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Volume One

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

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ARGONNE NATIONAL LABORATORY
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Volume I. Energy Scenarios, Technology Characterizations, Air and Water Resource Impacts, and Health Effects

Energy and Environmental Systems Division

Environmental Impact Studies Division

Biological and Medical Research Division

January, 1977

Prepared as part of the Regional Studies Program sponsored by the Assistant Administrator for Environment and Safety of ERDA.

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A PRELIMINARY ASSESSMENT OF THE HEALTH AND ENVIRONMENTAL EFFECTS OF COAL UTILIZATION IN THE MIDWEST

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 the period 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.

Volume I of the report 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.

EXECUTIVE SUMMARY

This report presents an initial identification of the region specific impacts and constraints associated with coal utilization in the Midwest from the present 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 ERDA. This initial assessment was limited to the six states of 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 play an important role 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 1/3 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.

Sulfur emission constraints will increase use of imported western coal.

Without significantly improved sulfur removal technology, Western low-sulfur coals will capture an increasing portion of the midwestern coal market. A more than 10-fold increase in Western coal demand for utilities in the six-state Midwest study area is possible for the 1975-2020 period. Potential problems with coal transportation system capacity must be determined. The acceptance of the extraction and other related impacts in the West will also be an important factor in determining level of coal use in the Midwest.

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

Available sites for large energy facilities that are near load centers, and also 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 technology in selected subareas. Much of the six-state area is prime agricultural land, which emphasizes land use issues related to construction of large reservoirs. These energy demands will also result in increasing pressure to use the Great Lake water resources, which are constrained by heavy competition for shoreline sites. Also approximately one-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 to further siting of coal facilities because of background air pollutant concentrations.

Short-term (24-hour maximum) standards for sulfur dioxide will limit coal facility size or require advanced control technologies.

With sulfur dioxide (SO_2) emissions at the rate allowable by New Source Performance Standards (NSPS), 3000 MWe is approximately 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 present a greater restraint to facility size, or equivalently 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 MWe with NSPS, new generation facilities may be excluded from buffer zones of 30 miles or more surrounding the Class I areas. Particulate emissions also present a constraint, but less severe than SO_2 constraints. Current standards for annual average air quality will not be a major constraint to coal utilization.

A public health impact may result from long-range transport of coal related sulfur emissions in the Midwest.

There is increasing evidence that sulfur emissions which have been transformed to a sulfate aerosol can have an adverse effect on the exposed population. Furthermore, the sulfur in its sulfate form may have widespread impact 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 currently under active reevaluation. Preliminary indications are that with the current pollutant levels now existing 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 water quality standards violations.

In sample study areas, a significant water quality effect was found due in part to the low flow volume of the river, and in part the assumed high effluent loading from the gasification plants. Although the actual impact levels 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 cause pollution problems for both surface and groundwater. Coal-burning power plants will probably not have a serious water quality impact if (1) the discharges comply with the New Source Performance Standards (NSPS), and (2) receiving waters have a relatively high streamflow.

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

Because of the larger acreages disturbed, the ecological implications of surface mining are more extensive than those of deep mining. Wildlife species associated with deciduous forests are expected to be more permanently impacted by future 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 vegetation impacts from coal-related atmospheric emissions.

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

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1.0 OVERVIEW OF THE ASSESSMENT

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 provide

(1) an identification of the region-specific impacts and constraints associated with coal utilization from the present to the year 2020. (The results of this analysis are to be published in draft form in in July 1977), and

(2) an analysis of mitigation strategies (i.e. options for siting, environmental controls, research and development programs, etc.) (A draft report of this analysis is to be completed by July 1978.).

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, which is an integral part of the NCUA, presents an initial assessment of the potential health and environmental impacts related to coal utilization in the six Midwestern states of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. A primary objective of this study was to identify the major region-specific impacts and constraints associated with the deployment of coal technologies at a level which would be required to satisfy a significant fraction of the future energy demands of the region.

This report is part of a series of iterative analyses leading to the 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. Subsequent analysis will also extend the geographic 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 (with the next report to be provided in July 1977) and because of the desire 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, electrical generation, and gasification coal processes 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 the period 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. In order to establish a reference point for future studies, the impacts of the coal-electric and gasification facilities were based on effluent levels and resource requirements for existing or demonstrated technologies, which are characterized in the report. A county-level siting pattern is developed for use in the area-specific evaluation of the air and water quality impacts and water and coal consumption attributable to the coal scenarios.

In Volume II of this report the native ecosystems, climate, soils, and agricultural land use within the six-state area are described. An initial assessment of the impacts to these ecosystems from coal utilization is presented based on a case study in Southern Illinois, which has ecosystems representative 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

An energy supply and demand characterization for the six-state study region was used in conjunction with an econometric analysis to develop scenarios for the years 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 for 2000, and 3.2×10^9 mWh for 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.

It was projected additionally that in the Interior Coal Province states of Illinois and Indiana, there would be located high Btu gasification plants with a capacity totaling 1750×10^6 scf/day in 2000, and 4750×10^6 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 resources, the Midwest region depends heavily on fossil fuels imported from outside the region. This position of net importation of fuels is particularly acute in Minnesota and Wisconsin.

- Natural gas shortages will force a considerable amount of fuel switching to electricity and to coal. Installations of electric space heating are growing at record rates in Ohio. Even with increasing numbers of electric space and water heating customers 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 for the states in the region will be somewhat greater for Ohio and Michigan which are forecast to have relatively slower increases in population and economic activity.

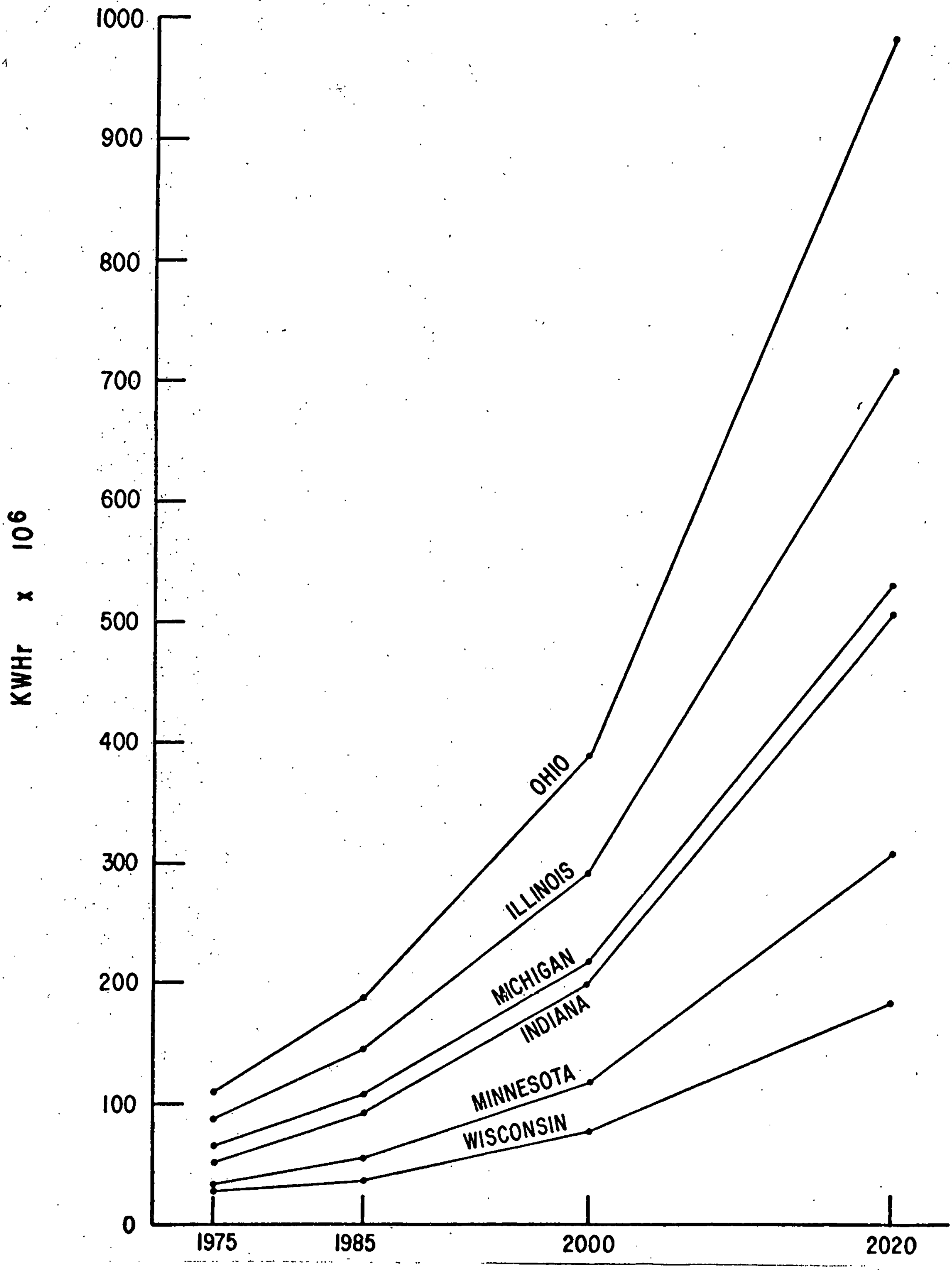


Fig. 1.1 Baseline Scenarios for State Generation of Electricity

• Some states in the region may slow down capacity growth by implementing load management programs. The state of Wisconsin is a leader in this area. Electric generating capacity is forecast to grow at about the same rate as electrical energy demand, at least until the turn of the century. The growth in capacity by type is shown in Fig. 1.2.

• Coal is now the dominant source of fuel for electrical generation in Minnesota, Wisconsin, and Indiana, other 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 one-fourth of its electricity generated from nuclear plants. This percentage may rise to nearly one-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 the year 2000. Figure 1.3 (b) shows a projected mix of utility fuels for power generation in the year 2020. Nuclear power captures about half of the generation mix in every state.

• The sources of this coal for the year 2020 are shown in Fig. 1.4. Illinois is the only state with the majority of its coal requirements produced in state. Ohio and Indiana are the only other states with a significant fraction of their utility coal needs produced locally. A large portion of the coal will come from low sulfur Western fields. Imports of high sulfur coal are minimal in all states but Ohio, which is close to significant deposits of high sulfur coal in Appalachia.

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

1.3 SITING

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

Electrical generation facilities of 3000 MWe capacity and high Btu gasification plants 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 MWe capacity for electrical generation is consistent with current trends in projected baseload capacity additions. The assumed sizes for the gasification facilities conforms to the majority of engineering design and environmental impact studies of coal gasification. Constraints on site availability may in fact 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.

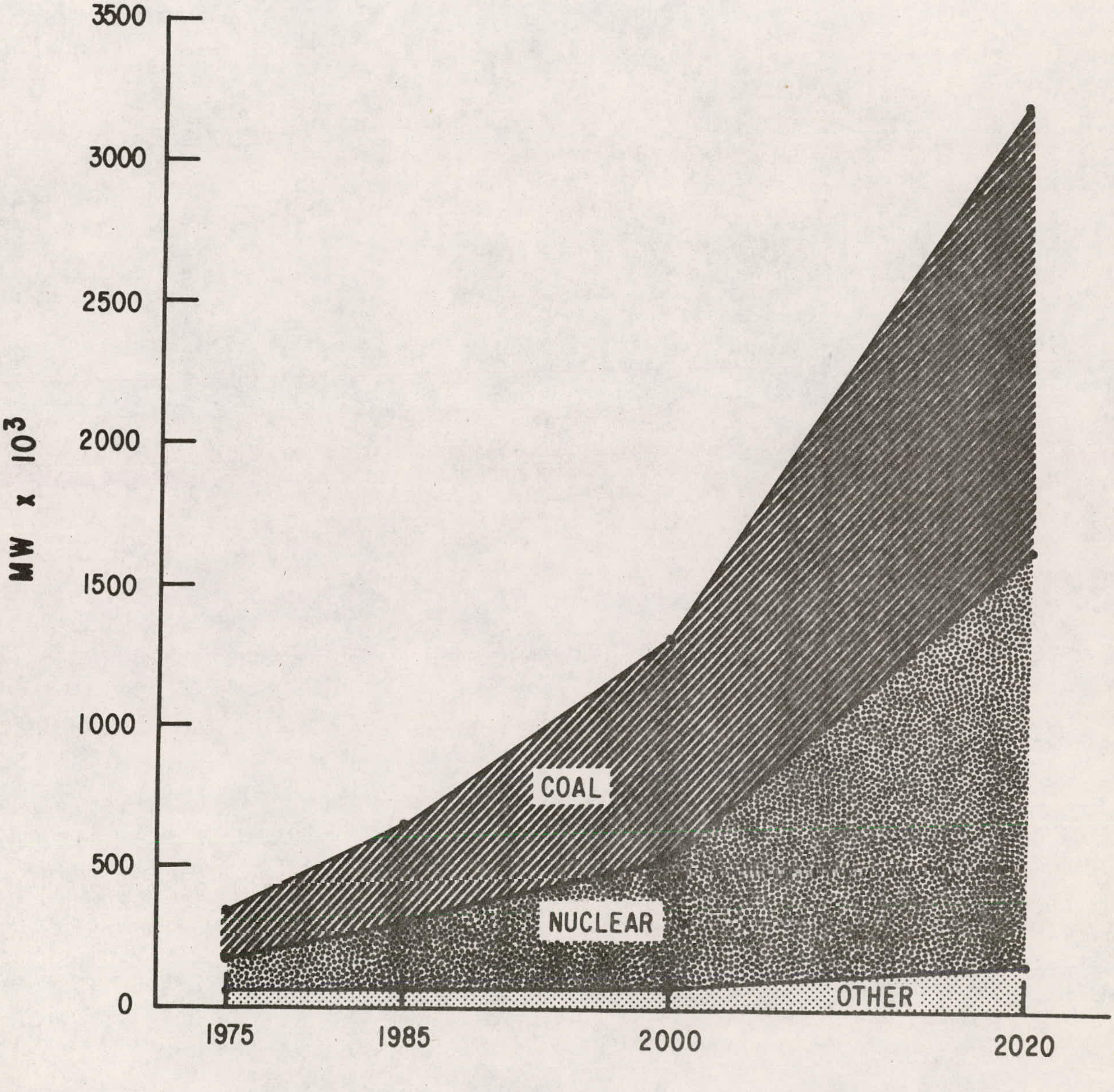
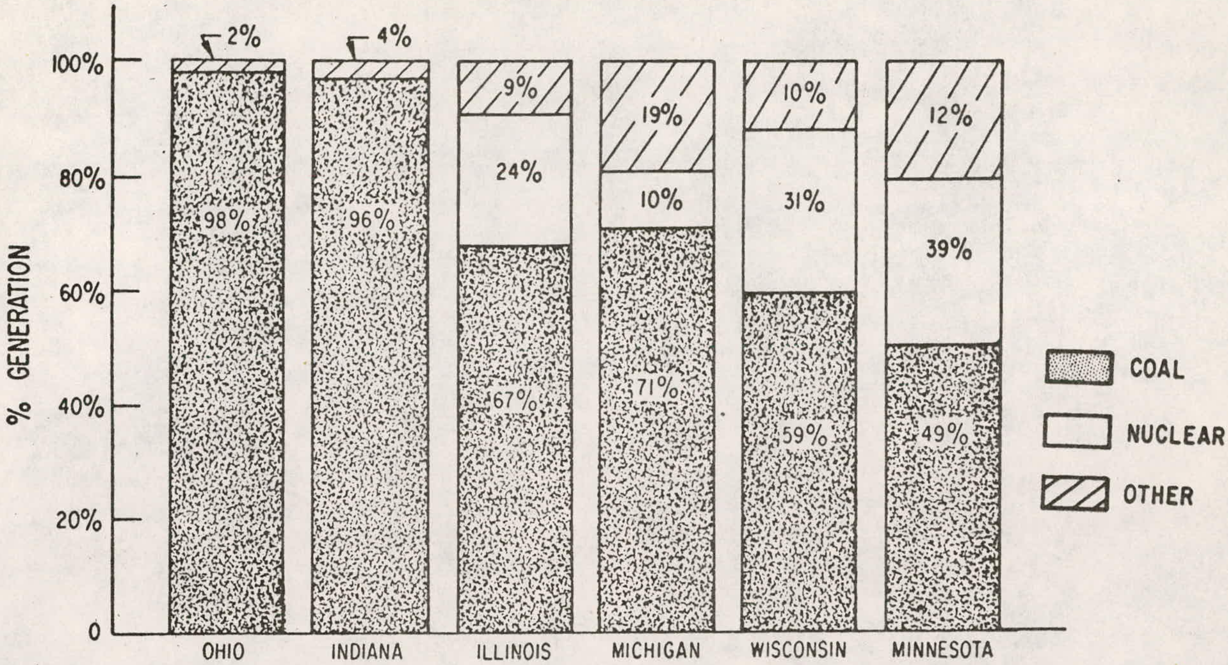
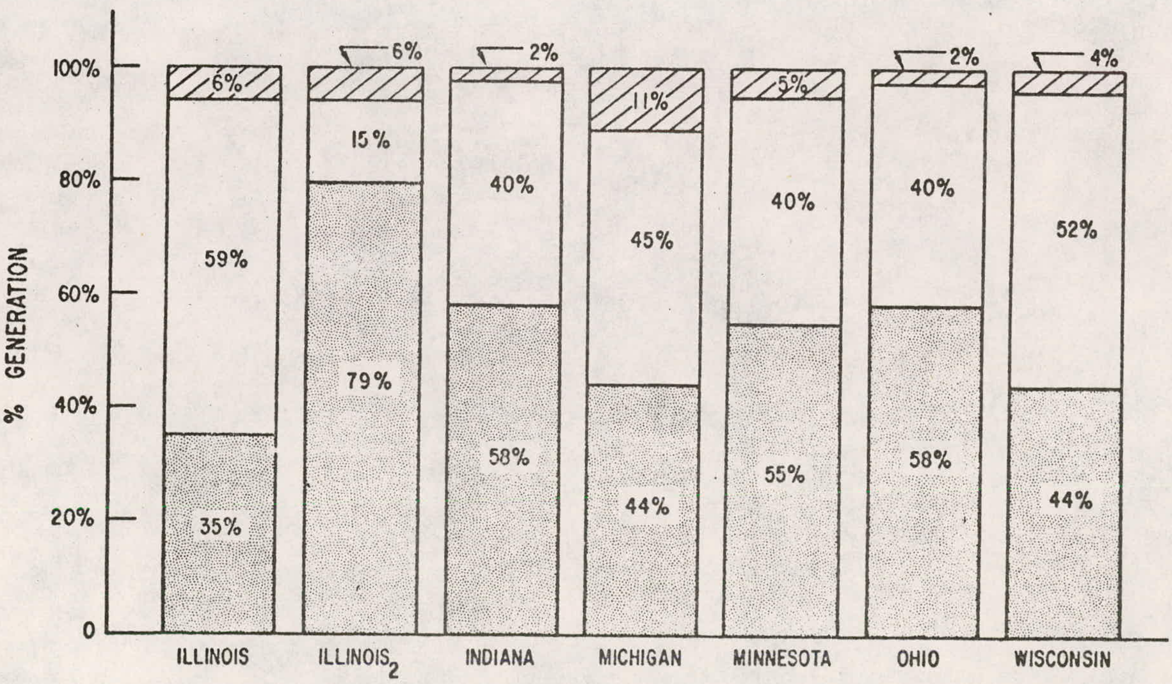


Fig. 1.2 Base-Line Scenarios for 6-State Total
Electrical Generation Capacity



(a) Year 1975



(b) Year 2020

Fig. 1.3 Fuel Mix Scenarios for Electrical Generation (% KWH Generated by Fuel Type; Illinois$_2$ Refers to High Coal Use Scenario)

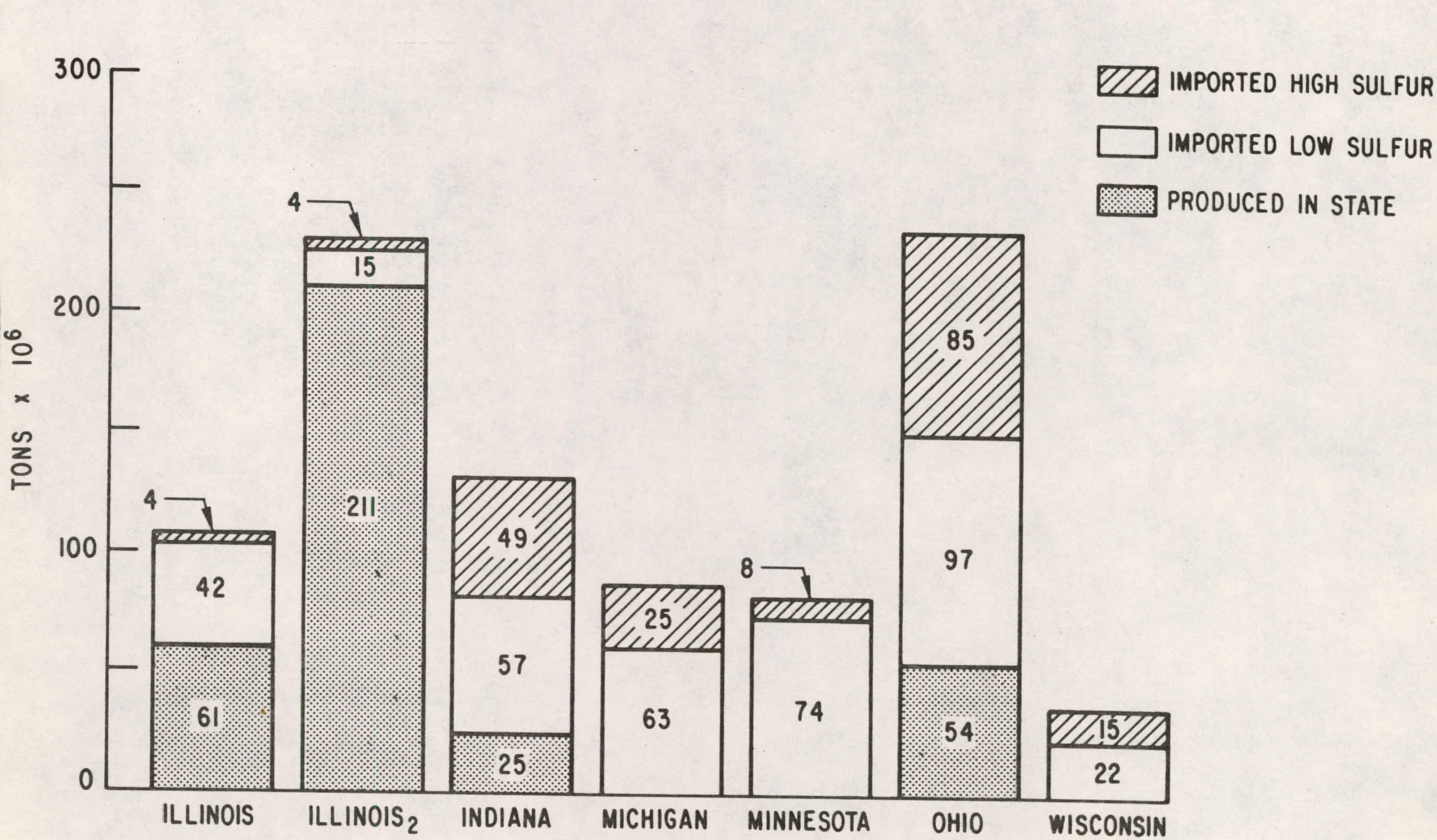


Fig. 1.4 Coal Use Scenarios for Electrical Generation in the Year 2020 (Illinois$_2$ Refers to High Coal Use Scenario)

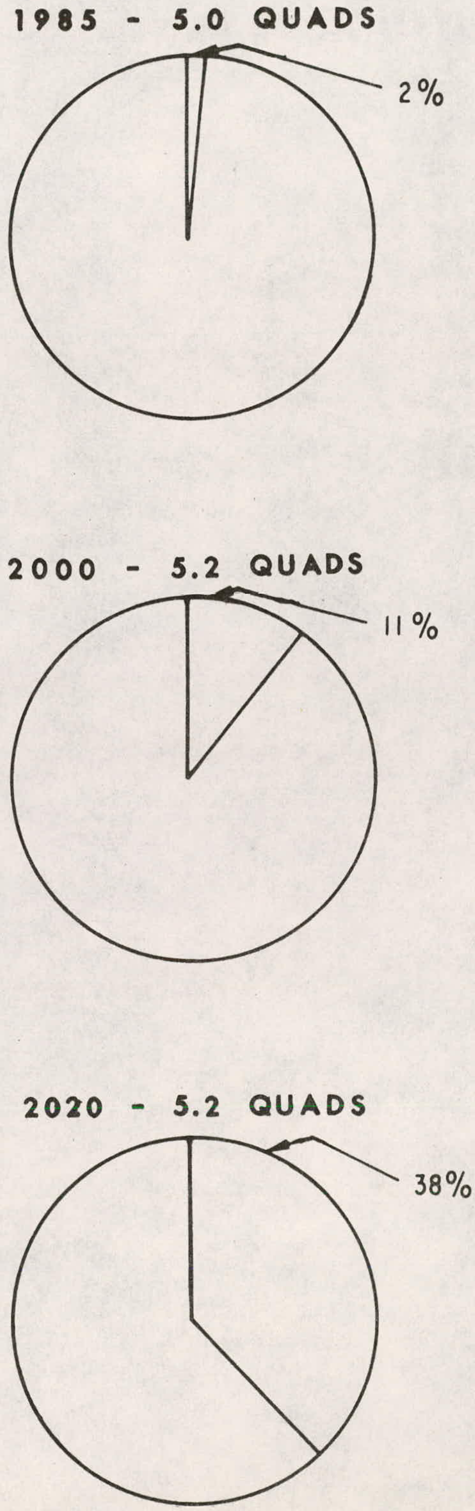


Fig. 1.5 Total Methane Demand in Midwest and Proportion Supplied by Coal Feedstock

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 major rivers from many of the large load centers.

- Separation of the available coal and water resources from the load centers will result in increased transmission requirements.

- The constraints to 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 in the vicinity of coal resources that are in many cases distant from water supplies also encourages 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.

- The coal resources in the study region are in general loxated in areas of good air quality and thus increments in pollutant concentration are possible without violation of standards. Exceptions are portions of eastern Ohio and the Springfield-Peoria areas in central Illinois in which more active air quality management is required.

- 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 analysis are partially dependent on the siting criteria and procedures used. The 7-day/10-year low flow constraints were the most restrictive because of the assumption that new plants were 3000 MWe and would primarily use wet cooling towers, which are intensive water consumers.

The analysis did not deal with site-specific issues at the subcounty level of analysis. 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 the existence of flood plains along river shorelines. Nor were the socioeconomic impacts of facilities considered. State-to-state energy transfers may also have a significant role in determining siting patterns.

1.4 AIR QUALITY STANDARDS

An evaluation of potential constraints to coal utilization imposed by air quality standards includes first of all a consideration of current and projected ambient background concentrations, and secondly, an analysis of air pollutant concentration increments 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 to 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.

Being designated to one of the above constraint categories does not necessarily eliminate that county as a site for coal conversion or electrical generation facility, but acceptable sites would be increasingly more difficult to locate within the higher levels of constraint categories.

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, indicating that these counties have either present problems in attaining National Ambient Air Quality Standards (NAAQS) or expect problems in maintaining them due to 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. Each of these counties had violations of the total suspended particulate (TSP) standards. Some SO_2 violations did occur but only at sites where TSP standards had also been violated.

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).

In summary 56, or 50%, of the counties in the region with coal resources were projected to be faced in the next 40 - 50 years with some level of constraint to further siting of coal facilities because of background air pollutant concentrations.

The evaluation of increments in air pollutant concentration from coal gasification and electrical generation 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 relative to standards is given in Tables 1.1 and 1.2. These results indicate that even with the upper emission level represented by the Illinois high coal use scenario, 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

Table 1.1 Comparison of SO_2 Air Quality Standards and Impact from Coal Utilization

	Maximum Concentration		
	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 MWe at NSPS	250-490	380-760	2.4[a]
12 x 3000 MWe Cluster at NSPS	450-900	690-1360	19.0[a]
250 x 106 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 Particulate Air Quality Standards and Impact from Coal Utilization

	Maximum Concentration ($\mu g/m^3$)	
	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 MWe at NSPS	21-41	0.2[b]
12 x 3000 MWe 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

are avoided in siting. Similarly, areas designated as Class II under proposed regulations for the Prevention of Significant Deterioration (PSD)* do not constrain coal use based on annual average increments with the possible exception of large clusters. However, the 3000 MWe facilities may produce an SO_2 annual average increment violation in areas designated as Class I according to proposed PSD regulations.

More constraining than the annual average standards are the short-term (3-hour, 24-hour) maximum standards. The 24-hour maximum NAAQS for SO_2 (not to be exceeded more than once per year) is within the range of uncertainty for the impact from the single 3000 MWe coal facility.

The most severe constraints result from designation of Class I areas for the proposed PSD regulations. Even with a factor of 10 reduction 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 the use of reduced facility size, or development of more advanced control technologies.

In comparison to SO_2, the contribution of coal facilities to TSP and possible violation of TSP standards is lower. However, as indicated above, the existing background levels are generally nearer to standards for TSP, and thus careful site evaluation is also required with respect to impacts of this pollutant. There is currently no short-term standard for NOx and the annual standard for this pollutant poses only minimal constraints. A possible effect of NOx and other power plant plumes on generation of photochemical oxidants has been indicated, but results are too inconclusive to allow an assessment of future constraints. The contribution of coal facilities to carbon monoxide levels is inconsequential when compared to standards. Because of lower emission rates for the currently regulated pollutants, gasification plants are less constrained in siting options as the result of air quality regulations. Further evaluation of other potentially hazardous emissions is required to fully assess air quality impacts of this technology.

1.5 HEALTH EFFECTS

There is increasing toxicological and epidemiological evidence that sulfur emissions which have been transformed from sulfur dioxide to a sulfate aerosol can have an adverse effect on the mortality and morbidity risk of the exposed population. Furthermore, the sulfur in its sulfate form may have widespread impact because of its long residence time in the atmosphere of up to five days or more before removal by natural processes. For example, Fig. 1.6 illustrates an estimate of the regional increment in sulfates which results from sulfur emissions associated with the Illinois high coal use scenario in 2020. Although the dose response relations for human exposure to sulfates has not been firmly established, a preliminary model estimates that the approximately 1.0 $\mu g/m^3$ concentration increment in Fig. 1.6 for the populous Northeastern U.S. would cause an increased mortality rate of 0.25% for that area.

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*The EPA regulations for PSD are currently undergoing Congressional review.

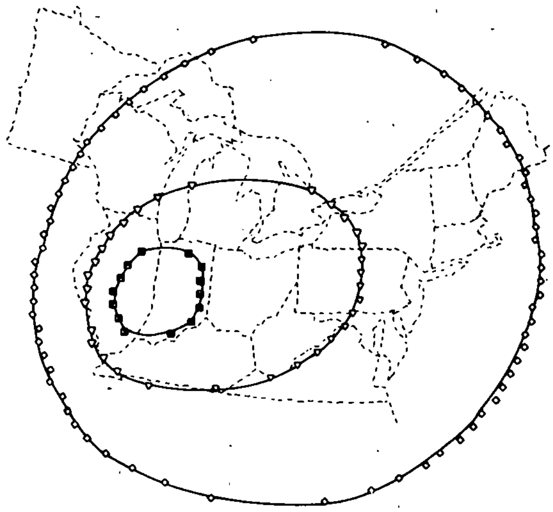

Fig. 1.6 Cumulative Long-Range Sulfate (SO_4) Concentrations from Illinois High Coal Use Scenario

Emissions from coal conversion facilities contain a large spectrum of other pollutant species in addition to sulfur, which, at sufficiently high concentrations, are known to cause adverse health effects either individually or in combination with other environmental conditions. However, there is a general lack of information to evaluate the impact of these pollutants at the low concentrations produced as coal utilization residues. A brief qualitative discussion of these potential health impacts is presented in this study report.

1.6 WATER CONSUMPTION IMPACTS

For each major river basin in the six-state area, an evaluation of water availability for future energy development was conducted. The evaluation included a calculation of direct water consumptive requirements for the projected steam power generation and coal gasification facilities, and a comparison of requirements with natural availability. Wet cooling towers and moderate water conservation practices for coal gasification were assumed. For the purposes of 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 illustrate that the aggragate water resources of the Great Lakes and Ohio and Mississippi Rivers are adequate to supply the overall energy production requirements.

Although aggregate supplies of water are adequate, a more detailed evaluation of subareas reveals potential conflicts with other water users and,

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

WRC Aggregated Subareas	Basin	Total Electrical Generating Capacity (MWe)[a] 198	Total Electrical Generating Capacity (MWe)[a] 2020	Coal Gasification Capacity, 2020 (10^6 scf/day)	Related Water Consumption, 2020 cfs	Related Water Consumption, 2020 % 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	2500	2,625	5.8%	45,000
701-705	Upper Miss.	50,114	167,693	2250	2,211	4.6%	48,500

[a]Does not include portions of basins outside six state 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.

as discussed in Section 1.3, natural flows are deficient in regions which are attractive for siting energy facilities on the basis of proximity to coal resources or load centers.

To illustrate the potential area specific water use conflicts, more detailed evaluations were conducted for the Rock, Illinois and Kaskaskia River Basins in Illinois. (These analysis were conducted for the Illinois high coal use scenario to emphasize the relationships to coal use.) The results of this analysis are shown in Table 1.4.

Water supply will be sufficient to support the projected 2020 energy developments on the Illinois and Rock Rivers due mainly to abundant surface and groundwater resources in these basins and development of potential reservoirs. However, increasing energy and non-energy uses could reduce streamflow to the extent of causing conflicts.

The Kaskaskia River Basin has a relatively small water resource and high water demand. If the water demand of the energy scenario for the year 2020 is to be met, serious water use conflicts could arise. Thus, alternative technologies, siting restrictions and/or water resource enhancement (e.g., importation from other basins or streamflow regulation by reservoirs) should be sought.

In summary it is concluded that, for the siting requirements of the energy scenarios 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 technology in selected subareas. These energy demands will also result in increasing pressure to use the Great Lake water resources, thus requiring more emphasis on sound coastal zone management. The impacts and constraints associated with the use of the Great Lake water resources were not considered in detail in the study.

1.7 WATER QUALITY IMPACTS

In coal related energy facilities, waste streams are generated from cleaning of stack gases; softening, neutralization and demineralization of boiler water; blowdown from various plant processes; cooling and cleaning of raw gases; quenching of gasifier ash and removal of slurry; runoff from coal storage piles, and other sources. Estimates of effluent concentrations were established for these waste streams and as an initial indicator of potential problems 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 water use effects, the nature and extent of water quality impacts from these loadings is area specific, depending on the existing water quality and the hydrologic characteristics of the receiving water.

To illustrate the water quality impacts of these pollutant loadings, analyses were conducted on the Illinois and Kaskaskia Rivers in Illinois. These rivers both flow through the Illinois coal resource areas 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,

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

	Illinois	Rock	Kaskaskia
Consumptive Uses (cfs)			
Municipal & Industrial	1908	178	203
Agricultural	420	1056	436
Mining	23	3	6
Electrical Generation & Coal Gasification	815	202	45
TOTAL	3177	1439	690
Instream Uses(cfs)			
Hydropower	9366	14210	0
Commercial Navigation	3140	0	337
Recreation, Fish and Wilflife	10680	3452	542
Water Quality Management	510	1594	25
Water Availability (cfs)			
Stream Flow			
7-day/10-yr Low Flow	3600	1440	120
Median Flow	21870	4300	1460
Lakes - Reservoirs	3232	0	193
Ground Water	5750	3495	428

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

	Concentration				
	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 Mwe capacity from coal at NSPS (where applicable); 70% Load factor.

[b] 1858 Mwe 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.

agriculture, industry, food processing, public water supply, and primary contact uses.

It is concluded 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 have a serious water quality impact if (1) the discharges comply with the New Source Performance Standards (NSPS), and (2) receiving waters have a relatively high streamflow. 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 the coal conversion facilities have not been established. For the purpose of this analysis, approximate pollutant loadings were used in the analysis for the Kaskaskia River where two gasification plants and one power plant are sited based on the 2020 scenario. A significant water quality effect was found as shown in Table 1.5, due in part to the low flow volume of the river, and in part the high effluent loading, particularly from the gasification plants. These assumed effluents from gasification plants contributed to violation of standards of phenols, cyanide, ammonia, copper, and lead, especially during the periods of low flow. Although the actual impact levels are uncertain because of lack of data for effluents from gasification facilities, the results indicate the importance of further studies to remove those uncertainties.

Drainage from mining areas and seepage from waste disposal sites and holding ponds could cause serious pollution problems for both surface and groundwater. Further assessments are required to determine their possible impacts.

1.8 TERRESTRIAL ECOSYSTEM IMPACTS FROM COAL EXTRACTION

Coal extraction impacts were analyzed for both surface and deep mines. The ecological impacts of deep mining in Southern Illinois are not as extensive as the impacts of surface mining. Impacts from deep mines primarily result from the gob and slurry areas created during the coal preparation process. The use of land for the deposition of gob and slurry materials will preclude its use for other pruposes. Acidic runoff from gob piles adversely impacts the local vegetation and watershed.

Strip mining, in contrast to deep mines, disrupts large acreages of land. During the period from 1975 to 1985, strip-mining to supply a 3000 MWe coal-fired power plant were projected to require an average of 440 acres of land per year in seven Illinois counties. Surface acreage mined to supply a 3000 MWe plant will increase from the year 1985 to 2020 as more of the coal seam is mined.

In general, wildlife species associated with deciduous forests are expected to be more permanently impacted by future surface mining than are species which inhabit prairies and agricultural pasture lands. Since most current reclamation amendments return mine spoils to a grassland or a mixture of agricultural pasture and grain crops, wildlife species typical of prairies are expected to re-colonize 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. A reduction in the acreage of upland deciduous forest and forest-edge will eliminate habitat available for common game species such as the fox squirrel, gray squirrel, eastern cottontail and white-tailed deer. Songbirds such as thrushes, wood-peckers, the red-eyed vireo and ovenbird will be displaced from forested areas being mined.

