydryl groups and for forming other kinds of free radicals gives it the capacity for mutagenic activity characteristic of many carcinogens. There is once again relatively little experimental verification.

8.3.3.4 *Direct Toxic Effects*

Ozone is very active biochemically and has been shown to cause premature aging in some experimental animals. This effect occurs even though most mammals, including man, have a very well-developed enzyme system (superoxide dismutase) for removing and denaturing O_3 and other active peroxides.

8.3.4 *Hydrocarbons*

Coal has no unique structure. It is generally considered to be a network of aromatic carbon compounds interspersed with heterocyclic compounds. Therefore, a wide variety of organic effluents might be formed, especially during transient operating conditions that permit incomplete combustion.

Many of the products of coal decomposition are equivalent to the advanced stages of pyrene synthesis. At about 900°C, the predominant reactions are ring closures, condensation, and aromatization. The main products tend to be polynuclear ring compounds. Products from low-temperature pyrolysis might be expected during periods of startup and shutdown. Most of these compounds would be single aromatic rings or heterocyclic compounds with alkyl side chains.

The consequences of inhalation of hydrocarbons are complex because the inhaled substances are always in mixtures. This mixing of compounds makes it virtually impossible to incriminate any single material as the causative agent for pathologic changes. However, some organic compounds arising from the combustion or processing of coal have been identified experimentally as either known or "suspect" carcinogens, others as strong eye and lung irritants.

8.3.4.1 *Irritant Effects*

The products of incomplete coal combustion include aliphatic and aromatic hydrocarbons, aldehydes, and ketones. Of the aldehydes, formaldehyde and acrolein are recognized as the two most common hydrocarbon irritants. These compounds are easily absorbed across the mucous membranes of the conjunctivae and alveoli. Their initial actions are to produce tears (lacrimation) or sneezing (sternutation).[9] Other effects associated with inhalation of these products include rhinorrhea, coughing, sore throat, and a sense of substernal oppression. Irritation from formaldehyde is apparent to most people at concentrations of 2-3 ppm; the same reactions from acrolein occur at less than 1 ppm.[10]

The intensity of acute and chronic inflammatory reactions will depend on the specific toxicological properties of the pollutant. The olefins or unsaturated aldehydes produce more noticeable irritation than do saturated aldehydes. Their toxicity increases with the addition of a double bond and decreases with increasing molecular weight.

Where a hydrocarbon is absorbed in the respiratory tract depends upon the water solubility. Highly water-soluble products tend to be absorbed in the nasal, buccal, nasopharyngeal, and laryngotracheal regions. Compounds of higher molecular weight and lower solubility can penetrate deeply into the lungs.

Products of photochemical reactions can be considered as secondary products of coal combustion. These compounds result from the further reaction of effluent compounds in the presence of ultraviolet radiation. Ozone and the PAN series are examples of this group. Photooxidation is also a pathway for aldehyde formation.[11] The PAN series--peroxyacetylnitrate (PAN), peroxybenzoylnitrate (PBZN), and their homologues -- are potentially more toxic than the aldehydes. However, because of their high reactivity and resulting short lifetimes, the extent to which the PANs are directly responsible for irritant effects is questionable.

8.3.4.2 Carcinogenic Effects

Among the products of coal combustion, those with the most serious potential for carcinogenic effects appears to be polycyclic compounds. Polycyclic aromatics and aza-arenes derived from the benz(a)anthracene skeleton have been shown to contain strong carcinogenic agents.[12,13] This compound has been clearly established as a causative factor in skin and lung cancers in experimental animals.

8.3.5 Carbon Monoxide

8.3.5.1 Direct Toxic Effect

Carbon monoxide is best known for its affinity for hemoglobin, with which it combines to form carboxyhemoglobin (COHb); this compound has a very long residence time in the blood. The victim suffers asphyxiation. At COHb levels >9.5 to mg/m^3 in the blood for over eight hours, persons with stable coronary artery disease (angina pectoris) may start to note increased frequency and duration of symptoms; at blood levels of 13.1 mg/m^3, excess deaths may occur among people with pre-existing cardiovascular disease.[14]

The effects of lower levels of CO in otherwise healthy persons is not well-defined.

8.3.6 Particulates (Including Trace Elements)

A significant portion of the combustion products from coal is in the form of particulates. Microscopic solid particles and liquid droplets are the result of processes that take place during and after combustion. Although the size range given for atmospheric particulates extends from about 0.005-500 μ, most particulates from coal combustion appear in a more limited range. Most are 0.01-10 μ diameters. Because this range brackets the size defined for respirable particles, the particulates are a major possible hazard to human health.

Mechanical procedures can reduce the coal itself or the ash to particles on the order of several micrometers in diameter. During combustion the constituents of coal can vaporize and later condense, or a fine ash can be produced with particles 0.1-1 μ. Partial combustion can result in the formation of soot particles 0.01-1 μ in diameter. The energy available from combustion can also be responsible for the formation of condensation nuclei 0.01 in diameter. The processes stated above give rise to primary particulates, the results of direct interactions during combustion. Secondary particulates can be formed from the post-combustion interactions of gaseous products and sunlight. Sulfates, nitrates, and hydrocarbons usually result from photochemical reactions. The size of these particles is 0.01-1 μ.[15]

Virtually all of the naturally occurring elements can be found in coal. Their emission depends on their chemical form before combustion and on their volatility.[9]

Most elements in coal, other than carbon, are in the form of aluminosilicates, inorganic sulfides, and organic complexes. During combustion, the sulfides and organic compounds are decomposed to produce SO_2 and other oxides and other chemical species of varying volatility. The aluminosilicates have very high vaporization temperatures, and tend, therefore, to survive more or less intact as fly ash and slag.[16]

Many of the elements and compounds that volatilize and adsorb on particulates are known to have adverse effects on human health;[17] one of the most interesting is SO_2. When adsorbed on such surfaces, SO_2 is often transformed into SO_3 and the sulfate ion far more readily than it is in the gaseous state, and in the presence of high humidity (and possibly hygroscopic particles) aerosols of sulfuric acid or other acid sulfates may form. Particles containing vanadium are particularly likely to catalyze this reaction.

8.3.6.1 Mechanisms of Action

The possible effects of particulate emissions on human health are determined by three factors; the composition of the particulates, their size, and the amount of time they spend in contact with sensitive tissues.

The lungs are the major route of entry for toxic airborne particulates. The probability of particle deposition and the anatomical position of the respiratory system in which deposition occurs depend primarily on particle size. Particles less than about 0.01 μ in diameter tend to behave like gases and generally do not deposit at all. Particles with diameters of 0.01-1 μ are predominantly deposited in the alveolar or pulmonary region. Larger particles show a greater tendency to deposit in the nasopharyngeal and tracheobronchial regions.

Most airways are lined with ciliated and mucus-secreting cells that trap impacted particles and move them, aided by the cough reflex, to the pharynx, from where they are swallowed or expectorated. The extraction of many toxic substances from such particles is inhibited by the mucus layer in the bronchial tree and may, therefore, take place in the stomach, where their residence time is relatively short. Some studies, however, have shown a positive correlation between particulate concentrations in air and stomach cancer.[9]

The surface of the alveoli must be kept clear of deposited matter to allow for efficient gas exchange. Phagocytosis by alveolar macrophage cells is the principle clearance mechanism of this area. Insoluble particles or aerosol droplets are engulfed by alveolar macrophage cells. The cell and particle may then migrate either to the ciliated epithelium of the terminal bronchioles, there to be swept out of the system by muco-ciliary action or pass through the alveolar membrane and enter the lymphatic system. If the deposited particle is soluble in the tissue fluid on the surface of the alveoli, it can be readily adsorbed into the bloodstream.

The rates at which particles are cleared from the pulmonary areas vary. For particles that are engulfed by macrophage cells and carried to the ciliated epithelium or lymphatic system, the residence half-life is two to six weeks. If the macrophage does not immediately clear the foreign particle, it may become sequestered in the lung. In this condition, the residence half-life rises to several months or years and the clearance rate will depend upon particle solubility.

A cytotoxic material can influence its own rate of clearance in several ways. Such a substance can damage or destroy the phagocyte, thereby directly reducing macrophage action. Tissue reaction to a sequestered particle can result in the progressive segregation of the foreign body behind a mass of fibrous material, making removal more difficult. Formation of silicotic nodules is an example of the latter type of reaction.[18]

8.3.6.2 Physiological Effects

The toxic effect produced by respirable particles depends on the chemical species that they contain. Small particles are generally more toxic than large ones.[17] Submicron fly-ash particles are a double threat to human health. Not only do these particles reach the pulmonary region of the lung and remain there for extended periods of time, but they also can deliver high concentrations of some of the effluents as the result of absorption (see Sec. 8.3.6.1). A detailed breakdown of the known effects that might be attributed to each of the individual components would tend to be repetitive. We, therefore, present only a brief list of the expected major effects and the important contributors in each.

Irritant Effect

By adsorbing SO_2 and other irritant gases and vapors, respirable particulates magnify their effects through holding high concentrations of these irritants close to sensitive tissues for long periods.

The sulfate ion, often associated with small particles and aerosols, appears to be a far more potent irritant than any of the others discussed here. This potency is probably due in part to the fact that the ion forms a very strong and reactive acid and is so strongly associated with particulates.[2]

The cations of the sulfate compounds have important effects on irritant potency.[19] Pure sulfuric acid (H_2SO_4) and ferric ammonium sulfate ($FE(NH_4)SO_4$) are the most potent forms. Other ions tend to be weaker in proportion to their acidity.

Most particles containing silica can, if they become permanently sequestered in the lung, induce various forms of fibrotic lung disease, such as silicosis and pneumoconiosis.[5] In the amounts likely to be produced by power plants, however, this effect is probably unimportant.

Carcinogenic Effect

Particulates act as carriers of many trace elements and hydrocarbons in the effluent stream. Nickel (as nickel carbonyl), chromium, (especially as chromic trioxide), beryllium, and arsenic have been implicated as carcinogens. Many organic particulates contain the known carcinogen benzo(a)pyrene and related compounds.

Direct Toxic Effects

Lead, tellurium, mercury, arsenic, selenium, nickel, chromium, and vanadium are all known to be highly toxic,[20] with many having a special propensity for cellular deposition and retention. These elements can interfere with and disrupt the function of the central nervous system and other organ systems of the body unrelated to the respiratory system.

8.4 QUANTITATIVE ESTIMATES OF RISK

Much is known about the qualitative effects of many of the substances found in coal-related substances in the pure state. Most of this information is based on short-term data at relatively high exposures. Properly measured dose-response data for long-term exposures to these substances at realistic levels and combinations are lacking. Dose-response functions for combinations of substances broadly similar in composition to coal effluents may, however, be developed for mortality and possibly for some types of disease incidence or disability from the available epidemiological literature. This is an application, however, for which most of these data are not well suited. In many of thse studies, the exposure term was not well related to individuals, nor in many cases is the previous history of the population's exposure to confounding factors well controlled.

In the current literature there are several efforts at deriving response functions to air pollution. Superficially, the variations in the results seem to cover orders of magnitude.[21] However, many of the disparities can be accounted for by the varying age and sex distributions used in the studies[22] or by reasonable estimate of the inherent statistical errors to be expected,[23] so that the actual variation in the implications of these studies in terms of human health probably vary within a much narrower range. Additional confusion has often resulted from the types of variations being studied. Studies concentrating on short-term (daily or weekly) fluctuations in air-pollution levels and measures of health status may show different effects at given levels of exposure than will studies in which the exposure and health effects indexes are averaged over a year or more. In the former case, an acute effect in a person already in impaired health is being measured; in the latter case, the actual degree of development of impaired health in the total population is being measured. The studies of Love and Seskin,[4] and Winkelstein,[9] for example, are based on mortality in the study areas as a function of the exposure to the annual average of the pollution exposure, which can be assumed to indicate the exposure of that population of most of its relevant history. Studies such as those done in the EPA CHESS[3,25] program, on the other hand, concentrate on day-to-day variations in exposure.

While remaining acutely aware that existing dose-response functions are in a very preliminary stage, it is instructive for defining potentially significant health effects to compare the projected air-quality impacts from Sec. 7.0 with existing models. For this purpose health-effects functions related to sulfate concentrations are reproduced in Table 8.1. These functions are based on a recently published report describing functions used by EPA researchers in a computerized model.[25] As an example, the threshold of 10 $\mu g/m^3$ sulfate for incidence of chronic respiratory disease for non-smokers is currently exceeded in the populous Northeastern U.S., as is shown in Fig. 7.13, Sec. 7.0. Further comparing the impact of 0.5-1.5 $\mu g/m^3$ sulfate in the northeast from the Illinois emissions in the High Coal Scenario (Fig. 7.12, Sec. 7.0) and the dose response for chronic respiratory disease of 134% per 10 $\mu g/m^3$ for non-smokers indicates a significant potential health effect. These calculations cannot be considered quantitative estimates of effects, but they do indicate qualitatively a high priority for further research to define these effects.

Table 8.1. Health Impacts of Sulfate Aerosol[25]

Health Effect	Population at Risk	Assumed Baseline Frequency of Disorder within Population at Risk	Pollutant Concentration Threshold For Effect	Effect of Increase as % of Baseline per Pollutant Unit Above Threshold
Mortality	Total Population	Daily death rate of 2.58 per 100,000	25 $\mu g/m^3$ for one day or more	2.5% per 10 $\mu g/m^3$
Aggravation of Heart and Lung Disease in Elderly	The prevalence of chronic heart and lung disease among the 11% of the population older than 65 years is 27%	One out of five of population at risk complain of sympton aggravation on any given day	9 $\mu g/m^3$ for one day or more	14.1% per 10 $\mu g/m^3$
Aggravation of Asthma	The prevalence of asthma in the general population is 3%	One out of 50 asthmatics experiences an attack each day	6 $\mu g/m^3$ for one day or more	33.5% per 10 $\mu g/m^3$
Lower Respiratory Disease in Children	All children in the population or 23.5% of population	50% of children have one attack per year	13 $\mu g/m^3$ for several years	76.9% per 10 $\mu g/m^3$
Chronic Respiratory Disease				
Non-Smokers	62% of population age 21 or older	2% prevalence	10 $\mu g/m^3$ for several years	134% per 10 $\mu g/m^3$
Smokers	38% of population age 21 or older	10% prevalence	15 $\mu g/m^3$ for several years	73.8% per 10 $\mu g/m^3$

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APPENDIX A

Model Used in Calculating Electricity Demand

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APPENDIX A

Model Used in Calculating Electricity Demand

The models were estimated from pooled cross-sectional, time-series data. Different time spans were used in estimating the models. The industrial model is based on 1962-1973 with the dummy variable for natural gas (to account for curtailments of natural gas) specified from 1966-1973 in Illinois and 1970-1973 in all other states.* For the residential and commercial models, the years 1962-1974 are used with the dummy gas variable specified from 1970-1974 for all states.

The regression results for the residential model, with t-statistics in parentheses, are:

$$\log q_{it} = C - \underset{(6.14)}{0.3174} \log P_{it} + \underset{(3.12)}{0.1896} \log Y_{it} + \underset{(17.75)}{0.7409} \log q_{it}\ (t-1),$$

where:

P_{it} = average price of electricity;

Y_{it} = per capita disposable income;

q_{it} = per capita electricity consumption in period t; and

Constant C= -1.235, -1.206, -1.254, -1.225, -1.195 and -1.230, respectively for Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.

The regression results for the commercial model are:

$$\log Q_{it} = C - \underset{(3.24)}{0.3796} \log P_{it} + \underset{(0.35)}{0.03251} \log g_{it} + \underset{(3.84)}{0.3929} \log Z_{it}$$

$$+ \underset{(11.23)}{0.6003} \log Q_i\ (t-1),$$

where:

g_{it} = average price of natural gas;

Z_{it} = total disposable income;

*Data for value added for manufacturing are not available for 1974.

Q_{it} = total electricity consumption in period t; and

Constant C= -0.941, -1.024, -1.034, -0.998, -1.078 and -0.997 respectively for Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.

The results for the industrial model are:

$$\log Q_{it} = C - \underset{(2.01)}{0.2568} \log P_{it} + \underset{(0.23)}{0.02516} \log g_{it}$$

$$+ \underset{(6.52)}{0.7732} \log V_{it} + \underset{(8.31)}{0.5495} \log Q_i (t-1),$$

where:

V_{it} = value added for manufacturing; and

C = -7.223, -6.675, -7.058, -6.879, -6.723 and -6.794, respectively for Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.

The data for estimating the model came from several standard sources. Sales and revenues of electricity came from the *Edison Electric Yearbook.*[1] Sales and revenues of natural gas were taken from *A.G.A. Gas Facts*.[2] Disposable Income and Per Capita Disposable Income came from the Bureau of Economic Analysis within the Department of Commerce.[3] The Consumer Price Indexes and Wholesale Price Indexes were taken from the "Monthly Labor Review" of the Bureau of Labor Statistics.[4] Average prices were calculated for each sector by dividing electricity or natural gas revenues by their respective sales and deflating by the appropriate price index. All electricity prices and quantities are stated in British thermal units, with the conversion of 1 kwh equaling 3412 Btu. Population is based on Bureau of Census estimates.

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APPENDIX B

Existing Electrical Generation Facilities in the Six States

Figures B-1 through B-6 show existing sites in Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

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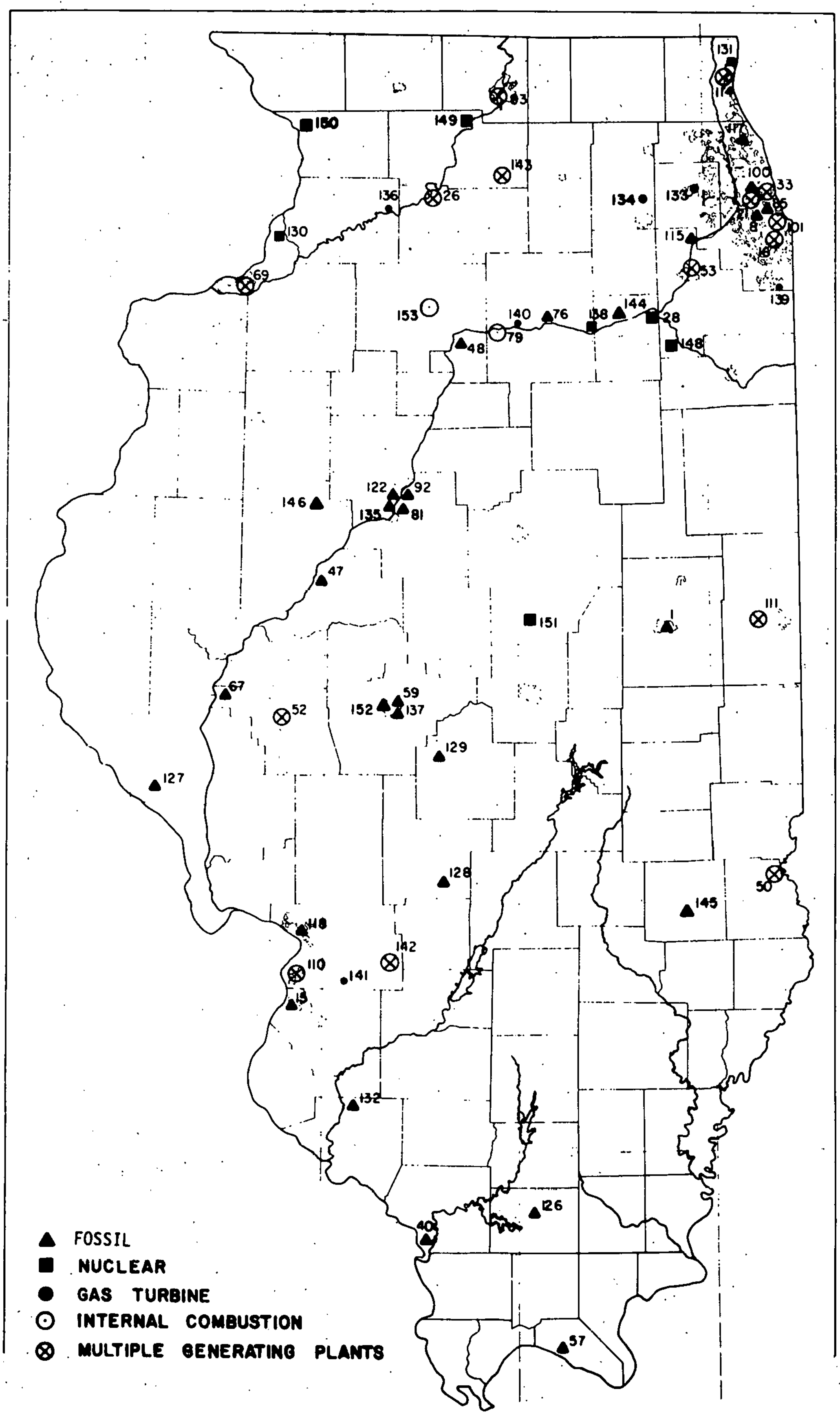