The impacts to agricultural land from strip-mining are considered temporary in comparison to the mining impacts on forests. In the year 2020 the following disturbances of agricultural land are projected based on the Illinois high coal use scenario.

County	Total Acres in Row Crops	Total Acres Disturbed	% 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 agricultural use. The rapid establishment of high income crops such as corn, soybeans, and oats will require extensive fertilization. The return of strip-mined land to use in row crop agriculture may require 10 years from the time of initial 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 prior to future mine development. Land use changes will result in the greatest ecological impact to terrestrial ecosystems from increased coal mining in Southern Illinois. The entire land use issue warrants extensive study in order to accurately predict the long term impacts of future surface mining.

1.9 AQUATIC ECOSYSTEM IMPACTS FROM COAL EXTRACTION

Impacts to specific aquatic ecosystems from coal mine and preparation plant development depends upon the location of coal reserves and types of mining. The impacts of pre-mining activities (e.g. vegetation removal, haul road construction, pit excavation) are expected to be negligible if appropriate measures are taken to control erosion. Operational impacts to aquatic ecosystems, historically, have resulted from the offsite disposal of mineral laden effluent pumped to local waterways from sumps located in low areas of the pit. Certain portions of Southern Illinois such as Saline County have experienced an acid mine drainage problem. Currently these discharges are exposed to chemical treatement, acid neutralizing facilities, and passed through settling basins to insure that impacts do not occur to the local water quality and aquatic biota. Consequently, acidic mine drainage from individual future surface mining should not pose a hazard to the biota of waterways.

The number of new surface mines in certain portions of the three river basins studied may be limited, however, since the availability of dilution water in some headwater streams is not sufficient to insure that water quality standards are maintained. Based on typical mine assumptions regarding 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; Kaskaskia River Drainage Basin - 10, Big Muddy River Drainage Basin - 5-10, Saline River Drainage Basin - none.

The 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 the amount of aquatic habitat has increased by more than 300% as a result of strip-mining. The creation of final cut reservoirs is not expected to greatly alter the distributional patterns of winter resident waterfowl. The biological productivity and water quality of these reservoirs is one aspect of reclamation which warrants further study. The potential long range uses of these reservoirs can be determined only after considerable social, economic, and environmental data are obtained and analyzed.

1.10 IMPACTS OF COAL COMBUSTION

Analysis indicated that SO_2 is the only primary gaseous pollutant resulting from operation of a 3000 MW plant sited singly or in the clustered configuration 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 approximately 608 acres. For the clustered configuration including twelve 3000 MWe plants injury to sensitive vegetation could occur in an area in excess of 22,000 acres. The area in which threshold to severe injury to sensitive vegetation may occur would approach 6400 acres. In each of the impacted areas 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 a particular plant that is injured. Regional agricultural species sensitive to SO_2 include alfalfa, barley, oats, rye, wheat and soybeans. On the basis of SO_2 damage to agricultural crops a cluster of 12 plants would be environmentally unacceptable.

The impact analysis of atmospheric particulate concentration and depositions dealt only with arsenic, beryllium, cadmium, fluoride, lead, and selenium. For the clustered siting arrangement, arsenic should be considered an element which potentially may have adverse effects on vegetation of low tolerance (e.g., soybeans). Impacts to vegetation are quite uncertain, however, because of the conservative assumptions and other uncertainties of the analysis. Beryllium deposition is not expected to adversely affect vegetation. Cadmium emissions are not expected to have impacts on the vegetation unless endogenous soil levels are just below toxic levels or other sources of cadmium pollution are entering the region. Since 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 impact to vegetation. Foliar damage to species such as sorghum, fruit trees and conifers may result from clustered siting. Impacts to these species is not expected to result in a major economic loss since they are relatively uncommon. No adverse impacts to biota are anticipated from lead deposition or selenium oxides.

The analysis of impacts on aquatic ecosystems considered the possibility of gaseous and particulate atmospheric emissions from combustion being deposited and entering the surface waters through run-off 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 to aquatic biota are anticipated from the electrical generation cooling water systems. In all locations the volume of makeup water required and the size of the intake structure considered with respect to the size of the water body present indicate that impacts from impingement and entrainment should be negligible. Construction of the blowdown discharge structure may cause a temporary adverse affect to some benthic invertebrates. Localized thermal gradients will be established in the vicinity of the discharge structure but are not expected to result in adverse impacts to fish populations and most other aquatic biota. No far field impacts to aquatic biota from aqueous trace element effluents, impingement or entrainment, or thermal additions are anticipated from a single electrical generation plant. For power plants sited on reservoirs these impacts are expected to be limited only to the reservoir.

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 certain aspects of those issues and an evaluation of strategies or alternatives for mitigating problems which have been identified. Also, various other issues which may be significant have been considered only marginally, or not at all. The following is a partial list of the topics related to health and environmental effects which require additional evaluations in future studies in the Midwest region.

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

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

3. Strategies for mitigating potential long-range impacts of sulfates should be considered, including siting and technology alternatives.

4. The potential regional health and environmental problems associated with atmospheric and water effluents of trace elements and other hazardous substances must be more fully identified so that appropriate research and control technology development programs may be initiated.

5. Although the overall regional water quality will apparently not be significantly affected by coal utilization processes, if appropriate control technologies which are available are utilized, further evaluation is required of possible local effects from intense development in limited areas, reduced capacity to assimilate municipal and industrial wastes because of energy related water consumption, and run-off from waste disposal sites.

6. The limitation on water availability in the regional river basins indicate the need for consideration of alternative water resource development or implementation of water conservation measures. This would include consideration of the possible role of once-through cooling, dry towers, reservoirs, and increased use of the Great Lakes water resources.

7. Not considered in this study are the possible impacts in the Midwest of the increased coal transportation required via rail, barge, and possibly slurry pipelines. Evaluation of impacts from development of right-of-ways for electrical transmission lines and gas pipelines were also not included.

8. Further consideration of the regional terrestrial and aquatic ecosystem impacts from synfuels technologies is required prior to widespread deployment. However, the current incomplete knowledge of the effluent characteristics and their health and environmental impacts would limit these studies.

9. Groundwater pollution by solid waste disposal (fly ash and bottom ash, etc.), and the impact of contaminated groundwater on surface water should be considered also.

10. Studies on the ecology, sociology and economics of final cut reservoir should be conducted to evaluate the impacts of these reservoirs prior to 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 amendments 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 technologies available, or under development, for industrial application.

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2.0 PRESENT PROBLEMS AND FUTURE TRENDS FOR ENERGY

2.1 INTRODUCTION

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

Contained in this section are the forecasts of electrical energy supply and coal utilization used to provide the facility siting patterns and background for the impact assessments. The section begins with an examination of the courses and impacts of abrupt shifts in the region's supply patterns. In the discussion particular emphasis is placed on those factors that cause an expanded role for electrical energy and coal. Forecasts are developed for electrical energy demand, generating capacity requirements, and the role of various fuels in power generation. These data provide the basis for power plant siting as well as establishing levels of air emission and water requirements. The potential for the production of high-Btu gas from coal is examined and candidate sites are selected. Finally, information is provided on the sources of coal input to electrical generation, along with the relative contribution of high-sulfur and low-sulfur coal.

A key feature that unites the region is a shared need to develop new energy sources to replace dwindling oil and natural gas supplies. Although at one time a substantial volume of oil and gas production existed within the states of Illinois, Ohio, and Michigan, it has been reduced to a small fraction of the region's needs.* The steady decline in the intraregional 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 phase out 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.

Shortfalls in natural gas supplies have resulted in varying degrees of disruption within all consuming sectors in each of the Midwestern states. Table 2.1 shows that only Michigan escaped the need to curtail "firm" customers during the last heating season. Yet this does not mean that even in Michigan gas was available 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

*Total oil and gas production for 1975 within the region was equivalent to approximately 98.4 million barrels of oil compared to a total 1975 demand of 1,678 million barrels.

Table 2.1. End Use Gas Requirements for Winter Periods November 1975 through March 1976[a] (billion cf)

State	Requirement	Shortage	Change in Shortage vs. Previous Winter
Illinois	741.7	14.7	8.7
Indiana	280.2	13.2	3.9
Michigan	532.9	--	--
Minnesota	166.9	15.8	.6
Ohio	679.5	94.9	37.1
Wisconsin	239.6	25.8	21.9

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

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, adding to the growth in electricity demand. The above supply restrictions are likely to spread in the foreseeable future.

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 electricity demand growth is expected to drop off from its historic growth rate of 6-7% per year (see Table 2.2), electricity's share of total energy will grow mainly because of the decrease in its prices relative to other fuels* and the worsening of natural gas shortages. Second, the direct combustion of coal for process heat may reverse its recent decline and begin to grow modestly. The growth of industrial demand is largely dependent on the availability of low-sulfur coal or small scale control technologies, such as fluidized bed combustion. Third, in the intermediate to long term, coal conversion to synthetic fuels may help to replace decling supplies of natural gas.

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*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 (<u>National Energy Outlook</u>) February 1976 were:

	Residential	Commercial	Industrial
Electricity	-.5%	-.8%	1.7%
Natural Gas	4.5%	5.4%	4.5%
Oil	1.0%	1.0%	0

Table 2.2. Electricity Sales 1960-1972

State		Millions of 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	5,674	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
	Commercial	2,371	5,652	7.51
	Industrial	4,558	10,705	7.37

Source: Edison Electrical Institute, *Statistical Yearbook.*

These general observations on the energy situation in the Midwest suggest an increasingly important future for electricity and coal. Following is a discussion of the probable growth in electricity demand and generating capacity. Estimates are made of the electric utility fuel mix for the years 1985,2000, and 2020, including a discussion of the coal production and interstate imports required to meet utility fuel needs. Finally, a discussion of the potential for use of coal for conversion to high-Btu gas is presented. Synthetic liquid fuels from coal are not considered.

2.2 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 anti-pollution regulations cannot be captured by the trend approach. As a result the predictive power of these models, particularly with respect to *turning point errors*, has been quite 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 employed in the model are electricity and natural gas prices, 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 purposes, one would like each sector to be relatively homogeneous. Unfortunately, classifications of individual users are generally made on the basis of the quantity of electricity they demand and not by the characteristics of the user. 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 electricity demand models: (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 sectoral 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 regarding 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)[7] forecasts of population and personal income were used. The price forecasts for electricity and natural gas are based largely on the FEA forecasts.[8]

Overall, the main driving forces associated with electricity demand are forecasted to decline from their historic rates of growth. Demographic analysis suggest that lower birth rates and net outmigration 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 forecasted values for electricity demand by state are given in Table 2.3.* Overall the growth in demand is significantly slower (especially after 1985) than the historic growth rates shown earlier.

*A more detailed discussion of model and parametric values are given in the Appendix to this section.

Table 2.3 Forecasted Total Demand for Electricity

(Millions of 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

Future electrical energy requirements 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 projected mix of fuels used to generate power had to be developed.

Forecasting system load factors was a largely judgemental undertaking. For the last few decades the rate of increase in generating capacity has outstripped the growth of electrical energy demand. For a variety of reasons the annual peak demand (PD) has grown very rapidly relative to 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 experiencing significant problems with financing and siting new baseload power plants. The marginal cost of installing incremental capacity to the utility (and society at large) is rising rapidly. It is, therefore, unlikely that this historic deterioration in system load factors will continue. Regulatory forces are likely to be set in motion to have users pay more of the true social cost of electrical power consumed during peak hours.*

The problem of controlling the growth of peak demand is economic, not technological. Technological means now exist for controlling peak utilization of power. England, Wasles, and West Germany have used storage techniques with appropriate tariffs to flatten system load curves within an amazingly short number of years** Several U.S. utilities are experimenting at present

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

**J. Asbury and A. Kovalis have described recent experiences in load leveling in "Electric Storage Heating: The Experience in England, Wales and in the Federal Republic of Germany," (unpublished manuscript), Energy and Environmental Systems Division, Argonne National Laboratory, April 28, 1976.

with similar peak-load pricing schemes and storage devices. Both Madison Gas and Electric and Detroit Edison now offer special rates for customers with hot water heaters that are designed to cease operations during peak periods. It is assumed that before 2000, Midwestern utilities generally will be successful in raising the ratio AD/PD. For this reason the growth in generating capacity is somewhat less than the growth in energy demand given in Table 2.3.*

A general improvement in system load factors will also be reflected in improved plant factors (fraction of potential output actually attained) for coal-fired plants and in a declining number of peaking units. The plant factors assumed for this study are given in Table 2.4. They were based upon an examination of historical operating trends for steam electric plants in each state. The relatively high nuclear plant factors are greater than recent experience suggusts, but are generally considered to be the minimal levels necessary for the economic operation of these plants.

For purposes of 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.[9]. These sources indicated that, on balance, Ohio, Minnesota, and Illinois import electricity, while Michigan and Wisconsin are in the net exporters. Indiana showed no significant transfers in either direction. Because these transfers appeared to be small (less than 3 percent of any given state's total demand) no adjustments were made to capacity needs to reflect transfers.

Table 2.4. 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

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

The present mix of fuels consumed in the generation of electrical power is described in Table 2.6. The Reliability Council Reports of MAIN, MARCA, and ECAR were used to formulate capacity mixes (Table 2.7) for each state in 1985. The capacity mix for 1985 was then used, in conjunction with the above assumed plant factors for each plant type, to arrive at the fuel mix for that year. The resulting fuel mix for 1985 is given contained in Table 2.5.

A detailed breakdown of capacity needs by state is given in Table 2.5. 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 electricity supply and demand relationships.

The fuel mix projections for 2000 and 2020, also contained in Table 2.6, were based on a number of judgemental 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 resource and environmental problems associated with the mining and combustion of coal. For example, the above factors will result in sharply rising prices for coal.

Wisconsin, Michigan and Minnesota are almost without fossil energy resources and may have to turn to relatively expensive fossil energy imports or nuclear power. This problem is not quite as difficult in Minnesota due to 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 fuels 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 usage for steam boilers. In the future, natural gas will be used almost exclusively for fueling turbine generators.

The relatively high price of oil makes it economically unsuited for extensive use in the Midwest. Oil will continue to be used as a fuel for peaking plants and as a backup for coal, but not as a primary fuel for base load power plants.

Hydroelectric power is an economically attractive alternative, but the potential of this power source is physically limited in the Midwest (see Table 2.8). Environmental and recreational interests can be expected to muster significant opposition to the further development of hydroelectric projects. Hydroelectric capacity is expected to be developed to its maximum extent by 1985, and will diminish in relative importance.

Table 2.5. Capacity (MW) by 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

Table 2.6. Electric Utility Fuel Generation Mix
(Percent of Total kWh Generated by Type)

State	Coal	Oil/ Natural Gas	Nuclear	Other	Total %
Fuel Mix 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
Fuel Mix 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
Fuel Mix 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
Fuel Mix 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 under high-coal use scenario

Table 2. 7. Electric Utility Generation Capacity Mixes (Percent of Total Installed Capacity)

	Capacity Mix - 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

	Capacity Mix - 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	3.12	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

All of these factors suggest that nuclear power will become, almost by default, an increasingly important source of electricity in the future* Table 2.9 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 in the future. This will occur because of Illinois' ability to maintain a high level of coal use concurrent with the depletion of coal reserves in the other states.

Fuel mix projections for the years 2000 and 2020 (shown in Table 2.6) were obtained by judgementally assessing the above trends in power generation and the relative costs of various 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 which have relatively equal fossil energy costs. Presumably capital and construction costs would also be similar in both states. Why then, have plant utilities in Cincinatti, Toledo, and Cleveland so rapidly expanded their use of nuclear power? 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 (which use known industry plans) and become more conjectural as they are extended from the industry planning horizon.

Also shown in Table 2.6 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 in lieu of increased generation capacity from nuclear or low-sulfur Western coal. This scenario represents a maximum credible upper bound in the possible use of instate 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 sections of this report. The two Illinois scenarios represent sharply contrasting situations that highlight some of the impacts of coal conversion for electrical generation.

2.3 UTILITY COAL DEMAND AND COAL SOURCE

The previous sections have discussed expected electricity demand growth and utility fuel mixes. These variables are the primary determinants of the electric utility demand for coal. It is expected that even though the percentage share of coal used in the fuel mix should decline over time, the exponential growth in demand for electricity will overwhelm this decline and prompt substantial absolute growth in demand for coal by electric utilities.

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*In the long term technologies 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 technologies 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, the exclusion of other "advanced" technologies was not inappropriate.

Table 2.8. Hydroelectric Generation Capacity

State	Developed MWe capacity	Developed MWe capacity	Percent of 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).

This growth is illustrated by contrasting the historical levels of utility coal consumption in Table 2.10 with the projected coal consumption patterns in Table 2.11.

Recently enacted air pollution standards have strongly affected the electric utility demand for coal. The choice of coal type has a strong influence on the environmental, economic, and land use impacts of coal use in the generation of electricity. Newly constructed 1,000-MW power plants must meet Federal sulfur combustion limits of 1.2 lb SO per $_2$MBtu of fuel burned. They can do this in most cases by utilizing either low sulfur coal alone or by employing high sulfur coal along with control devices.

However, some state standards are sufficiently stringent that utilities will have to either scrub or wash even western coal to obtain compliance. Furthermore, low sulfur lignite must be scrubbed to meet even Federal standards because of its very low Btu content.

In general, the most important factors affecting the use of low sulfur coal are the compliance strategy of electric utilities and the relative transportation costs to high- and low-sulfur coal sources. Presently, utilities in the Midwest generally are choosing to burn low sulfur coal rather than applying control technologies to high sulfur coal.[10] It is expected that in the future the proportion out of compliance will diminish and that over time the ratio of control usage to low sulfur coal will increase due to technological improvements. Coal consumption projections contained in Table 2.10 are based on an overall regional usage for 1985 or 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 demand center is allocated low sulfur coal, intermediate sulfur coal with washing, or high sulfur coal with scrubbers.

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*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 the degree to which the cost of control technology will decrease is also in doubt.

Table 2.9 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

Table 2.10. 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	.6	.4
Indiana	.4	25.0	0	3.2	.1
Illinois	.2	21.2	0	9.0	.1
Michigan	21.8	2.5	0	1.0	.2
Wisconsin	.8	6.8	0	3.0	0
Minnesota	0	1.6	0	7.9	.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 in nature since in many cases end use was not specified precisely for coal from a given supply region.

Within the Midwest, the utility sulfur control strategy varies from company to company. No systematic pattern seems to be emerging by state. As sulfur control technologies receive more industry acceptance, transportation cost differences in acquiring western low sulfur coal will be the primary determinant of the share of low sulfur versus high sulfur coal.[11] For this reason, Ohio and Michigan will use the most high sulfur coal and Minnesota will burn low sulfur coal almost exclusively due to the proximity of the lignite fields of the Dakotas and the subbituminous coal of the Powder River Basin. Annual Coal consumption for electric generation by source is given in Table 2.11.

Although the proportion of low sulfur coal utilized in each state is held approximately constant from 1985 to 2020, these percentages represented a substantial increase over those present in 1975, especially in Ohio, Indiana, and Michigan. This can be seen by contrasting Tables 2.10 and 2.11. The other significant change is that high sulfur coal consumption is conceptualized as being slightly more localized. Therefore, Ohio and Indiana for example are projected to cease shipping coal to each other. It was decided that since their coal reserves were of approximately 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 coal production estimates in Table 2.11 show that all significant regional production will occur in Ohio, Indiana, and Illinois and will be relatively high in sulfur.[12] Intrastate production for industrial consumption (in direct combustion) should decline, given that industrial boilers will require low sulfur coal as the only practical control technology and that negligible low sulfur reserves exist in these states. The low sulfur coal that is extracted is expected to be bid away from the electric utilities by the industrial sector, which can be assumed to have a more inelastic demand for low sulfur coal. Yet, electric utility consumption of intrastate high sulfur coal is not expected to increase greatly from present amounts in Indiana and

Table 2.11. Annual Coal Consumption for Electrical Generation (10^6 tons per year)

	Interior Coal Province			Eastern Coal Province			
Year	Illinois	Indiana	W. Ky.	Ohio	Other, High S.	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.[a]	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

[b]Assumes 33% thermal efficiency for 1985 and 38% for 2000 and 2020. Coal heat content assumed a 22×10^6 Btu/ton for Interior Province, 23.8×10^6 for Eastern Province, and 18×10^6 for Western coals.

Ohio due to reserve depletion and the high costs of expanding production in these areas. Cost increases can be anticipated because of movement toward thinner seams and deep mining. On the other hand, Illinois has the most abundant minable reserves of any state. In addition, more coal should be strippable at competitive prices in Illinois than in Indiana or Ohio.[14] For these reasons total production within Illinois for utility markets should increase considerably in absolute terms.

2.4 COAL GASIFICATION

Diminishing supplies of oil and natural gas have not only created a demand for coal in conventional uses, i.e., electricity generation and direct combustion, but also have created a potential market for coal conversion to synthetic fuels. A number of rather well developed technologies exist for the conversion of coal into substitute gaseous and liquid fuels. Although these conversion processes are technically feasible, economic environmental uncertainties complicate the growth of a synthetic fuels industry.

The potential size of a synthetic fuels industry in the U.S. is quite limited for the next ten years. The lead times necessary for bringing first generation conversion plants on line is at least five years, even longer for more advanced processes. Two first generation commercial-scale gasification plants may come on line by 1985, one located in North Dakota, and the other in New Mexico. At present, no commercial plants are scheduled for the Midwest. In the longer term, beyond 2000, the range of possible synthetic fuel outputs is quite large. Several studies have estimated U.S. synfuel production to be between 5 and 20 quadrillion Btu's by the year 2020.

The Midwestern coal producing states of Illinois and Indiana are likely to capture a significant share of the U.S. synthetic fuels industry. Illinois, in particular, is likely to be a leading state in synfuel production. Illinois has already attracted three major ERDA-sponsored coal conversion demonstration projects. In the long run, 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. Finally, a well developed transportation network connected to nearby demand centers completes the set of favorable conditions Illinois offers to a potential synfuels industry.

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

The tenuous near-term-future of the synfuels industry leads us to consider a 50-year time frame within which synfuel conversion might reach significant levels. Due to the currently unfavorable economics of synfuels no commercial plants were expected to be in operation by 1985. It was assumed that by the year 2000, Illinois could contain 6 standard size (250 Mcf/day) second generation gasification plants, and 14 plants by 2020. It was further assumed that Indiana would contain one and five standard gasification plants in 2000 and 2020 respectively. These plants would all be located near feed-supplying mines and would supply in turn their synthetic gas products to markets in the Midwest. Likely sites for these plants were largely drawn from an earlier study of gasification potential for Illinois[15] as well as recently announced industry plants.[16] The projected number of plants and associated coal consumption is summarized in Table 2.12.

The impact of the above level of gasification on supplies of gaseous fuels is shown in Figure 2.4. In it the relative share of coal syngas to all sources of gaseous fuels, basically methane, is depicted against the projected total volume of gaseous fuel demand. The total demand numbers display a rather slow growth, attributable to price increases and population stabilization. Thus, the assumed level of gasification activity accounts for almost one half of total gaseous fuel supplies by the year 2020.

Table 2.12. Annual Coal Consumption Scenarios for Coal Synfuel Conversion in the Midwest

Year	Number of Commercial Plants	(10^6 tons/year) Coal Consumption[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 250x10^6 scf/day (950 Btu/scf) facility with 70% thermal efficiency, 330 days/year, 22x10^6 Btu/ton coal, or approximately 5x10^6 tons/year per facility.

APPENDIX TO SECTION 2.0

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

$$\log q_{it} = C - \underset{(6.14)}{.3174} \log P_{it} + \underset{(3.12)}{.1896} \log Y_{it} + \underset{(17.75)}{.7409} \log q_{it}\ (t-1)$$

where:

P_{it} = average price of electricity

Y_{it} = per capita disposable income

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

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 commercial model regression results are:

$$\log Q_{it} = C - \underset{(3.24)}{.3796} \log P_{it} + \underset{(0.35)}{.03251} \log g_{it} + \underset{(3.84)}{.3929} \log Z_{it}$$

$$+ \underset{(11.23)}{.6003} \log Q_i\ (t-1)$$

where:

g_{it} = average price of natural gas

Z_{it} = total disposable income

Q_{it} = total electricity consumption in period t.

Constant C = -.941, -1.024, -1.034, -.998, -1.078 and -.997 respectively for Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.

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

The industrial model results are:

$$\log Q_{it} = C - \underset{(2.01)}{.2568} \log P_{it} + \underset{(0.23)}{.02516} \log g_{it}$$

$$+ \underset{(6.52}{.7732} \log V_{it} + \underset{(8.31)}{.5495} \log Q_i (t-1),$$

where:

V_{it} = value added for manufacturing

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.*[4] Sales and revenues of natural gas were taken from *A.G.A. Gas Facts.*[3] Disposable Income and Per Capita Disposable Income came from the Bureau of Economic Analysis within the Department of Commerce.[5] The Consumer Price Indexes and Wholesale Price Indexes were taken from the "Monthly Labor Review" of the Bureau of Labor Statistics.[6] 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 kilowatt hour equaling 3412 Btu. Population data is based on Bureau of Census estimates.

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3.0 CHARACTERIZATION OF COAL CONVERSION TECHNOLOGIES

3.1 GENERAL

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, it is not necessary that all phases be distinctly considered. (For example, conversion may occur at the point of extraction, or end use at the point of conversion, etc.) This preliminary assessment focuses on the phases of extraction and conversion, since the major health and environmental impacts result from these activities.

The discussion in this section is limited to a characterization of the conversion technologies, including electrical generation and synfuel production. The extraction technologies as they relate to surface water contamination are discussed in Sec. 8 and in Vol. 2 in terms of their impact on natural ecosystems.

Data for the characterizations under discussion here were obtained from numerous sources, as noted. Although similar in many cases, the values indicated are not identical to those subsequently produced for use in the ERDA-sponsored National Coal Utilization Assessment.

Where the technology characterizations required specification of single coal parameters, it was assumed that these parameters were representative of the Central Interior Province coal as indicated in Table 3.1. This table also includes, for comparison, parameters for Northern Great Plains coal and solvent refined coal (SRC) referenced in this section.

Coal conversion technologies can be conveniently grouped for purposes of description into two categories; combustion technologies usually involving boilers, and synfuel technologies involving destructive hydrogenation to produce cleaner fuels. Combustion technologies are considered in this interim assessment as they are used in electric power production and as auxiliary energy sources for synfuel technologies. Figure 3.1 shows the general paths along which synfuel production may proceed. Synfuel technologies will be considered for the production of SNG (high Btu gas) and, generally, syncrude products; fuel gas (low Btu) production and solvent refining of coal will be described briefly as they relate to electric power production.

The technologies assumed to be implemented in this assessment are generally those that represent the current state of the art, and those reasonably expected to be commercially available in the next fifteen years. Many unique synfuel and electric power production technologies are in the conceptual stage at present, and these are not included in the interim assessment; only processes for which sufficient design and test data are available are included here. The potential benefits and impacts of more advanced technologies will be included in later work.

It is appropriate to make some comparisons among conversion technologies before describing the specific types of processes leading to the end

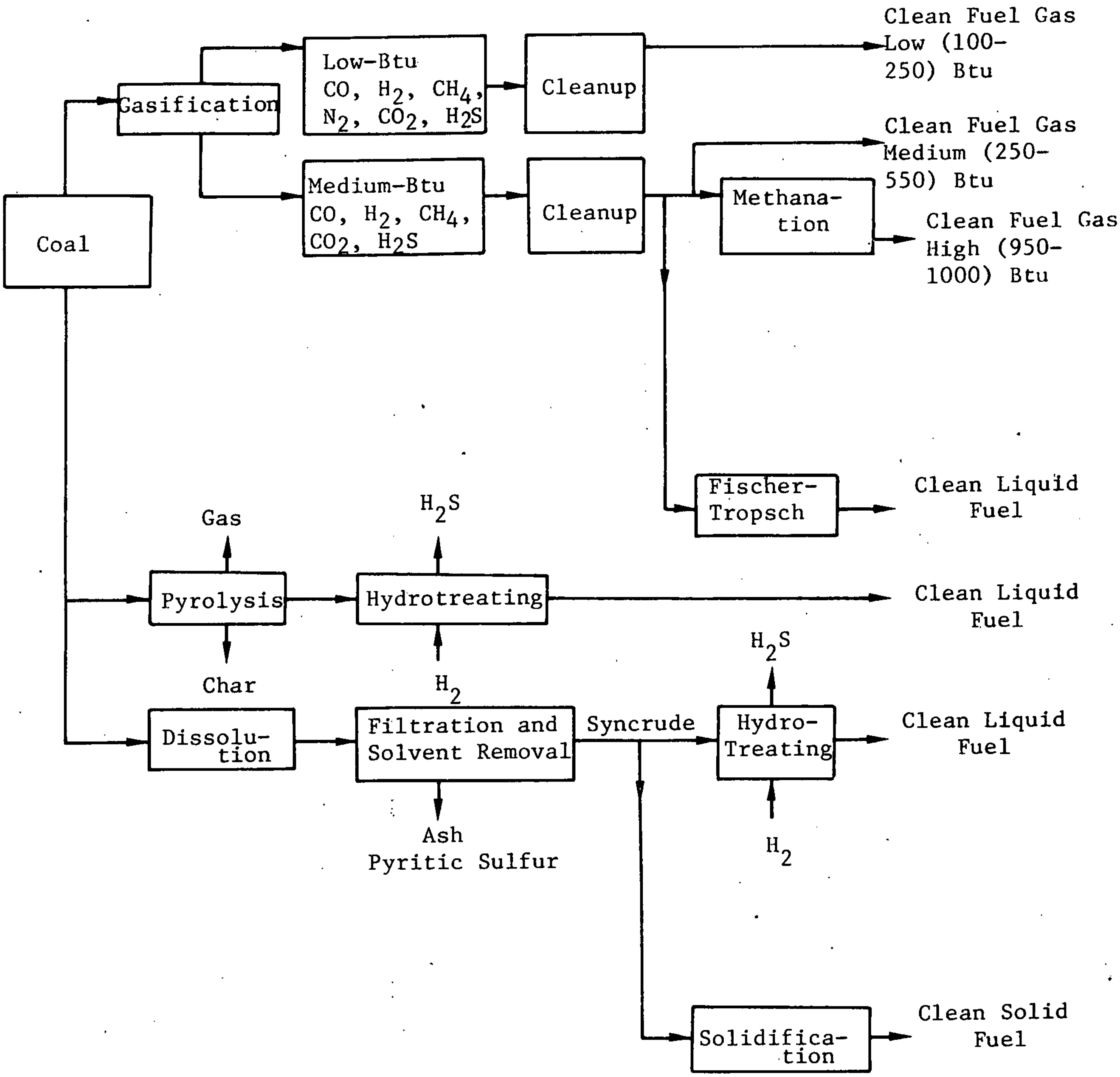

Fig. 3.1 Paths of Synfuel Production[7]

Table 3.1 Characteristics of Regional Coals and SRC: Proximate and Ultimate Analyses in Weight %

(Regional coal data are geometric means of many samples.)

(Wt. %)	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. 16.

products of gases, liquids, or electricity. All the conversion processes require the input of two key natural resources -- coal and water. (In some processes, the control of sulfur emissions requires, in addition, limestone, dolomite or lime). The quantity of coal required obviously is related directly to the volume of output energy required and the overall plant efficiency. The efficiency of conversion varies significantly among the conversion processes; generally, the more refined the product energy, the lower the overall efficiency.

Electric power production is the least efficient because of the inherent (second law) limitations on the efficiency of a condensing steam (Rankine) power cycle. Thus, although the efficiency of energy conversion from coal to heated steam is quite high (90% or better), and a steam turbo generator is very efficient (95%), the overall plant efficiency never exceeds 40%. More advanced, noncondensing power cycles, such as combustion turbines or MHD, may raise this efficiency as high as 50% in the future. Conversion of coal to synfuels, on the other hand, is a more efficient process; the less severe the temperature and pressure processing conditions, the higher in general the conversion efficiency. Production of Substitute 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; the efficiency of the various conversion processes varies with design details, but is usually between 55-65%. If less hydrogen is added in the synfuel production process, then 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. The manufacture of fuel gases of low energy density (low Btu gas) enjoys similar efficiency advantages. The simplest and most efficient processing of coal is a chemical washing process to remove only pyritic sulfur; the overall conversion efficiency is just over 80%.

The use of water is a critical environmental factor for all coal conversion technologies. All of the conversion processes use water in the process that makes either electric power or synfuels, and they all require cooling of process streams, which is usually accomplished, at least to some extent, by an evaporative cooling water circuit. The water used in the process may be the makeup used in a boiler steam circuit, or it may enter directly into a synfuel production process. Boiler feedwater must be treated to 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 circuits may involve 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, and thus require a continuous blowdown stream to prevent the 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 processes 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 amount of evaporative cooling required, since the quantity consumed within the conversion process or elsewhere in the plant is small by comparison.

Some of the environmental pollution problems associated with conversion are common to all coal utilization technologies: the results of storing and handling coal, treating water, and disposing of various solid wastes. Coal storage piles must be carefully constructed so as to capture all water runoff [in order to prevent the many toxic, leachable constituents in raw coal from reaching ground or surface waters. Synfuel plants should extend the runoff] control measures to the entire plant site, since leaks and spills of toxic substances are quite possible. Coal handling causes dust that must be consort. Such preventive measures are common practice at modern coal conversion facilities. Crushing of the coal to a size suitable for combustion or other conversion is accomplished in grinding machines that are sealed because the crushed coal is usually conveyed from them pneumatically. Synfuel conversion frequently requires that the coal be dryed 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 arise at the facility that pertain to ash disposal. 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 various paving and construction materials. Bottom ash from boilers and gasification processes is usually quenched with water and sluiced to a storage pond. In 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 as toxic substances leach out and seep into ground and surface waters; although the ash contains a lesser quantity of leachable, harmful elements than raw coal, the ultimate hazard is probably far more serious. Conversion facilities located near a supplying mine will be able to avoid much of this problem by burying the ash. Problems similar to ash disposal are involved in disposing of sludges from water treatment facilities. Disposal problems, which are perhaps insurmountable, result from the use of limestone flue gas scrubbers for sulfur removal that generate enormous volumes of thixotropic sludge.

As discussed in connection with water consumption, all coal utilization technologies, both present and future, must reject large amounts of heat to the environment. In the case of steam electric power production, 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 the processing of the product gases and liquids. The key to synfuel process efficiency is, in large part, the minimization of this latter thermal waste. Heat is not generally considered a pollutant, except when it is discharged to a body of surface water; thus, it is only in steam electric power plants using once-through cooling that the heat discharge is analyzed for environmental effects. But, in all closed-cooling circuits using towers or ponds, there is the environmental problem of the 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 some subsequent treatment. Current technology does not provide for this stream, with its high solids content, to be feasibly cleaned and recycled within the plant.

After these generalizations about coal conversion technologies, electric power production, and synfuel processes are discussed more particularly.

3.2 ELECTRIC GENERATION

For this assessment, electric power production using coal is considered to be represented by a pulverized coal-burning boiler with an electrostatic precipitator and, optionally, a flue gas desulfurization (FGD) unit. The detailed characteristics 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 is about 38% (8970 Btu/kWh 2260kcal/kWh) without the FGD unit. The basic power plant is assumed to have closed cycle cooling using mechanical or natural draft wet towers; this cooling system will drop the net station efficiency to about 34% (10,000 Btu/kWh 2520kcal/kWh) in 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 2432kcal/kWh) in base load service.

The nominal unit size of a new coal fired power plant could be between 500-1000 MW, depending primarily on the total size of the utility system in which it is placed; for this assessment we assume the size is 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 leaves with the flue gas in this type of boiler. As mentioned above, 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 is released as sulfur dioxide and can be reduced by an FGD or *scrubber* system as discussed below. 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. For this assessment, it is assumed that federal new source standards (NSPS) listed in Table 3.2 are met for nitrogen oxides and that no more stringent control is feasible.

Sulfur is the pollutant that, for better or worse, has been the focal point for measuring the environmental damage done by coal-fired power plants. There are three options available to reduce sulfur emissions and still burn coal; the flue gas can be cleaned of sulfur dioxide, the coal can be cleaned of sulfur prior to combustion, or a coal that is naturally low in sulfur can be used. The option of burning low sulfur coal is currently, and in the near future, the approach likely to be preferred. In the geographical area covered by this assessment, the only source of low sulfur steam coal is the Northern Great Plains Province. The salient characteristics of this coal are shown in Table 3.1. The lower energy density of this coal aggravates all the potential environmental hazards associated with coal handling and solid waste disposal, since it must be fired at a greater rate to maintain the nominal output. Besides many operational difficulties in burning this low quality, low sulfur coal, the fly ash has electrical resistive properties that cause conventional precipitators to function much less efficiently. It is assumed here that any power plant designed to use this coal will incorporate high temperature precipitators in order to maintain a collection efficiency of 99%, or better (by weight). As shown in Table 3.2, use of western low sulfur coal allows a power plant to meet or to improve slightly on NSPS for sulfur emissions.

The second available option for sulfur control is by a scrubber that washes the flue gas with one of many solutions that chemically combine with the sulfur. The general division of scrubbers into regenerable and throw-away types follows from the processing of the scrubbing liquid; regenerable processes extract sulfur as an acid or a solid and recycle most of the scrubbing liquid. Throw-away processes use lime or limestone to combine with the sulfur and then dispose of a more or less wet sludge. Without going into all the many problems that beset FGD systems, it is sufficient to note that they require parasitic energy for their operation, they also cause plant efficiency to decline, they are at present less reliable than the rest of the power plant, they are expensive, and they cause solid and liquid waste disposal problems of their own. They do work, however, in that they remove 85-90% of the sulfur in the flue gas, and they may have a beneficial side effect of reducing fine particulate emissions, although it has not as yet been demonstrated. In this assessment it is assumed that a limestone, throw-away FGD device represents a near-term control technology and a regenerable process represents a more advanced option. 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;

Table 3.2. Air Pollutant Emissions from Uncontrolled and Controlled Combustion [Emissions ($lb/10^6$ Btu)][d]

Pollutant	NSPS	Central Interior Province Coal		Northern Great Plains Coal		Solvent Refined Coal, Controlled[c]
		Uncontrolled	Controlled[a]	Uncontrolled	Controlled[b]	
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] Assumes FGD with 85% sulfur removal efficiency, ESP with 99% removal efficiency, and state-of-art furnace for NO_x control.

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

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

[d] To convert $lb/10^6$ Btu to gm/kcal multiply by 1.8×10^{-3}

since about 3.3 lbs of limestone are needed per lb of sulfur removed, a 1000-MW power plant burning the 3% sulfur central interior coal of Table 3.1 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 control by limestone scrubbing can also be accomplished in a fluidized bed combustion process where limestone or dolomite is mixed with the coal in the fluidized bed to absorb the sulfur. Although still in the developmental stage, fluidized bed combustion may hold advantages in construction costs and operating efficiencies. From an environmental standpoint 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 an economically feasible thing to do. In this assessment, fluidized bed combustion is one of many potential future processes for controlling some or several environmental pollutants at better efficiency and lower cost than FGD.

The third option of reducing the sulfur conten tof the coal by pre-combustion processing covers a range of possible technologies, including physical or chemical washing, solvent refining, or conversion to a low Btu fuel gas. Coal washing is widely used to remove excessive sulfur and ash before combustion and may be continued in the future in conjunction with other fuel processing technologies or with less efficient, but cheaper FGD units. However, in the geographical region of this assessment, this process will not bring a substantial quantity of coal into compliance with federal NSPS.

Solvent refining of coal is a specific technology in the general category of coal liquefaction; it involves a very mild hydrogenation process to produce a low ash, low sulfur product, SRC, which is usually in the form of a soft, low melting point solid. As shown in Tables 3.1 and 3.2, the properties of SRC result upon combustion in sulfur emissions that are well within the NSPS; nor should undue problems arise with particulate or nitrogen oxide emissions. There are some minor problems in handling SRC at a power plant, but these should present no problem for new facilities. The combustion of SRC for electric power production 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 the production of SRC reduce the total benefits to a point at which they are approximately competitive with first generation flue gas desulfurization. The primary use of SRC in the future 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 in areas 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 technology is the most complex of the options and is still in the developmental stage; but, from an environmental standpoint, it is a promising technology in that most atmospheric pollutants can be controlled to a very low level. Because the energy density of the fuel gas is very low, it cannot be economically stored or transported over any distance. Also for reasons of 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 combustion turbine followed by a waste heat recovery steam boiler. Therefore, the fuel gas production facility must be integrated into the power plant facility and be capable of the same degree of load following. In contrast, coal washing or liquefaction technologies can be located remote from the power plant and operate smoothly without following variations in the demand for electricity. In spite of the added complexity there is the potential in an integrated facility and in the use of combined cycles for future gains in process efficiency that make the concept viable.

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

The preceding brief discussion of electric power production technologies has focused on the criteria atmospheric pollutants. Attention must be given to the multitude of other effluents that are emitted with flue gases from combustion, especially those identified as being especially toxic. Fine (respirable) particulate emissions are neither well characterized nor regulated at present. By weight probably about 15% of the total particulate emissions left with the use of an efficient electrostatic precipitator (ESP) unit are in the size range of less than 2 um; the distribution by size below 3 um is not well documented. The only control technologies that may be effective on these fine particles are the use of fabric filters in the flue gas or the use of fuel gas conversion followed by a gas clean-up that washes the fuel. It is not clear that the use of wet scrubbers for sulfur removal from the flue gas has a beneficial effect on fine particulate emissions. If regulatory standards for fine particulates were developed, other techniques and improved ESPs might be necessary for combustion processes.

The release to the environment of the many trace elements naturally found in coal is another source of environmental hazards and data uncertainty. Table 3.3 shows the trace elements and their concentration in the representative coals used by this assessment. It must be remembered that 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, not to be volatile during conversion but to remain with the coal ash. But some ash does escape with flue gas and the captured ash may be stored for long periods of time during which it is subject to leaching and erosion. For all these trace elements, little firm data is available on their fate during storage or conversion of the coal, or the form they may take as they leave the process with various waste streams.

For purposes of this assessment, a 3000-MW standard facility was chosen with the characteristics given in Table 3.4* The emission rates for atmospheric dispersion modeling were chosen in order to be consistent with those used by the General Electric Co. in their study for the National Science Foundation. These are shown in Table 3.5. The trace element emissions reflect the volatility estimates shown in Table 3.3, and thus are an upper bound on emissions, since precipitator capture is ignored.

In coal electric conversion, water is used primarily for steam and evaporative cooling. The consumption for cooling purposes varies greatly for alternative cooling system designs. Once-through systems and cooling ponds are similar in that water consumed by the heat rejection of the power plant is very dependent on the surface area of the water body and local climatic conditions. The cooling pond is here assumed to cover about one acre per MW. Evaporative cooling towers are the most likely system to be used in new power stations. Natural draft and mechanical, or forced draft, towers both consume water at about the same rate. The water consumption rate is not as sensitive to variations in climatic conditions. Consistent with the work by General Electric[6] water consumption rates at 70% of rated capacity are as shown in Table 3.6

Treatment of intake water for boiler use creates waste streams of sludges 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 operations, and floor drains in the plant area. For purposes of this assessment, rough estimates were made[5] of the various pollutants that would contaminate waste water streams in a power plant (Table 3.7). 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)[5] The estimates in Table 3.7 combine the pollutant loadings from the following waste streams:

boiler blowdown
metal cleaning wastes
cooling system blowdown
ash handling overflow
miscellaneous low volume wastes.

* Impacts of alternative parameter values in air quality are discussed in Sec. 6.

Table 3.3. Trace Elements in Representative Coals (Data are average values from many samples of whole coal[16])

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]Non-volatile at furnace conditions

Table 3.4 Physical Plant Characteristics

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

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. Waste heat is rejected during combustion of coal to the cooling water passing through the condensor. The amount of heat rejected depends on several parameters, but averages around 6000 Btu(1512kcal)/kWh. This input of heat results in an increase in cooling water temperature of approximately 8.5°C with once-through cooling or 12°C with cooling towers[5].

Effluent guidelines currently restrict the discharge of heated effluents to the environment; therefore, treatment measures are necessary. Treatment devices for cooling, such as towers, sometimes generate chemical pollutants, as already discussed. To evaluate the impact of thermal discharges, it will be assumed that no heated effluents will be discharged warmer than the EPA standards and that cooling towers, spray ponds, or other mechanical cooling facilities will be employed for treatment of the heated waste stream.

3.3 COAL GASIFICATION

Coal gasification, in this assessment, covers processes that make a clean, methane-rich gas from coal by destructive hydrogenation at elevated temperature and pressure. This preliminary assessment does not attempt to differentiate between specific process designs, but, rather, uses a generalized process with regard to inputs and environmental 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 clean-up train and not the gasifier chamber, the differences between specific gasification designs will be found more in the costs and efficiencies as related to coal feed than in the residuals to the environment. The major exceptions to this statement are the effluents from the onsite production of auxiliary steam and electric power; the amount of auxiliary energy needed varies with the design and efficiency of the process.

Table 3.5. Emission Rates for the Standard 3000 MWe Plant at 60% Capacity Using Interior Province Coal

Pollutant	Emission Rate ($lb/10^6$ Btu input)[b]	Baseline Plant Emission Rate (gm/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

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

Table 3.6 Water Consumption by Coal 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 consumption for a 1000 MW plant operating at an annual capacity factor of 100%

Figure 3.2 shows the process stages and streams of inputs and effluents for coal gasification. The exact nature and location of each basic process block within the diagram will vary between the individual processes. Likewise, not all of the effluents noted on the diagram may be present for all processes; some gasifiers favor production of certain species more than do others. Coal is prepared by crushing to size and drying; the degree of drying (if any) is dependent on the operating economics of each specific process. The flue gas vented from drying is treated for particulate removal and then vented to the atmosphere. The prepared coal is fed to the gasifier either in batches by means of a lock hopper, or continuously by mechanical feeders or in a pumped slurry. It is assumed that any gases released during the feeding are 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 temperatures of 700-1150°C and pressures of 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 and H_2 using steam and catalysts, but no effluents normally arise from this stage.

The gas cooling and cleaning stages are those in which most of the environmental pollutants present in the coal feedstock are separated from the conversion product gases. The gas cleaning must be very effective in order to protect the catalysts in the methanation stage and to produce SNG, which can be acceptably mixed with natural gas. The dirty systhesis gas is cooled by heat exchangers and then cooled and scrubbed by a direct water spray wash. The liquid effluent, consisting of the wash water and water condensed from the synthesis gas, is called the gas liquor and requires considerable treatment before reuse or release to the environment. The aqueous effluents, as shown in Table 3.8, reflect the levels of possible treatment before a waste stream is sent to the cooling water circuit and then released to the surroundings through blowdown.

The gas liquor is treated first by a pressure letdown to release dissolved gases that are sent to the sulfur recovery section. Next, tars and oils are separated by mechanical skimming and phenols by chemical solvents.

Table 3.7. Estimated Water Pollutant Loadings from Coal-fired Power Generation Facilities

Pollutant	Uncontrolled (lb/day/MW)[a]	Controlled (NSPS) (lb/day/MW)[a]
TSS	0.3649[b]	0.328 max. 0.099 avg.
Oil & 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	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/day/MW 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/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

Table 3.8. Representative Pollutant Concentrations in Gas Liquor Condensate from Coal Gasification

Substance	Untreated Level	Treated Level
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 in Refs. 5, 11, 14, and 15.

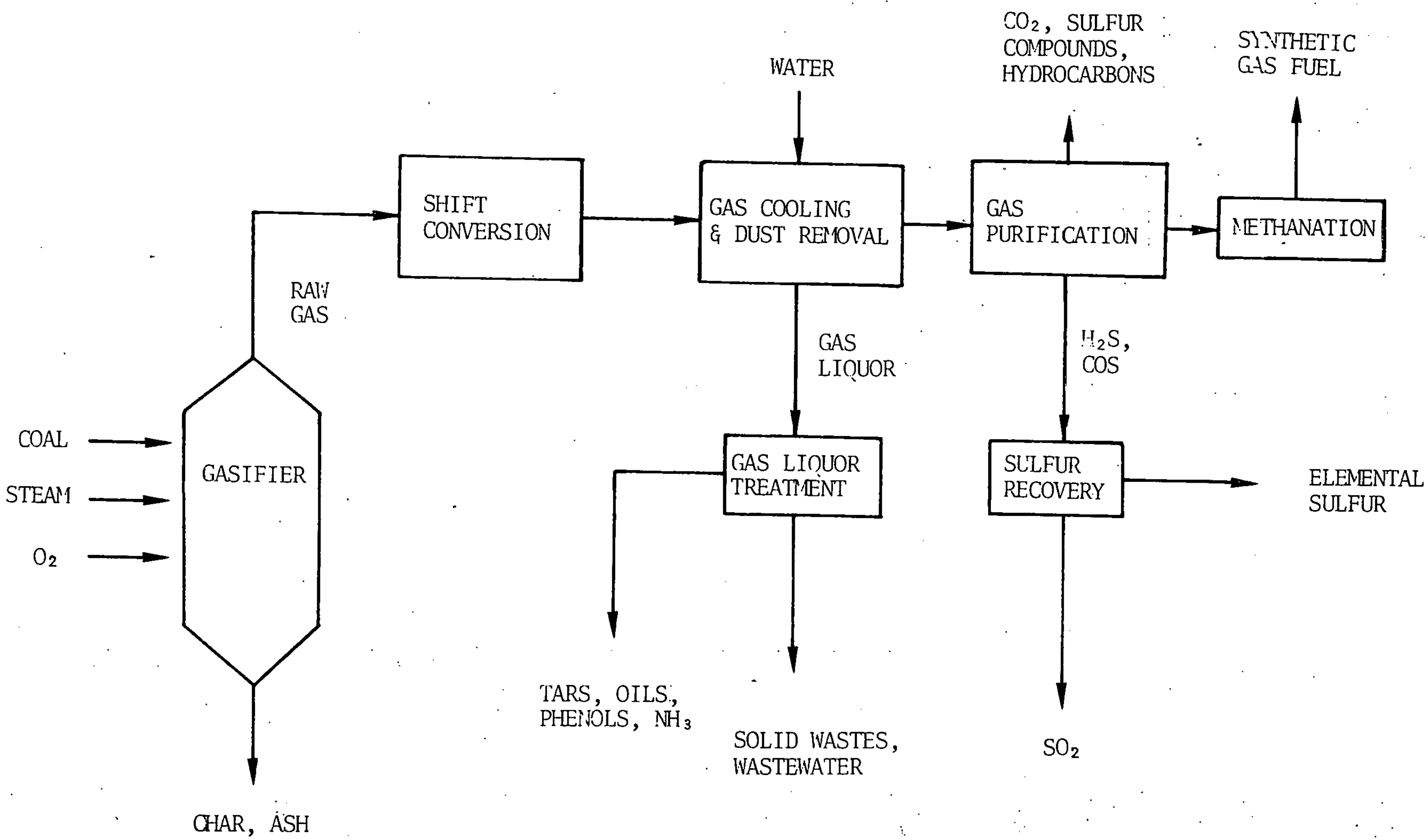

Fig. 3.2 Basic Coal Gasification Process Diagram

If these hydrocarbons are present in large quantities, they may be recovered as by-products or reinjected into the gasifier. Very high temperature gasification processes produce little or none of these heavier hydrocarbons. Ammonia is formed in the gasifier from the fuel nitrogen in the coal and is removed from the gas stream with the gas liquor. Distillation by steam stripping is used to recover it 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 done at temperatures of 50°C down to -45°C, depending on the specific 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 level of purity required of the SNG product. The solvent is regenerated to release the carbon dioxide and sulfur compounds selectively, the former to be vented to the atmosphere and the latter to be sent to a sulfur recovery train to recover elemental sulfur. The CO_2 vent stream is very large in volume and carries small quantities of gaseous pollutants with it. The sulfur recover train uses Claus or Stretford processes 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 intermixing with natural gas. This process releases only large amounts of heat and some water that is recovered for reuse in the drying of the SNG.

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. With the exception of small quantities of nitrogen oxides released if the off-gas vents are incinerated, NOx 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. Certain acid gas processes are more adept at removing COS or H_2S species than others. Estimates for sulfur emissions vary widely among designs. As an example, one design states that a commercial Synthane plant operating on central Interior Province coal would emit about 900 lb/hr (408kg/hr) of SO_2, but would not emit COS. An equivalent HYGAS plant might emit only about 100 lb/hr (45kg/hr) of SO_2, but also emit 400-500 lb/hr (180-225kg/hr) of COS. It might be expected that (45kg/hr) sulfur emissions fall somewhere between these limits.

In addition to the primary process flow is the use of coal to produce the ancillary energy required by the gasification process for steam, oxygen production, compression of gases, pumping of liquids and cooling water, etc. This may be accomplished by a direct coal combustion boiler, or the coal may be processed into a liquid or gaseous form before use. The levels of environmental control that may be exerted here parallel those used in electric power production. In many cases, this auxiliary power production will contribute more environmental pollutants than the main gasification process stream. This need not be so, and the residuals in Table 3.9 reflect the high and low levels of control that may be imposed on this source. For this assessment, the data available from the EMDB was used for the HYGAS process to represent gasification technologies[1,2]. These air emission rates are shown in Table 3.10.

Table 3.9 High- and Low-Control Environmental Residuals for Auxiliary Facilities for SNG Plant[12,13]

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	$6 \cdot 10^6$ gal/day	$2.8 \cdot 10^6$ gal/day
Blowdowns	$2 \cdot 10^6$ gal/day	$0.9 \cdot 10^6$ 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 @ 10,000 Btu/kWh(2520 kcal/kWh).
To convert from $lb/10^6$ Btu to gm/kcal multiply by $1.8 \cdot 10^{-3}$.
To convert from lb/hr to kg/hr multiply by 0.4536.
To convert from gal/day to m^3/day multiply by $3.78 \cdot 10^{-3}$.

Table 3.10 Atmospheric Emission Rates for the Standard $250 \cdot 10^6$ scf/day SNG Plant[1,2]
(90% annual load factor)

Pollutant	Emission Rate ($lb/10^6$ Btu Input)	Baseline Plant Emission Rate (gm/sec)
SO_2	0.126	$2.02 \cdot 10^2$
NO_x	0.136	$2.42 \cdot 10^2$
Particulates	0.014	$2.49 \cdot 10^1$
CO	$6.7 \cdot 10^{-3}$	$1.19 \cdot 10^1$
Total HC	$1.79 \cdot 10^{-3}$	$3.19 \cdot 10^0$

Note:

Btu input is total to entire facility - process plus auxiliaries.
To convert from $lb/10^6$ Btu to gm/kcal multiply by $1.8 \cdot 10^{-3}$.

Very few data are available on quality or quantity of waste water from coal conversion processes. Only crude estimates can be made of water pollutants that may emanate from coal conversion facilities. Because the plants designed to date are in dryer regions, they, do not plan to discharge any waste water at all; there is no exact specification of water treatment or of residual water contamination. For an area rich in water supply, one cannot say with assurance whether it would be more economical to treat waste water streams for release or to partially clean those streams for reuse within the facility. It may turn out that certain waste streams would be recycled and others could, and would, be economically treated and released.

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 amount of cooling consumption can be reduced greatly by means of air cooling and heat recovery within the process. Cooling water makeup usually will come from cleaned-up process water. Blowdown will be used to sluice ash and then ponded, evaporated, or discharged. Detailed water consumption estimates 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 in response to site-specific factors of water availability, quality, cost, and of waste water disposal options. Table 3.11 gives ranges of water consumption for a 250 Mscf/day SNG plant based on design data, estimations of minimum possible use, and simple thermodynamic balances.

The lower limits would apply to SNG facilities located in water scarce areas, or where discharge of waste water posed significant problems. In this assessment, it was assumed that water consumption limits and waste disposal restrictions would be relatively stout; a consumption rate of 10.8 cfs was used for unit (250 SCF/day) SNG plants.

In this analysis, two approaches were used to estimate the type and quantity of pollutants to be expected from coal gasification and liquefaction processes. The first approach is to examine the process liquid waste streams for pollutant loadings; this will supply the absolute upper bound on the loadings that could be released. Treatment process information could be superimposed on these raw levels to estimate more realistic levels of possible effluents. The second approach is based on analogy to other, somewhat similar, process facilities. New Source Performance Standards (NSPS) are based on the available waste water treatment technology - not on the levels of pollutants generated in the process. Whenever the NSPS are promulgated for coal gasification facilities, they will contain process effluent rates based on the same treatment technology as for "similar" facilities. Thus, by appropriate scaling of process size, one can estimate the maximum levels of discharge that may be allowed in the future.

Table 3.11 Water Consumption by a Unit SNG Facility

Upper Limits	17.05 cfs - 20.15 cfs
Lower Limits	6.2 cfs - 11.6 cfs

Table 3.12 lists, for both treated and untreated options, the approximate loading rates that might be observed for various compounds in waste streams from coal gasification processes. These rates are based on 250 Mscf/day of gas production using Illinois No. 6 coal. Recovery of certain by-products before discharge was *not* assumed in data under *untreated* option. Waste water stream volume of 3.3 x 10^6 gal(1.25 x 10^4cu m)/day is assumed.

3.4 COAL LIQUEFACTION

Coal liquefaction is a term used to describe a wide range of processes that convert coal to a type of clean liquid fuel. The primary product may be equivalent to refined petroleum products, or to unrefined crude oil, or it may be a heavy boiler fuel that possibly might be a solid at ambient temperatures. Most liquefaction processes produce a range of gaseous, liquid or solid by-product streams besides the primary conversion products. Figure 3.1 shows the three general paths to making liquid synfuels: one is by a clean synthesis gas, produced and processed as in the manufacture of SNG, and passing it through a catalytic Fischer-Tropsch process to produce a range of liquid products equivalent to grades of refined petroleum; another way is by subjecting the coal to pyrolysis to drive off volatile hydrocarbons that can be condensed to liquid products; the third path is by dissolution of the coal in a solvent in the presence of hydrogen and (perhaps) catalysts followed by filtration and distillation to extract products.

The environmental residuals generated by these processes are, generally, similar to those resulting from processes for manufacturing SNG. The coal is usually pretreated by crushing and drying, creating the same potential problems of dust and volatiles in the flue gas. The liquefaction stage has no normal direct releases to the environment, since, as in gasification, the process is contained under elevated temperature and pressure. A gas stream very similar to synthesis gas is released from the liquefaction process, and this is cleaned by the same steps used in SNG plants. This synthesis gas can be methanated to SNG for sale, or it can be used to produce the hydrogen needed in the liquefaction process. The gas cleaning steps give rise to the same types of liquid and gaseous effluent problems as in SNG facilities, although at a reduced total level. The liquid product stream may be hydrotreated to upgrade the quality of the fuel; this treatment will drive off any sulfur in the liquid as H_2S gas. The gas stream is then handled in the same steps as the acid gas stream from the purification of synthesis gas -- usually a Claus process followed by incineration and scrubbing of the tail gas. The filtration of liquid products leaves a filter cake residue to be disposed of; in pyrolysis processes there is a large amount of residual char. These solids must be disposed of either by conventional solid waste storage or burial, or by converting the remaining carbon in them into useful energy by combustion or gasification. Because of the high ash and sulfur content of these solid effluent streams, they will most likely be gasified to form a fuel gas or a synthesis gas.

The overall result is that under normal operating conditions, the liquid synfuel process stream does not directly release pollutants to the environment. Pollutants reach the environment either through the solid waste stream, or through the liquid and gaseous effluent streams from the gas clean-up train.

Table 3.12. Representative Water Pollutant Loading from a 250 Mscf/day SNG Plant Using Illinois #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

For this reason, it is reasonable to assume that normal operating pollutant releases from a liquefaction facility will be similar in type and quantity to those from a comparable sized gasification plant. Future assessments should examine the differences in environmental impact that may result from the alternative synfuel technologies. These differences may become sharper as pilot plants make available data on startup and transient effluents, system leaks and spills, product and by-product storage problems, and on the exact composition of all the effluent streams.

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4.0 ENERGY FACILITY SITING PATTERNS

To fully assess the impacts and constraints related to coal utilization, it is necessary to have available a description of the geographical distribution of the various processes that are part of the coal energy cycle. This siting pattern is necessary first of all to consider area-specific impacts related to these processes, and, secondly, to consider the cumulative impacts of the entire coal-related energy system within a region.

It is of course not possible to predict the future siting patterns, including the technology characteristics of the facilities at each site, and there is no claim to have done so here. 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 siting/technology pattern consistent with those assumptions. An evaluation of the impacts and constraints associated with that pattern can then be used to guide the definition of alternate 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 reflecting high instate coal use, have been developed from the criteria and procedures described below. The resulting siting patterns are shown in Figs. 4.1. and 4.2.

The remaining sections of this report are an evaluation of some of the individual and cumulative impacts associated with those coal-related facilities. Although possible options for siting and technology are mentioned in conjunction with the impact and constraint evaluations, a study of the actual feedback into regional siting alternatives to mitigate impacts has not been conducted here, but will be the subject of future analyses.

4.1 CAPACITY REQUIREMENTS

The electrical generation capacity requirements for each of the six states for each fuel type (coal, nuclear, oil, other) are given in Section 2.0. Generation by coal is further disaggregated into type of coal (produced instate, imported low sulfur, imported high sulfur). Although the health and environmental impacts of generation by fuels other than coal were not considered, it was essential to site all major facilities for all fuel types in order to obtain a consistent siting pattern that takes into account competition for water, land, and other resources by noncoal facilities.

Due to the long lead times necessary to place baseload power plants into operation, the sites of most plants that will be in operation (or decommissioned) by 1985 are already planned, and this information can be obtained from the Federal Power Commission.[1] The locations of the existing or planned facilities in the six-state area are illustrated in the appendix for this section. Also given is a listing of the plant name, location, type, capacity, etc.

Although most power plants in existence today will not be in operation in 2020, it was assumed for this study that all plants that will exist in 1985

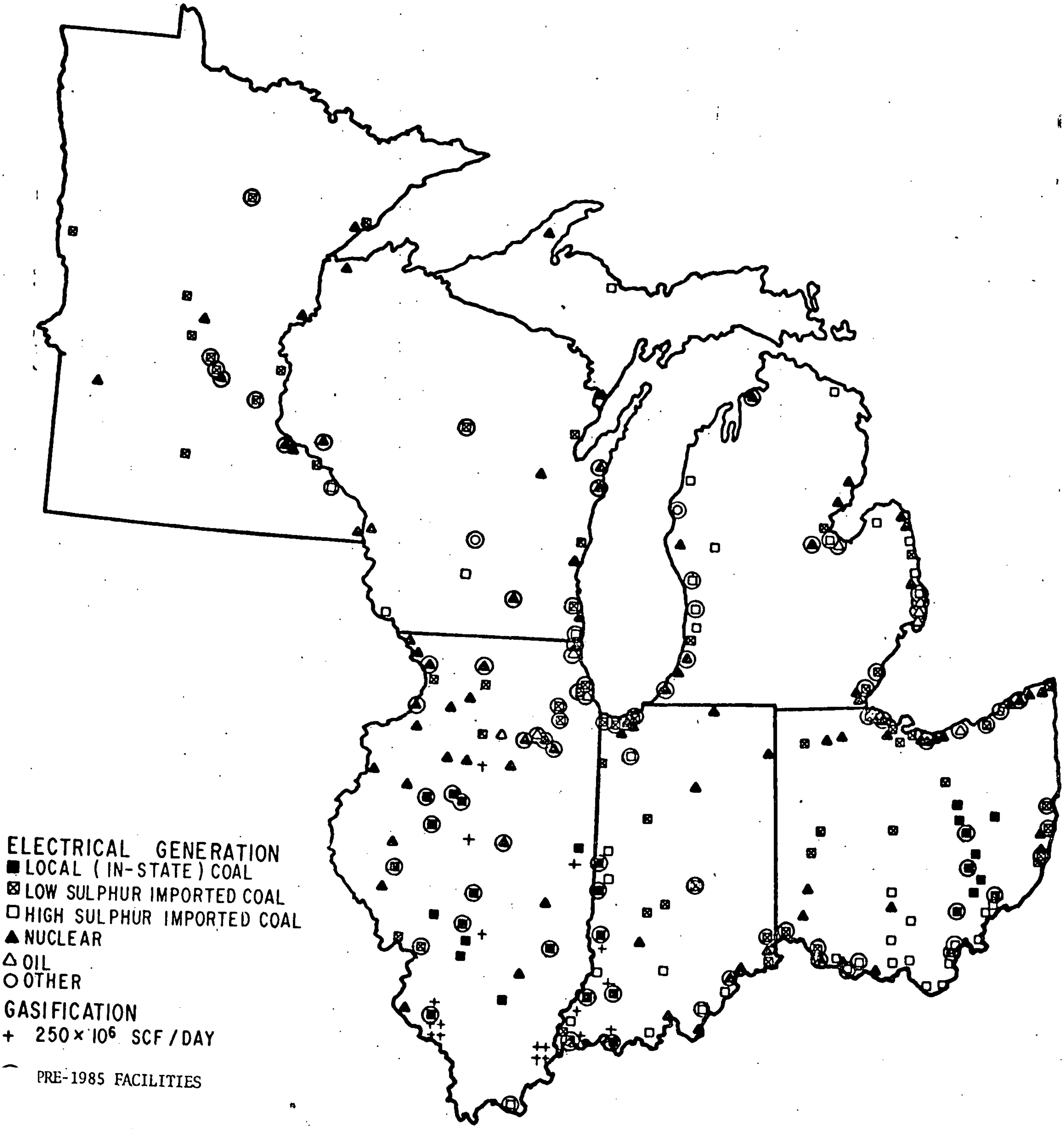

Fig. 4.1 Energy Facility Siting for Base-Line Scenario (2020)

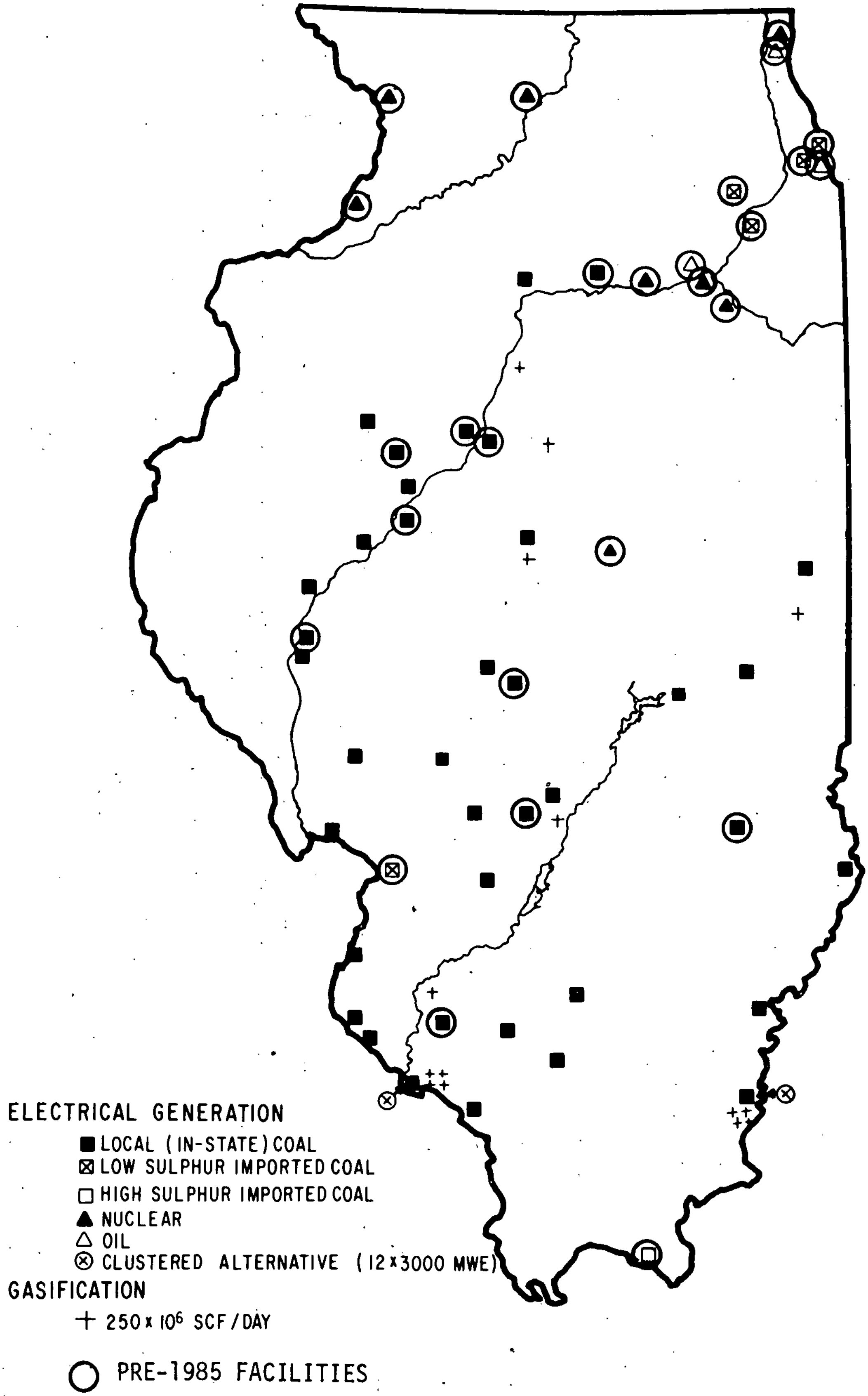

Fig. 4.2 Energy Facility Siting for Illinois High Coal Use Scenario (2020)

will continue to exist in 2000 and 2020. This is not unreasonable in that any existing site is generally considered a good location by the utility, which could then build a similar (or larger) plant on the site after retirement of the present facility. The only exceptions made to this assumption were plants that will be less than 200 MW in 2000 and plants less than 500 MW in 2020, on the basis that they would be either retired or converted to peaking plants and thus not included in this initial study. The plants that continue in existence maintain their present fuel. However, the source of coal for the coal plants was not restricted to that presently 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 Section 2.0 for the energy development scenarios for Illinois and Indiana were sited using similar procedures. The siting projection for these facilities was identical for both Illinois scenarios.

New facilities that were projected for this study were assumed to have uniform total site capacities of 3000 MWe for electrical generation and 250 x 10^6 scf/day for high Btu gasification. The assumed 3000-MWe capacity for electrical generation is consistent with current trends in projected baseload capacity additions (see Appendix to Sec. 4.0). These utility projections include numerous sites containing, multiple 500-1000 MWe units at single sites. The largest of these in the six-state area is the coal-fired Sherburne facility in Minnesota, which is projected to have two 680-MWe and two 800-MWe units upon completion in 1984, or a total of 2960 MWe. Constraints on site availability may in fact reverse this trend toward large facilities; however, the uniform assumption of large plants in this initial study served to emphasize the importance of those constraints. The assumed sizes for the gasification facilities is consistent with the majority of engineering design and environmental impact studies of coal gasification. A further advantage of these unit sizes is that 3000 MWe is nearly equivalent to 250 x 10^6 scf/day at 1000 Btu/scf, thus facilitating comparison of these alternative forms of energy production.

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

4.2 SITING CRITERIA AND DATA SOURCES

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

Water

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 utilize 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, since these lakes or reservoirs are less impacted by short periods of low flow. (For Illinois a more detailed evaluation of potential reservoirs was 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 has a 40-year recurrence interval.)

A more detailed discussion of water availability and low flow constraints is presented in Section 8.0.

Air

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 was avoided.

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

The relationship of siting and air quality is discussed in more detail in Section 6.0.

Population

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

Transportation

1. New plants burning instate coal must be located near an adequate coal resource (coal resources are discussed in Section 5.0.

2. All plants using imported fuels must be located in proximity to navigable waterways or adequate rail networks.

Public Lands

1. Conversion facilities cannot be placed on publicly owned lands.

4.3 SITING PROCEDURES

The first step in siting the 3000 MWe plants involved siting the plants burning instate coal. It was assumed that these plants would be located 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, and all mines after 2000 will be 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 strip/deep ratio will be higher than that used in the nominal case as previously marginal strip mines become profitable in line with the rise of coal prices 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 instate coal are expected to serve the nearest load centers.

Using the water availability criteria, the remaining plants (those using out-of-state coal. nuclear, other) 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 is 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 those plants using imported coal (there are no coal resources in the coastal zone) if the following conditions were met:

1. The coastal zone site was nearest the load center in view of the constraints considered, or

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

4.4 SITING CONSTRAINTS AND ISSUES

Application of the siting criteria and procedures to obtain the siting patterns in Figs. 4.1 and 4.2 resulted in the identification of factors that are expected to constrain future siting options. The principal constraints and related siting issues 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 constrained by heavy competition for shoreline sites and by the distance of these major rivers from many of the large load centers.

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

4. The constraints to 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 in the vicinity of coal resources that are in many cases distant from water supplies also encourages 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 Section 6.1) and thus increments in pollutant concentration are possible without violation of standards. Exceptions are portions of eastern Ohio and the Springfield-Peoria areas in central Illinois in which more active air quality management 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 are partially dependent 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 MWe 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 climate.

The analysis did not deal with site-specific issues that surface at the subcounty level of analysis. 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 the existence of flood plains along river shorelines. Nor were the socioeconomic impacts of facilities considered. State-to-state energy transfers may also have a significant role in determining siting patterns.

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

<u>Illinois.</u> The demand for energy in this state 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 instate coal in the vicinity of 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 agriculture uses. Except for the southern reach, the Mississippi River is not in the vicinity of the Illinois coal resources and is also a considerable distance from the Chicago load center. A shift from nuclear to instate 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 in this state. More than one-third of the 3000-MWe 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/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, however, available flows are significantly below those of the Ohio River. Nearly all sited new plants that are not on the Ohio River or lowest reach of the Wabash River required reservoirs.

Michigan. The lack of major inland rivers leads to the siting of nearly all new energy facilities in Michigan along the extenxive Great Lakes shorelines in that state based on the siting procedures used. Since Michigan has virtally no coal resources, this coastal siting also has the potential advantage of permitting coal transportation by Great Lakes barges. Coastal zone management would become an important issue under this siting scenario, especially in view of the emphasis placed on conservation and wilderness preservation in Michigan.

Minnesota. The existence of the Mississippi and St. Croix Rivers near the major Minneapolis-St. Paul load center in Minnesota allowed siting of energy facilities to supply needs of that state without serious constraints, based on the siting criteria and procedures used. Possible coal-related siting issues in this state requiring evaluation are the 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) constructing energy facilities burning Great Plains coal to produce electricity for transmission to Midwestern markets.

Ohio. Using the established criteria, the greatest discrepancy between required and potential sites occurred in Ohio. These siting difficulties resulted from a combination of (1) a high projected demand in the energy scenario, (2) existing heavy development along the Ohio River and Lake Erie shores, (3) an absence of large rivers in the state interior, and (4) existence of 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, constraint if wet cooling towers are used; that is, reservoirs to enhance water supplies, or alternate 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. Based on the limited criteria of this siting analysis, the constraints to power plant siting Wisconsin are not as severs 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, the generation and export of electrical energy may become an issue.