Fig. B.1 Existing Electrical Generation Sites in Illinois

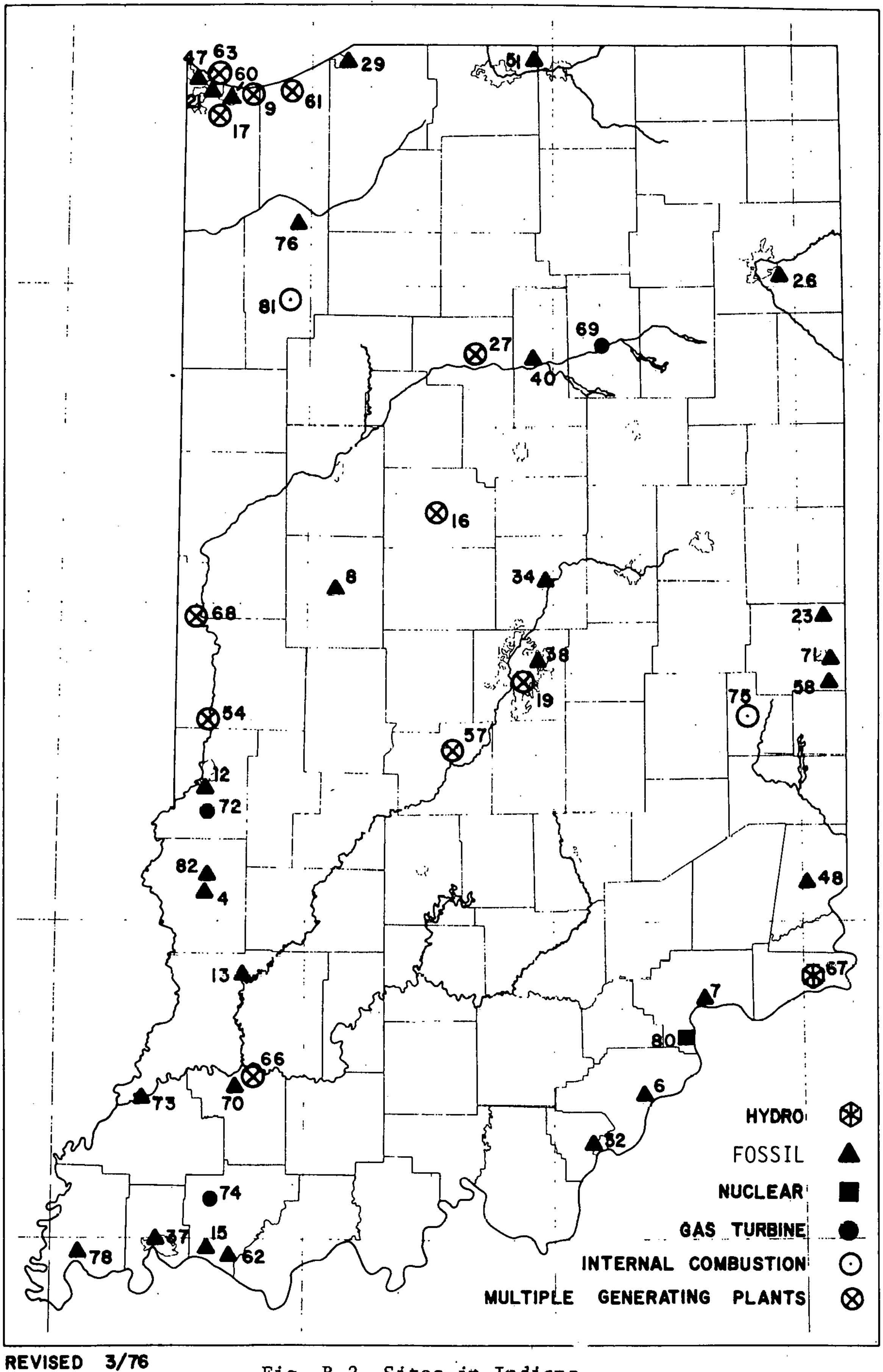

Fig. B.2 Sites in Indiana

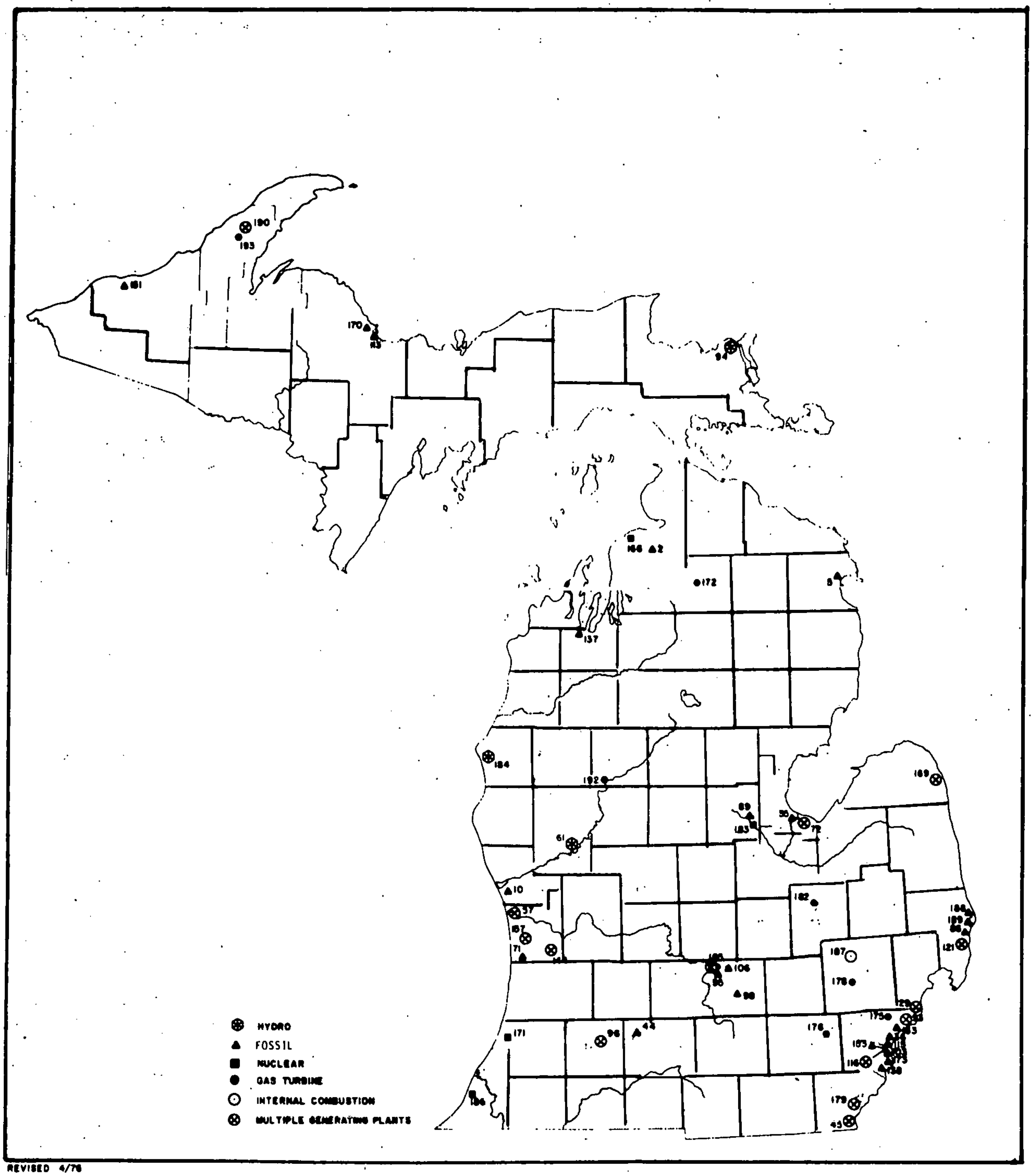

Fig. B.3 Sites in Michigan

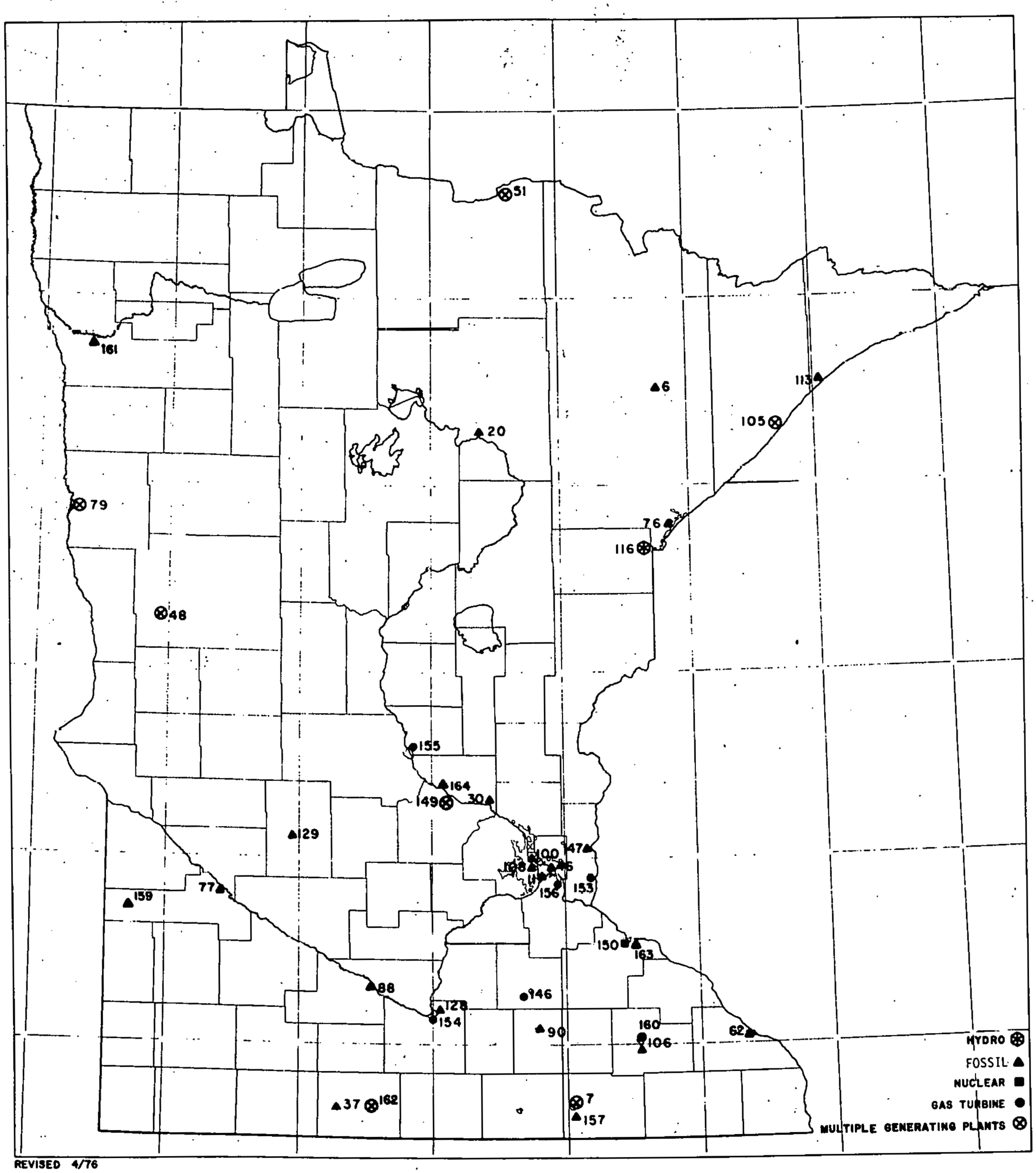

Fig. B.4 Sites in Minnesota

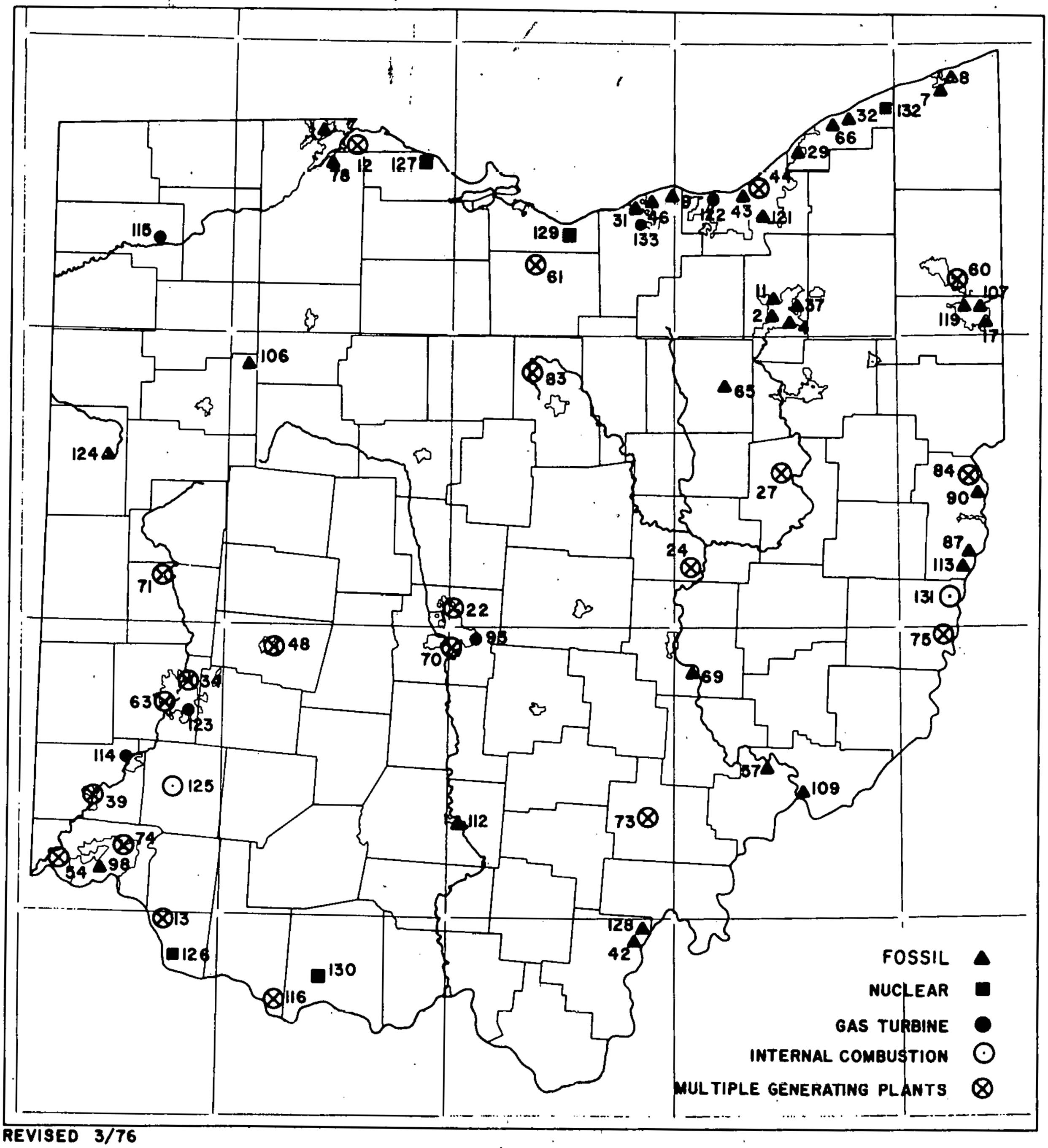

Fig. B.5 Sites in Ohio

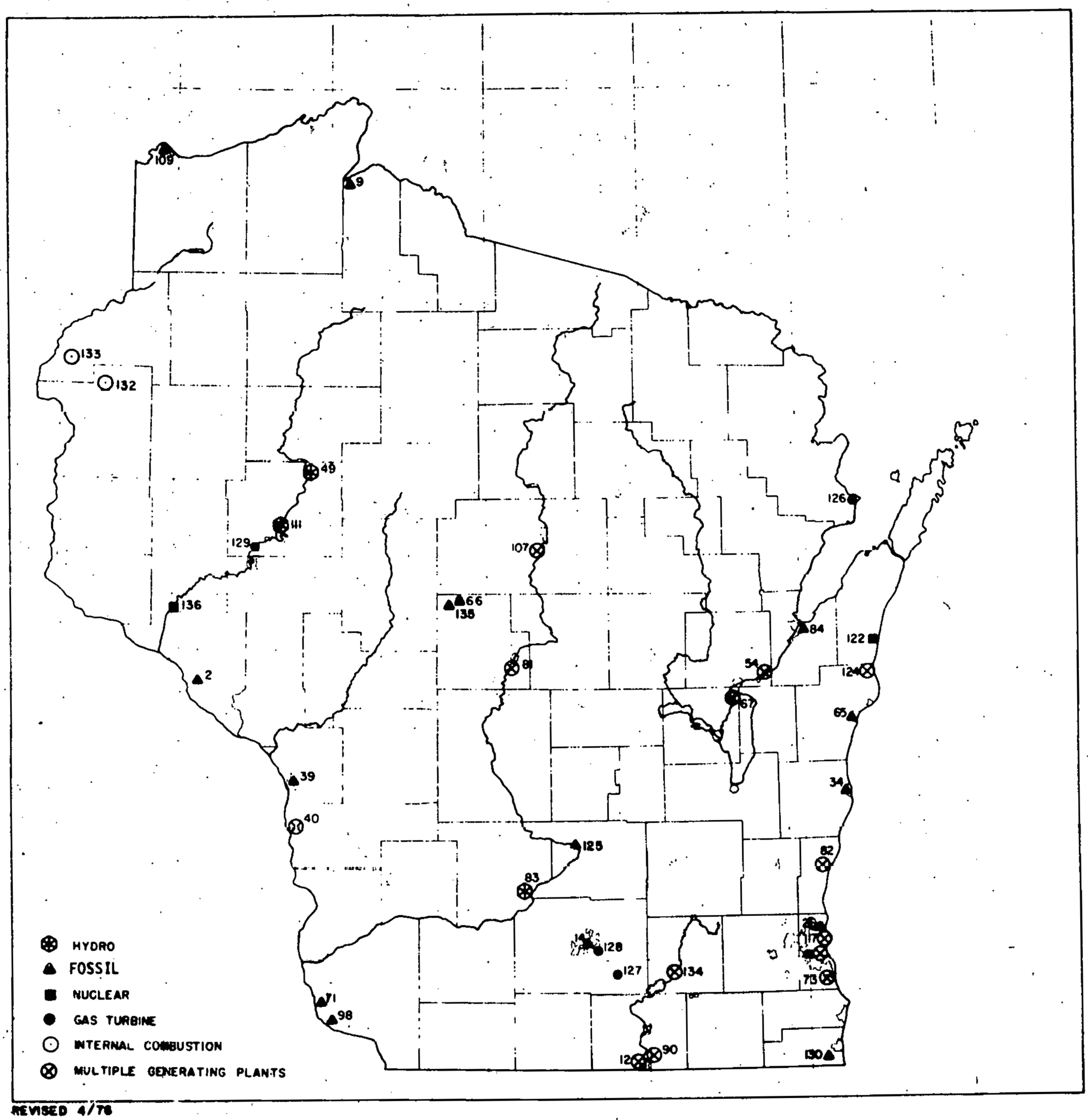

Fig. B.6 Sites in Wisconsin

APPENDIX C

Coal Reserve Base and 1974 Production for Illinois, Indiana, Michigan, and Ohio

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Table C-1. Illinois Coal Reserve Base and 1974 Production Levels (10^6 tons)