APPENDIX TO SECTION 4.0

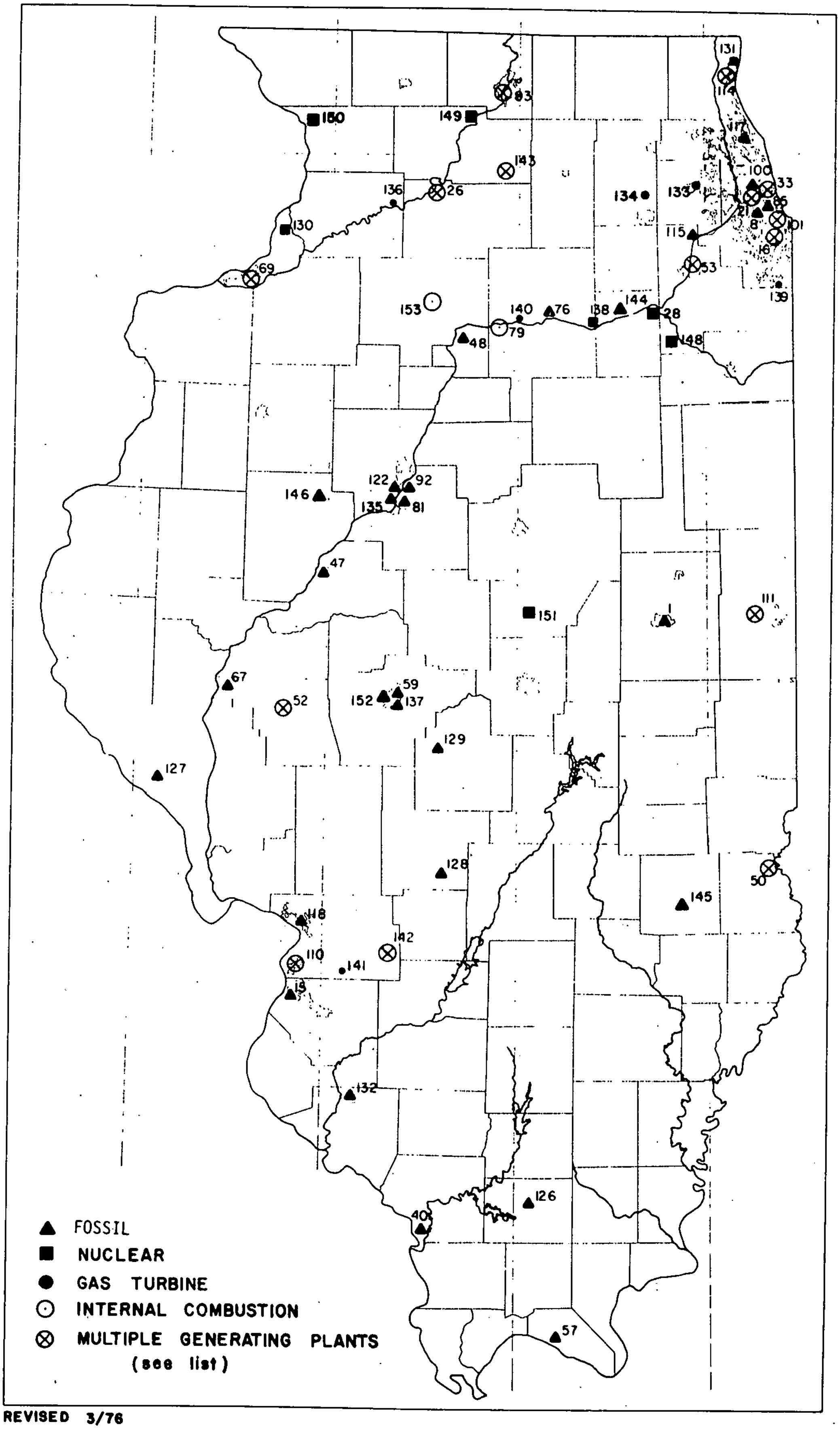

Fig. 4A.1 Existing Electrical Generation Sites in Illinois

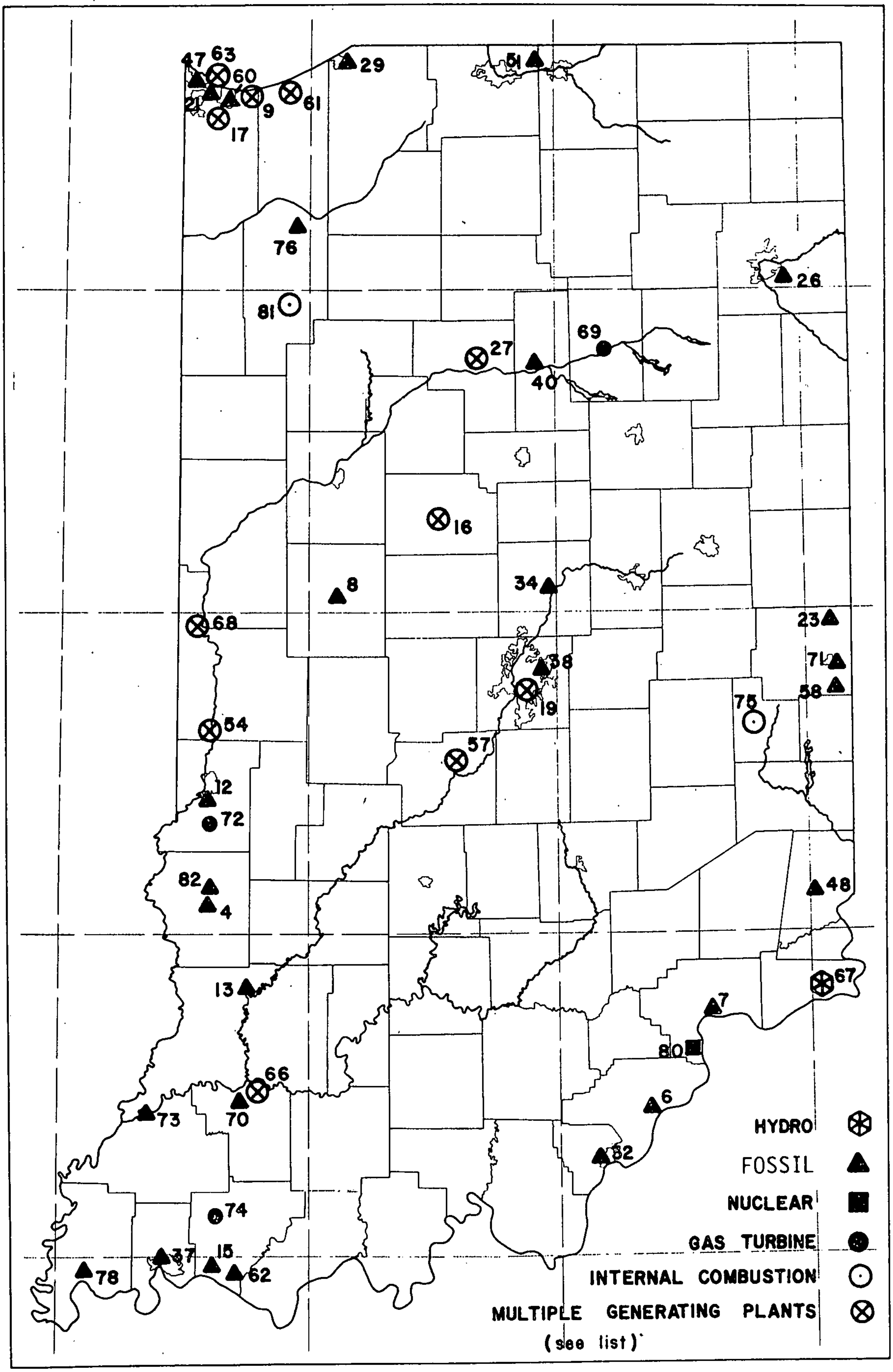

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Fig. 4A.2 Existing Electrical Generation Sites in Indiana

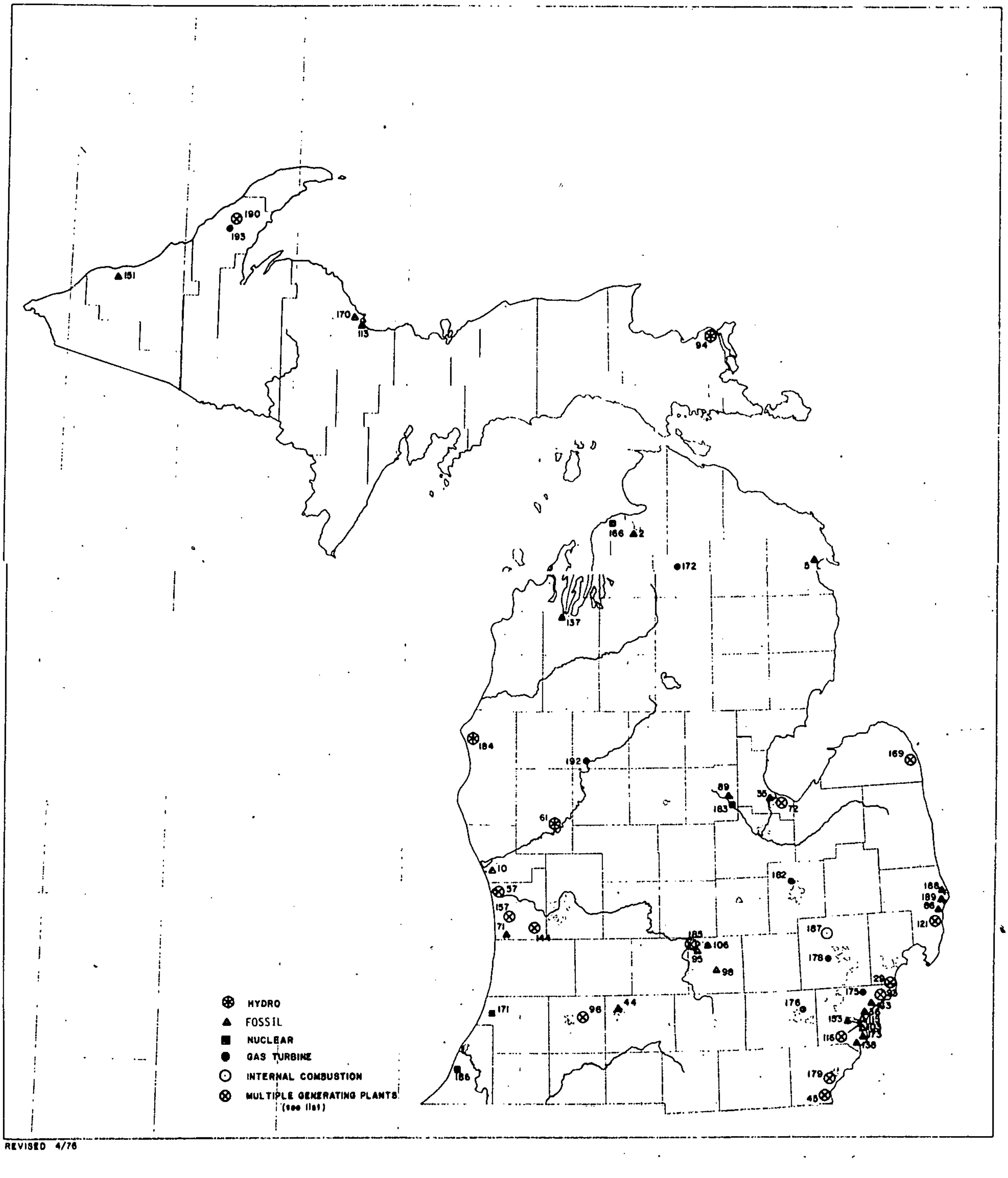

Fig. 4A.3 Existing Electrical Generation Sites in Michigan

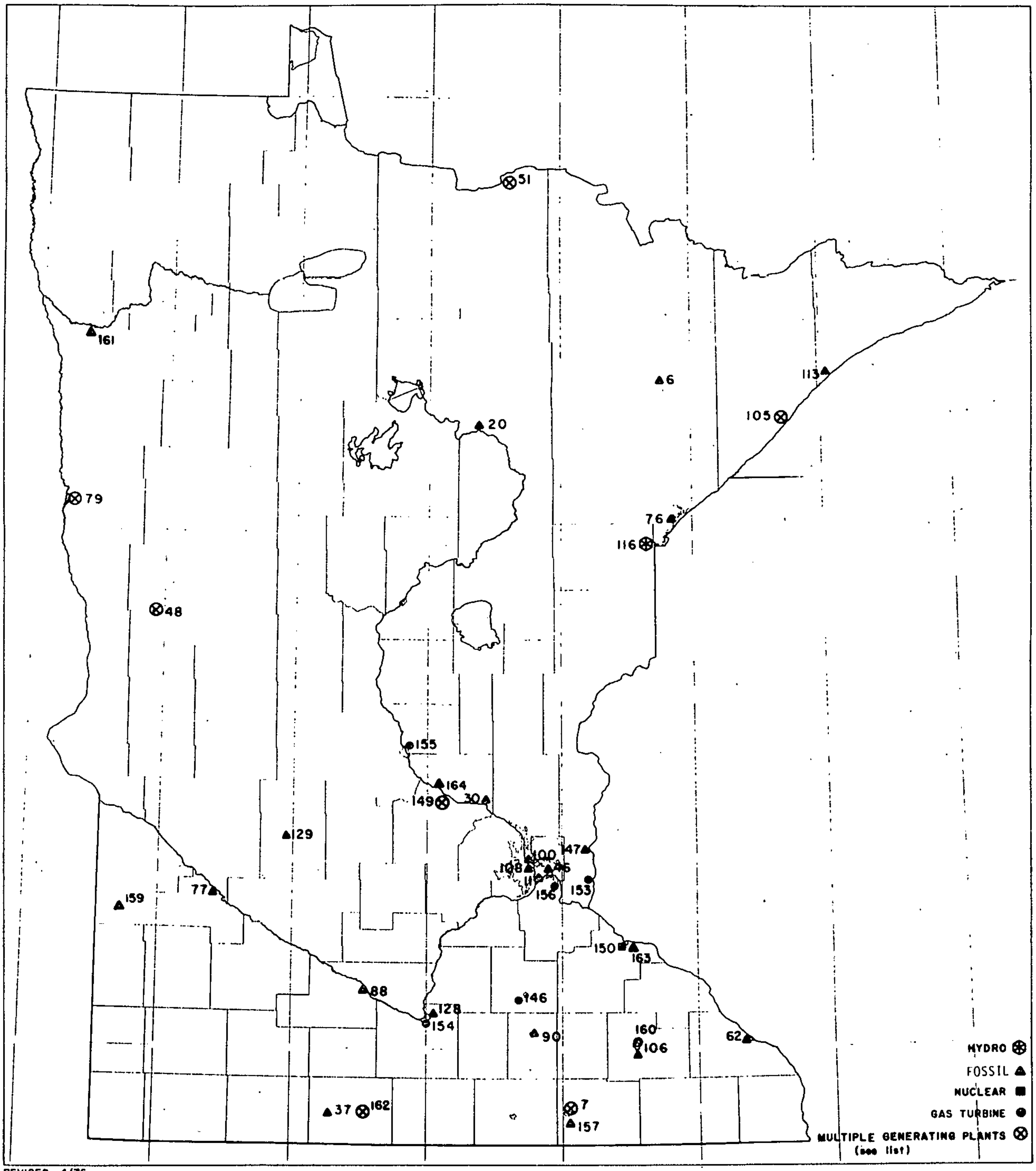

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Fig. 4A.4 Existing Electrical Generation Sites in Minnesota

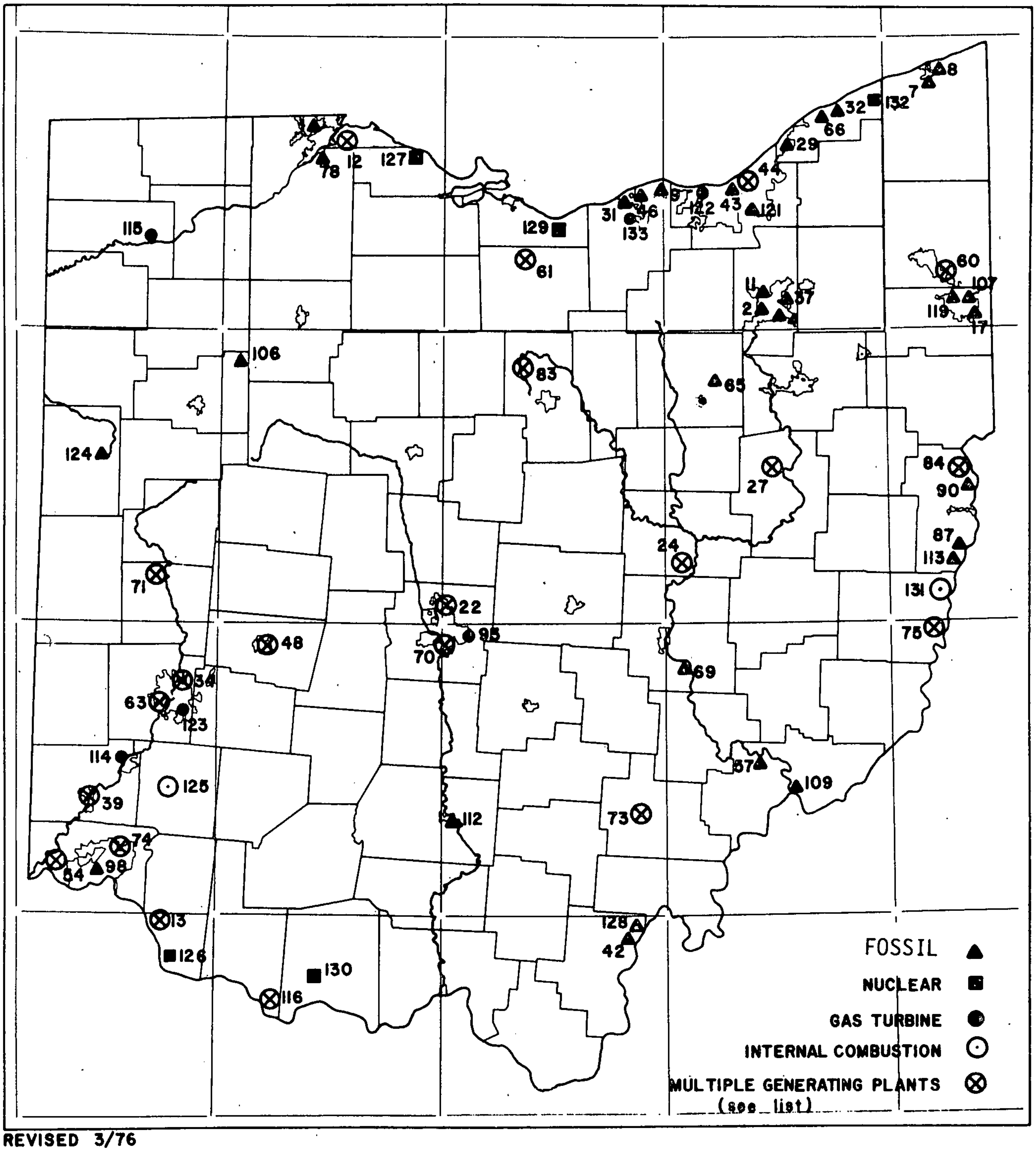

Fig. 4A.5 Existing Electrical Generation Sites in Ohio

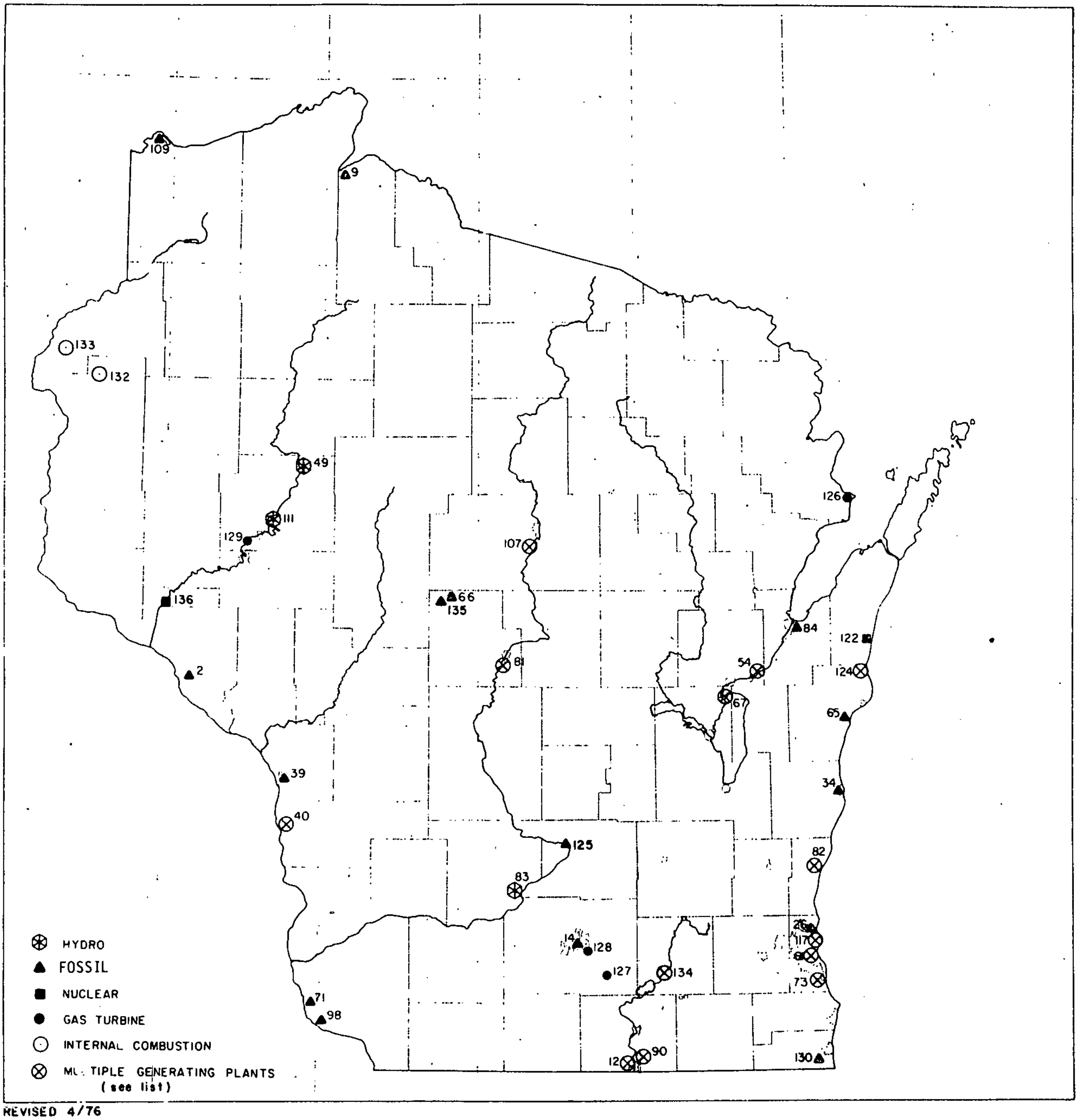

Fig. 4A.6 Existing Electrical Generation Sites in Wisconsin

Table 4A.1 Existing and Planned Electrical Generating Facilities (to be included in final draft)

REFERENCES FOR SECTION 4.0

1. Office of Public Information, Federal Power Commission, Washington, D.C. 20426

2. *Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities*, National Science Foundation Report NSF. 75-500 (1975)

3. Smith, A.E., T.D. Wolsko, and R.R.Cirillo, *Coal Supply and Air Quality Limitations on Fossil-Fueled Energy Centers*, prepared under NRC Activity No. 01-19-01, draft Argonne National Laboratory Report (Aug. 1976)

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

5.0 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 contained within the Interior Coal Province, which includes the Illinois and Indiana coalfields, and the Appalachian Coal Region in the Eastern Province which includes the coal resources 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 additives, disaggregated by deep vs. strip mining is shown in Table 5.1. The reserve base for the states of Illinois, Indiana, Michigan, and Ohio represent 15, 2, 0.03, and 5%, respectively, of the total U.S. reserve base of 437 billion tons.[1,*] The reserves in these states are primarily of the bituminous category.

Of the states considered, Illinois has the largest reserve base and also the largest 1974 production of coal. The 1974 production levels indicate 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 being exploited currently, and there are no announced intentions to do so in the near future.

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.

The county-by-county distribution of the coal reserve base is shown graphically in Fig. 5.2, and in tabular form in the Sec. 5 appendix along with 1974 county production levels.

The fraction of the reserve base that can be recovered depends on whether the coalbed is suited for underground or surface mining. With respect to the coal reserve base, average recovery by underground mining

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*Coal resource data presented in this section refer to the 'reserve base' category. As defined by U.S. Bureau of Mines (BOM),[2] the reserve base includes: beds of bituminous coal and anthracity 28 inches, or more, in thickness and beds of subbituminous coal 60 inches, or more, in thickness that occur at depths to 1000 feet; thinner and/or deeper beds presently being mined or for which there is evidence that they could be mined commercially at this time; and beds of lignite 60 inches, or more, in thickness that can be surface mined -- generally those that occur at depths no greater than 120 feet. 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]

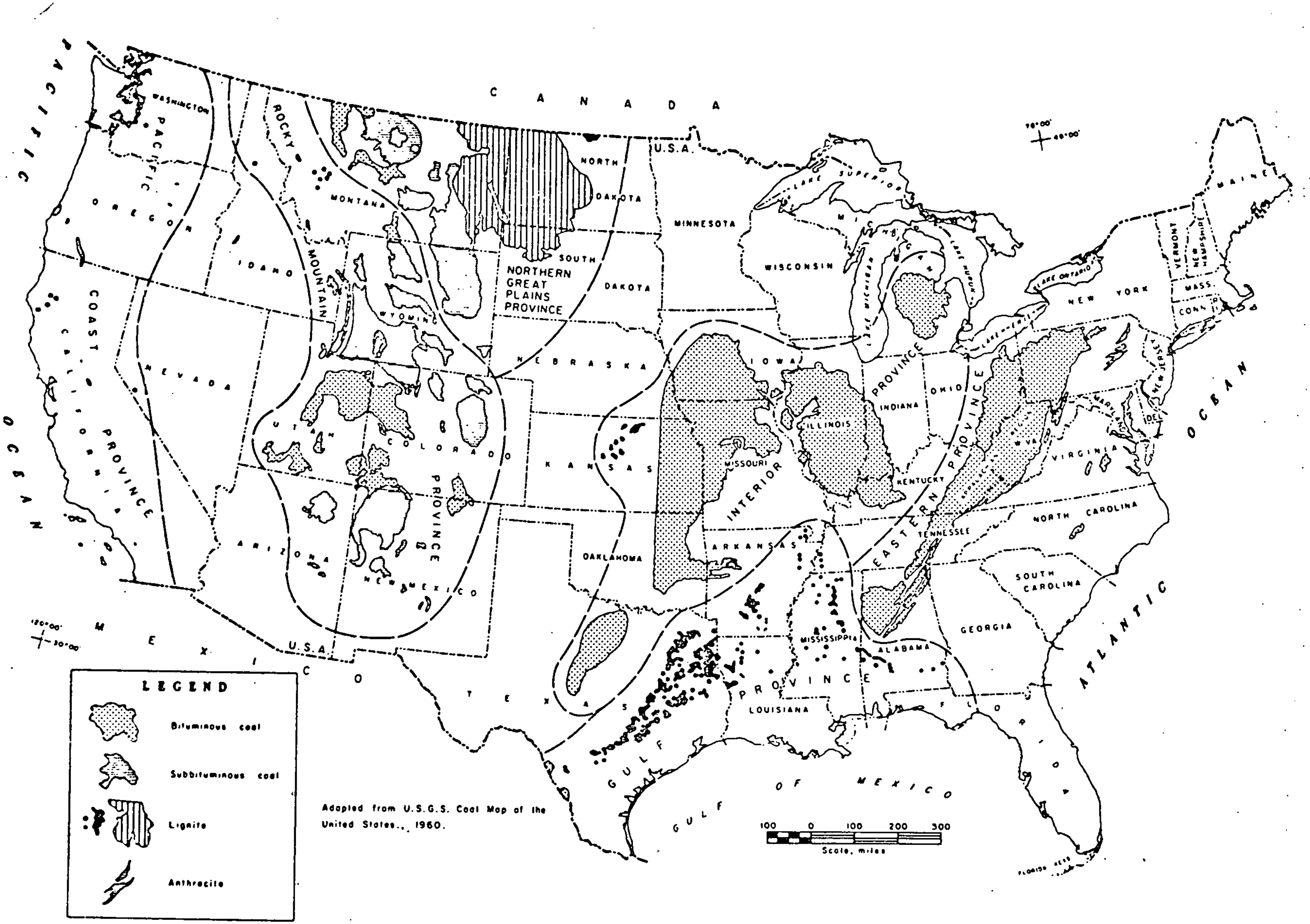

Fig. 5.1 Bituminous and Subbituminous Coal and Lignite Fields of the United States

COUNTY COAL RESERVE BASE ($x 10^6$ tons)

DEEP	STRIP
○ 1-600	□ 1-300
600-1350	301-600
1351-2100	601-1200
2101-2850	1201-1650
● 2851-4000	■ 1650-2000

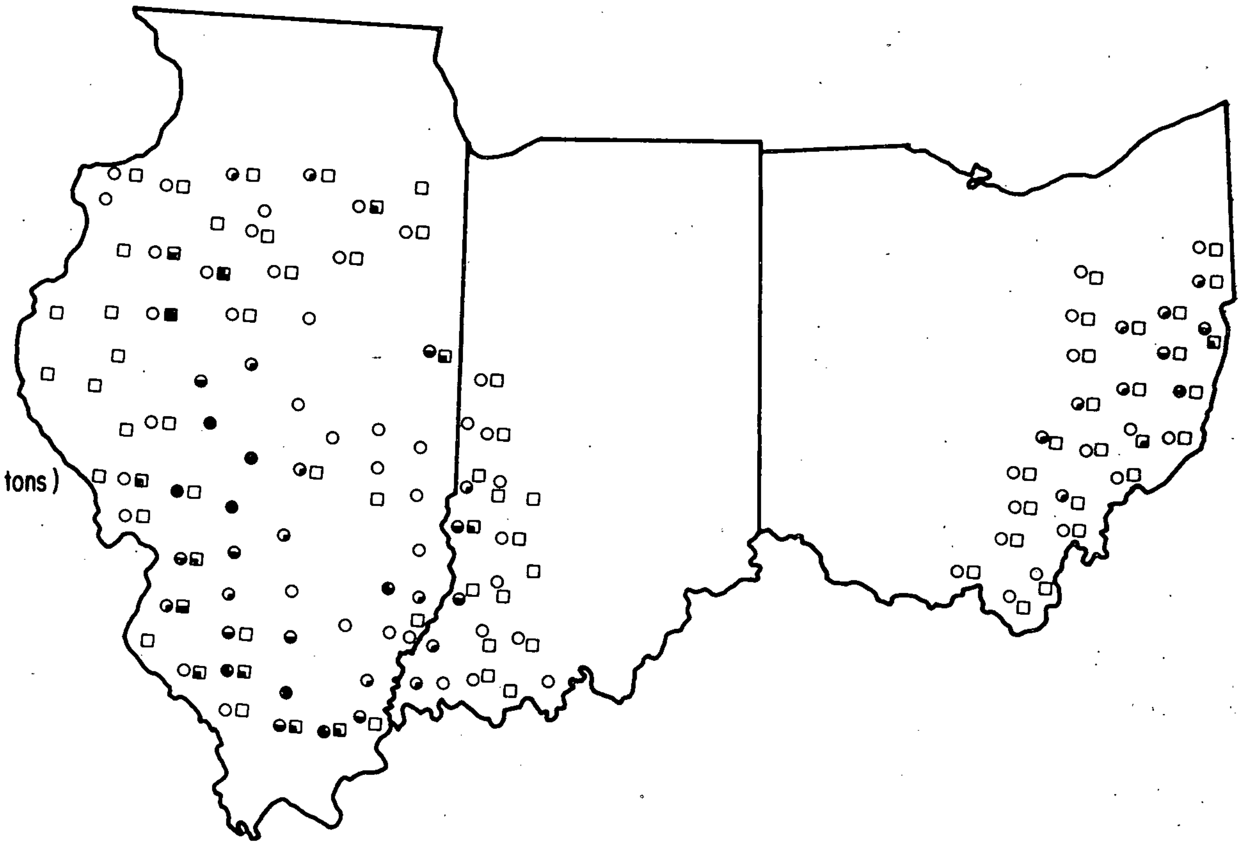

Fig. 5.2 County Coal Reserve Base Recoverable by Deep and Strip Mining

Table 5.1. Reserve Base, 1974 Production, and 1975–1985 Planned Additions by Mining Method (10^5 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.

methods 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 as follows: coal underlying urban areas; deep-minable coal reserves lying beneath airports, parks, recreation areas, public institutions, or major waterways; and coal in areas of active mining where there are multiple coalbeds, 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 coalbed. Basically, a ratio of 15 feet 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. 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%.

Air quality and emission standards have resulted in increased attention being given to sulfur content of coal. New Source Performance Standards (NSPS) for sulfur dioxide 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 an important factor in considering suitability of coal on the basis of these standards. Table 5.3 presents 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

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

State	Minimum Coalbed 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 highwall per foot of coalbed thickness.

considered in this study can be used without sulfur removal in the flue gas or by preprocessing of coals, whereas a significant fraction of the Western coals will meet the NSPS without the addition of sulfur control measures.

5.2 EXTRACTION REQUIREMENTS FOR ELECTRICAL GENERATION AND GASIFICATION

The annual coal consumption for the electrical generation and coal gasification projected by the scenarios has been given previously in Tables 2.11 and 2.12 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, the combined coal consumption for energy generation in Illinois is 6% of the reserve base for the baseline scenario, and 9% for the high-coal electric scenario. For Indiana, the scenario requires 11% of the reserve base, and for Ohio, 8%. Thus, the high levels of coal production generated do not deplete the total reserve base to any significant level. Yet, it can be expected that the coal extracted to meet this demand will be significantly less attractive economically than that currently being mined. Also, these extraction levels have the potential for causing significant local environmental and socioeconomic impacts in areas with intense mining activities.

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 bound for the area disturbed in Illinois is given by the high-coal scenario, and this limit was used as the basis for evaluation.

To obtain a value for total acreage disturbed the extraction level for all years must be specified and not just for the 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 serve the purposes of giving an upper bound for evaluation.

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)							
		.021	.042	.050	.063[c]	.100	.210	.246	.316
Alabama	13.0	0	0	.01	.27	.70	1	1	1
Arizona	10.5	0	0	0	0	.94	1	1	1
Arkansas	13.5	0	0	.03	.04	.68	1	1	1
Colorado	11.5	.01	.54	.63	.71	.93	1	1	1
Illinois	11.0	0	0	0	0	.08	.16	.19	.35
Indiana	11.5	0	0	0	.08	.23	.38	.44	.78
Iowa	10.0	0	0	0	0	0	0	0	.28
Kansas	12.0	0	0	0	0	0	.21	.36	.56
Kentucky	12.5	0	.07	.07	.30	.44	.50	.51	.84
Maryland	13.5	0	0	0	0	.41	.77	.93	1
Michigan	11.5	0	0	0	0	0	.77	.95	1
Missouri	11.0	0	0	0	0	0	0	.11	.11
Montana	8.5	0	.68	.72	.97	.99	1	1	1
New Mexico	12.0	0	.40	.40	.98	.99	1	1	1
North Dakota	6.5	0	.04	.05	.05	.48	.99	.99	1
Ohio	12.0	0	0	0	0	0	.21	.49	.78
Oklahoma	13.0	0	.08	.08	.32	.42	.72	.72	.93
Pennsylvania	13.0	0	0	.02	.02	.11	.80	.92	.99
South Dakota	6.5	0	0	0	0	.65	1	1	1
Tennessee	13.0	0	.02	.02	.20	.45	.75	.92	1
Texas	8.5	0	0	0	0	0	1	1	1
Utah	12.0	0	.76	.76	.76	.79	1	1	1
Virginia	13.5	0	.32	.48	.71	.92	1	1	1
Washington	8.5	0	.16	.16	.18	.84	1	1	1
West Virginia	13.5	0	.16	.26	.44	.55	.83	.88	.96
Wyoming	9.0	0	.37	.37	.45	.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 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		Gasification
	Baseline	High Coal[b]	
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 2.11 and 2.12.

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

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 the Sec. 5 appendix, plus additional siting factors as discussed in Sec. 4.0.

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 strip/deep ratio will be higher than that used in the baseline case, for previously marginal strip mines will become profitable as coal rise with higher demand.

There are two important points to note in regard to the start-up date listings in Table 5.5. First, only existing or planned plants greater than 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 greater than 500 MW are already located on "good" sites, as far as the utilities are concerned, and would therefore be good candidate sites for new, same-sized plants when the existing plants shut down. The argument does not apply to smaller coal plants, which are expected to decrease in numbers. By not considering the smaller plants, the estimated land disturbance in the 1975-1985 time period may be underestimated.

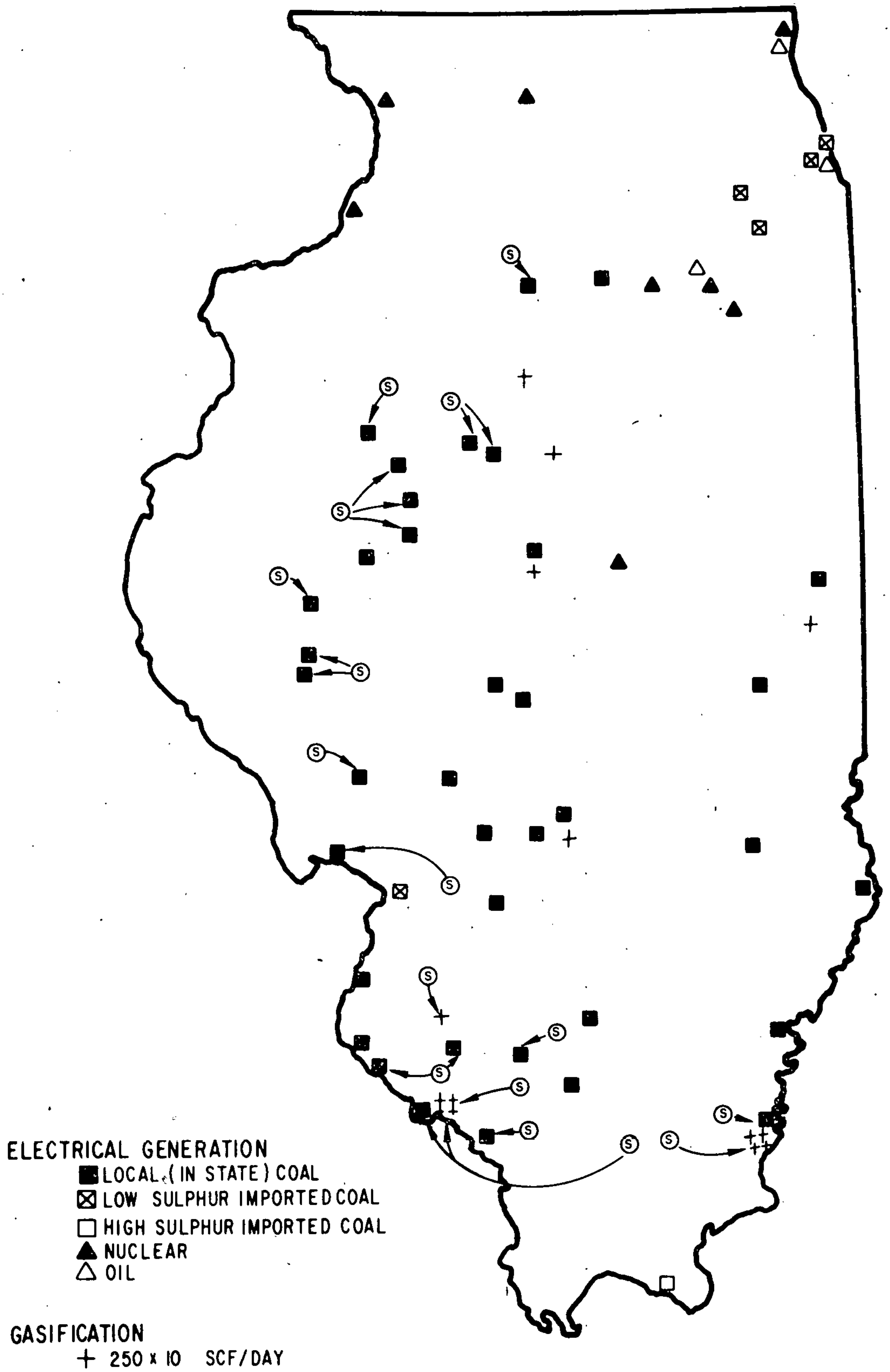

Fig. 5.3 Strippable Coal Resources in the Vicinity of Sites for Illinois High Coal Use Scenario

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

County	Start-up 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. It may be argued that the proposed strip mines will open earlier than suggested here, due to the "lower" costs of strip mining. If this alternative should occur, then the total land disturbed by 2020 will be greater than the value to be reported later.

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

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) 1975-1984	1985-1999	2000-2020	Total	Strippable Reserve Base (10^6 tons)	Average Seam Depth (ft)
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		

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 ($Mile^2$)				Total area in County ($mile^2$)
	1975-1984	1985-1999	2000-2020	Total	
Peoria	5.0	8.0	13.4	26.4	623
	3.5	5.8	9.7	19.0	
Fulton	1.4	3.0	5.1	9.5	877
	3.5	6.3	10.5	20.3	
	---	11.6	22.6	34.2	
St. Clair	---	3.6	12.9	16.5	673
Williamson	---	2.1	12.9	15.0	429
Madison	---	0.5	12.9	13.4	733
Bureau	---	---	20.3	20.3	866
Knox	---	---	17.2	17.2	728
Randolph	2.9	4.7	8.0	15.6	594
	---	---	8.0	8.0	
Schuyler	---	---	14.3	14.3	434
Jackson	---	---	3.8	3.8	605
Morgan	0.9	1.5	2.5	4.9	561
	---	---	4.3	4.3	
Gallatin	---	---	4.3	4.3	328
Green	---	---	4.3	4.3	543
Perry	---	---	0.6	0.6	439
State Total	17.2	47.1	184.6	248.9	

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.

To estimate the land disturbance, in each county, associated with the above production figures, it was necessary to develop an average seam thickness for each county. 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. Using these maps, an average seam thickness for each seam and county was estimated. If the distance between the seams was greater than 30 ft, then it was assumed that only the No. 6 seam would be mined. If the seams were less than 30 ft apart, then 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.

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

Using 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 from Tables 5.8 and 5.9 is over 300 square miles for this upper bound projection. The implications of this level surface extraction are discussed in the Volume II report on Ecological Effects.

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%

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

Start-up Date	County	Coal Consumption tons$\cdot 10^6$			Land Disturbed (Miles)^2			Reserve Base (tons$\cdot 10^6$)
		1985-2000	2000-2020	Total	1985-2000	2000-2020	Total	
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: $250\cdot 10^6$ scf/day capacity per plant; 950 Btu/scf; 70% thermal efficiency; 90% load factor; 11,000 Btu/lb coal heating value.

APPENDIX TO SECTION 5.0

Table 5A.1. Illinois Coal Reserve Base and 1974 Production Levels (10^6 tons)

	Reserve Base			1974 Production	
County	Total	Deep (>28")	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	-	-
Marshall	474	358	116	-	-

Table 5A.1. (Cont'd)

County	Reserve Base			1974 Production	
	Total	Deep (>28")	Strip	Deep	Strip
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 5A.2. Indiana Coal Reserve Base and 1974 Production Levels (10^6 tons)

County	Reserve Base Total	Reserve Base Deep (>28")	Reserve Base Strip	1974 Production Deep	1974 Production 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 5A.3. Michigan Coal Reserve Base and 1974 Production Levels (10^6 tons)

County	Reserve Base Total	Reserve Base Deep (>28")	Reserve Base Strip	1974 Production Deep	1974 Production 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 5A.4. Ohio Coal Reserve Base and 1974 Production Levels (10^6 tons)

	Reserve Base			1974 Production	
County	Total	Deep (>28")	Strip	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

REFERENCES FOR SECTION 5.0

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6.0 AIR QUALITY IMPACTS

This section describes the impact of atmospheric pollutant emissions from coal utilization facilities on the ambient air quality and rate of pollutant deposition. On the basis of this evaluation, possible constraints to coal utilization imposed by air quality regulations are 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.

An initial subsection characterizes existing air quality in the region to identify regions that now, or in the future, may be restricted from further air quality degredation from coal utilization. Section 6.2 presents unit average concentrations and depositions for subregions throughout the six-state area as well as the concentration and deposition pattern produced by a cluster of 12 power plants. The unit impacts are used to compute the 2020 cumulative impacts of the base-line scenario and Illinois high-coal-use scenario. The short-term maximum concentrations, which may be the most constraining, are considered generically in Section 6.3; cumulative short-term maximums are difficult to assess on a regional basis and are not included in this initial study. The present understanding on the potential for photochemical oxidant formation in power plant plumes is summarized in Section 6.4. The results of these initial subsections are used to discuss potential constraints that are imposed by air quality regulations, including regulations for the Prevention of Significant Deterioration (Sec. 6.5). A consideration of the relative advantages of alternative siting areas on the basis of the total human exposure that would result is presented in Section 6.6. In the final subsection (6.8), the impact of sulfur emissions beyond the immediate vicinity of the facilities is evaluated using a long-range trajectory model that includes transformation from SO_2 to sulfate aerosol.

The air quality assessment in this section considers impacts of both electrical generation and gasification from coal; however, the primary emphasis is on the electrical generation impacts because of the much larger emission rate per unit plant for the pollutants considered and the larger number of the facilities. The calculations 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.

6.1 EXISTING AND PROJECTED BACKGROUND CONCENTRATIONS

The advantages of siting a coal utilization facility in a given subregion are to a large extent constrained by the existing air quality in the subregion. Areas that should be automatically excluded as sites are those in which current air pollution exceeds the local standards or is projected to exceed air quality standards due to emissions associated with 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 ongoing or potential air quality problem was discovered.

6.1.1 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 methodology for the determination of AQMAs included the compilation of 1970 emissions from various state files, State Implementation Plans (SIPs), and the National Emissions Data System NEDS) data bank.[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 using these projected emissions in an atmospheric dispersion model. When data was available in the various regions, calibrated models were the preferred method. Areas with air quality projections exceeding NAAQS for a given pollutant were then designated as AQMAs for that pollutant. Additionally, a few areas whose 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 AQMA for particulates or sulfur dioxide would restrict the siting of additional facilities beyond those planned through 1985. The designated AQMAs in the six-state study area are shown in Fig. 6.1, along with other designated areas, as discussed in the following.

6.1.2 EPA/SAROAD Data

In counties not designated as AQMAs, an attempt was made to assess the present air quality through air monitoring data stored on EPA's Storage and Retrieval of Aerometric Data (SAROAD) system. Summary data from the years 1972-1974 were consulted, and the most recent year of data was used for those sites in which data was available for more than one year. Counties in which data from a given monitoring station were in violation of the annual and/or 24-hour primary state of federal standards for SO_2 or total suspended particulates TSP) were identified as relatively poor siting areas. A county containing a station that exceeded only the 24-hour secondary standard was not automatically identified as a poor county, since this violation could be indicative of only a single bad meteorological condition or, perhaps, a single pollutant source in the vicinity of the station, rather than indicative of a county-wide air quality problem. Locations of the counties with monitoring stations in which standards were violated (but not AQMAs) are also indicated in Fig. 6.1.

One difficulty with monitoring data is that it generally represents air quality at only idnividual sites. Unless several stations are present in a given county, one cannot obtain an adequate estimate of the air quality of the entire county. Nevertheless, a violation at a given point in a county probably does indicate 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

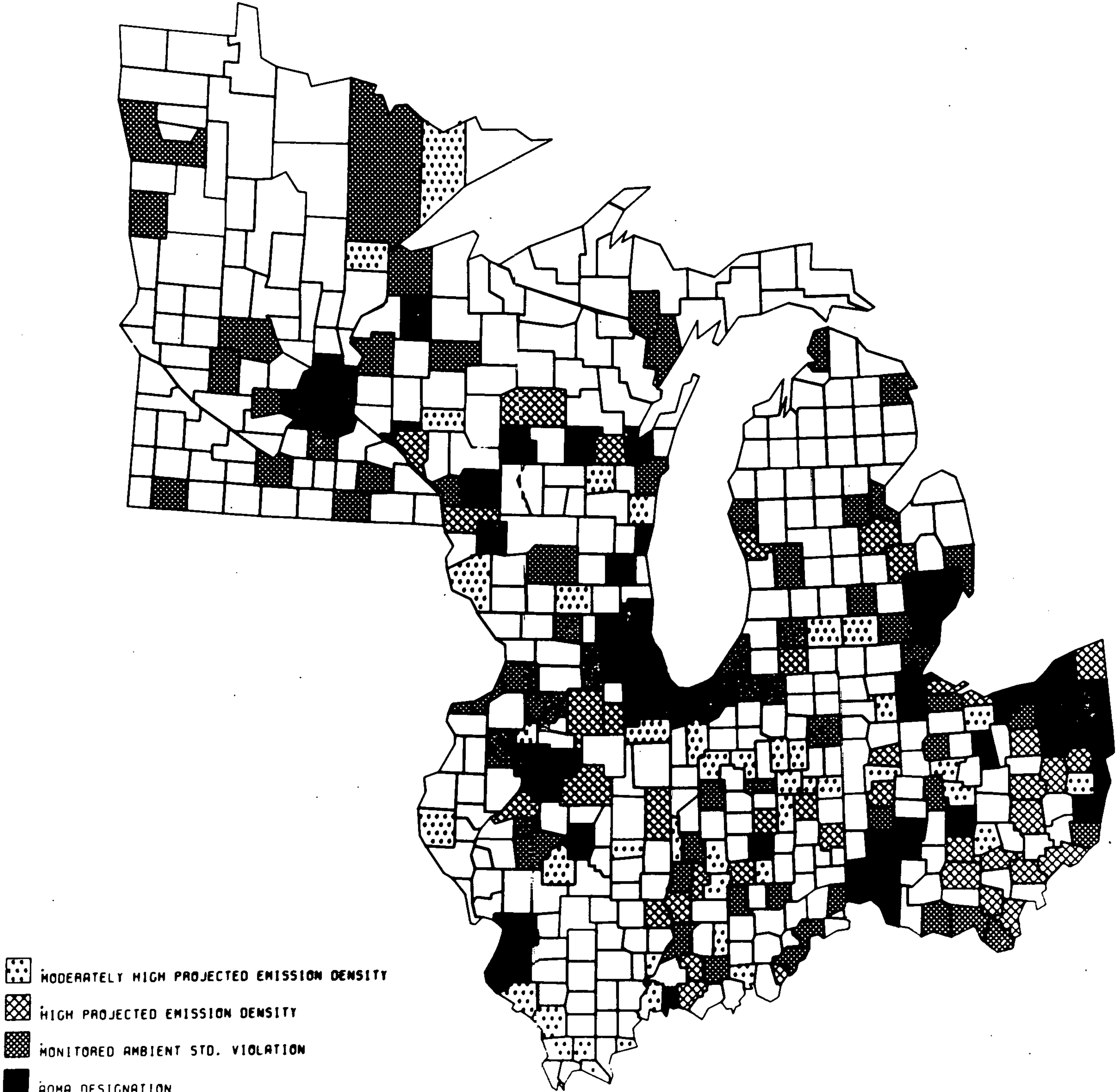


Fig. 6.1 County Classifications Based on Existing and Projected Emissions and Air Quality

sites, while many violations of TSP standards occur. Of all the SO_2 violations that occurred, each of these was at a site where TSP standards had also been violated. These coincidences would indicate that TSP is an important contaminant in constraining coal facility siting on the basis of existing air quality even though current technology can remove 99% or more of the flue gas particulates.

The EPA Monitoring and Air Quality Trends Report, 1973, revealed a general nationwide decrease in measured TSP levels.[4] This decrease is believed to represent the general success of control measures for particulates, which could imply that, in the future, background particulate levels will 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 sites for coal utilization facilities.

6.1.3 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 countywide 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 area of each county to yield an emission density for the two pollutants in units of (tons/yr)/mi^2. Future particulate and sulfur emission levels within each individual county were, according to an initial estimate, assumed to be directly proportional to the population within the county. 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.[5] 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 might 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 certain classes of sources should increase more rapidly than others, depending on the type of growth experienced in the individual counties. However, a difficulty is that using the OVERS projections of manufacturing earnings, personal income, and employment yields projected emissions that by 2020 are five times those of 1975.[3] Obviously, the problem here and the one in general with projecting emissions is in determining the effect future emission control emissions from new sources.

With present and projected emission densities available, it is necessary to determine approximately what levels of sulfur and particulate emission densities will produce an air quality problem. An attempt was made to accomplish this by observing what values of the countywide 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 breached, 52% and a 1975 TSP emission density 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 data for monitoring sites within counties that violate no TSP standards. Therefore, it was difficult to determine a representative emission density for a "clean county." Nevertheless, on the basis of available data, those counties with projected TSP emission densities greater than (20 tons/yr)/mi^2 were qualitatively designated as having "high" emission densities and those counties with TSP emission densities between 10-20 (tons/yr)/mi^2 were designated as having "moderately high" densities.

All SO_2 standard violations occurred within counties that had TSP violations or were designated as part of an AQMA. Thus, it was assumed unnecessary to determine a sulfur dioxide emission density level that would classify a county as having high emission levels. Nevertheless, SO_2 concentrations that are a significant fraction of the annual standards could possibly constrain coal utilization facility siting by providing high background concentrations. From the data, it was discovered that SO_2 emission densities in excess of 40 (tons/yr)/mi^2 resulted in yearly SO_2 concentration averages at the monitoring stations of 40 $\mu g/m^3$ to 75 $\mu g/m^3$ compared to the NAAQS of 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. 6.1. Designation of counties as AQMAs or having NAAQS violations supersede the emission density criteria in Fig. 6.1.

6.1.4 Sensitive Geographical Areas

The areas in Fig. 6.1 shaded according to various criteria indicate those areas in which a current or projected air quality problem exists. Comparison of these areas with projected siting patterns is useful in designating regions in which the demand for increased energy production could possibly come in conflict with the maintenance of adequate air quality. Figure 4.1 indicates a siting pattern for the baseline scenario for the year 2020. Direct comparison of Fig. 6.1 with Fig. 4.1 serves to identify several "sensitive areas" in the region in which current or future coal facility siting occurs within areas of poor or potentially poor air quality.

Figure 6.2 shows the result of such a comparison and indicates that the greatest number of sensitive areas lie in the states of Illinois and Ohio. These states have a large number of counties with current or projected air quality problems as well as high projected energy demand. Most of the sensitive areas lie in and around the larger population centers from which these air quality energy demand problems emanate.

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

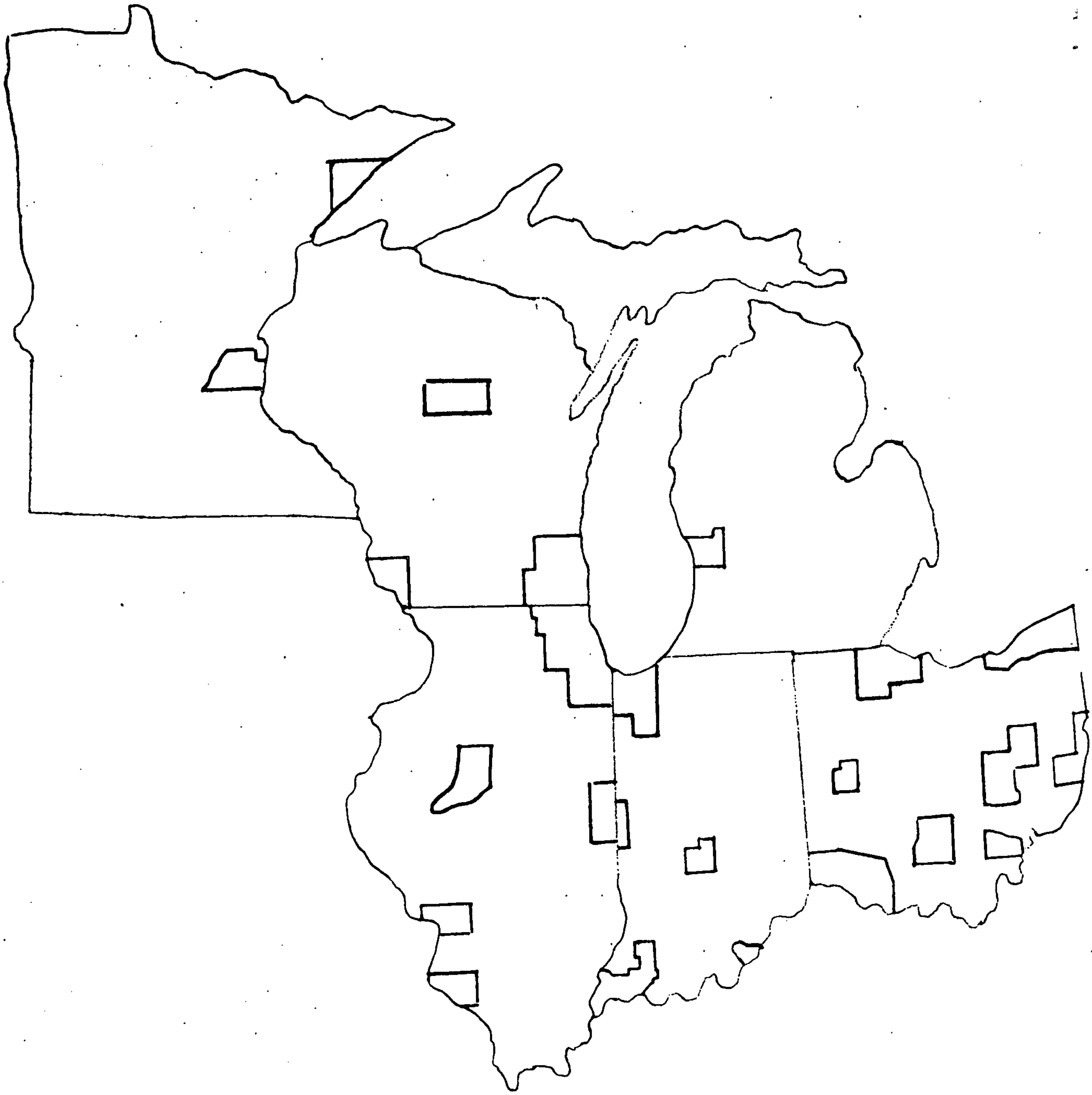


Fig. 6.2 Areas with Projected Air Quality Maintenance Problems Coinciding with Coal Facility Siting Areas for 2020 Baseline Scenario

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 such that the plume(s) originating from it would have minimal interaction with existing plumes in the county.

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

6.2 ANNUAL AVERAGE IMPACT OF COAL USE SCENARIOS

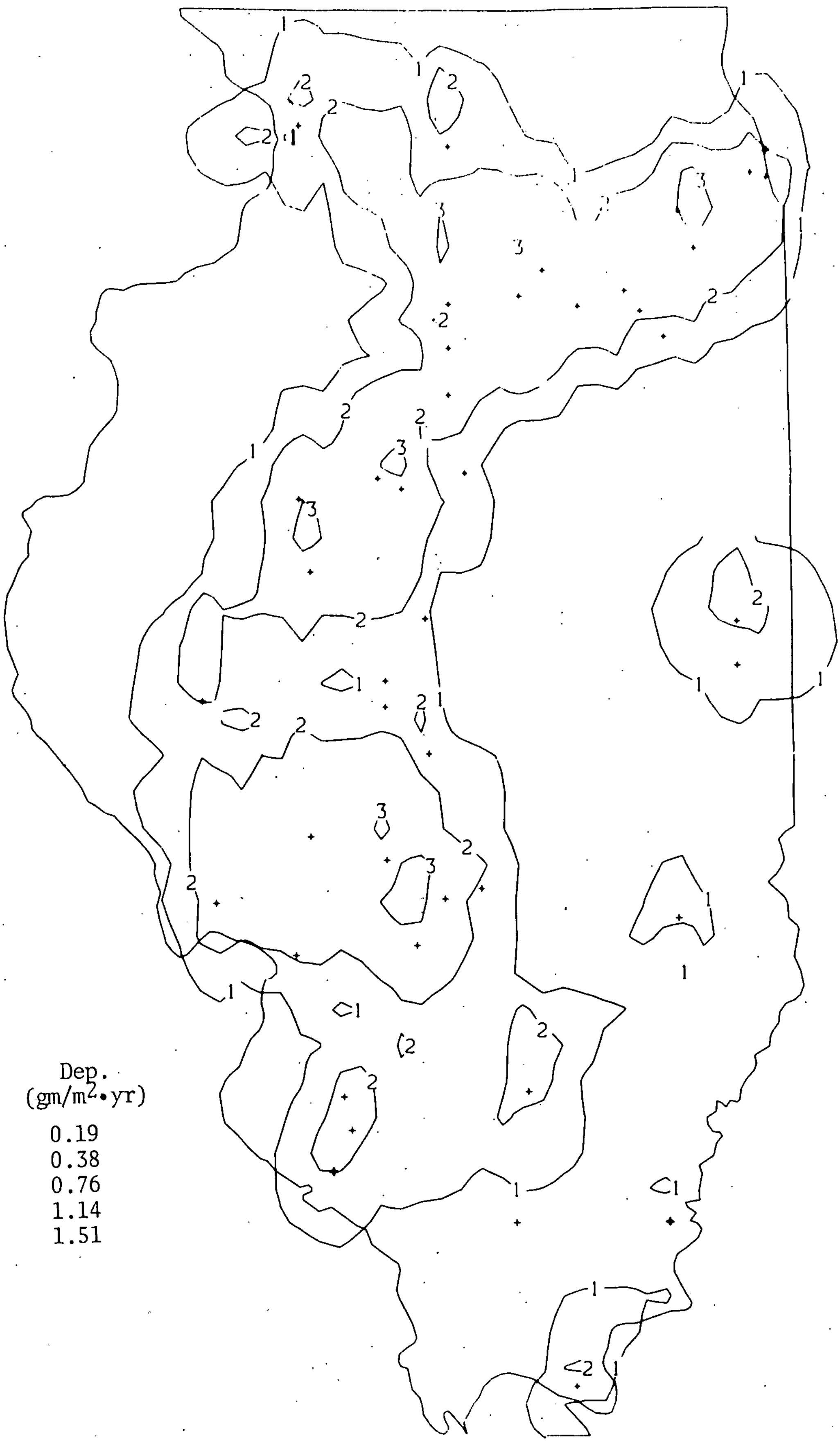
A rather extensive modeling effort was carried out to identify the annual concentration and deposition impacts from coal-fired power plants and gasification plants. The methods and detailed results of this effort are contained in Sec. 6A.1 and 6A.2 of the Appendix to Section 6.0. This effort took into account the variation of impacts at different parts of the six-state region due to the variability in meteorological conditions. The determination of the dispersion patterns from 71 different subregions within the six-state region served as input to calculating the cumulative impacts of the region's scenario. In addition to the characterization of the impacts on air quality of individual facilities, the representative impacts of a cluster of 12 facilities, a 6-sq-mi area, were analyzed. The configuration utilized is described in the G.E. study[8] and is illustrated in Fig. 6A.3.

The annual average impact analysis 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 ambient air quality standards do not presently exist for trace elements, the analysis was carried out to provide a coarse estimate of the magnitude of the trace element problem.

The local air quality impacts 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 the Figs. 6.3 and 6.4 for SO_2 with the contour values for various other pollutants as given in Table 6.1. Table 6.2 gives the annual deposition estimates using the results in the Appendix for this section.

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. 2.0. An evaluation of impacts at 100% load, which would produce a conservative upper bound for those 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 containing the greatest number of facilities. The largest 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.



Conc. ($\mu g/m^3$)		Dep. ($gm/m^2 \cdot yr$)
1	0.6	0.19
2	1.20	0.38
3	2.40	0.76
4	3.60	1.14
5	4.80	1.51

Fig. 6.3 Cumulative Annual Average SO_2 Concentration and Deposition for Base-Line Scenario (2020). (a) Illinois