	Reserve Base[1]			1974 Production[2]	
County	Total	Deep (>28 in.)	Strip	Deep	Strip
Adams	68	0	68	-	-
Bond	1,831	1,831	0	-	-
Brown	83	0	83	-	-
Bureau	1,251	1,029	222	-	-
Calhoun	6	0	6	-	-
Cass	116	13	103	-	-
Christian	3,347	3,347	0	4.1	-
Clark	168	168	0	-	-
Clinton	1,322	1,322	0	-	-
Coles	81	81	0	-	-
Crawford	443	443	0	-	-
Cumberland	4	0	4	-	-
Douglas	412	412	0	2.1	0
Edgar	1,750	1,750	0	-	-
Edwards	54	54	0	-	-
Fayette	1,174	1,174	0	-	-
Franklin	3,038	3,038	0	5.4	0
Fulton	2,031	221	1,810	0	2.5
Gallatin	1,991	1,761	230	1.4	0.3
Greene	475	52	423	-	-
Grundy	627	246	381	-	-
Hamilton	2,440	2,440	0	-	-
Hancock	28	0	28	-	-
Henry	409	28	381	-	-
Jackson	526	227	299	0	0.06
Jefferson	1,801	1,801	0	6.1	0.6
Jersey	162	40	120	-	-
Kankakee	95	80	15	0	0.1
Knox	673	68	605	0	1.0
LaSalle	1,244	1,083	161	-	-
Lawrence	894	894	0	-	-
Livingston	624	586	38	-	-
Logan	814	814	0	-	-
McDonough	47	0	47	-	-
McLean	421	421	0	-	-
Macon	439	439	0	-	-
Macoupin	3,597	3,421	176	2.5	0
Madison	1,876	1,367	509	-	-
Marion	421	421	0	-	-

Table C-1. (Cont'd)

County	Reserve Base[1]			1974 Production[2]	
	Total	Deep (>28 in.)	Strip	Deep	Strip
Marshall	474	358	116	-	-
Menard	1,460	1,460	0	-	-
Mercer	52	13	39	-	-
Monroe	7	0	7	-	-
Montgomery	3,907	3,907	0	1.6	0
Morgan	396	145	251	-	-
Moultrie	123	123	0	-	-
Peoria	1,711	289	1,422	0	1.1
Perry	2,174	1,201	973	0	11.1
Putnam	589	589	0	-	-
Randolph	631	214	417	1.6	6.5
Rock Island	39	13	26	-	-
St. Clair	2,114	951	1,163	2.8	0.5
Saline	2,985	2,554	431	1.2	1.2
Sangamon	3,540	3,540	0	-	-
Schuyler	202	0	202	-	-
Scott	165	0	165	-	-
Shelby	725	713	12	-	-
Stark	237	0	237	0	0.3
Tazewell	167	69	98	-	-
Vermillion	1,897	1,544	353	-	-
Wabash	286	262	24	0.7	0
Warren	19	0	19		
Washington	1,563	1,555	8	-	-
Wayne	89	89	0	-	-
White	992	992	0	-	-
Will	15	0	15	-	-
Williamson	2,103	1,573	530	1.7	1.6
Woodford	214	214	0	-	-
TOTAL	65,665	53,442	12,223	31.3	27.0

Table C-2. Indiana Coal Reserve Base and 1974 Production Levels (10^6 tons)

County	Reserve Base[1] Total	Deep (>28 in.)	Strip	1974 Production[2] Deep	Strip
Clay	326	168	158	0	1.1
Davies	187	109	78	-	-
Dubois	9	5	4	-	-
Fountain	48	7	41	0	0.06
Gibson	1,302	1,302	0	-	-
Greene	410	255	155	0	0.8
Knox	1,594	1,453	141	-	0.8
Martin	21	0	21	-	-
Owen	23	0	23	-	-
Parke	69	57	12	0	-
Perry	10	10	0	-	-
Pike	439	245	194	0.08	5.0
Posey	721	721	0	-	-
Spencer	19	0	19	0	0.6
Sullivan	2,238	1,922	316	0	3.2
Vanderburgh	451	451	0	-	-
Vermillion	553	498	55	0	2.8
Vigo	1,355	1,212	143	0.06	0
Warrick	846	533	313	0	9.3
TOTAL	10,622	8,948	1,674	0.14	23.6

Table C-3. Michigan Coal Reserve Base and 1974 Production Levels (10^6 tons)

County	Reserve Base[1] Total	Deep (>28 in.)	Strip	1974 Production[2] Deep	Strip
Bay	56	56	0	-	-
Genesee	7	7	0	-	-
Huron	6	6	0	-	-
Saginaw	27	27	0	-	-
Shiawasee	2	2	0	-	-
Tuscola	20	20	0	-	-
TOTAL	118	118	0		

Table C-4. Ohio Coal Reserve Base and 1974 Production Levels (10^6 tons)

County	Reserve Base[1] Total	Deep (>28 in.)	Strip	1974 Production[2] Deep	Strip
Athens	1,479	1,327	152	-	-
Belmont	4,219	3,927	292	6.1	9.8
Carroll	877	758	119	0	0.2
Columbinana	876	748	128	0.05	0.7
Coshocton	359	127	232	0.7	1.1
Gallia	493	340	153	0	0.1
Guernsey	1,237	1,184	53	0	0.9
Harrison	1,745	1,523	222	3.0	2.7
Hocking	221	205	16	0	0.3
Holmes	68	29	39	0	0.7
Jackson	354	155	199	0.06	0.4
Jefferson	1,695	1,356	339	0.8	4.36
Lawrence	594	477	117	0	0.09
Mahoning	342	308	34	0	0.4
Meigs	485	396	89	0.8	0
Monroe	469	468	1	0.8	0
Morgan	513	435	78	0	0.5
Muskingum	932	721	211	0.04	4.4
Noble	913	570	343	0	0.8
Perry	911	645	266	2.0	0.2
Scioto	6	5	1	-	-
Stark	526	377	149	0	0.4
Tuscarawas	1,115	841	274	0	1.4
Vinton	411	301	110	0.08	1.2
Washington	230	196	34	0	0.05
Wayne	5	3	2	-	-
TOTAL	21,077	17,423	3,654	14.4	31.0[a]

[a]Includes 10.2 million tons auger-mined.

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APPENDIX D

Low-Flow Data by River Reaches and Quality Standards for Public Water Supply for the Illinois, Rock, and Kaskaskia Rivers

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Table D-1. Low-Flow Data by River Reaches

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow, cfs
406	Maumee	1	27	175
		2	65	160
502	Ohio	11	562	5500
		12	633	4500
		13	694	3500
		14	741	3000
		15	780	2000
		16	816	1500
		17	848	1000
503	Muskingum	1	23	900
		2	60	875
		3	87	725
	Scioto	1	15	390
		2	47	147
		3	81	128
		4	111	41
	Miami	1	20	425
		2	54	375
		3	79	350
		4	103	50
	Ohio	9	424	7000
		10	489	6000
402	Wolf	1	14	440
		2	46	300
		3	78	225
		4	119	100
	Fox	1	9	840
		2	29	330
404	St. Joseph	1	19	570
		2	54	360
	Grand	1	15	700
		2	38	695
		3	69	193
		4	110	111
		5	146	75

Table D-1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow, cfs
404	Muskegon	1	20	660
		2	53	450
		3	87	307
	Kalamazoo	1	23	350
		2	68	143
		3	105	87
506	White	1	20	700
		2	68	500
		3	120	120
		4	172	50
		5	212	15
	Wabash	1	25	2800
		2	74	1800
		3	126	1200
		4	188	1000
		5	254	800
		6	307	500
		7	348	100
	Ohio	1	15	45000
		2	55	43000
		3	93	11300
		4	128	11100
		5	159	9500
		6	221	8500
		7	284	8000
		8	357	7500
701	St. Croix	1	40	1050
		2	120	670
	Minnesota	1	25	190
		2	70	150
		3	120	100
		4	197	30
	Mississippi	22	817	2000
		23	857	1500
		24	904	1400
		25	965	1000
		26	1036	500
		27	1086	150

Table D-1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow, cfs
702	Chippewa	1	16	1900
		2	48	775
		3	76	500
		4	109	285
		5	150	200
	Wisconsin	1	17	2660
		2	52	2500
		3	86	2250
		4	124	1800
		5	190	1400
		6	240	1000
		7	280	710
		8	332	500
703	Rock	1	13	1440
		2	51	1163
		3	98	1100
		4	131	870
		5	156	240
	Mississippi	12	445	15000
		13	447	14500
		14	508	13500
		15	537	13250
		16	567	13000
		17	600	12000
704	Illinois	1	21	3600
		2	64	3500
		3	106	3250
		4	146	2800
		5	188	3250
		6	239	3000
	Mississippi	7	222	21000
		8	260	18500
		9	298	16500
		10	348	16000
		11	395	15500
705	Kaskaskia	1	14	120
		2	55	73
		3	101	48
		4	129	25

Table D-1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow, cfs
705	Kaskaskia	5	160	15
		6	196	10
		7	231	3
	Mississippi	1	18	48500
		2	54	47750
		3	85	47250
		4	108	47000
		5	135	46500
		6	175	45500

Table D-2. Quality Standards for Public Water Supply[a] for the Illinois, Rock, and Kaskaskia Rivers

Parameters	Limiting Conditions or Concentrations
pH	6.5-9.0
P	0.05 mg/l
D.O.	6.0 mg/l
<u>Radioactivity</u>	
B	100 pci/l
^{226}Ra	1
^{90}Sr	2
Fecal Coliform (5 samples/30 day)	200 per 100 mi
NH_3	1.5 mg/l
As	0.01
Ba	1.0
B	1.0
Cd	0.01
Cl^-	250.0
Cr^{+6}	0.05
Cr^{+3}	1.0
Cu	0.02
Cn^-	0.01
F	1.4
Fe	0.3
Pb	0.05
Mn	0.05
Hg	0.0005
Ni	1.0
Phenols	0.001
Se	0.01
Ag	0.005
SO_4	250
TDS	500

Table D-2. (Cont'd)

Parameters	Limiting Conditions or Concentrations
Zn	1.0 mg/l
CCE	0.2
MBAS	0.5
Oils	0.1
N (NO_2, NO_3)	10.0
TSS	15.0

[a]*Illinois Pollution Control Board Rules and Regulations, Chapter 3, Water Pollution:* Effective Aug. 14, 1975, Environmental Reporter, Vol. 766.

APPENDIX E

Model for Short-Range Air Quality

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APPENDIX E

Model for Short-Range Air Quality

The basic model used in all of the short-range calculations is a modified version of the Climatological Dispersion Model (CDM), a model developed by USEPA for use in calculating long-term average concentrations of conservative pollutants, particularly in multiple-source applications.[1] The treatment of vertical dispersion in CDM is based on the gaussian plume concept. As such, it incorporates the following assumptions: (1) the wind velocity is constant in magnitude and direction and is uniform throughout the entire planetary boundary layer; (2) the emission rate is constant over a period equal to, or greater than, the travel time from source to the farthest receptor of interest; (3) no material is removed from the plume at the surface of the ground (perfect reflection-boundary condition). The treatment of horizontal dispersion makes use of the narrow-plume approximation and assumes in effect that, over a long period, the pollutant from a continuously emitting point source is, for a given distance from the source, uniformly spread within each of 16 angular sectors of 22.5° centered on the principal compass points. The total amount of pollutant emitted over the averaging time of interest (e.g., a year or a season) is distributed into the 16 sectors according to the relative frequency of wind direction falling within each sector.