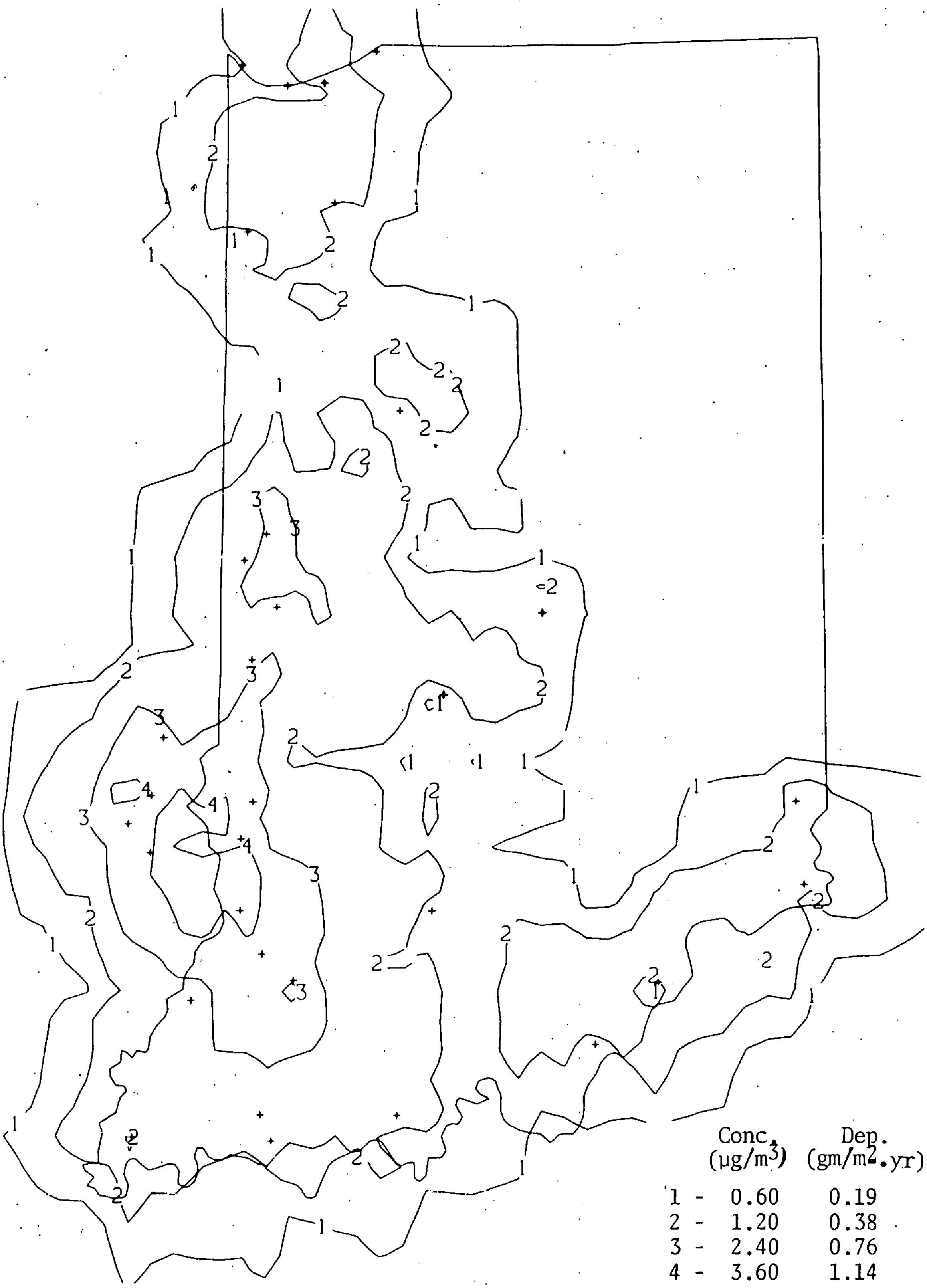


Fig. 6.3 (Cont'd) (b) Indiana

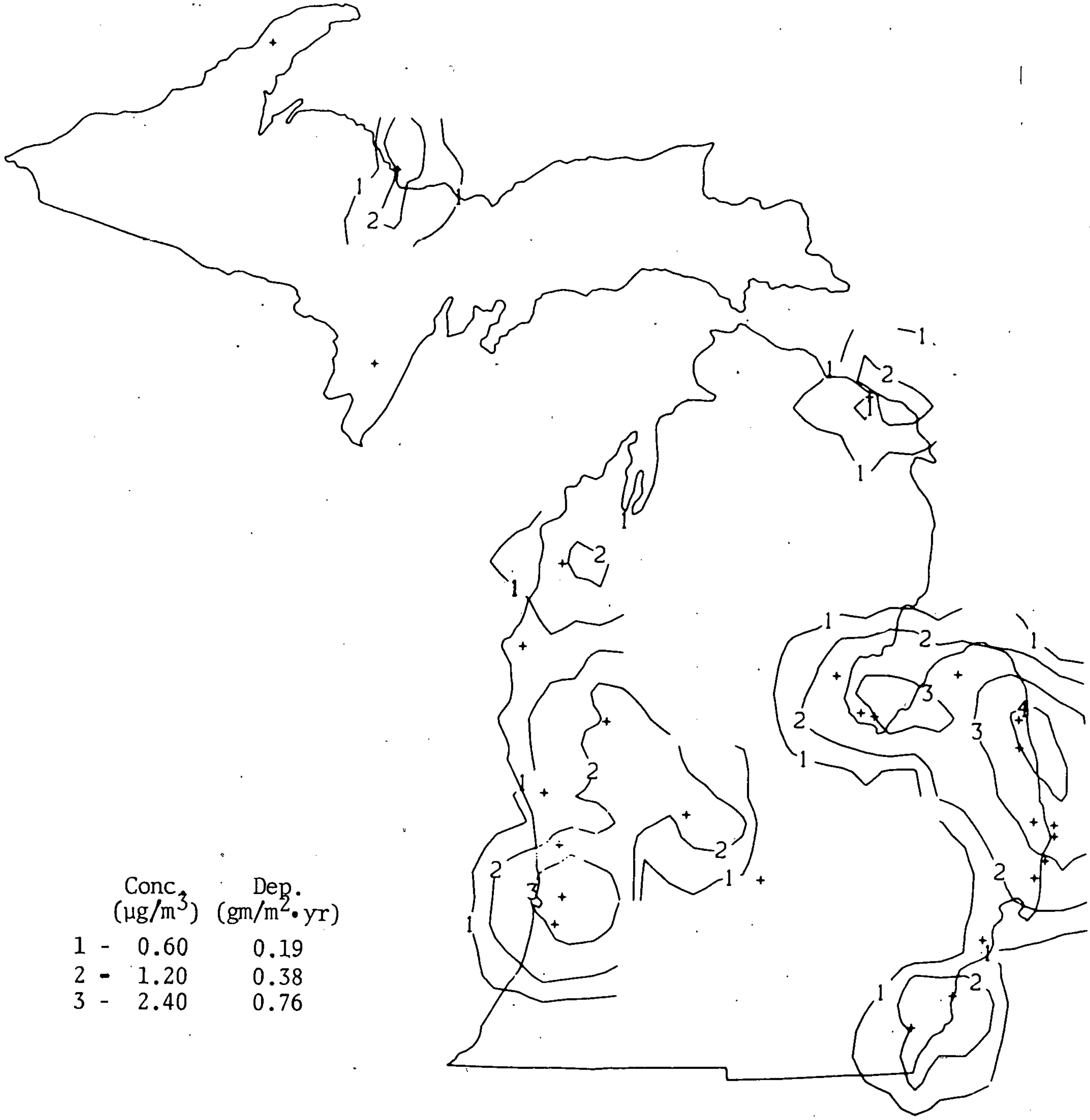


Fig. 6. Fig. 6.3 (Cont'd) (c) Michigan

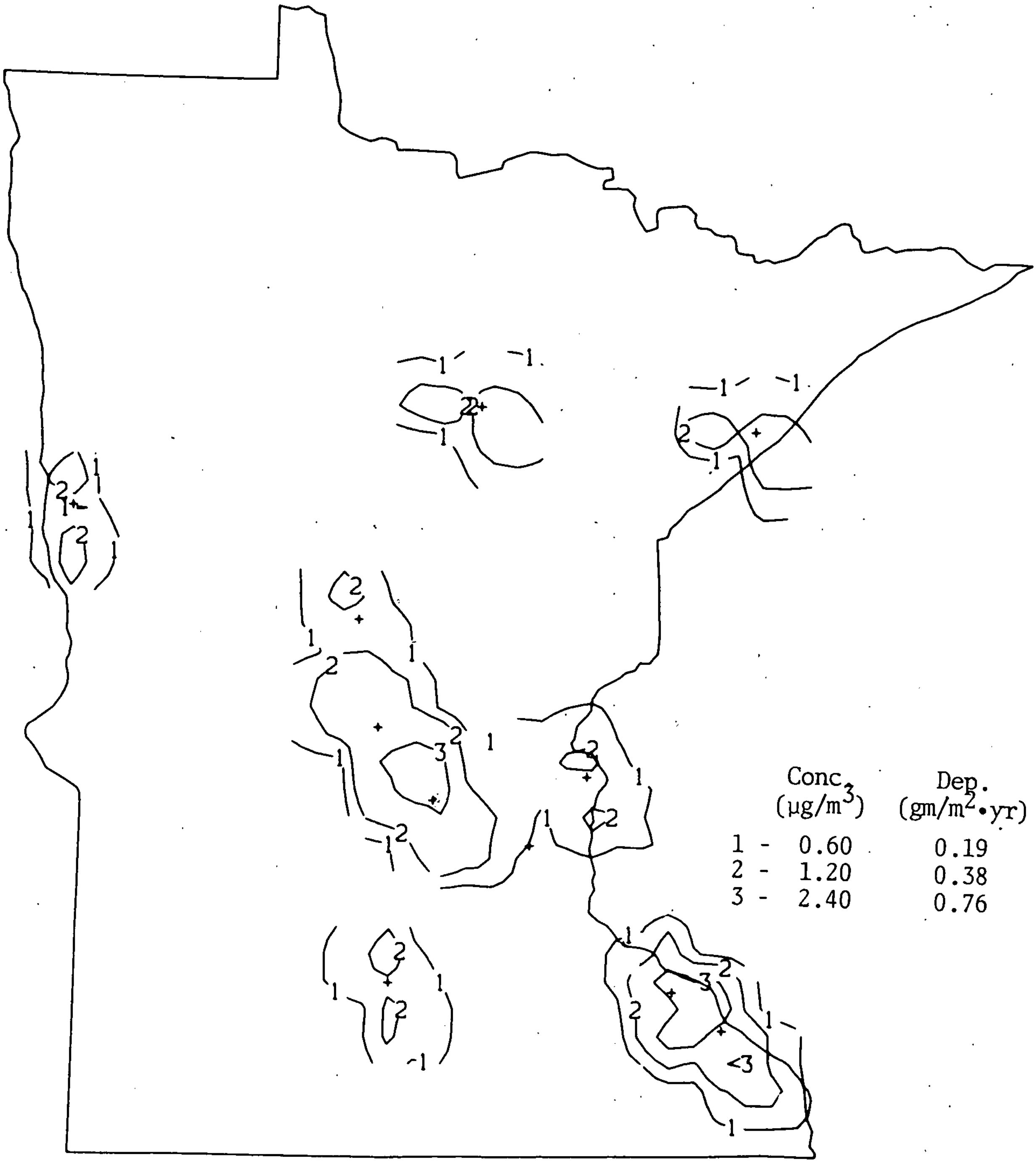


Fig. 6.3 (Cont'd) (d) Minnesota

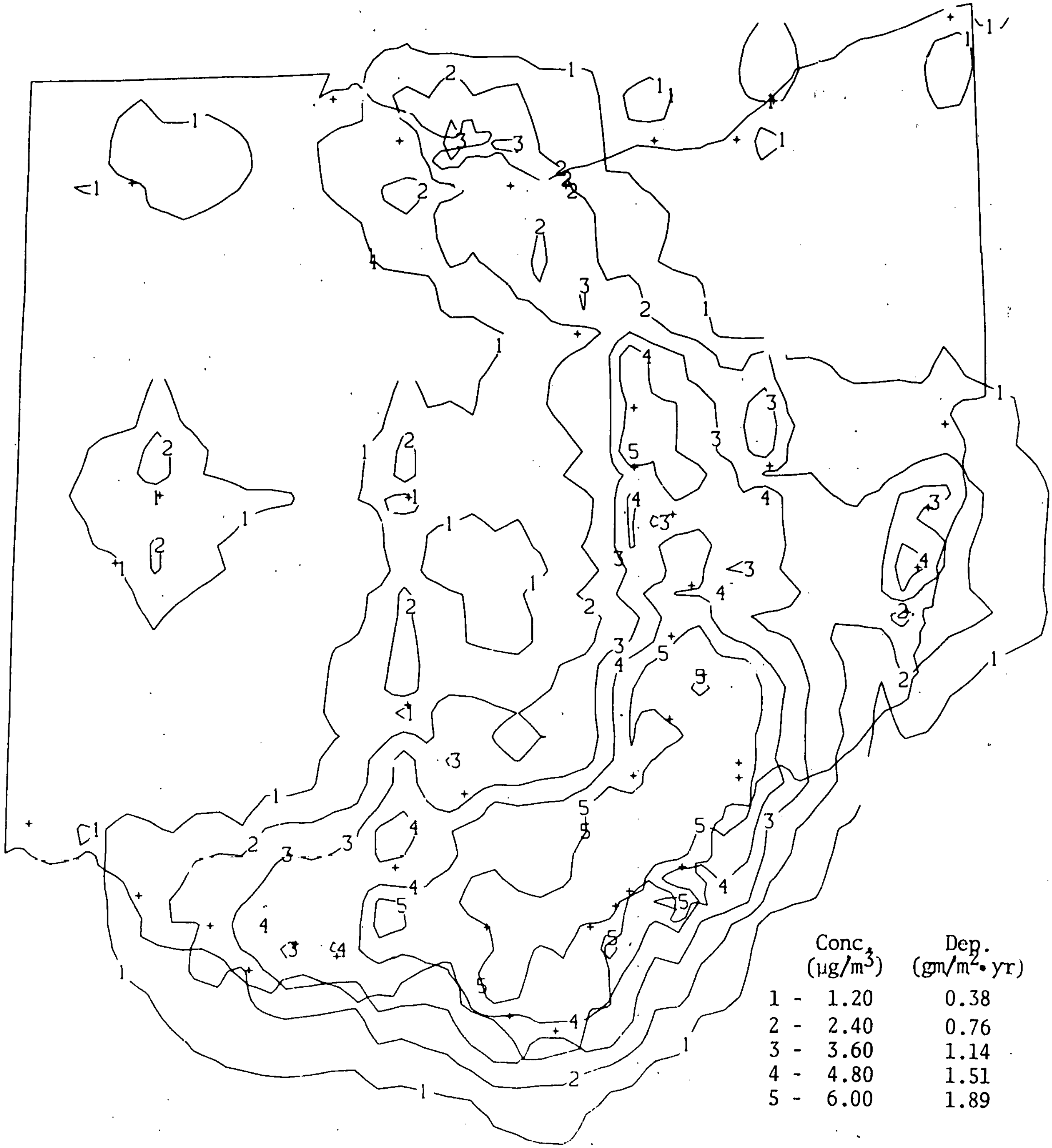


Fig. 6.3 (Cont'd) (e) Ohio

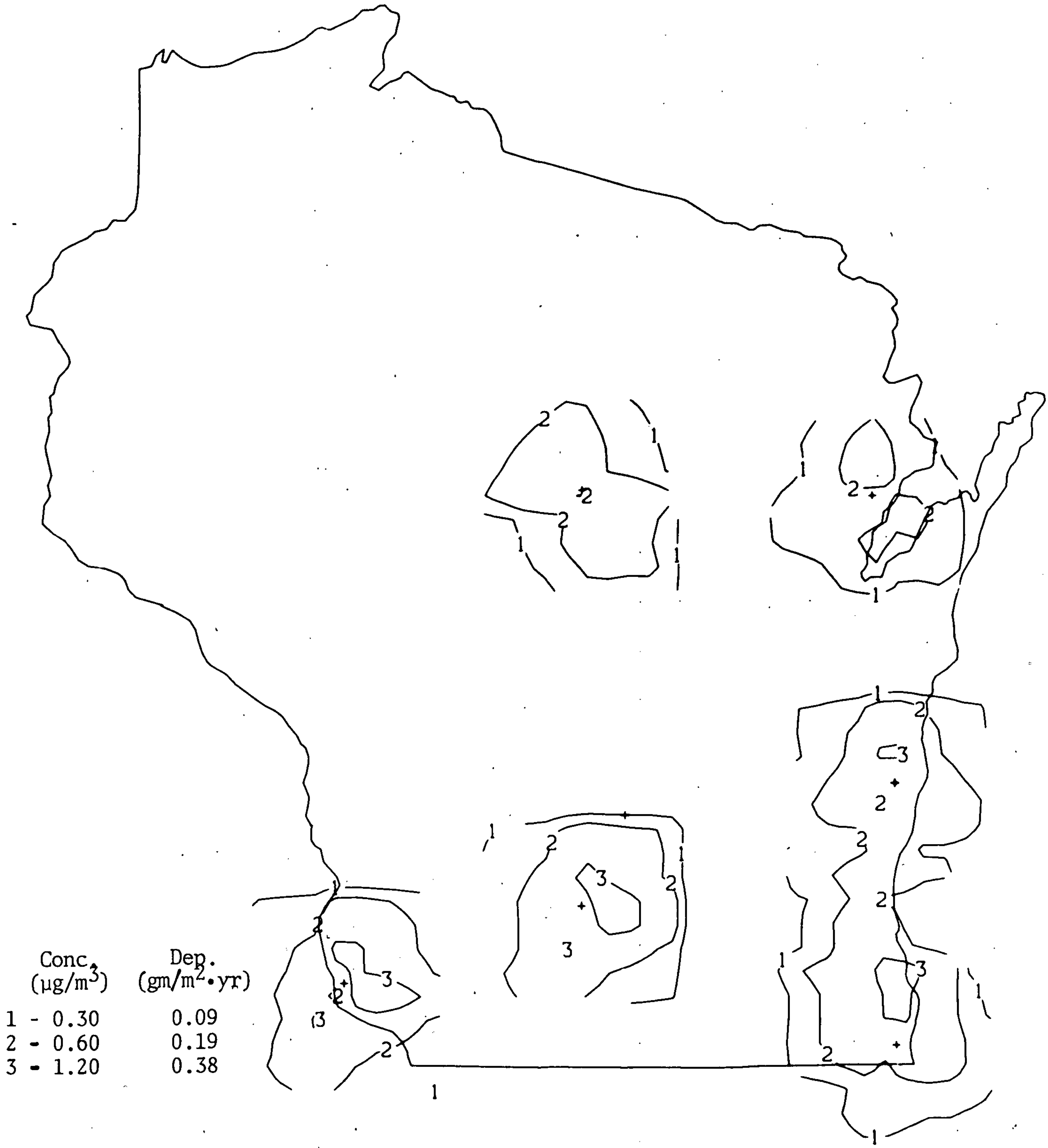


Fig. 6.3 (Cont'd) (f) Wisconsin

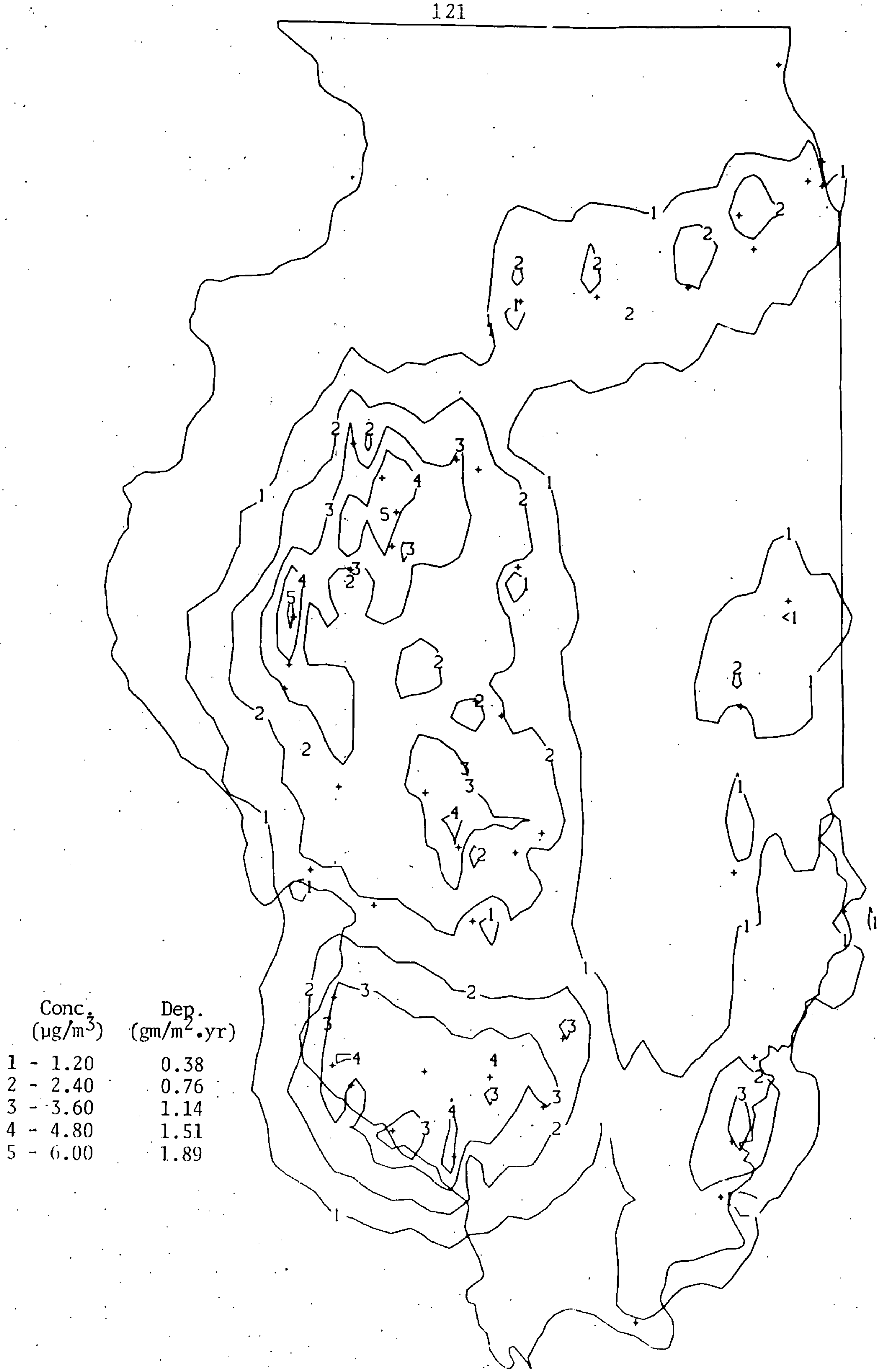


Fig. 6.4 Cumulative Annual Average SO_2 Concentration and Deposition for Illinois High Coal Scenario (2020)

Table 6.1. Various Pollutant Concentrations Corresponding to SO_2 Isopleths in Figs. 6.3 and 6.4

Pollutant	Concentration ($\mu g/m^3$)						
SO_2	0.30	0.60	1.20	2.40	3.60	4.80	6.00
NO_x	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 6.2. Various Pollutant Deposition Rates Corresponding to SO_2 Isopleths in Figs. 6.3 and 6.4

Pollutant	Deposition Rate (g/m^2 yr)						
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.

Figure 6.4 presents the cumulative impacts of the Illinois high-coal-use scenario. Comparison of this figure with Fig. 6.3a reveals that the dispersion patterns are similar, but the magnitude of the concentrations quite different. The magnitude of the concentrations produced by the high-coal-use scenario is about twice the magnitude of the concentrations produced by the baseline scenario in Illinois.

Comparison of Figs. 6.3a-6.3f with Fig. 6.2, 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 takes precedence in these areas over air quality criteria. A notable exception occurs in northeast Ohio, where most of the facilities in this sensitive area are nuclear plants.

6.3 SHORT-TERM CONCENTRATION IMPACTS

Short-term maximum concentrations were estimated primarily from the results of a G.E. Study.[8] The G.E. results were adjusted for the emissions from the standard 3000-MWe electrical generation and 250 x 10^6 scf/day gasification facilities. The results of the analysis as well as the methodology employed appear in Section 6A.3 of the Appendix to Section 6.0.

On the basis of the analysis, it was concluded only two controllable factors exist that 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 through the application of various emission control devices. The second factor is the height of the stack itself. An increased stack height will tend to minimize the occurrences of extremely high ground-level concentrations, although it cannot guarantee that high concentrations will never exist. However, decreasing the 244-m stack height used in this study by ½ to 122-m increased the estimated short-term maximum concentration by approximately 50%.

Meteorological factors such as atmospheric stability, wind speed, and mixing height also produce a wide amount of variation in short-term ground level concentrations. Unlike the two factors already mentioned the meteorological factors cannot be controlled. However, the meteorology of an area in which a power plant is to be sited should be closely studied to determine the frequency of occurrences of conditions that produce high ground-level concentrations. Areas with a frequency of such characteristics are certainly less desirable as sites and probably require greater emission controls. A comparison of short-term estimated concentrations from various coal utilization facilities to the NAAQS and PSD regulations is contained in Sec. 6.5.

6.4 POTENTIAL FOR PHOTOCHEMICAL OXIDANT FORMATION IN POWER PLANT PLUMES*

Exposures to elevated 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 as is discussed in more detail

*Adapted from Ref. 9

in other sections of this report. Coal processes relate to these oxidant levels and their ill effects first of all because of the possible synergistic effects of the oxidants and the primary coal process emission, and, secondly, because these emissions may contribute to the chemical and physical processes leading to the production of the oxidants. The following is a brief summary of this latter potential role of coal derived emissions in contributing to increased oxidant levels.

Ozone (O_3) the major oxidant of smog, is formed when oxygen atoms react with oxygen molecules in the presence of a third body (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 happens very quickly. Therefore, the important reaction for the 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).

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

In this reaction, $h\nu$ is the 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 currently known to be important in urban smog formation, the reactions that drive or keep this ratio high are the peroxy radical reactions:

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

where R can be hydrogen (H) 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 back 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 large quantities of reactive hydrocarbons required to increase the NO_2/NO ratio. In the absence of existing background concentration of hydrocarbons the NO emissions may in fact deplete the ozone concentrations within the plume. On the other hand, ozone increases results from the NO_x emissions if associated with high hydrocarbon levels as might occur in an urban area. Furthermore, it may be that for power plant plumes some mechanism not associated with hydrocarbons could oxidize NO_2 to NO to drive the ratio and hence ozone concentrations up. A chlorine mechanism and a sulfur mechanism have been proposed, but little, if any, data are available to support either of these mechanisms. Indeed experimental field data does 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 are significant enough to warrant further study to define more adequately the complex relations between constituents of the power plant plume. Also of importance is an evaluation of the impact on urban photochemical smog from coal process nitrogen oxide emissions, in particular as these emissions possibly become more dominant because of more stringent standards on automobile emissions.

6.5 COAL UTILIZATION CONSTRAINTS RELATED TO AIR QUALITY STANDARDS

6.5.1 National Ambient Air Quality Standards (NAAQS)

Under the mandate of 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 this pollutant was not considered further. There have been levels of ozone exceeding the 24-hour standard of 160 μg/m in the vicinity of power plants; however, there is no conclusive evidence as to what extent there levels are attributable to plant emissions alone.

The NAAQS for the remaining four pollutants are given in Table 6.3 along with estimates from previous sections of the impacts from the 3000-MWe electric generation facility and the 250 x 10^6 scf/day gasification plant with emissions as given in Tables 3.5 and 3.10, respectively.

Table 6.3 clearly illustrates that the coal utilization facilities considered do not of themselves 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 Illinois high-coal-electric scenario, which represents the plausible upper bound in coal conversion facility density for any state, cumulatively contribute less than 10% of the annual NAAQS in any one location.

On the other hand, the short-term 24-hour standard for SO_2 will limit the size and emission rate of the electrical generation facilities. The 3000-MWe facilities considered in this study appear to represent the upper limit in 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 Section 6.4.

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. 6.1.2, existing ambient TSP concentrations are generally higher relative to standards than are SO_2 levels; hence, careful consideration must also be given to particulate impacts when assigning priority to facility siting.

On the basis of the estimates given in Table 6.3, deployment of Gasification facilities is not to any significant degree constrained by existing NAAQS.

Table 6.3 Comparison of NAAQS and Estimated Maximum Concentrations from Coal Utilization Facilities

				Maximum Concentration $\mu g/m^3$				
Pollutant	Type of Standard	Avg'ng Time	Frequency Parameter	NAAQS	3000 MWe	Cluster $12 \cdot 3000$ MWe	HYGAS[a] Gasification $250 \cdot 10^6$ 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 windspeed and load factors as in Table 6.7. For the gasification alternate windspeeds 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 implementation plans for achieving the annual maximum 24-hour standard. Computed concentrations for facilities are arithmetic mean.

Table 6.3 also shows that carbon monoxide can be ignored as a potential inhibiting factor.

6.5.2 Regulations for the Prevention of Significant Deterioration

Potentially more constraining to coal utilization than the NAAQS, are the regulations for Prevention of Significant Deterioration (PSD) promulgated by the USEPA for the purpose of preventing certain areas from large increases in ambient SO_2 and particulate concentrations beyond existing levels, even if those existing levels are significantly below NAAQS. These EPA PSD regulations are summarized in Table 6.4.[10] As shown in Table 6.4, the EPA regulations would establish three classes of areas with curbs as follows:

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

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

Class III - Applies to areas in which deterioration would be permitted to allow concentrated or very large scale energy or industrial development, as long as the national secondary ambient air quality standards 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 6.4 Allowable Air Quality Increments under EPA PSD Regulations

Pollutant	Averaging Time	Allowable aq Increments ($\mu g/m_3$) Class I	Class II	Class III
SO_2				
	Annual	2	15	80
	24-hour Max	5	100	365
	3-hour Max	25	700	1300
Part.	Annual	5	10	75
	24-hour 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 the Congress is in the process of considering amendments to the Clean Air Act that provide explicit guidelines in relation to 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 6.4. However, the proposal under consideration does not provide for Class III areas. Also the proposed amendment differs substantially from the existing EPA regulations in that certain areas are designated as mandatory Class I areas and other areas as Class I, 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 greater that are International Parks, National Parks, National Wilderness Areas, or National Wildlife Refuges.

The following is an initial evaluation of how either the existing or proposed PSD regulations as summarized above would constrain the coal utilization scenarios considered in this report. The EPA Class III area allowable concentrations are defined as being equal to the NAAQS. Thus, no additional curbs exist beyond those possibly resulting from the short-term 24-hour maximum NAAQS as discussed previously.

From comparison of Table 6.4 and the estimated maximum concentrations in Table 6.3, the allowable Class II area increments would not be a constraining factor in terms of the annual average concentrations, except for the large 36,000-MWe clusters. However, the more stringent 24-hour SO_2 standard would require a 40-80% reduction in coal electric emissions at individual source locations, either through reduction in plant capacity, lowered coal sulfur content, 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, thereby in all likelihood eliminating the possibility of using intermittent controls as a principal mechanism for reducing short-term maximums in lieu of other available control technologies.

For any foreseeable technology the large coal utilization facilities considered in this study would be prohibited from siting in Class I areas with their very stringent constraints on allowable increments, 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 estimated 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 implemented 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. The removal of SO_2 is included using the linear model discussed in the Appendix Section 6A.1.

The resulting estimates of maximum 24-hour concentrations versus distance are shown in Fig. 6.5 for various types of facilities.[14] The standard 3000-MWe 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 the order of 100 miles out, 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

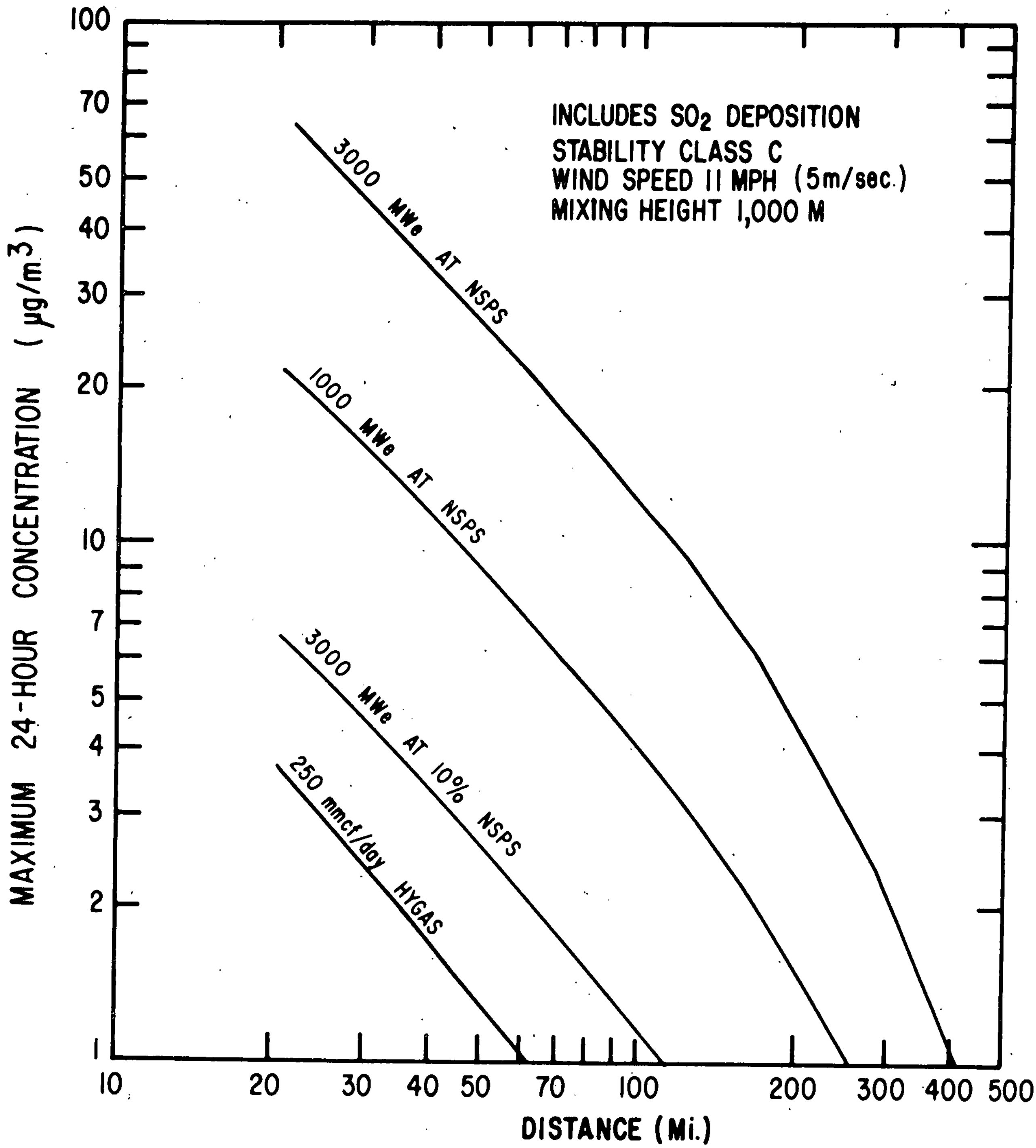


Fig. 6.5 Maximum 24 hour SO_2 Concentration vs. Distance from Source

of low sulfur coal and flue gas desulfurization, or other advanced technologies (or equivalently, reducing the capacity to 300 MWe at NSPS), would reduce the required distance from the site to the Class I area to approximately 30 miles, according to the model. Because of their lower SO_2 emission rates, gasification plants would only be excluded from the immediate vicinity of the Class I areas.

Implications of the proposed PSD regulations with respect to the siting scenarios used in this study are shown in Figs. 6.6 and 6.7 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.

6.6 TOTAL POPULATION EXPOSURES FOR ALTERNATE SITING AREAS

The representative subregion concentration described in Section 6.2 may be used in a varity 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, one of the considerations involved in siting a new facility is the incremental increase in SO_2 and sulfate dosage to population. Calculations have been carried out of the incremental dosage that would result from siting a power plant at each point on an approximately 20km grid established within each of the 71 regions throughout the six states for which concentration maps were calculated. Figure 6.8 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 smeared out 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. 6.8.

Figure 6.8 reveals that the highest incremental increase of exposure for a single facility in Illinois will occur if that facility is located in the Chicago metropolitan area. The maximum exposure will occur if the plant is located slightly south and west of the center of the city. This 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. 6.8 occurs around the Peoria area. However, the exposure resulting from siting a power plant there is on an approximate order of magnitude smaller than that which results from siting near Chicago. The projected sites for the Illinois high-coal scenario plotted on the map can be compared to the exposure isopleths to determine whether the projected sites are advantageous from a health-effects viewpoint.

Due to the lack of coal reserves in the north and northeast sections of Illinois, mine-mouth coal utilization facilities cannot 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

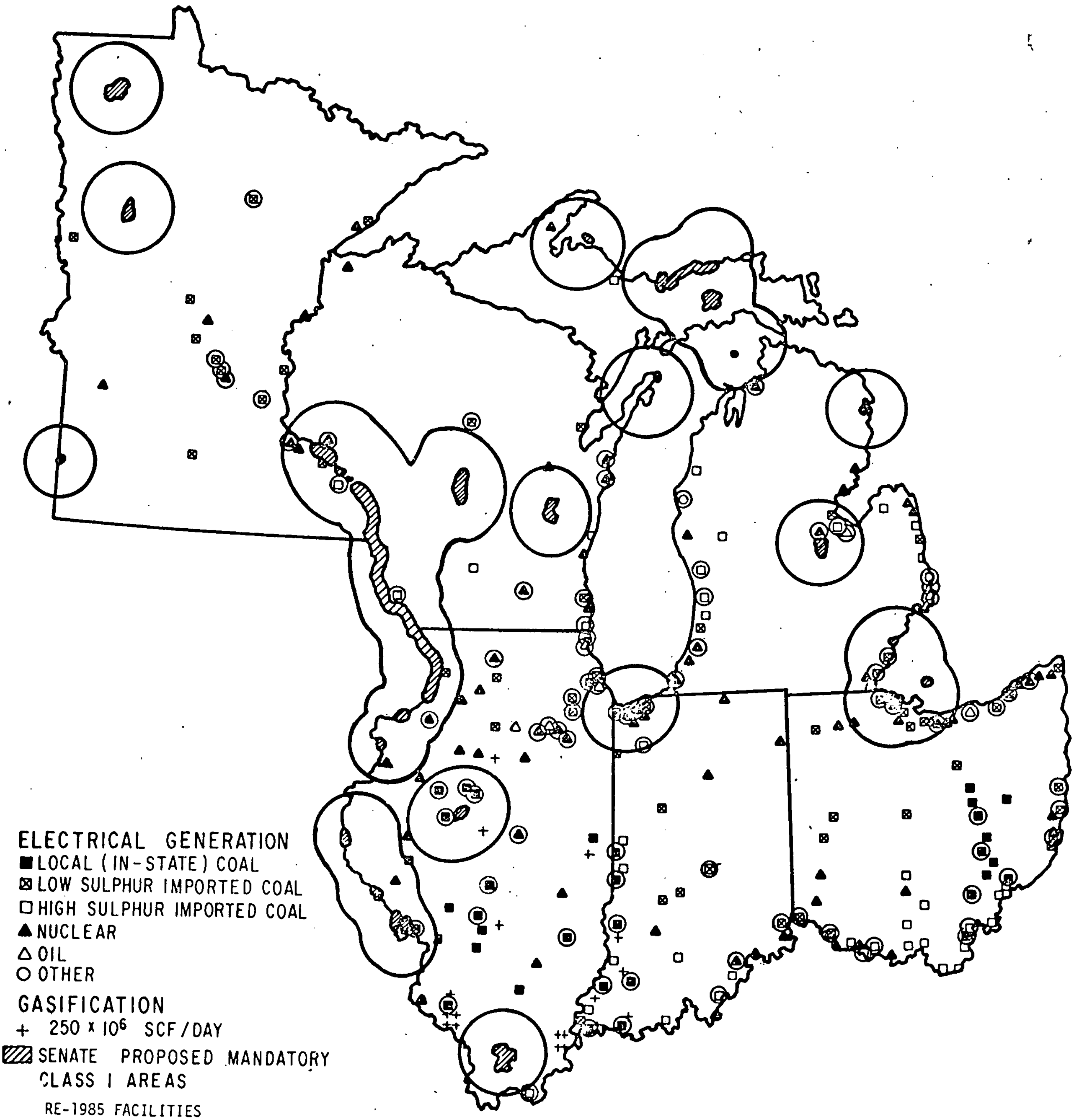


Fig. 6.6 Superposition of Baseline Siting Pattern and 30-mile Buffer Zone for Proposed PSD Class I Areas

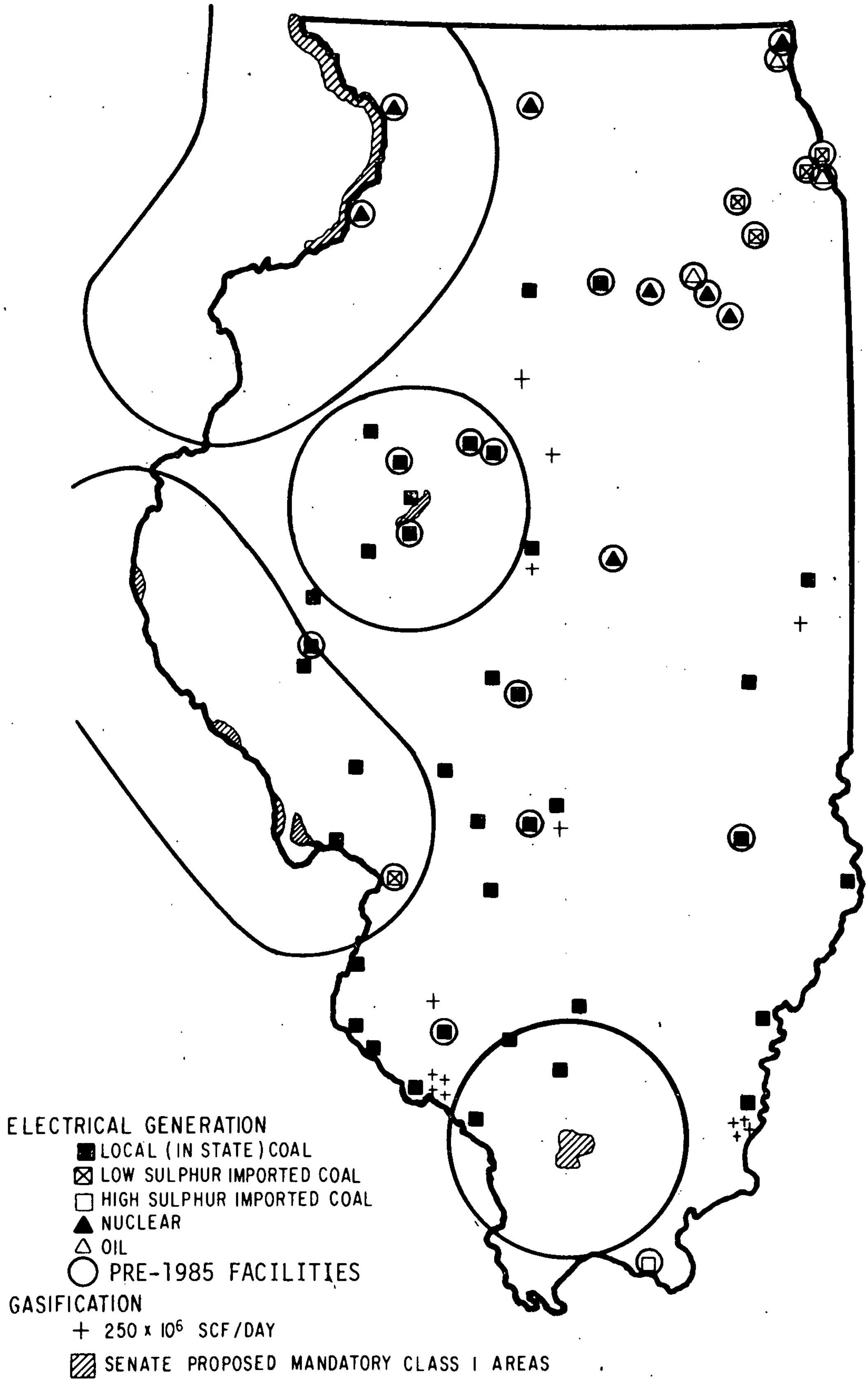


Fig. 6.7 Superposition of Illinois High Coal Use Siting Pattern and 30-mile Buffer Zone for Proposed PSD Class I Areas

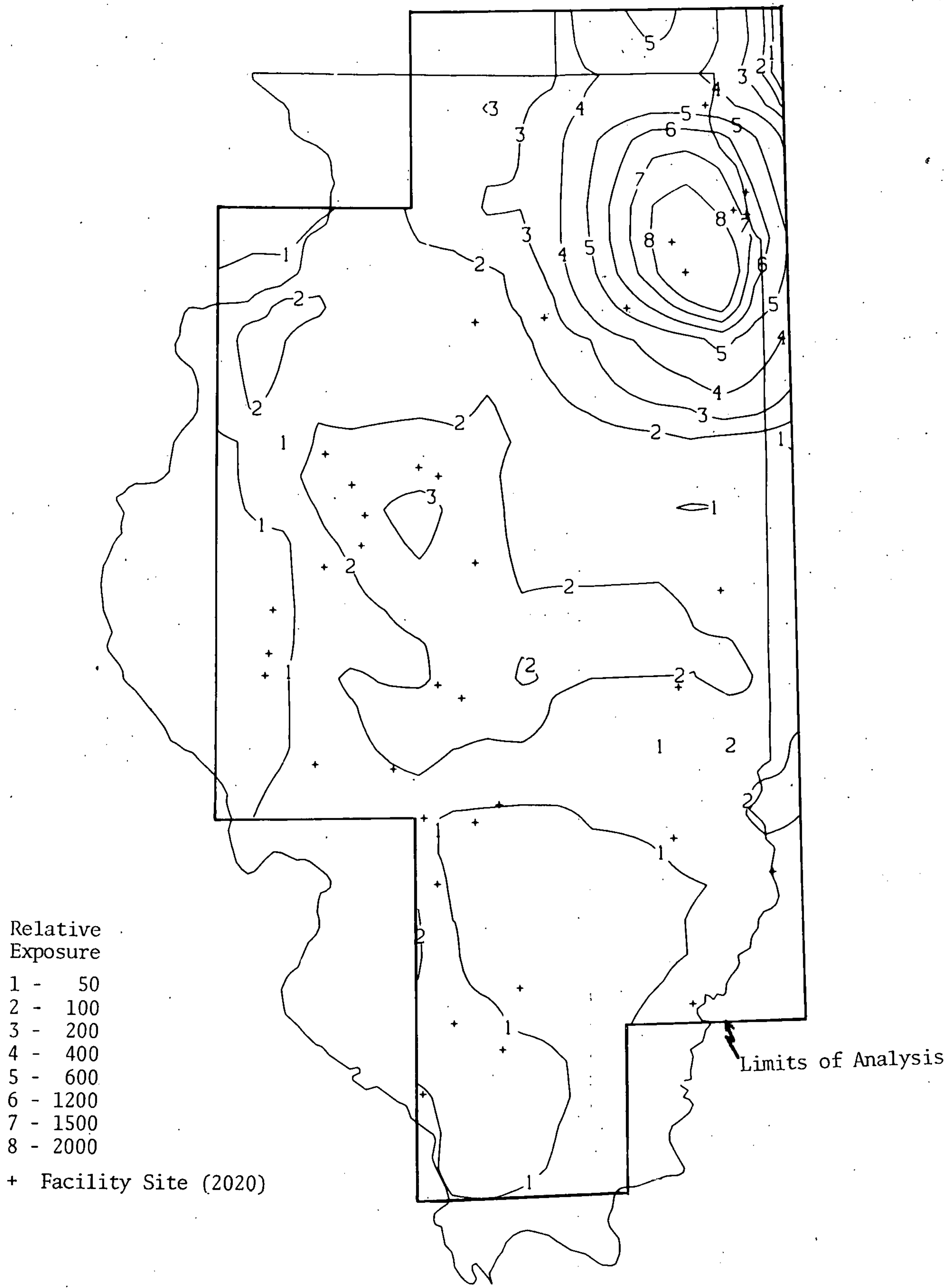


Fig. 6.8 Isopleths for Site Dependent Integrated Population Exposures (persons x μg/m^3) from Single Coal Facilities in Illinois

occurs. Unfortunately, southern Illinois, which is a very desirable area for siting from a standpoint of minimizing exposure, has a lack of significant water resources. Hence, it can be concluded that 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 resources are fairly abundant and the exposure due to coal facility siting is relatively low.

The advantage of these contour maps shown 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 for example.

It is important to realize that the distance over which the concentration distributions extend is about 50 km from the source, and for sulfur dioxide this is probably sufficient. For sulfate aerosol, however, transport beyond this distance must be taken into account, and for this reason population dosage maps for sulfate aerosol calculated as for SO_2 would be somewhat misleading in that they would be ignoring a very substantial part of the total dosage increment. Consequently, they are not presented here.

6.7 LONG-RANGE SULFUR TRANSPORT

One of the impacts of coal-fired power plants that is 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. Regarding 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 anthorpogenic source is coal-fired electric power production.

Evidence indicates that the production of sulfate aerosol is rather slow and that the distance over which one needs to relate cause and effect is consequently rather large, thus causing 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 between 1-5%/hr. Assuming furthermore a typical tropospheric wind speed of 5m/sec the relevant distance scale for the problem is between 360-1800 km. This distance scale is sufficiently large that completely different modeling techniques are needed for the purpose of predicting 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.

6.7.1 Methodology

The model used for this long-range impact study is described by Sheih[11] and 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 in question 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 hours. Each such distribution allows the contribution from trajectories of a particular age to be calculated, and 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 for the present work, this is done by numerically integrating the one-dimensional (vertical) dispersion equation 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

$$K = \begin{cases} ku_* z & z \le 85\text{m} \\ 85ku_* & 85 < z < H \\ 0 & z \ge H \end{cases}$$

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.

6.7.2 Analysis Results

As described above, the model makes use of the spatial distribution of the endpoints of trajectories of various ages in calculating the concentration of SO_2 and sulfate aerosol at any given point. These distributions are obtained from trajectories initiated once every twelve hours from the source location and followed for 120 hours 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 possibly different standard deviations in the east-west as compared to 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 6.9 shows the locations of the five sites considered.

The dispersion of trajectories about the mean are 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 6.5. These are typical of those from the other sites also. There seems to be a trend toward higher east-west than north-south deviations, 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 Allegheny Mountains and the generally flat terrain for several hundred kilometers about the other sites may explain the difference. It may also be seen that 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 6.5.

Regarding the concentration calculations, the fact that the standard deviations used are relatively constant after a day and a half is offset by the fact that the contribution from trajectories of a certain age is scaled by the

Table 6.5. Standard Deviations about the Mean for Trajectories Originating in Southern Illinois

Travel Time (days)	Standard Deviations (km) North-South	East-West	Number of Trajectories
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

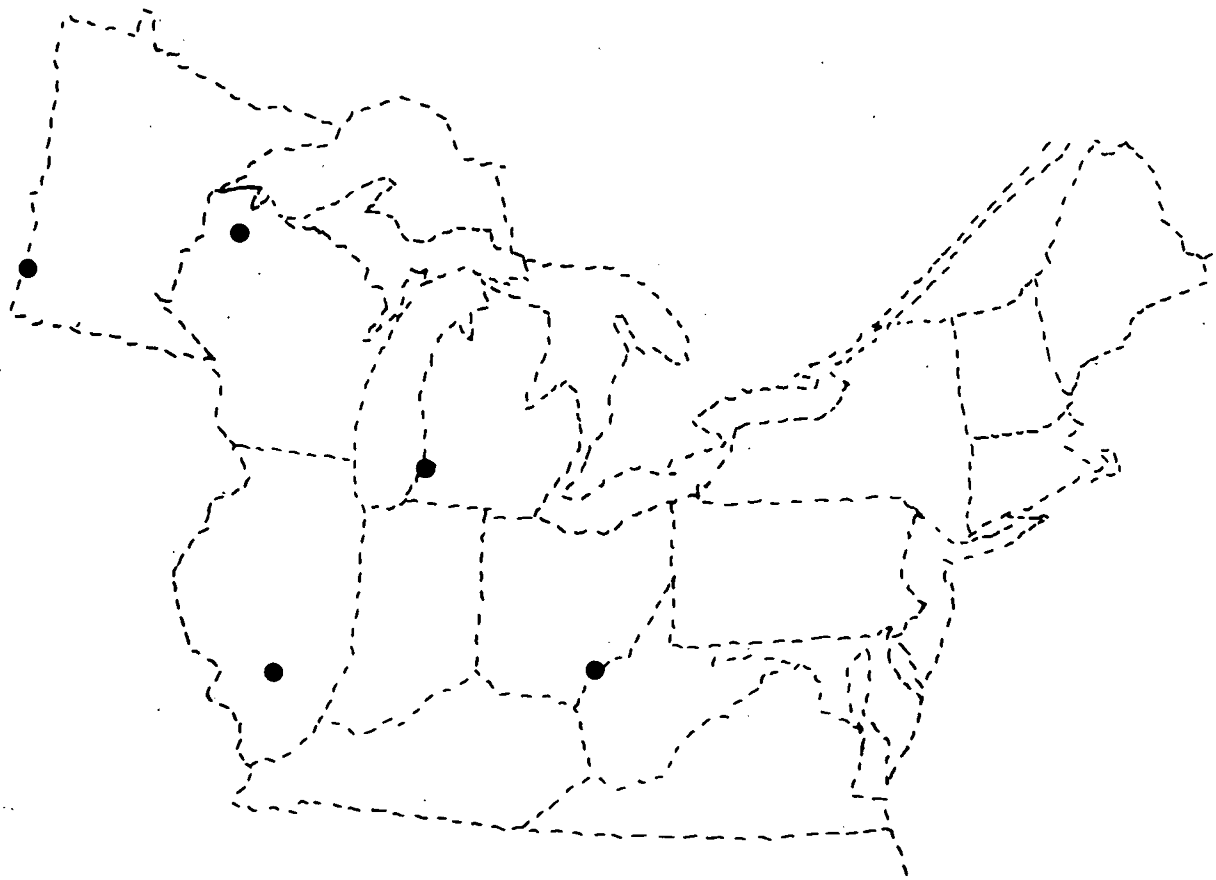


Fig. 6.9 Source Locations for Representative Calculations of Long-Range Sulfur Transport, Transformation and Deposition

number of trajectories of that age. This essentially means that in 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 involve the determination of 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 ignoring any variation with time of those factors such as surface roughness and solar radiation that affect the value of the eddy diffusivity. The only variation in the input parameters considered: 350 and 525 meters. Figure 6.10 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. There is very little difference between the two sets of curves, the conclusion being that once the effective emission height has reached 350 m, very little is gained by increasing it, at least on average.

Figures 6.11a-6.11e show the SO_2 and sulfate aerosol maps for each of the five source locations considered, for an effective emission height of 350 m. Figure 6.11a also shows the SO_2 and sulfate deposition for the southern Illinois source, which is typical of the depositions for the other sources. From these figures it is clear thet the impact of large coal-fired electric power generating facilities with regard to sulfate aerosol extends over a much longer and wider range than does the impact with regard to sulfur dioxide. The calculations also imply that the area of maximum sulfate impact from a given source is an area 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 those levels now observed in the East.

Calculations were carried out for the specific scenario corresponding to high coal usage in Illinois. Figure 6.12 shows the SO_2 and sulfate distributions together with the SO_2 and sulfate deposition maps resulting from this distribution of sources in Illinois. As mentioned above, the maximum impact on sulfate levels occurs relatively near the source, but it is clear that highly populated areas in the Midwest will be affected, particularly Chicago and Indianapolis, The maximum (scaled) ground-level SO_2 and sulfate concentrations pre-dicted 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. 6.13.[13]

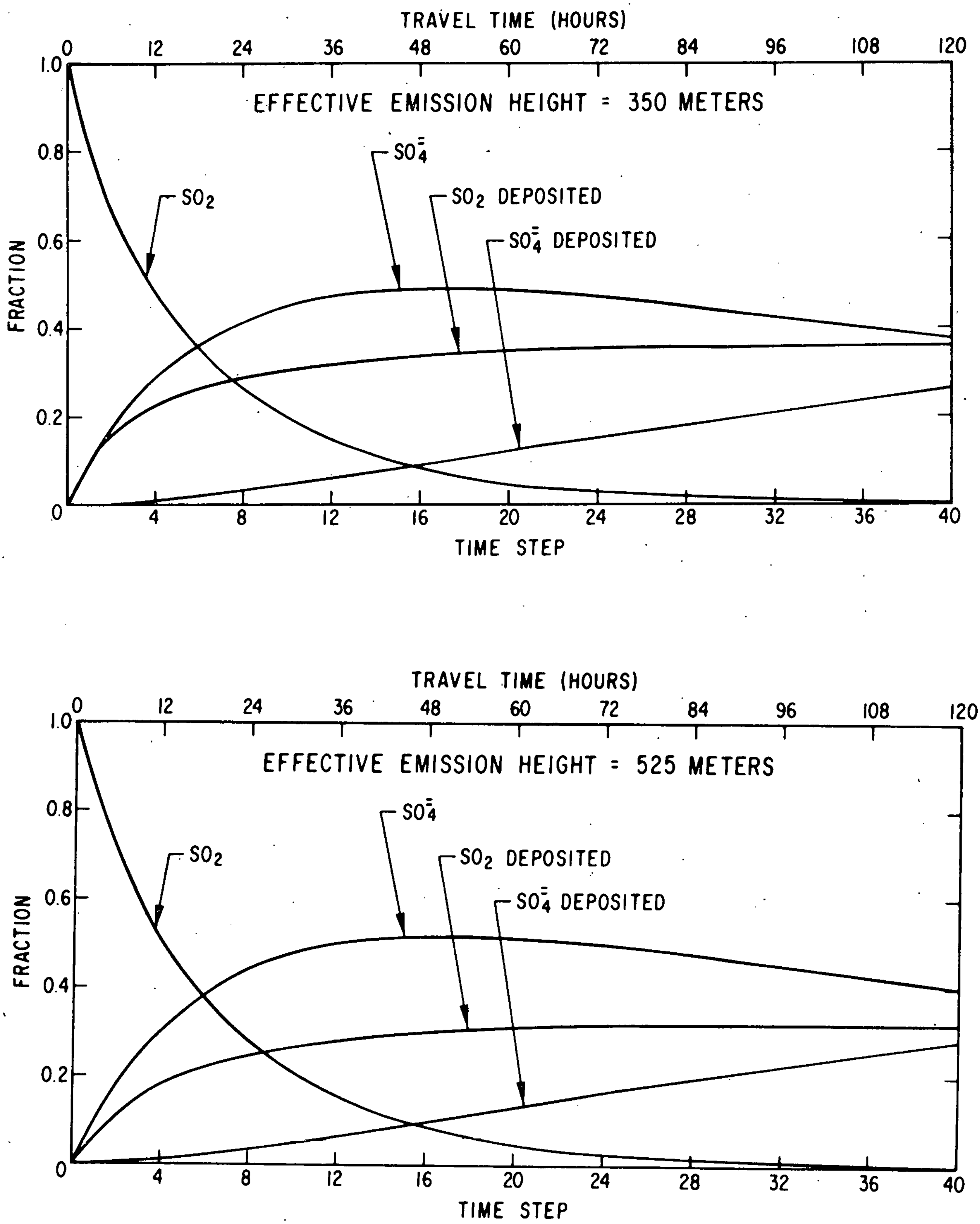


Fig. 6.10 Relative SO_2 and SO_4 Concentrations and Depositions as a Function Time for 350m and 525 Effective Emissions Heights

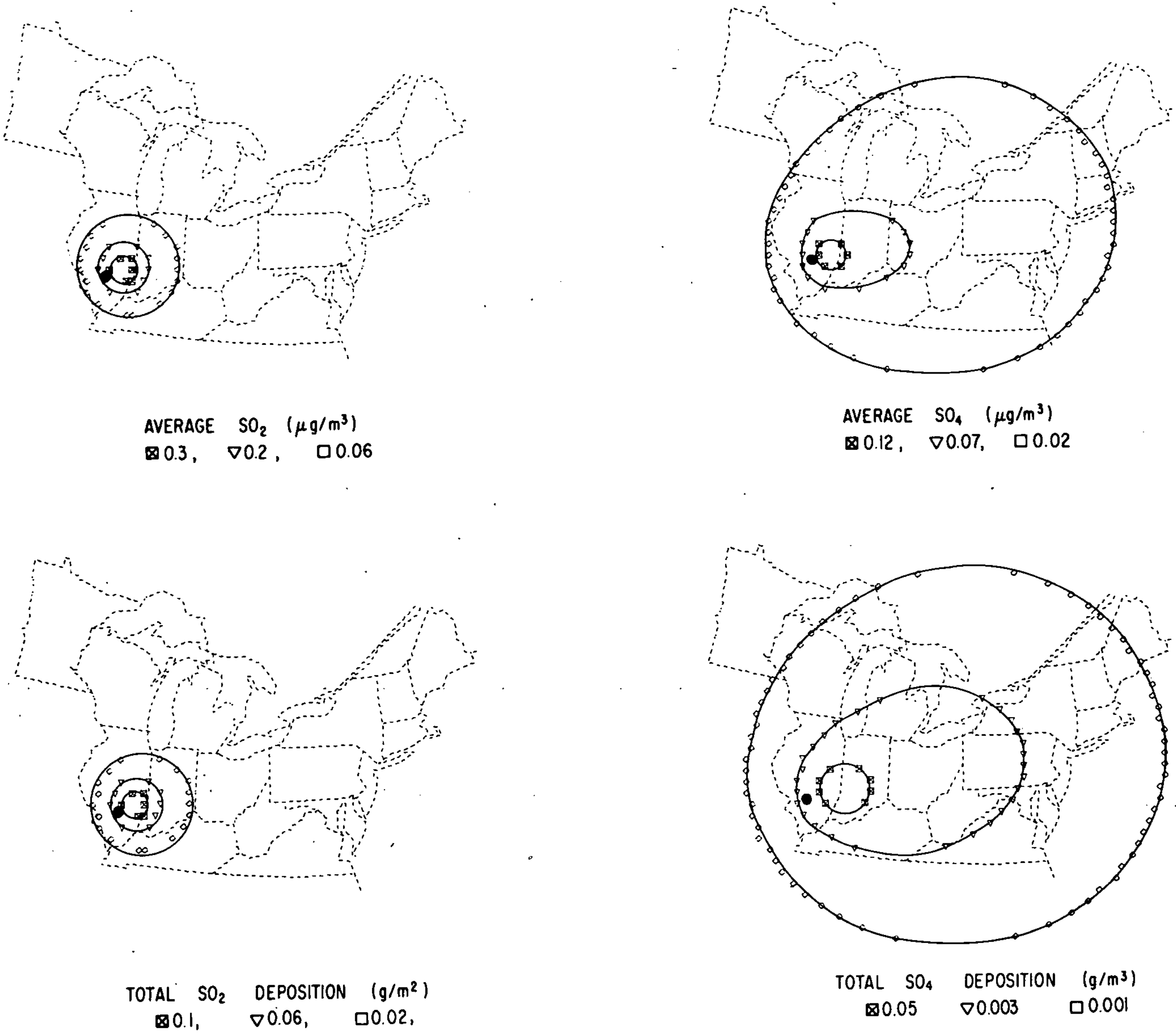


Fig. 6.11 Long-Range Sulfur Transport from 3000 MWe Reference Source at 60% Load Factor (a) Southern Illinois Source

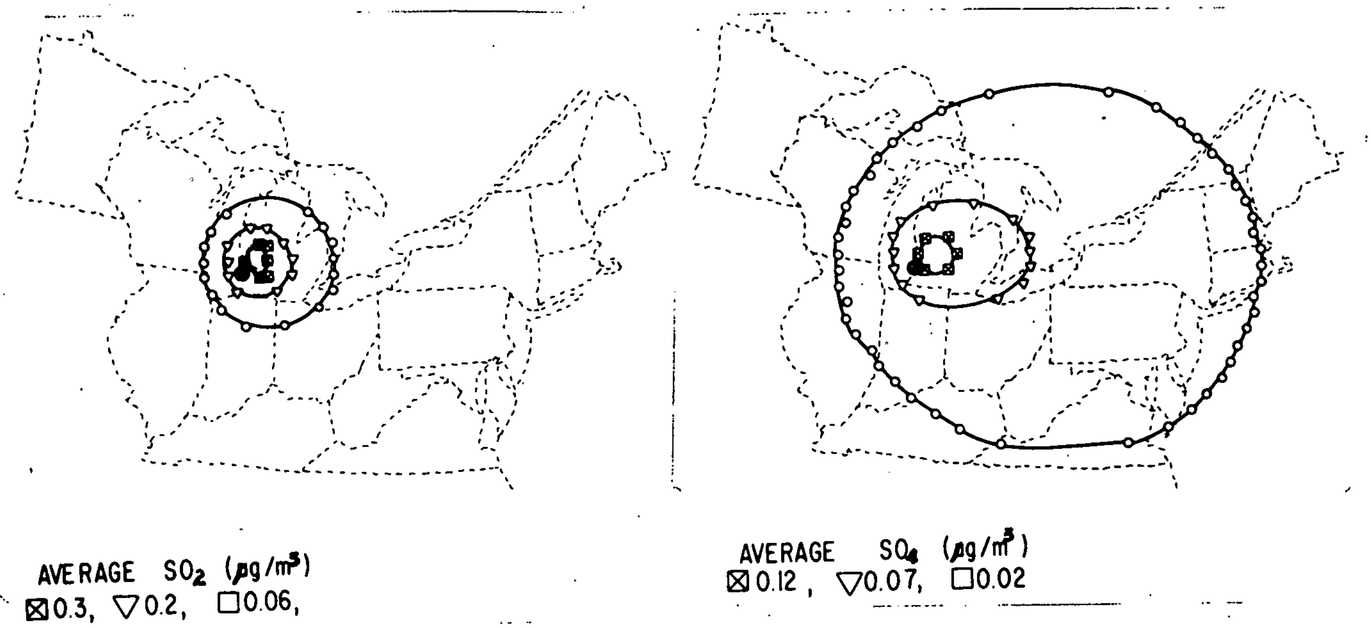


Fig. 6.11 (Cont'd) (b) Southern Michigan Source

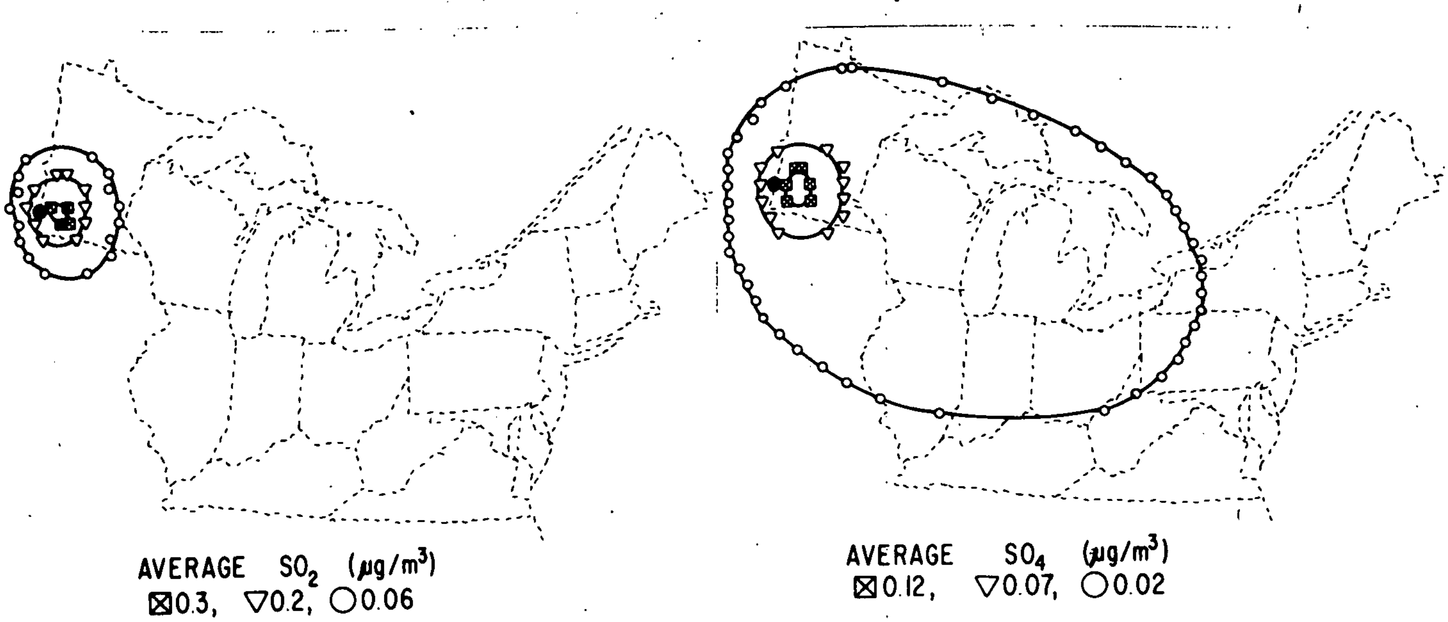
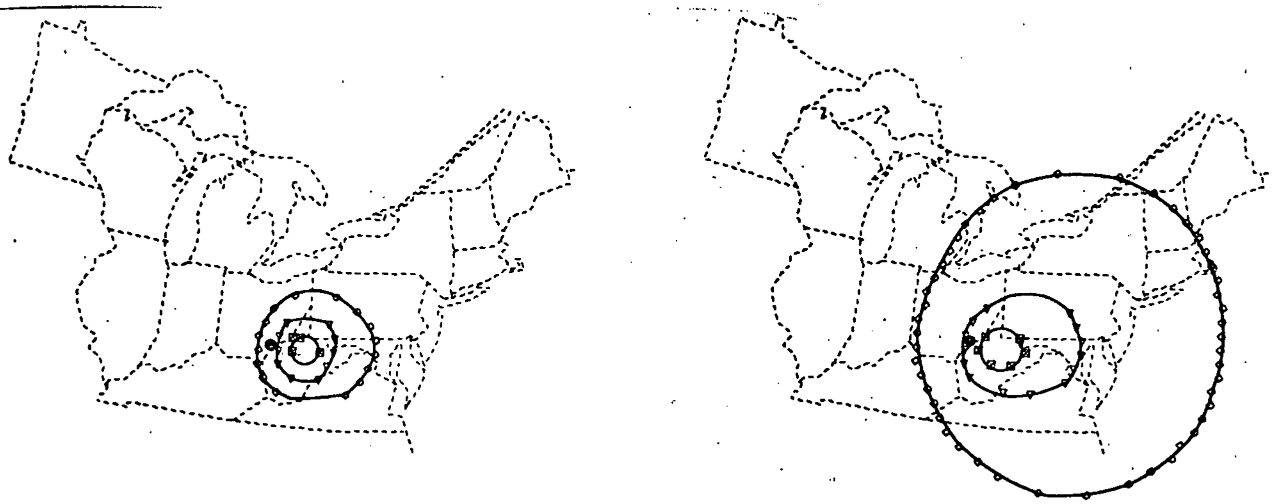


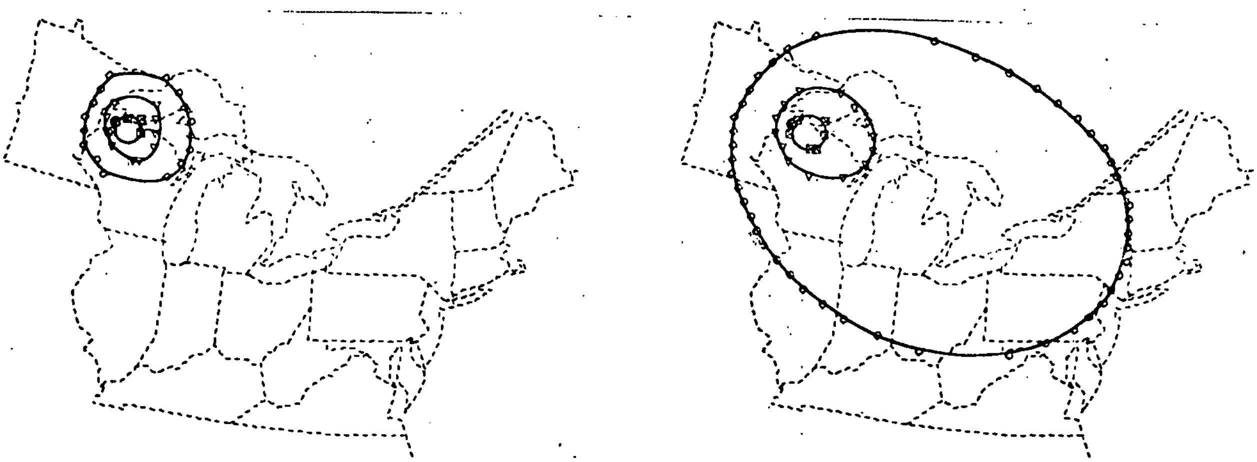
Fig. 6.11 (Cont'd) (c) Southern Minnesota Source



AVERAGE SO_2 ($\mu g/m^3$)
⊠ 0.3, ▽ 0.2, □ 0.06

AVERAGE SO_4 ($\mu g/m^3$)
⊠ 0.12, ▽ 0.07, □ 0.02

Fig. 6.11 (Cont'd) (d) Southern Ohio Source



AVERAGE SO_2 ($\mu g/m^3$)
⊠ 0.3, ▽ 0.2, □ 0.06

AVERAGE SO_4 ($\mu g/m^3$)
⊠ 0.12, ▽ 0.07, □ 0.02

Fig. 6.11 (Cont'd) (e) Northern Wisconsin Source

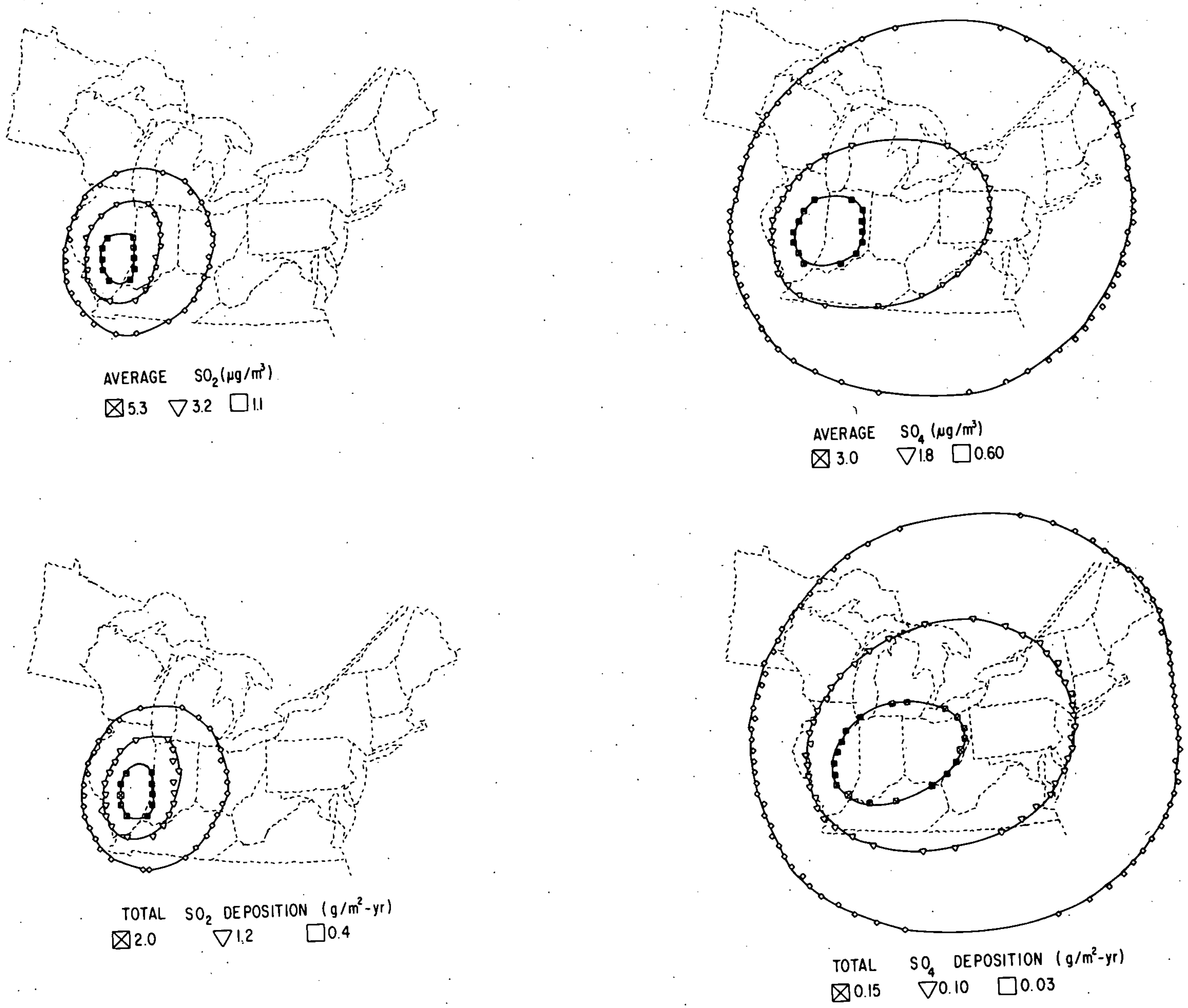
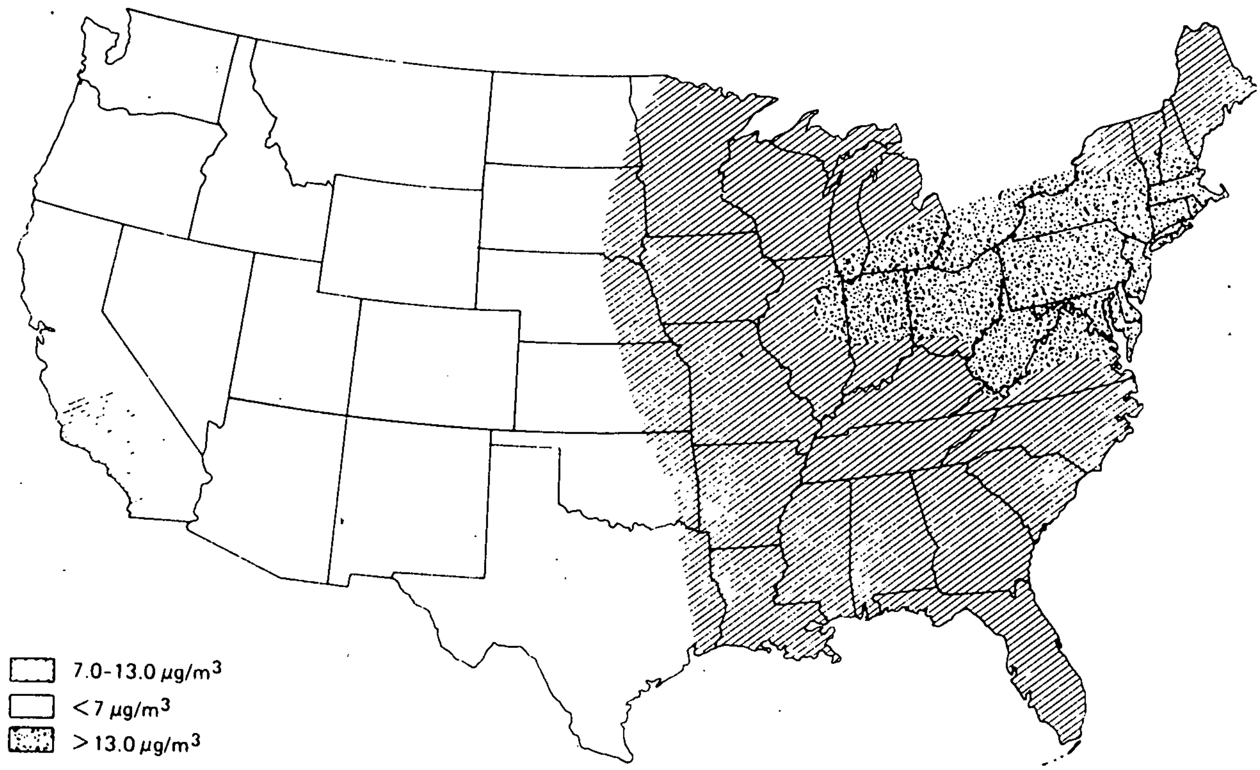
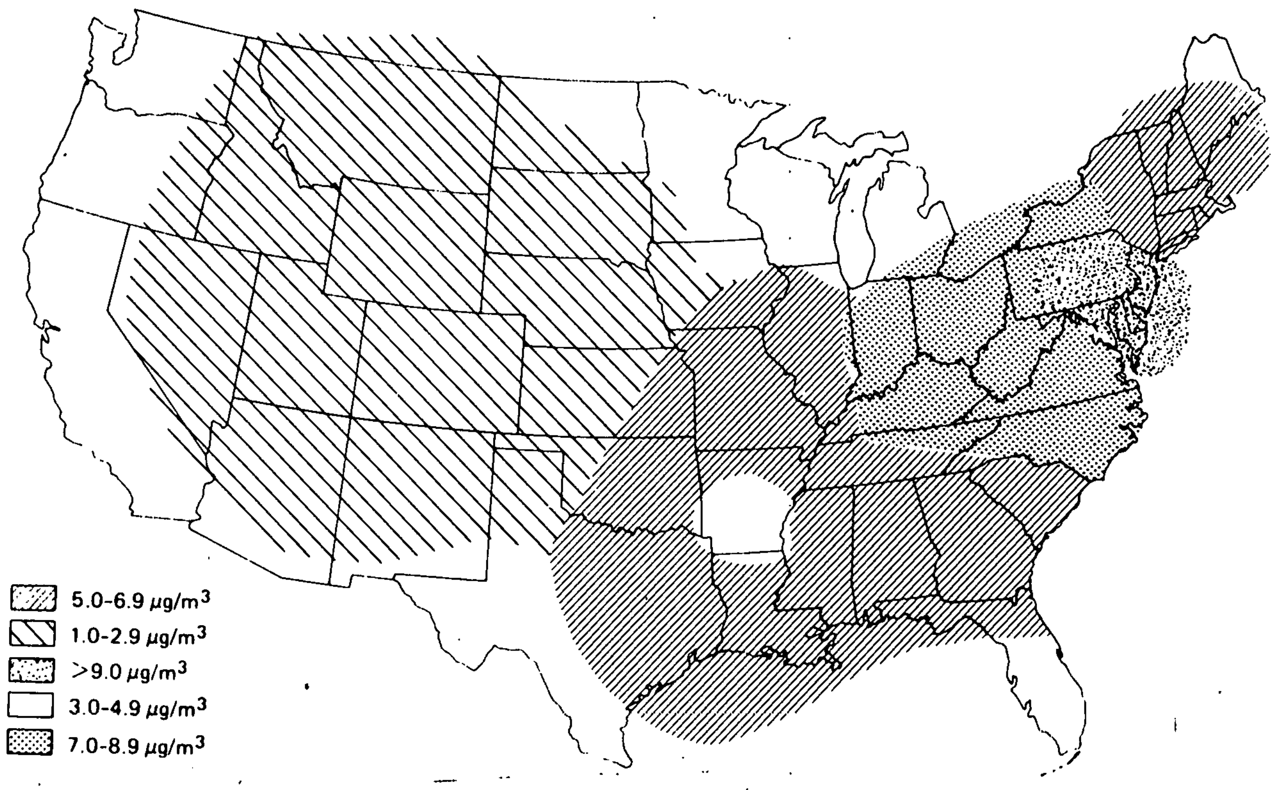


Fig. 6.12 Cumulative SO_2 and SO_4 Concentration and Deposition from Long-Range Transport for Illinois High Coal Use Scenario Emissions



(a) Urban Levels



(b) Rural Levels

Fig. 6.13 Geographical Distribution of Typical Sulfate Levels in the United States[13]

APPENDIX TO SECTION 6.0

6A.1 SHORT RANGE AIR QUALITY MODEL

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.[6] 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 time 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 of time 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 (a year, a season, etc.) 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 the determination of 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 for that particular meteorological situation what the pollutant concentration will be at the receptor of interest, and then a weighted average is determined 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 22.5 degree wide sectors, and the atmospheric stability in one of six different classes. The National Climatic Center, Asheville, N.C. can supply the necessary joint probability data (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 crudely allows the simulation of chemical and physical removal processes in terms of an exponential decay type dependence on source-receptor travel time, using different user-specified half-lives for the two pollutants.

Several modifications were made for our purposes but only two are sufficiently important to mention here. First, we added the capability for doing population dosage calculations. 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 of time that the concentration value corresponds to. In the type of application that CDM is used for, one usually desires monthly, seasonal, or annual averages.

The second significant modification that we made is the addition of the capability of describing in a simple way the conversion of one of the two pollutants into the other, the principal motivation for this being the desire 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

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

$$dC_2 \qquad k_2C_1 - k_3C_2 \tag{2}$$

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 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 sulfate aerosol direct emission rate Q_2 by Q_2(effective), given by

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

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 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 that the rate of removal of pollutant per unit area at the lower boundary is 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

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

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

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

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

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

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.

Table 6A.1 Reaction Rate, Decay Parameter Values

SO_2-SO_4 conversion rate constant (k_2)	$1.0 \times 10^{-5} sec^{-1}$
SO_2 physical removal rate constant (k_1)	$1.0 \times 10^{-5} sec^{-1}$
corresponding to deposition velocity (v)	1.0 cm sec^{-1}
and effective mixing height (H)	1000 m
SO_4 physical removal rate constant (k_3)	$1.0 \times 10^{-6} sec^{-1}$
corresponding to deposition velocity (v)	0.1 cm sec^{-1}
and effective mixing height (H)	1000 m

6A.2 REPRESENTATIVE ANNUAL CONCENTRATION AND DEPOSITION IMPACTS

Ambient Concentrations

In order to initially allow a reasonably general analysis of the regional air quality impacts of coal-fired power plants and gasification plants, the point of view has been taken that any modeling of the dispersion of the emissions should not be dependent 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. 6A.1 have been defined, each approximately 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 the presence of complex topography or large water bodies, would certainly need to be taken into account if a detailed analysis of the dispersion in a given location were to be made. However, the siting of plants on a county basis, as was done in this study, does not justify the more detailed analysis.

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-MWe power plant with physical characteristics given in Table 3.4 and emissions in Table 3.5 (60% load factor). As a first approximation, estimation of ambient concentrations for different pollutants is simply accomplished through the use of weighting factors equal to the ratio of emission rates. Differences in deposition or transformation rates 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. 6A.1 are shown in Fig. 6A.2 and the contour values for the various pollutants is given in Table 6A.2. Table 6A.2 also indicates maximum levels of annual averages for each of the pollutants for the southern Illinois subregion.

From these isopleth maps, it is possible to consider any pattern of siting for one or several such sources within the subregion 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 3.4. 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 3.5 are used. (Short-term maximums are more dependent on physical characteristics, as is discussed in Section 6A.3 of the Appendix).

The basic model used in these dispersion calculations is a modified version of the Climatological Dispersion Model (CDM) developed by the U.S. 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 a second pollutant and the removal of both the primary and transformed pollutant by deposition and other physical processes. The transformation and removal processes 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). For this analysis an SO_2 to SO_4 conversion rate of 1.0×10^{-5}/sec was used along with removal rates of SO_2 and SO_4 of 1.0×10^{-5}/sec and 1.0×10^{-6}/sec, respectively.