In other words, CDM adopts a climatological approach to determining long-term average concentrations. In such an approach, a set of meteorological conditions is identified; dispersion calculations are carried out for each member of the set to predict the pollutant concentration for that meteorological situation at the receptor of interest; then a weighted average is determined by using the relative probabilities of the various meteorological situations included in the set. Specifically, CDM requires the joint probabilities of observing the wind speed in one of six different ranges, the wind direction in one of sixteen setors 22.5°-wide, and the atmospheric stability in one of six different classes. The National Climatic Center, Asheville, NC, can supply the necessary data on joint probability (normally called a stability-wind rose) in precisely the form required by CDM for any of the stations in their network. Finally, CDM can treat two pollutants at once, and it crudely allows for simulation of chemical and physical processes for pollutant removal in terms of an exponential decay type of dependence on source-receptor travel time, with different user-specified half-lives being used for the two pollutants.

Several modifications were made for our purposes but only two are important enough to mention here. First, we added the capability for calculating population dosage. To do this, the user supplies a list of population centroid locations together with the population associated with each; then, at each location, the average concentration is calculated as before and is multiplied by the corresponding population. These products are then summed over all centroids to obtain a total population dosage value. This value represents an average over the same period to which the concentration value corresponds. In the type of application for CDM, one usually desires monthly, seasonal, or annual averages.

The second significant modification that we made is adding the capability of describing simple conversion of one of the two pollutants into the other. The principal reason for this change is to model the conversion of sulfur dioxide to sulfate aerosol. The conversion was assumed to follow first-order kinetics; that is, the rate of sulfate production at a point was assumed proportional to the sulfur dioxide concentration at that point and independent of any other factor. Mathematically, at any point in the plume, the rates of removal of SO_2 and production of sulfate aerosol are assumed to be given by:

$$\frac{dC_1}{dt} = -(k_1 + k_2)\ C_1 \qquad (1)$$

$$\frac{dC_2}{dt} = \frac{3}{2}\ k_2C_1 - k_3C_2, \qquad (2)$$

where:

C_1 and C_2	=	the mass concentrations of sulfur dioxide and sulfate ion (SO_4), respectively;
$(-k_1C_1)$ and $(-k_3C_2)$	=	the rates of removal of SO_2 and sulfate aerosol by some arbitrary mechanism;
$\frac{3}{2}\ k_2C_1$ -	=	the rate of production of sulfate aerosol from SO_2,
k_2	=	the effective rate constant for the process; and,

3/2 = the ratio of the molecular weight of the sulfate ion to that of sulfur dioxide.

When the removal of SO_2 and production of sulfate aerosol are incorporated into a gaussian plume model, the effect is to replace the SO_2 emission rate Q_1 by Q_1 (effective), given by:

$$Q_1(\text{effective}) = Q_1 \exp\left[(k_1 + k_2)\frac{x}{u}\right], \tag{3}$$

and to replace the direct emission rate for sulfate aerosol, Q_2, by Q_2 (effective), given by:

$$Q_2(\text{effective}) = Q_2\, e^{-k_3\frac{x}{u}} + Q_1 \left\{\frac{k_2}{k_3-(k_1-k_2)}\right\}\left[e^{-(k_1+k_2)\frac{x}{u}} - e^{-k_3\frac{x}{u}}\right], \tag{4}$$

where:

x = the downwind distance at which the concentration is to be evaluated; and

u = the wind speed.

If k_2 equals zero, the formulas reduce to those already built into CDM.

In all of the work using this model, we simulated the effect of dry deposition by choosing the values of the parameters k_1 and k_3 in the following way. If one assumes uniform vertical mixing of a pollutant up to a height H (the mixing height) and a rate of removal of pollutant per unit area at the lower boundary equal to a constant v (the effective deposition velocity) times the concentration, one easily finds that the concentration is given as a function of time by:

$$C(t) = C(o) \exp\left[\frac{v}{-H}\ t.\right] \tag{5}$$

One can, therefore, estimate reasonable values for k, and k_3 by dividing appropriate values of v by some effective mixing height; we used this approach in our calculations.

Parameter values used in this study are in Table E-1. Although we have chosen to model conversion of SO_2 to sulfate, the concentration of SO_2 that would be calculated by assuming no conversion may be estimated from the predicted SO_2 and sulfate levels using Eq. 6:

$$C_{SO_2} \text{ (No conversion)} = C_{SO_2} + \frac{2}{3}\, C \text{ sulfate.} \tag{6}$$

The direct emission rate of sulfate aerosol, Q_2, was assumed to be zero in all calculations.

Table E-1. Values of Parameters for Reaction Rates and Decay

Rate Constant (k_2) for SO_2-SO_4 conversion	1.0×10^{-5} sec^{-1}
Rate Constant (k_1) for physical removal of SO_2	1.0×10^{-5} sec^{-1}
corresponding to deposition velocity (v)	1.0 cm sec^{-1}
and effective mixing height (H)	1000 m
Rate Constant (k_3) for physical removal of SO_4	1.0×10^{-6} sec^{-1}
corresponding to deposition velocity (v)	0.1 cm sec^{-1}
and effective mixing height (H)	1000 m

The parameter values estimated for SO_2 are reasonably representative of other pollutants emitted from power plants as well, and in the approximation that they can be taken to be the same, the results for sulfur dioxide may simply be scaled by the relative emission rates to obtain concentration estimates for the other pollutants. This procedure has been adopted for the purposes of this initial assessment. The error incurred by this procedure is estimated to be within the range of uncertainty of the basic model itself.

E.1 REPRESENTATIVE ANNUAL IMPACTS OF CONCENTRATION AND DEPOSITION

Ambient Concentrations

To initially allow a reasonably general analysis of the impacts on regional air quality of coal-fired power plants and gasification plants, we assumed any modeling of the dispersion of the emissions should not depend on microscale site characteristics. The only distinction made between sites is that different subregions within the six-state area will, in general, have different stability-wind roses, ambient temperatures, and mixing heights. To account for these differences between subregions, the 71 subregions shown in Fig. E-1 have been defined, each about 100 km^2, depending on latitude. All sites within each of these subregions are considered to have identical pollutant dispersion patterns.

Any site-specific features, such as complex topography or large water bodies, would certainly need to be taken into account for a detailed analysis of the dispersion in a given location. However, siting of plants on a county basis, as was done in this study, does not justify the more detailed analysis.

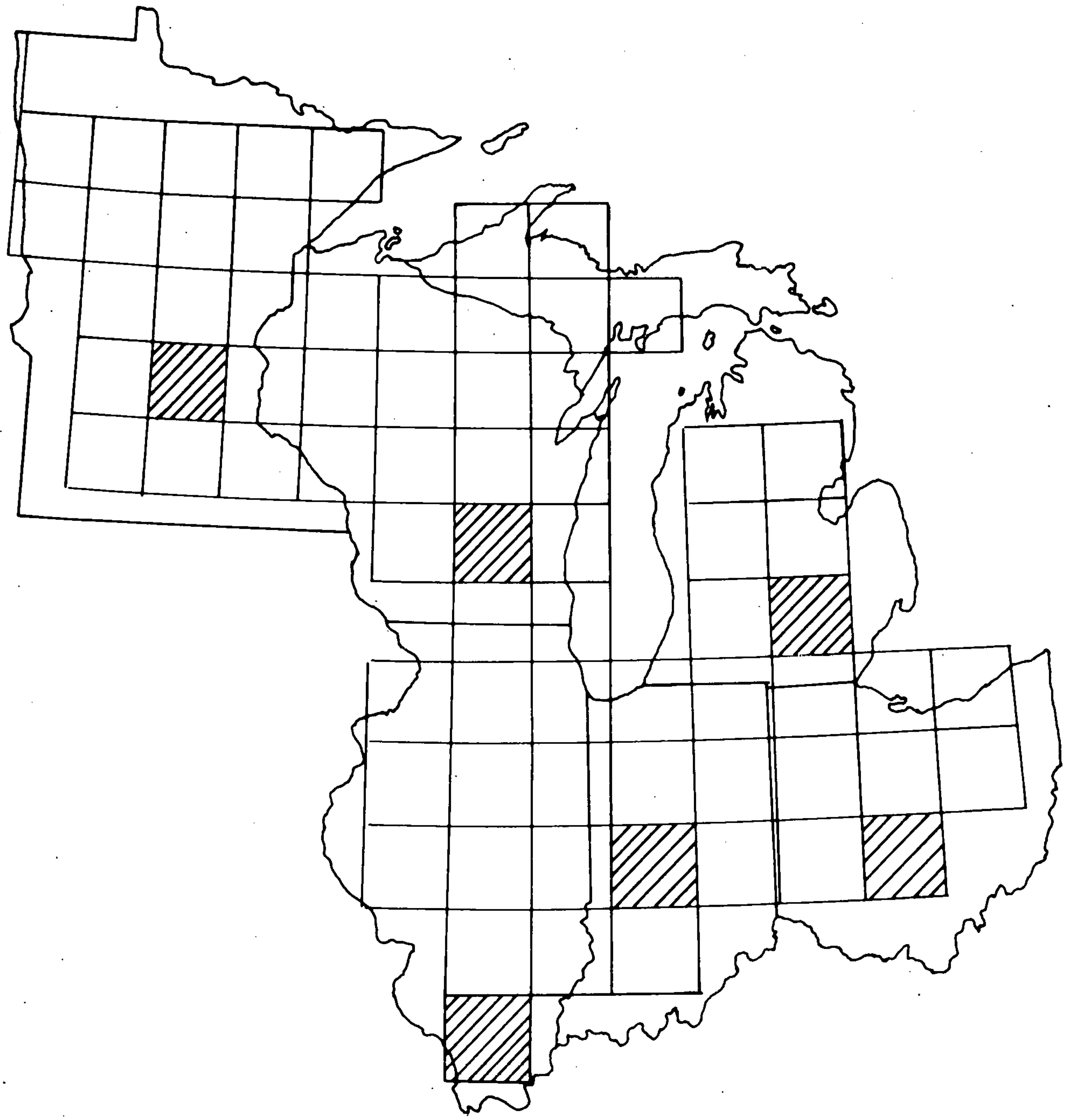

Fig. E.1 Study Area Subregionalization for Computation of Typical Air Pollutant Concentrations and Depositions

Since all sites within a subregion are considered to have identical dispersion patterns, it was useful to generate a set of annual average concentration isopleths for each subregion reference source. The reference source used is the 3000 MW power plant with physical characteristics given in Table 2.4 and emissions in Table 2.5 (60% load factor). As a first approximation, ambient concentrations for different pollutants are estimated by use of weighting factors equal to the ratio of emission rates. Differences in rates of deposition or transformation will introduce errors, but the magnitude of errors is expected to be within the range of uncertainty of the emission rates and the basic model itself. The isopleths for the selected subregions shown in Fig. E-1 are shown in Fig. E-2 and the contour values for the various pollutants are given in Table E-2. Table E-2 also indicates maximum levels of annual averages for each of the pollutants for the southern Illinois subregion.

For these isopleth maps, any pattern of siting for one or several such sources within the subregion can be considered simply by superimposing the proper maps with the appropriate weighting factors based on emission rates. These superpositions will in theory be correct only if all facilities included have physical characteristics given in Table 2.4. However, these characteristics of stack height, gas temperature, and volume flow do not greatly influence annual average concentrations significantly beyond 1-2 km from the source. As a result, the isopleths give sufficient accuracy for other facilities, such as gasification plants, if the appropriate emission rates as given in Table 2.5 are used. (Short-term maximums are more dependent on physical characteristics, as is discussed in Section E-3.).

The basic model used in these dispersion calculations is a modified version of the Climatological Dispersion Model (CDM) developed by the US EPA The modifications included, first of all, a routine for computing the population exposure, based on user-input populations at specified centroids. The second modification was a simplified simulation of the transformation from one pollutant to another and the removal of both the primary transformed pollutant by deposition and other physical processes. Transformation and removal were assumed to occur at a rate proportional to the concentration of the respective pollutants. The principal motivation for this latter modification was to simulate the conversion of sulfur dioxide (SO_2) to the sulfate aerosol (SO_4).

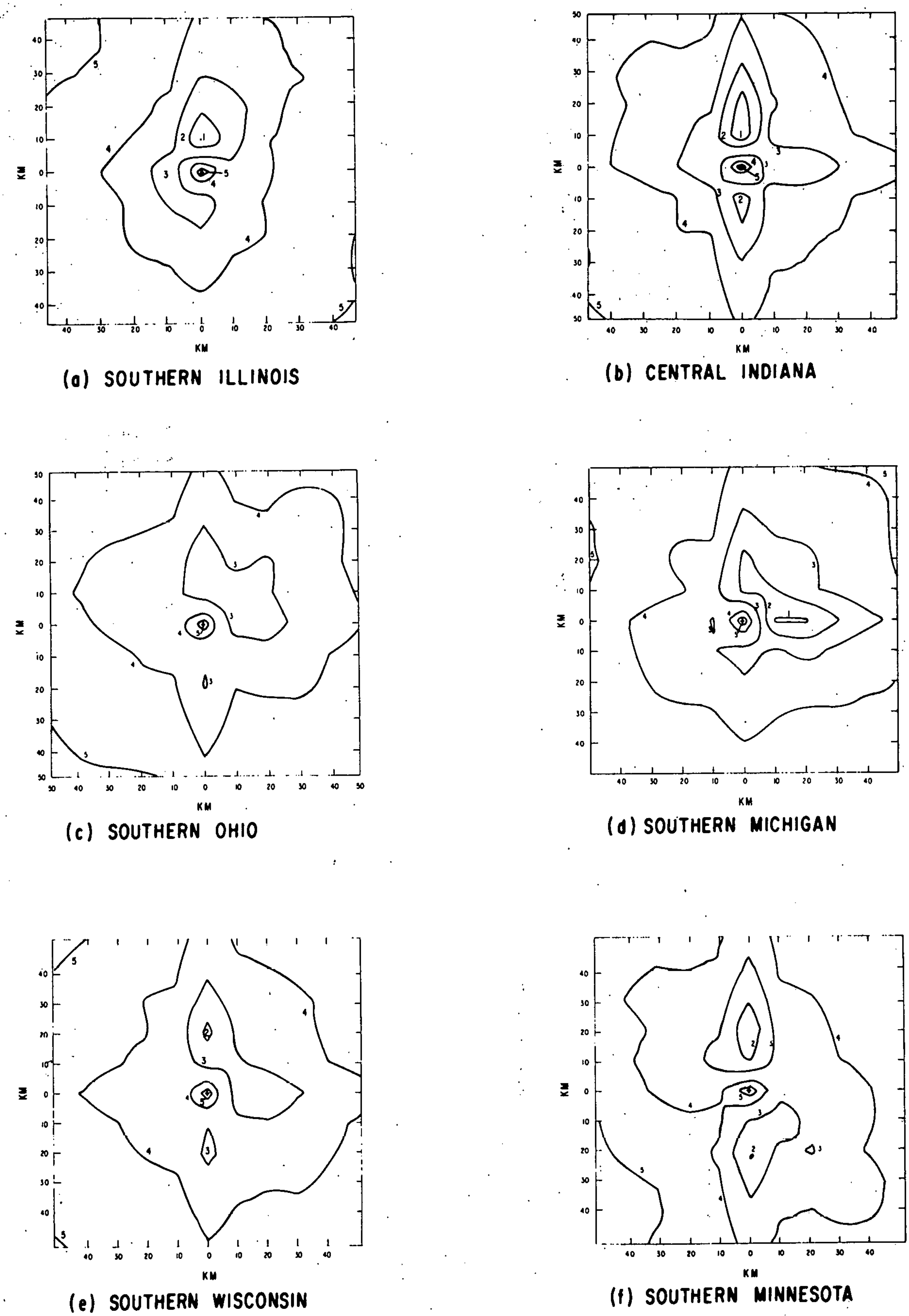

Fig. E.2 Annual Average Air Pollutant Isopleths for a 3000 MW Reference Source

Table E-2. Annual Average Concentrations at Isopleths and Local Maximum for 3000 MW Reference Source in Selected Subregions (Fig. 7.4).

Pollutant	Concentration, μg/m³					
	Isopleth No.					
	1	2	3	4	5	S. Ill. Max.
SO_2	2.45	1.84	1.22	6.13 (-1)	2.45 (-1)	2.45
NO_x	1.42	1.07	7.10 (-1)	3.55 (-1)	1.42 (-1)	1.42
Particulates	2.03 (-1)[a]	1.52 (-1)	1.02 (-1)	5.08 (-2)	2.03 (-2)	2.03 (-1)
CO	7.73 (-2)	5.80 (-2)	3.87 (-2)	1.93 (-2)	7.73 (-3)	7.73 (-2)
As	1.07 (-3)	8.02 (-4)	5.34 (-4)	2.68 (-4)	1.07 (-4)	1.07 (-3)
Be	2.69 (-5)	2.02 (-5)	1.35 (-5)	6.71 (-6)	2.69 (-6)	2.69 (-5)
Cd	1.28 (-5)	9.60 (-6)	6.40 (-6)	3.20 (-6)	1.28 (-6)	1.28 (-5)
F	9.26 (-3)	6.95 (-3)	4.64 (-3)	2.31 (-3)	9.26 (-4)	9.26 (-3)
Hg	1.59 (-5)	1.20 (-5)	7.96 (-6)	3.98 (-6)	1.59 (-6)	1.59 (-5)
Pb	1.69 (-3)	1.27 (-3)	8.48 (-4)	4.23 (-4)	1.69 (-4)	1.69 (-3)
Se	2.50 (-4)	1.88 (-4)	1.25 (-4)	6.25 (-5)	2.50 (-5)	2.50 (-4)

[a](-1) denotes x 10^{-1}, etc.

For this analysis a conversion rate, SO_2 to SO_4, of 1.0×10^{-5}/sec was used, along with removal rates of SO_2 and SO_4 of 1.0×10^{-6}/sec, respectively.

One of the options for future facilities for electric-power generation is clustering several generating units relatively close to each other, to achieve certain economies. One such pattern considered in the GE report is shown in Fig. E-3. In this pattern, twelve 3000 MW facilities are located within a 36-m (93-km) area. Examining the impact on air quality of this siting pattern required only referring to the calculations for the reference point source and superimposing those results appropriately to simulate the total effect of all sources being considered. The resulting annual average contours at 60% load factor for Fig. E-4 and the contour values for various pollutants are given in Table E-3.

Deposition Rates

An important aspect of impacts of air pollutants on ecosystems is deposition of these pollutants on the surrounding terrain, where they become available for uptake into those systems. Presented here are estimated based on a first-order approximation of a pollutant deposition rate given by the ambient concentrations supplied in the previous section times a proportionality constant called the deposition velocity. Except for mercury and fluorine, the trace elements listed in Table 2.3 leave the stack primarily as particulates; thus, the following estimates of particulate deposition can also be used to estimate deposition of these elements.

The rate of particle deposition is dependent on particle size. For an electrostatic precipitator, the collection efficiency as a function of particle size can be approximated by

Particle Size, μm	Collection Efficiency, %
0-5	72
5-10	95
10-20	97

If future power plants have electrostatic precipitators or other control devices more efficient in removing larger particles, it can be assumed that the emitted particles are under 5μm. For deposition over grass,

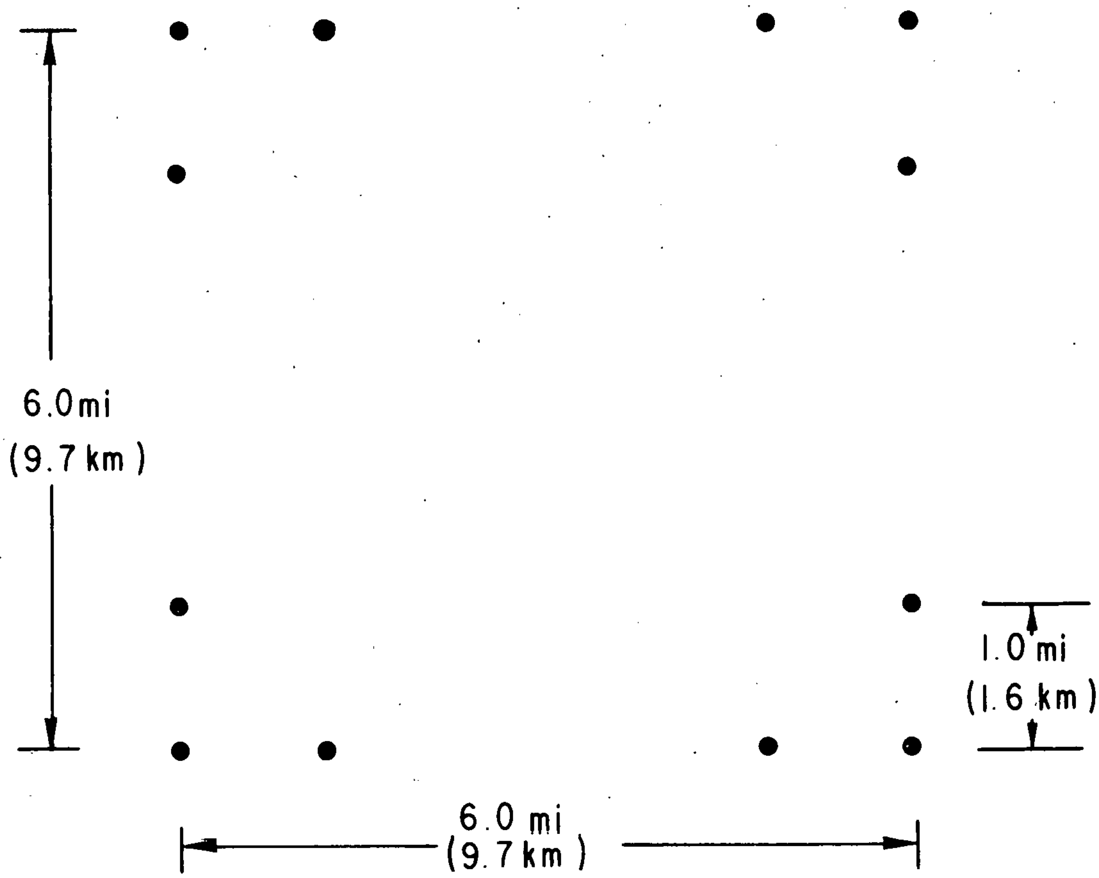

Fig. E.3 Clustered Siting for Twelve 3000 MW Reference Sources

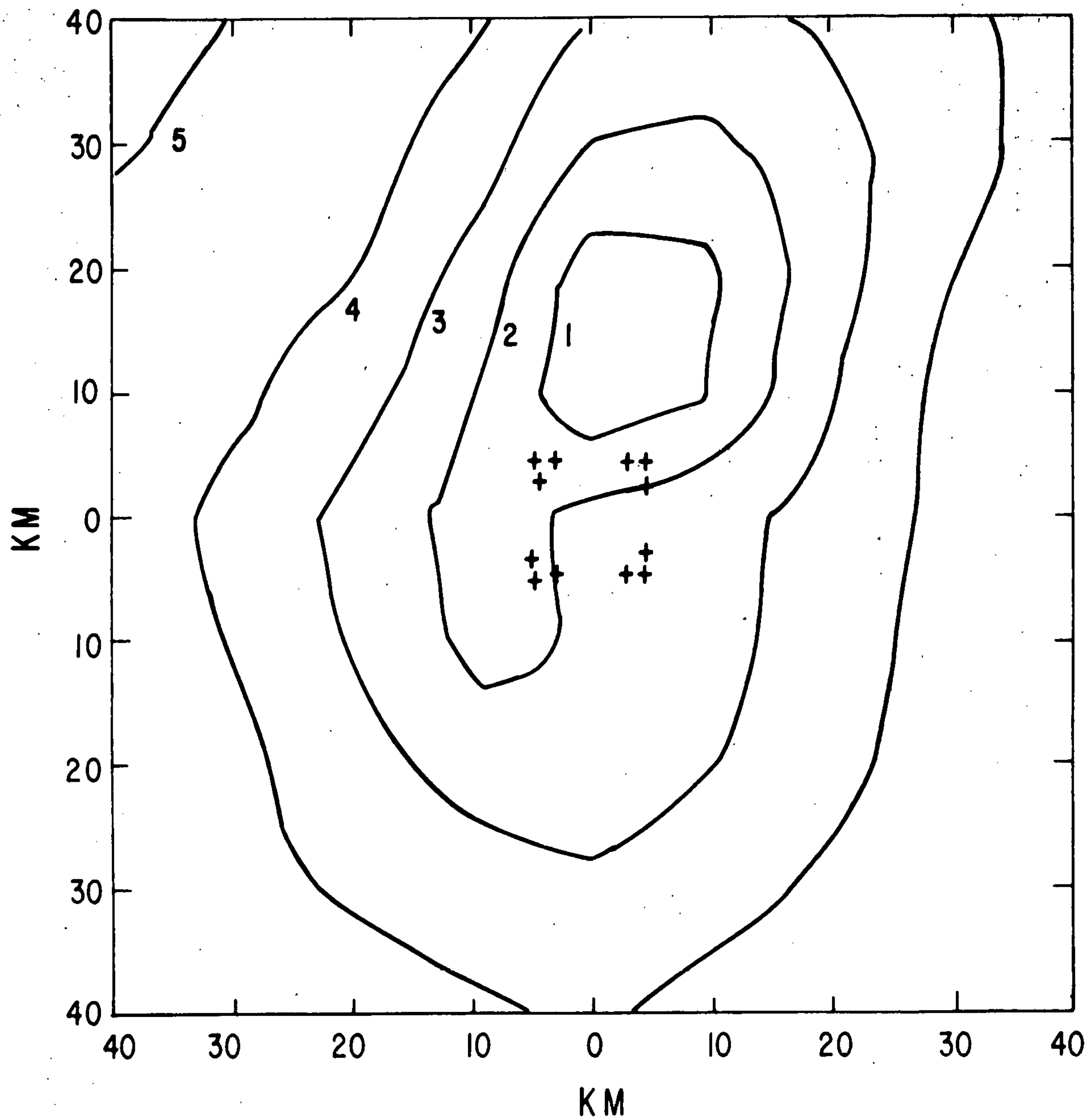

Fig. E.4 Annual Average Air Pollutant Isopleths for Clustered Reference Sources in Southern Illinois

Table E-3. Annual Average Concentrations at Isopleths and Local Maximum for Cluster of Twelve 3000-MW Reference Sources in Southern Illinois (Fig. 7.6)

	Concentration, μg/m³					
	Isopleth No.					
Pollutant	1	2	3	4	5	Maximum
SO_2	17.1	13.6	10.2	6.82	3.41	19.3
NO_x	9.95	7.96	5.97	3.98	1.99	11.2
Particulates	1.42	1.14	8.52 (-1)	5.68 (-1)	2.84 (-1)	1.60
CO	5.40 (-1)[a]	4.32 (-1)	3.24 (-1)	2.16 (-1)	1.08 (-1)	6.10 (-1)
As	7.48 (-3)	5.97 (-3)	4.49 (-3)	2.99 (-3)	1.49 (-3)	8.43 (-3)
Be	1.87 (-4)	1.50 (-4)	1.13 (-4)	7.50 (-5)	3.75 (-5)	2.12 (-4)
Cd	8.95 (-5)	7.16 (-5)	5.37 (-5)	3.58 (-5)	1.79 (-5)	1.01 (-4)
F	6.46 (-2)	5.17 (-2)	3.88 (-2)	2.58 (-2)	1.29 (-2)	7.30 (-2)
Hg	1.11 (-4)	8.88 (-5)	6.67 (-5)	4.44 (-5)	2.22 (-5)	1.26 (-4)
Pb	1.18 (-2)	9.43 (-3)	7.06 (-3)	4.72 (-3)	2.36 (-3)	1.33 (-2)
Se	1.75 (-3)	1.39 (-3)	1.04 (-3)	6.97 (-4)	3.48 (-4)	1.97 (-3)

[a](-1) denotes x 10^{-1}, etc.

the deposition velocity has been estimated to vary from 0.03 cm/s for 0.05-μm particles and 0.3 cm/s for 5-μm particles.[2] For deposition over plants more than one m in height, (e.g., bushes and shrubbery) the deposition velocity increases by a factor of 5 to 10. In the following analysis the value of 0.3 cm/s is assumed. Clearly the variation in particle size and terrain cover, in addition to the crude modeling approach, makes the results only rough approximations. However, these results should be adequate to indicate potential problem areas worth further detailed analysis; this indication is a primary objective of this initial study.

With this straightforward approach, the concentration isopleths given in Figs. E-2 and E-4 for the single and clustered facilities are also estimates of deposition isopleths. The total deposition over a one-year period at the contours and local maximum determined from 0.3 cm/s deposition velocity for particles and the 1.0 cm/s for gases, is given in Tables E-4 and E-5.

Because of the many uncertainties in these estimates, an evaluation of potential impacts should consider an increase or decrease of these values by an order of magnitude as being possible in the actual depositions.

E.2 SHORT-TERM MAXIMUM CONCENTRATIONS

Estimates of short-term maximum concentrations as presented here are based primarily on results of the GE study as adjusted for the emissions from the standard 3000-MW electrical generation and the 250 x 10^6 scf/day gasification facilities.[3] This study made use of the EPA PTMTP model, which is basically a coning-plus-trapping model with gaussian diffusion, Pasquill-Gifford dispersion parameters, and a Briggs plume-rise formula. The pollutants are assumed conservative, with no interference from topographical features. The plant characteristics are given in Table 2-4. A 1000-m mixing height is assumed.

Maximum concentrations for 15-min averaging times are obtained under these conditions for atmospheric stability class A and a 5 m/s wind speed. When these conditions are combined with the assumption that the plant is operating at full capacity, the theoretical maximum concentration is obtained. However, these meteorological conditions are expected to occur only few hours annually, and it is very unlikely that these conditions will occur simultaneously

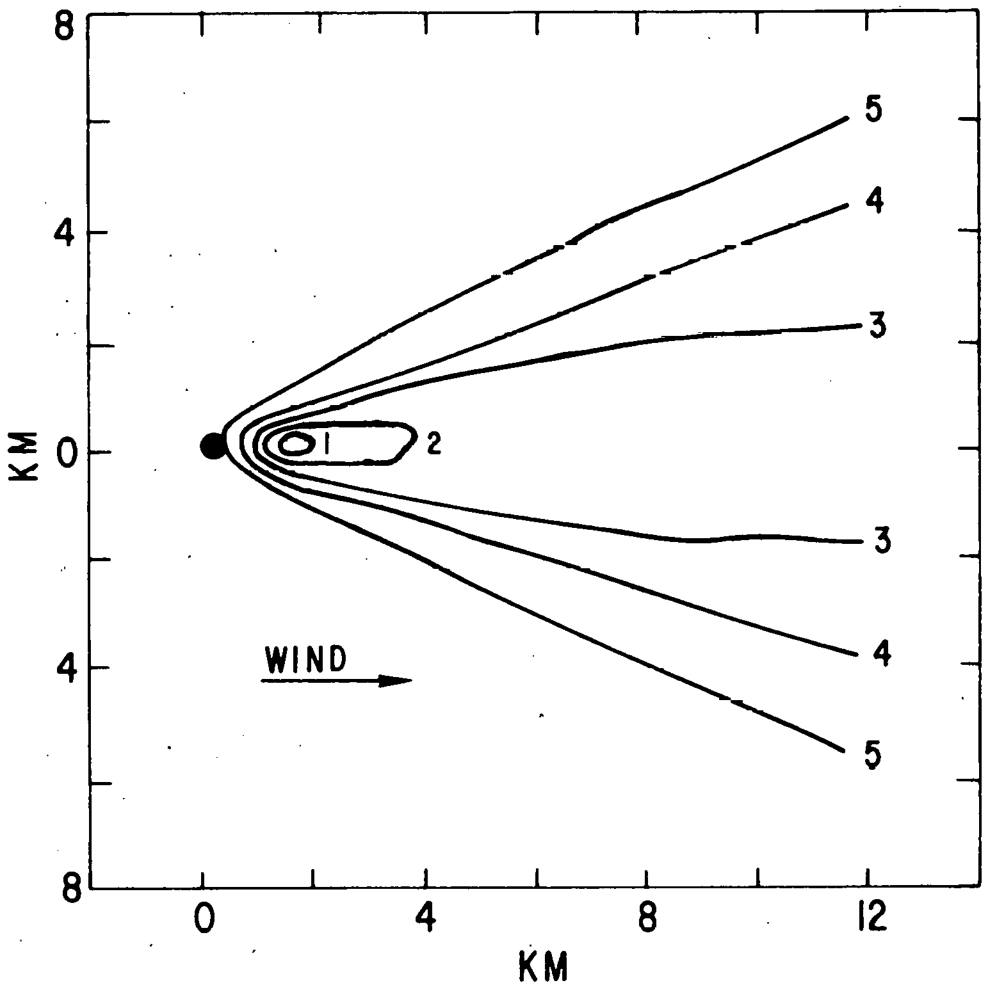

Fig. E.5 Maximum Short-Term Concentration Isopleths for a 3000-MW Reference Source

Table E-4. Annual Depositions at Isopleths and Local Maximum for 3000 MW Reference Sources in Selected Subregions (Fig. 7.4).

	Depositions, $g/m^2/yr$					
	Isopleth No.					
Pollutant	1	2	3	4	5	S. Ill. Max.
SO_2	7.73 (-1)[a]	5.80 (-1)	3.83 (-1)	1.93 (-1)	7.73 (-2)	7.73 (-1)
NO_x	4.46 (-1)	3.37 (-1)	2.24 (-1)	1.12 (-1)	4.46 (-2)	4.46 (-1)
Particulates	1.92 (-2)	1.44 (-2)	9.65 (-3)	4.81 (-3)	1.92 (-3)	1.92 (-2)
CO	2.43 (-2)	1.83 (-2)	1.22 (-2)	6.10 (-3)	2.43 (-3)	2.43 (-2)
As	1.01 (-4)	7.59 (-5)	5.05 (-5)	2.53 (-5)	1.01 (-5)	1.01 (-4)
Be	2.54 (-6)	1.91 (-6)	1.28 (-6)	6.35 (-7)	2.54 (-7)	2.54 (-6)
Cd	1.21 (-6)	9.08 (-7)	6.05 (-7)	3.03 (-7)	1.21 (-7)	1.21 (-6)
F	2.92 (-3)	2.19 (-3)	1.46 (-3)	7.30 (-4)	2.92 (-4)	2.92 (-3)
Hg	5.00 (-6)	3.80 (-6)	2.51 (-6)	1.26 (-6)	5.00 (-7)	5.00 (-6)
Pb	1.60 (-4)	1.20 (-4)	8.02 (-5)	4.00 (-5)	1.60 (-5)	1.60 (-4)
Se	2.36 (-5)	1.78 (-5)	1.18 (-5)	5.91 (-6)	2.36 (-6)	2.36 (-5)

[a](-1) denotes x 10^{-1}, etc.

Table E-5. Annual Depositions at Isopleths and Local Maximum for Cluster of 12 3000 MW Reference Sources in Southern Illinois (Fig. 7.6)

	Depositions, $g/m^2/yr$					
	Isopleth No.					
Pollutant	1	2	3	4	5	Maximum
SO_2	5.37	4.30	3.60	2.15	1.07	6.07
NO_x	3.14	2.51	1.88	1.26	6.27 (-1)	3.53
Particulates	1.34 (-1)[a]	1.07 (-1)	8.05 (-2)	5.37 (-2)	2.69 (-2)	1.51 (-1)
CO	1.70 (-1)	1.36 (-1)	1.02 (-1)	6.80 (-2)	3.40 (-2)	1.92 (-1)
As	7.08 (-4)	5.65 (-4)	4.25 (-4)	2.83 (-4)	1.41 (-4)	7.97 (-4)
Be	1.77 (-5)	1.42 (-5)	1.07 (-5)	7.10 (-6)	3.75 (-6)	2.01 (-5)
Cd	8.47 (-6)	6.77 (-6)	5.08 (-6)	3.39 (-6)	1.69 (-6)	9.55 (-6)
F	2.04 (-2)	1.63 (-2)	1.22 (-2)	8.13 (-3)	4.07 (-3)	2.30 (-2)
Hg	3.50 (-5)	2.80 (-5)	2.10 (-5)	1.40 (-5)	7.00 (-6)	3.97 (-5)
Pb	1.12 (-3)	8.92 (-4)	6.68 (-4)	4.47 (-4)	2.23 (-4)	1.26 (-3)
Se	1.66 (-4)	1.31 (-4)	9.84 (-5)	6.59 (-5)	3.29 (-5)	1.86 (-4)

[a](-1) denotes x 10^{-1}, etc.

with plant operation at full capacity if the annual load factor is a maximum of 60%. Therefore, the emissions for the average 60% load as given in Sec. 2.5 were used with expectations of more realistic estimates of maximum values.

As indicated above, conditions that produce the estimated maximum concentrations occur very infrequently, and in fact may not occur at all. To illustrate the implications of the nonoccurrence of these conditions, Table E-6 compares the projected maximum 24-hr concentrations with stability class A at wind speeds of 5.0 and 2.5 m/s at load factors of 60 and 100%. The lower wind speed results in lower concentrations (because of greater plume rise); and these are more likely to occur. Uncertainties in meterological conditions that give maximum concentrations also apply to trace elements; however, the uncertainties in emission rates, perhaps as high as an order of magnitude, are dominant.

Table E-6. Comparison of 24-hr Maximum Concentrations with Different Load Factors and Wind Speeds for the Reference 3000 MW Source

Load Factor, %	Wind Speed, m/s	Maximum 24-hr Concentration $\mu g/m^3$		
		SO_2	TSP	NO_x
100	5	490	41	290
100	2.5	415	35	240
60	5	300	25	170
60	2.5	250	21	150

Note: For longer averaging times the maximum 15-min concentrations are multiplied by the factors in Table E-7, which are determined from the formula: C(avg time = t) = C(15 min) x $(15\ \text{min}/t)^{0.2}$.

The short-term concentration contours from the single 3000-MW facility emissions are given in Fig. E-5 and the contours for the cluster of facilities (Fig. E-3) are given in Fig. E-6 for perpendicular and diagonal wind directions. The contour values and maximum point concentrations associated with these figures are given in Table E-8 for 15-min, 3-hr, and 24-hr averaging times.

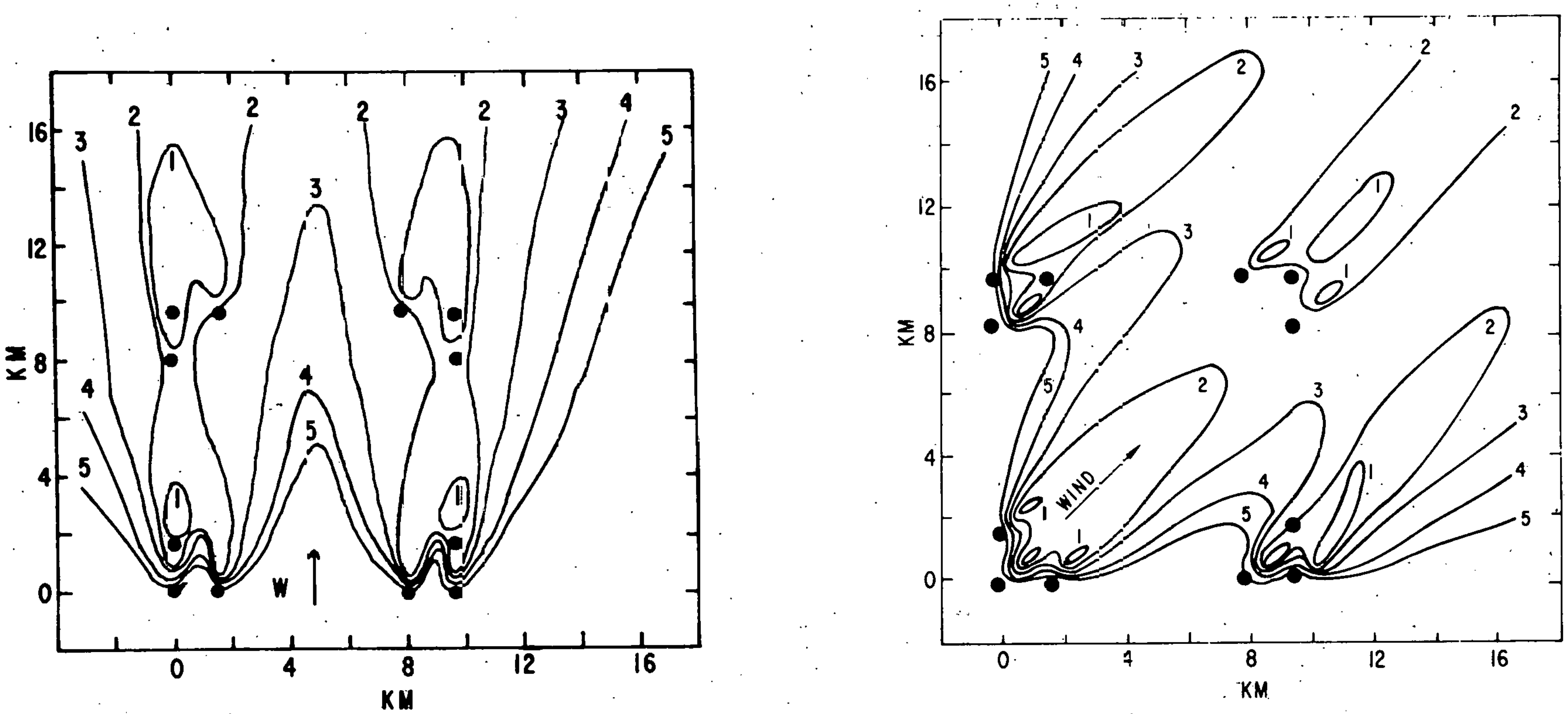

Fig. E.6 Maximum Short-Term Concentration Isopleths for Clustered 3000 MW Reference Sources

Table E-7. Relative Maximum Short-Term Concentration as a Function of Averaging Time

Averaging Time, hr	Relative Concentration
0.25	1.0
0.5	0.87
1.0	0.76
2.0	0.66
3.0	0.61
8.0	0.50
24.0	0.40

The estimates of short-term concentration presented above are also affected by a number of other parametric assumptions. In the GE study[3] an analysis was conducted to identify the critical input parameters with the greatest effect on the predicted short-term concentration. Considered were variations in stability class, wind speed, mixing height, exhaust-gas temperature, stack height, volume flows, and combinations of variations in these factors. Results of this sensitivity analysis are summarized in Table E-9.

On the basis of that study, it was concluded that:

- Of the many factors involved in producing ground-level concentrations of [pollutants] from a power plant, only two controllable ones apparently can alter the maximum ground-level concentration by any great amount. The first, obviously, is to minimize pollution emitted from a stack.

- The second method is the use of tall stacks. Although this method cannot guarantee that high ground-level concentrations of pollution will <u>never</u> occur, it can drastically reduce the probabilities of such an occurrence. (Decreasing the 244-m, correspondingly increased the estimated short-term maximum concentration by about half.)

- Other factors, such as stability class, wind speed, and mixing height, can also cause large variations in the maximum short-term, ground-level concentration of pollution. Although these factors cannot be controlled, they should be considered before a power plant is constructed.

Table E-8. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000 MW Reference Sources (Figs. E-5, E-6): 15-min Maximums

	Concentrations, $\mu g/m^3$							
	Isopleth No.							
Pollutant	1	2	3	4	5	Max. (Fig. E-5)	Max. (Fig. E-6)	Max. (Fig. E-7)
SO_2	6.82 (+2)[a]	3.41 (+2)	6.82 (+1)	6.82	6.82 (-1)	7.42 (+2)	1.34 (+3)	1.07 (+3)
NO_x	3.98 (+2)	1.99 (+2)	3.98 (+1)	3.98	3.98 (-1)	4.33 (+2)	1.79 (+2)	6.23 (+2)
Particulates	5.68 (+1)	2.84 (+1)	5.68	5.68	5.68 (-2)	6.18 (+1)	1.11 (+2)	8.89 (+1)
CO	2.16 (+1)	1.08 (+1)	2.16	2.16 (-1)	2.16 (-2)	2.35 (+1)	4.23 (+1)	3.38 (+1)
As	2.99 (-1)	1.49 (-1)	2.99 (-2)	2.99 (-3)	2.99 (-4)	3.26 (-1)	5.85 (-1)	4.67 (-1)
Be	7.34 (-3)	3.67 (-3)	7.34 (-4)	7.34 (-5	7.34 (-6)	7.97 (-3)	1.44 (-2)	1.15 (-2)
Cd	3.58 (-3)	1.79 (-3)	3.58 (-4)	3.58 (-5)	3.58 (-6)	3.90 (-3)	7.01 (-3)	5.60 (-3)
F	2.57	1.29	2.57 (-1)	2.57 (-2)	2.57 (-3)	2.80	5.06	4.04
Hg	4.44 (-3)	2.22 (-3)	4.44 (-4)	4.44 (-5)	4.44 (-6)	4.83 (-3)	8.69 (-3)	6.95 (-3)
Pb	4.72 (-1)	2.36 (-1)	4.72 (-2)	4.72 (-3)	4.72 (-4)	5.14	9.25	7.41
Se	6.97 (-2)	3.48 (-2)	6.97 (-3)	6.97 (-4)	6.97 (-5)	7.57 (-2)	1.36 (-1)	1.09 (-1)

[a](+2) denotes x 10^{+2}, etc.

Table E-8A. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000 MW Reference Sources (Figs. E-5, E-6): 3-hr Maximums

	Concentrations, μg/m³							
	Isopleth No.							
Pollutant	1	2	3	4	5	Max. (Fig.E-5)	Max. (Fig. E-6)	Max. (Fig. E-7)
SO_2	4.16 (+2)[a]	2.08 (+2)	4.16 (+1)	4.16	4.16 (-1)	4.53 (+2)	8.17 (+2)	6.53 (+2)
NO_x	2.43 (+2)	1.21 (+2)	2.43 (+1)	2.43	2.43 (-1)	2.64 (+2)	4.70 (+2)	3.80)(+2)
Particulates	3.46 (+1)	1.73 (+1)	3.46	3.46 (-1)	3.46 (-2)	3.77 (+1)	6.77 (+1)	5.42 (+1)
CO	1.32 (+1)	6.60	1.32	1.32 (-1)	1.32 (-2)	1.43 (+1)	2.58 (+1)	2.06 (+1)
As	1.82 (-1)	9.10 (-2)	1.82 (-2)	1.82 (-3)	1.82 (-4)	1.99 (-1)	3.57 (-1)	2.85 (-1)
Be	4.48 (-3)	2.24 (-3)	4.48 (-4)	4.48 (-5)	4.48 (-6)	4.86 (-3)	8.78 (-3)	7.02 (-3)
Cd	2.18 (-3)	1.09 (-3)	2.18 (-4)	2.18 (-5)	2.18 (-6)	2.38 (-3)	4.28 (-3)	3.42 (-3)
F	1.57	7.80 (-1)	1.57 (-1)	1.57 (-2)	1.57 (-3)	1.71	3.09	2.46
Hg	2.71 (-3)	1.35 (-3)	2.71 (-4)	2.71 (-5)	2.71 (-6)	2.95 (-3)	5.30 (-3)	4.24 (-3)
Pb	2.88 (-1)	1.44 (-1)	2.88 (-2)	2.88 (-3)	2.88 (-4)	3.14	5.64	4.52
Se	4.25 (-2)	2.13 (-2)	4.25 (-3)	4.25 (-4)	4.25 (-5)	4.62 (-2)	8.30 (-2)	6.65 (-2)

[a](+2) denotes x 10^{+2}, etc.

Table E-8B. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000 MW Reference Sources (Figs. E-5, E-6): 24-hr Maximums

	Concentration, $\mu g/m^3$							
	Isopleth No.							
Pollutant	1	2	3	4	5	Max. (Fig. E-5)	Max. (Fig. E-6)	Max. (Fig. E-7)
SO_2	2.73 (+2)[a]	1.36 (+2)	2.73 (+1)	2.73	2.73 (-1)	2.97 (+2)	5.36 (+2)	4.28 (+2)
NO_x	1.59 (+2)	7.96 (+1)	1.59 (+1)	1.59	1.59 (-1)	1.73 (+2)	3.12 (+2)	2.49 (+2)
Particu-lates	2.27 (+1)	1.14 (+1)	2.27	2.27 (-1)	2.27 (-2)	2.47 (+1)	4.44 (+1)	3.56 (+1)
CO	8.64	4.32	8.64 (-1)	8.64 (-2)	8.64 (-3)	9.40	1.69 (+1)	1.35 (+1)
As	1.20 (-1)	5.98 (-2)	1.20 (-2)	1.20 (-3)	1.20 (-4)	1.30 (-1)	2.34 (-1)	1.87 (-1)
Be	2.94 (-3)	1.47 (-3)	2.94 (-4)	2.94 (-5)	2.94 (-6)	3.19 (-3)	5.76 (-3)	4.60 (-1)
Cd	1.43 (-3)	7.16 (-4)	1.43 (-4)	1.43 (-5)	1.43 (-6)	1.56 (-3)	2.80 (-3)	2.24 (-3)
F	1.03	5.14 (-1)	1.03 (-1)	1.03 (-2)	1.03 (-3)	1.12	2.02	1.62
Hg	1.78 (-3)	8.88 (-4)	1.78 (-4)	1.78 (-5)	1.78 (-6)	1.93 (-3)	3.48 (-3)	2.78 (-3)
Pb	1.89 (-1)	9.44 (-2)	1.89 (-2)	1.89 (-3)	1.89 (-4)	2.06	3.70	2.96
Se	2.79 (-2)	1.39 (-2)	2.79 (-3)	2.79 (-4)	2.79 (-5)	3.03 (-2)	5.44 (-2)	4.36 (-2)

[a](+2) denotes x 10^{+2}, etc.

If a certain areas has an unusually high proportion of undesirable conditions, greater care must be taken to prevent high ground-level concentrations.

The estimates of short-term maximums are also very dependent on the model used for the computation. The EPA model used is among the more conservative. For example, the 24:1-hr average ratio is larger by approximately a factor of 2 with the EPA model than with the TVA and AEP models (see Table E-9).

The emphasis in this section has been on short-term impacts from the reference 3000-MW electrical generation facility because emission rates of SO_2, particulates, and NO_x are much larger than those from the reference 250 x 10^6 scf/day gasification plant. Differences in stack height and flue-gas temperatures and volume flow will have an impact on the relative ambient concentrations from these facilities, but the impact of these parameters will not offset the large differences in emission rates of SO_2, particulates, and NO_x. The possible identification of emissions of trace substances, which are more dominant in gasification facilities, would justify future air-quality analysis specifically related to gasification.

Table E-9. Sensitivity of Maximum Short-Term Concentration Estimates to Selected Parameters

Emission Rate, g/s	1.0	0.5	2.0
Max. Conc (relative)	1.0	0.5	2.0
Stack Height, m	244	122	366
Max. Conc (relative)	1.0	1.45	0.91
Stability Class	1	2	3
Max. Conc (relative)	1.0	0.34	0.23
Wind Speed, m/sec	5.0	10.0	2.5
Max. Conc (relative)	1.0	0.82	0.85
Mixing Height, m	1000	800	1200
Max. Conc (relative)	1.0	1.27	0.96
Exhaust Gas Temp, °K	394	350	450
Max. Conc (relative)	1.0	1.16	0.95
Estimation Model	EPA	TVA	AEP
(24-hr/1-hr) Average	0.53	0.2	0.28

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