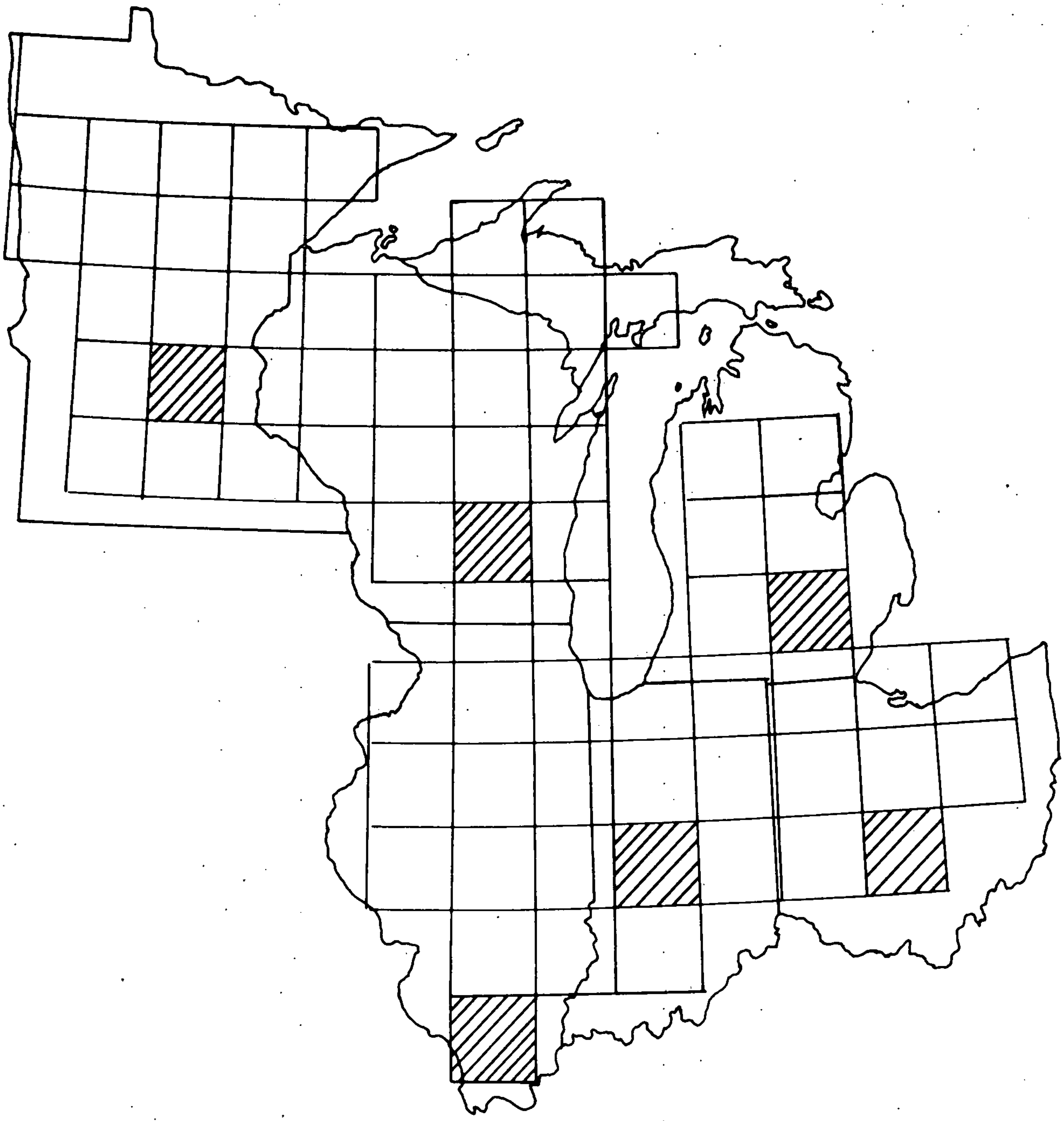
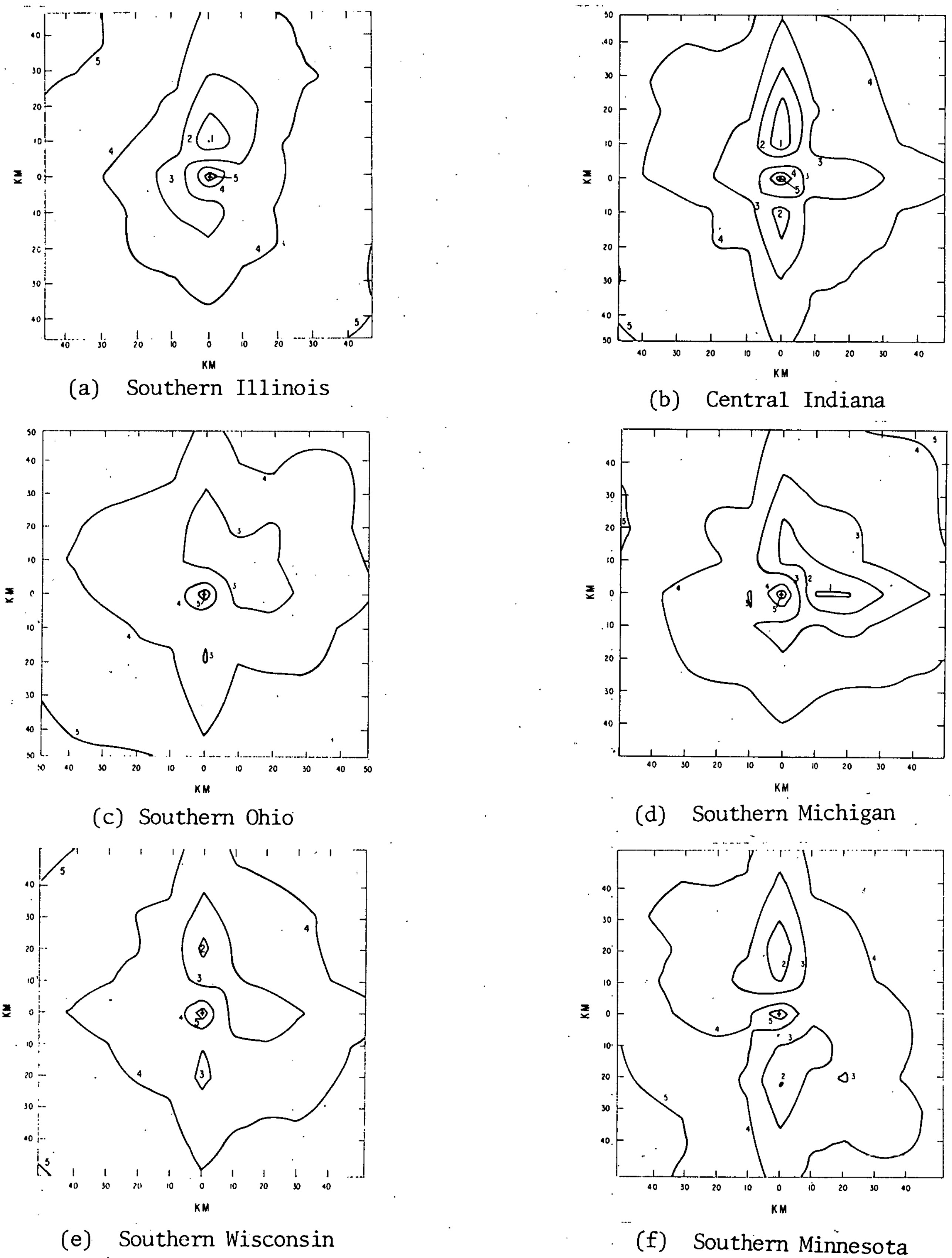


Fig. 6A.1 Study Area Subregionalization for Computation of Typical Air Pollutant Concentrations and Depositions (Results for shaded areas are shown in Fig. 6A.2.)



(a) Southern Illinois

(b) Central Indiana

(c) Southern Ohio

(d) Southern Michigan

(e) Southern Wisconsin

(f) Southern Minnesota

Fig. 6A.2 Annual Average Air Pollutant Isopleths for a 3000 MWe Reference Source in Selected Subregions (Subregion locations shown in Fig. 6A.1; isopleth values given in Table 6A.2)

Table 6A.2. Annual Average Concentrations at Isopleths and Local Maximum for 3000 MWe Reference Source in Selected Subregions (Fig. 6.4)

Pollutant	Concentration ($\mu g/m^3$)					
	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 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 $\times 10^{-1}$, etc.

One of the options for future electric power generation facilities is the clustering of facilities in which certain economies are achieved by locating several generating units relatively close to each other. One such pattern considered in the GE Report is shown in Fig. 6A.3. In this pattern, twelve 3000MWe facilities are located within a 36-square-mile (93-square-km) area. In order to examine the impact on air quality of this siting pattern, it is only required to refer back to the reference point source calculations and superimpose those results appropriately to simulate the total effect of all sources being considered. The resulting annual average contours at 60% load factor for the Fig. 6A.4 and the contour values for various pollutants are given in Table 6A.3.

Deposition Rates

An important aspect in the consideration of air pollutant impacts on ecosystems is deposition of these pollutants on the surrounding terrain where they become available for uptake into those systems. Presented here are estimates 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. With the exception of Hg and F, the trace elements in Table 3.3 are primarily in the form of particulates as they leave the stack, and thus the following estimates of particulate deposition can also be used to estimate trace element deposition.

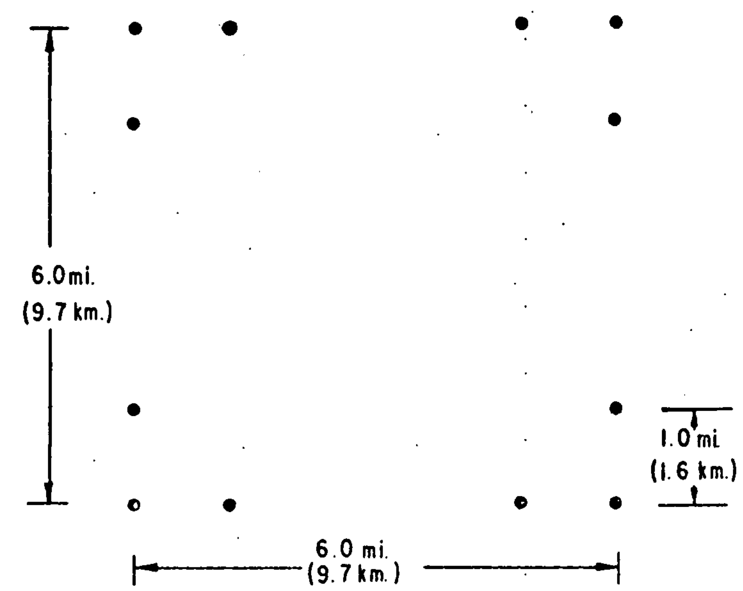


Fig. 6A.3 Clustered Siting Configuration for Twelve 3000 MWe Reference Sources

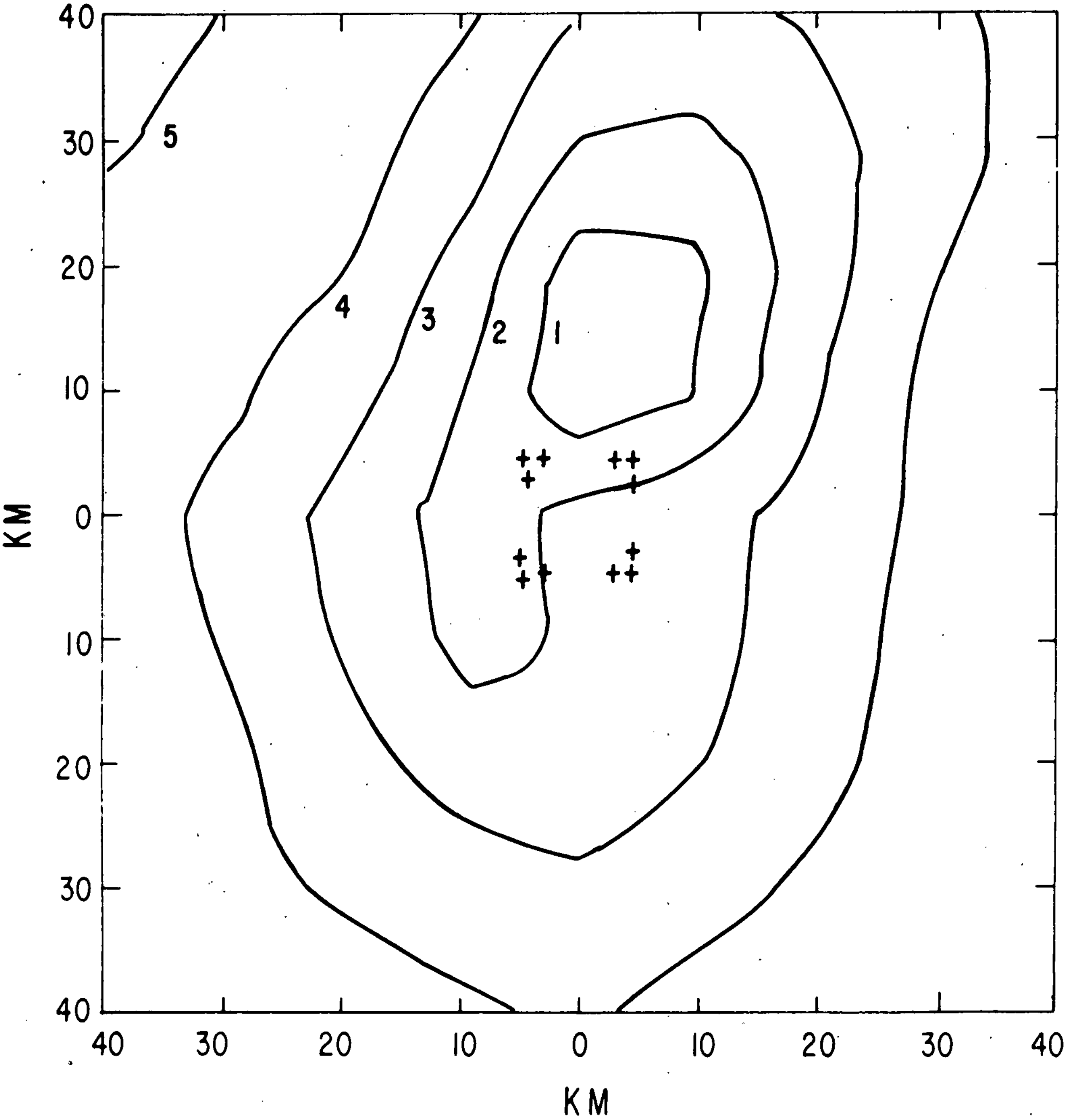


Fig. 6A.4 Annual Average Air Pollutant Isopleths for Clustered Reference Sources in Southern Illinois (Isopleth values given in Table 6A.3)

Table 6A.3. Annual Average Concentrations at Isopleths and Local Maximum for Cluster of 12-3000 MWe Reference Sources in Southern Illinois (Fig. 6.6)

Pollutant	Concentration ($\mu g/m^3$)					
	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 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 × 10^{-1}, etc.

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 the following:

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

Assuming that future power plants will have electrostatic precipitators or other control devices that in general are more efficient at removing larger particles, it can be assumed that the emitted particles are under 5 μm. For deposition over grass the deposition velocity has been estimated to vary from 0.03 cm/sec for 0.05 μm particles and 0.3 cm/sec for 5 μm particles.[7] For deposition over plants more than one meter 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/sec is assumed. Clearly the variation in particle size and terrain cover, in addition to the crude modeling approach, makes the results obtained only rough approximations. However, these results should be adequate to indicate potential problem areas worthy of further detailed analysis, which is a primary objective of this initial study.

Using this straightforward approach, the concentration isopleths given previously in Figs. 6A.2 and 6A.4 for the single and clustered facilities are also estimates of deposition isopleths. Using the 0.3 cm/sec deposition velocity for particles and the 1.0 cm/sec deposition velocity for gases, the total deposition over a one-year period at the contours and local maximum is as given in Tables 6A.4 and 6A.5.

Because of the many uncertainties in these estimates, an evaluation of potential impacts should consider an order of magnitude increase or decrease of these values as being possible in the actual depositions.

6A.3 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-MWe electrical generation and the 250 x 10^6 scf/day gasification facilities.[8] 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 and there is no interference from topographical features. The plant characteristics are given in Table 3.4. A 1000-m mixing height is assumed.

Maximum concentrations for 15-minute averaging times are obtained under these conditions for atmospheric stability class A and a 5 m/sec 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 a small number of hours annually, and it is very unlikely that these conditions will

Table 6A.4. Annual Depositions at Isopleths and Local Maximum for 3000 MWe Reference Sources in Selected Subregions (Fig. 6.4)

Pollutant	Depositions ($gm/m^2/yr$)					
	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 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 $\times 10^{-1}$, etc.

Table 6A.5. Annual Depositions at Isopleths and Local Maximum for Cluster of 12-3000 MWe Reference Sources in Southern Illinois (Fig. 6.6)

	Depositions ($g/m^2/yr$)					
Pollutant	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 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 $\times 10^{-1}$, etc.

occur simultaneously 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. 3.5 were used with expectations of more realistic estimates of maximum values.

As indicated above, the 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 the projected conditions, Table 6A.6 compares the projected maximum 24-hour concentrations with stability class A at 5.0 m/sec and 2.5 m/sec wind speed at 60% and 100% load factors. The lower wind speed results in lower concentrations (because of greater plume rise), and these are the conditions more likely to occur. Uncertainties in meterological conditions that give maximum concentrations also apply to the trace elements; however, the uncertainties in emission rates, perhaps as high as an order of magnitude, are dominant.

Table 6A.6 Comparison of 24-hour Maximum Concentrations with Alternate Wind Speed and Load Factors for the Reference 3000-MWe Source

Load Factor	Wind Speed	Maximum 24-hr Concentration ($\mu g/m^3$)		
		SO_2	TSP	NO_x
100%	5 m/sec	490	41	290
100%	2.5 m/sec	415	35	240
60%	5 m/sec	300	25	170
60%	2.5 m/sec	250	21	150

Note: For longer averaging times the maximum 15-minute concentrations are multiplied by the factors in Table 6A.7 which are determined from the formula: $C(\text{avg time} = t) = C(15\text{ min}) \times (15\text{ min}/t)^{0.2}$.

Table 6A.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 short-term concentration contours from the single 300-MWe facility emissions are given in Fig. 6A.5 and the contours for the cluster of facilities (Fig. 6A.3) are given in Fig. 6A.6 for perpendicular and diagonal wind directions. The contour values and maximum point concentrations associated with these figures are given in Table 6A.8 for 15-min., 3-hr, and 24-hr averaging times.

The estimates of short term concentration as presented above are also affected by a number of other parametric assumptions. In the GE study[8] an analysis was conducted to identify the critical input parameters having 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 6A.9.

On the basis of that study, it was concluded that:

> of the many different factors involved in producing ground-level concentrations of [pollutants] from a power plant, there seem to be only two controllable ones that can alter the maximum ground-level concentration by any great amount. The first one, obviously, is to minimize the amount of pollution that is 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 stack height used in this study by 50%, to 122-m, correspondingly increased the estimated short-term maximum concentration by approximately 50%.)
>
> 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. Unfortunately, these factors are not subject to control by man. However, they are matters that should be taken into consideration before a power plant is constructed. If a certain area has an unusually high proportion of undesirable conditions, greater care must be taken to insure that high ground level concentrations do not occur.

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 approximately a factor of 2 larger with the EPA model as compared to the TVA and AEP models (see Table 6A.).[8]

The emphasis in this section has been on short-term impacts from the reference 3000-MWe electrical generation facility because of the much larger emission rate of SO_2, particulates, and NO_x compared to the emissions from the reference 250 x 10^6 scf/day gasification plant. Differences in stack height

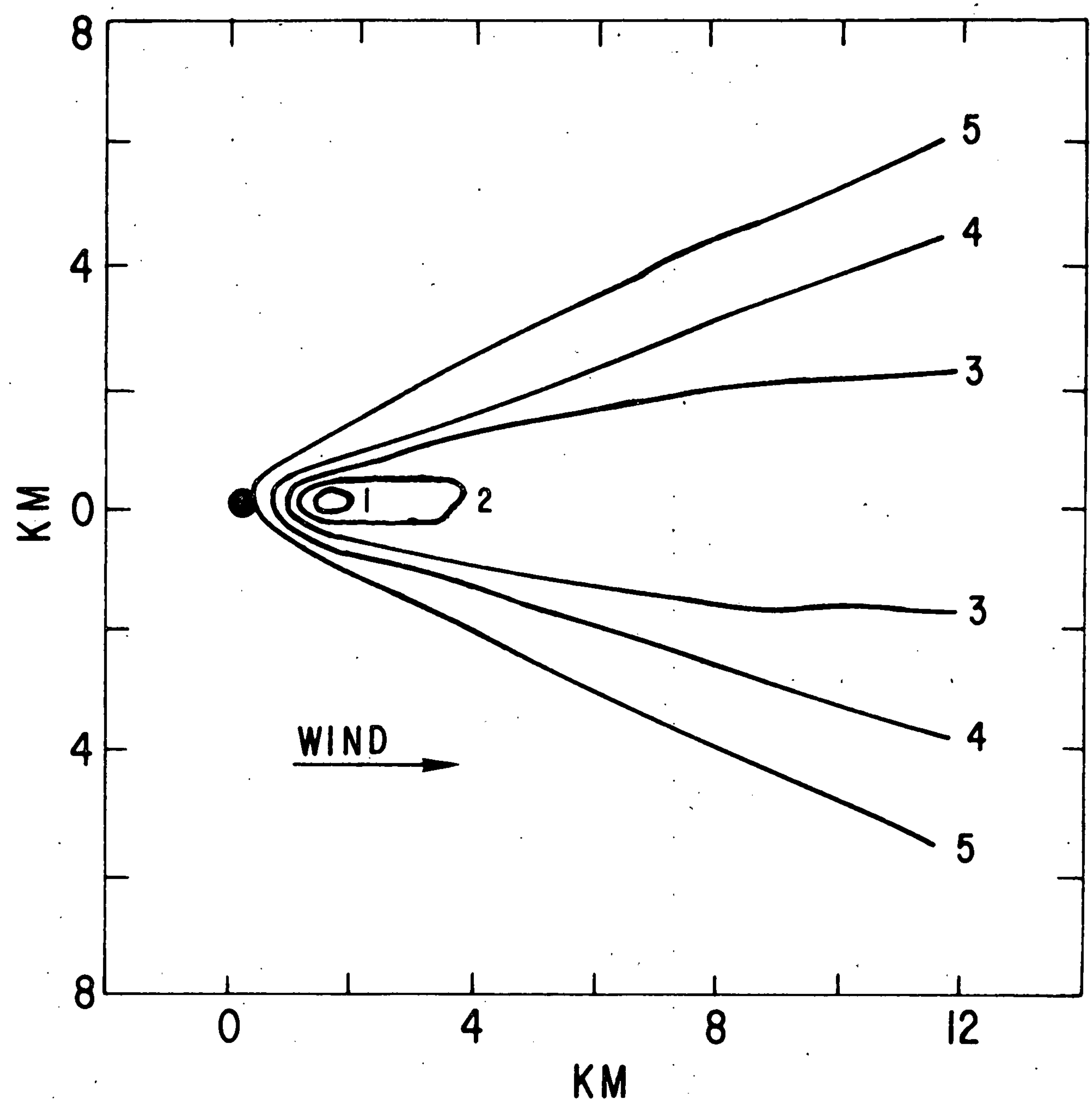


Fig. 6A.5 Maximum Short-Term Concentration Isopleths for a 3000 MWe Reference Source (Isopleth values given in Table 6A.8)

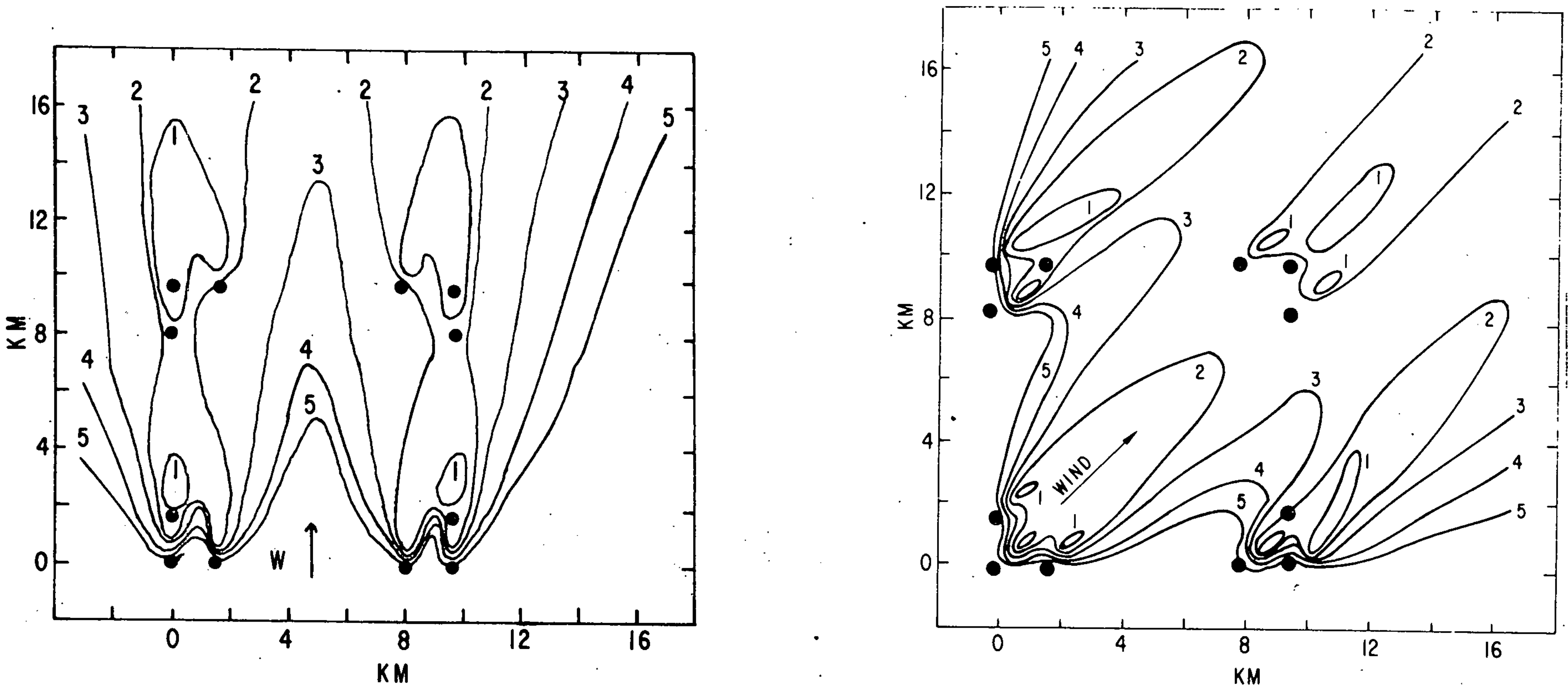


Fig. 6A.6 Maximum Short Concentration Isopleths for Clustered 3000 MWe Reference Sources (Isopleth values given in Table 6A.8)

Table 6A.8a. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000-MWe Reference Sources (Figs. 6A.5-6) 15-Minute Maximums

	Concentration ($\mu g/m^3$)							
Pollutant	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 5	Max. (Fig. 6A.5)	Max. (Fig. 6A.6a)	Max. (Fig. 6A.6b)
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 $\times 10^{+2}$, etc.

Table 6A.8b. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000-MWe Reference Sources (Figs. 6A.5-6) 3-Hour Maximums

	Concentration ($\mu g/m^3$)							
Pollutant	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 5	Max. (Fig. 6.9)	Max. (Fig. 6.10a)	Max. (Fig. 6.10b)
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 $\times 10^{+2}$, etc.

Table 6A.8c. Maximum Short-Term Concentrations at Isopleths and Overall Maximum for Single and Clustered 3000-MWe Reference Sources (Figs. 6A.5-6) 24-Hour Maximums

	Concentration ($\mu g/m^3$)							
Pollutant	Isopl. 1	Isopl. 2	Isopl. 3	Isopl. 4	Isopl. 5	Max. (Fig. 6A.5)	Max. (Fig. 6A.6a)	Max. (Fig. 6A.6b)
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)
Particulates	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 × 10^{+2}, etc..

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 trace substance emissions, which are more dominant in gasification facilities, would justify future air quality analysis specifically related to gasification.

Table 6A.9. Sensitivity of Maximum Short-Term Concentration Estimates to Selected Parameters

Emission Rate (gm/sec)	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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7.0 HEALTH EFFECTS*

7.1 "HEALTH" DEFINED

7.1.1 The Measurement of "Health"

The distinction between good health and poor health is not sharp. The health status of individuals can range along a continuum 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, which might be considered a mild annoyance in a high school student, could be cause for alarm in an elderly person with a heart condition.

Nevertheless, an objective definition of health is needed. The one most commonly used, because it is most easily measured, is mortality. There are more useful measures of the health status of a population, which are far less readily available. These are the incidence of disease (the rate at which unaffected persons develop a given disease per unit time) and disease prevalence (the proportion of the population suffering the given disease at any time).

The characteristics of the population under study are important aspects of the expected health status. Even under the best of circumstances, the risk of death is always relatively high at birth, reaches a minimum around ages 10-15, and increases roughly exponentially thereafter. Females tend to live longer than males, and smokers tend to die earlier than those who abstain. A variety of social and economic factors also influence mortality rates, and in some cases these factors vary markedly among easily identifiable racial and ethnic groups. Therefore, it is important that age, sex and race be controlled in any health effects measurement scheme.

7.1.2 The Study of Health Effects

The health effects of an environmental stress or noxious agent in humans are often hard to study. For ethical reasons, it is usually impossible to study in man substances suspected of leading to lethal outcomes. As a consequence, the results of animal experimentation, with all of the problems of interspecies variation which that implies, are nevertheless a major source of data. Thus, we are often in possession of excellent dose-response data for substances in animals which cannot be applied directly to humans.

On the other hand, when data come from 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

*This section represents results of a survey of health effects undertaken jointly with the Environmental Control Programs at ANL, and thus this section follows closely the similar section on health effects in that report!

are not well defined. Thus while the nature of the effects may be well described for humans, quantitative dose-response relationships may remain obscure, since the circumstances of exposure may be unknown. This problem is particularly acute in the case of long-term or latent effects in which the history of exposure over a 10 to 20 year period must be estimated.

7.2 HEALTH EFFECTS ASSOCIATED WITH AIR POLLUTION FROM COAL USE

Most of the effluents from current modes of coal utilization which are of direct impact on human health are found in the stack emissions from coal-burning facilities, and hence appear as airborne pollutants. These characteristically have four major types of health impacts:

7.2.1 Physiological Effects

7.2.1.1 Irritation

In this case, 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 to reject foreign materials. It is characteristically seen as a local reaction, for example, around a wound, where the effect will be to wall off and later destroy invading pathogens and/or other foreign material which 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 which it induces, it may do far more damage than the challenge or foreign material which stimulated the reaction. The result may interfere with other immunological mechanisms to the point where susceptibility to attack by pathogenic organisms is actually enhanced.[2]

7.2.1.2 Direct Toxicity

The pollutant causes direct damage to the cells with which it comes in contact. This 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 shown up anywhere in the body after absorption.

7.2.1.3 Carcinogenesis

The pollutant and/or its metabolic by-products stimulate the development of tumors after some latent period which may range from a few years to several decades. This 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.

3

7.2.1.4 Physical Synergism - Lung Clearance

In the respiratory system in particular, there is a further class of effects which, while not directly harmful in and of themselves, can potentiate 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.

7.2.2 Clinical Conditions Resulting from the Physiological Effects

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

7.2.2.1 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 elevated 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 the prior exposure to other irritants.

7.2.2.2 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 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.

7.2.2.3 Aggravation of Pre-existing Conditions

A person already in poor health from a condition such as 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.

7.2.2.4 Neoplastic Diseases

Exposure to carcinogens of the kinds found among coal combustion products 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 seen in coal.

7.3 HEALTH EFFECTS ASSOCIATED WITH SPECIFIC POLLUTANTS

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

7.3.1 Sulfur Dioxide (SO_2)

SO_2 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 a slight acrid odor. In high concentrations, it is largely absorbed in the upper respiratory tract (URT) never reaching 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 which 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.[3]

7.3.1.1 Irritant Effects[3,4,5,6]

In humans, initial exposure at levels which might be realistically encountered produces a slight temporary vasoconstriction which lasts about 10-20 minutes in a previously unexposed subject, with measurable reduction in the elasticity of the lung lasting for somewhat longer periods of time. 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 with prior exposure 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 tends to decrease with habituation.

7.3.1.2 Co-irritant Effects

SO_2 has been found in some studies 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 involving ozone (O_3) and histamine wherein prior exposure to SO_2 will result in more severe reactions to those irritants.

SO_2 can be adsorbed on the surfaces of otherwise benign particulates, which markedly enhance the irritant effect. It is not known whether this results from the longer residence time the SO_2 in the area of the particle deposition or from an enhancement of the irritant of the particle itself.[14]

7.3.1.3 Carcinogenic Effects

SO_2 passes readily through cell membranes, and once in an aqueous medium, such as cell cytoplasm, can form a number of free radicals and ions, notably sulfite, bisulfite, and SO_2-. The first two can be quite toxic, however there is a well developed enzyme system which rapidly neutralizes and removes those ions. The risk associated with these ions is therefore quite low for most people. The SO_2- radical, however, is a relatively long-lived species with an affinity for breaking disulfide (S-S) bonds,[7] which makes it a potential cause of gene mutations and possibly a long-term carcinogen.

7.3.1.4 Co-Carcinogenic Effects

One experiment showed in rats that prior exposure to SO_2 facilitated the induction of lung tumors by benz(a)pyrene administered by aerosol. In fact, in this particular experiment benz(a)pyrene did not appear carcinogenic in the absence of SO_2.[3]

7.3.1.5 Effects on Lung Clearing

SO_2 in acute high-level doses temporarily suppresses the action of ciliated cells lining the bronchial passages. As these are responsible for removing 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, but instead result in the thickening of the protective mucus layer over the cilia, which inhibits their ability to move the debris and therefore has in the long run an effect similar to that seen following acute exposure.[3]

7.3.2 Oxides of Nitrogen

Nitrogen oxides (NO_x) are produced by both the oxidation of organically bound nitrogen in coal and the secondary oxidation of atmospheric nitrogen during the combustion of coal and most other hydrocarbons, especially at high temperatures and/or pressures. The two most important species are nitric oxide (NO) and nitrogen dioxide (also known as N. Peroxide) (NO_2). Nitric oxide is an unstable species which oxidizes readily to NO_2, which will be the component discussed below.

7.3.2.1 Irritant Effect[3]

NO_2 is a strong irritant. Rats experimentally exposed to as little as .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 were nonetheless sufficient to produce irreversible emphysema-like lesions. Human experiments at moderate levels have shown 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 0, 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, in the opinion of many researchers the reverse is true, that the mechanism of habituation to the acute inflammatory response may be part of the effect of chronic toxicity.

7.3.2.2 Co-irritant Effect

See 3.3.1.2.

7.3.2.3 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, which are 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, and although there are suggestive relationships between stomach cancer and air pollution[9] in some localities, there is a little verification available as yet of this hypothesis.

7.3.2.4 Co-Carcinogenic Effect

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

7.3.2.5 Lung Clearance Effect

NO_2 seems to reduce ciliary action in the same fashion as SO_2.

7.3.3 Ozone[3]

Ozone may appear as the result of secondary reactions following combustion as discussed in Sec. 6.4. It is a highly reactive trimeric molecule of oxygen.

7.3.3.1 Irritant Effect

O_3 is among the stronger of the simple inorganic gaseous irritants.

7.3.3.2 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 cross tolerances to a much greater spectrum of irritants than is the case with most of the others. When exposure to ozone and other irritants is simultaneous the effect is usually additive or synergistic. Prior exposure to substances containing disulfide groups or sulfhydryl groups tends to be protective against the acute response.

7.3.3.3 Carcinogenic Effects

O_3 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, give it the capacity for mutagenic activity characteristic of many carcinogens. There is once again relatively little experimental verification.

7.3.3.4 Direct Toxic Effects

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

7.3.4 Hydrocarbons

Coal has no unique structure. It is generally viewed as a network of aromatic carbon compounds interspersed with various heterocyclic compounds. The potential therefore exists for the formation of a wide variety of organic effluents, especially during transient operating conditions which permit incomplete combustion.

Many of the products of coal decomposition are equivalent to the advanced stages of pyrene synthesis. At temperatures on the order of 900°C the predominant reactions are ring closures, condensation, and aromatization reactions.[1] The main products tend to be polynuclear ring compounds. Products from low temperature pyrolysis might be expected to be encountered during periods of startup and shutdown. These compounds would tend to 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 intermingling of compounds makes it virtually impossible to incriminate any single material as the agent in the causation of pathologic changes. However, in experimental situations a number of organic compounds arising from the combustion or processing of coal have been identified as either known or "suspect" carcinogens, others as strong eye and lung irritants.

7.3.4.1 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).[10] Other effects associated with inhalation of these products include rhinorrhea, cough, sore throat, and a sense of substernal oppression. Irritation from formaldehyde is apparent to most people at concentrations of 2 to 3 PPM, the same reactions from acrolein are associated with concentrations of less than 1 PPM.[11]

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 pollutant's water solubility. Highly water soluble products tend to be absorbed in the nasal, buccal, nasopharyngeal, and laryngotracheal regions. The higher molecular weight, less soluble compounds are able to penetrate deeply into the lungs.

Photochemical reaction products can be considered as secondary products of coal combustion. These compounds result from the interaction with ultraviolet radiation and the oxidation of effluent hydrocarbons. Ozone and the PAN series are examples of this group. Photooxidation is also a pathway for aldehyde formation.[11] The PAN series, peroxyacteylnitrate (PAN) peroxybenzoylnitrate (PBZN) and its homologues, are potentially more toxic than the aldehydes. However, due to their high reactivity and resultant short lifetimes, the extent to which the PANs are directly responsible for irritant effects is questionable.

7.3.4.2 Carcinogenic Effects

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

7.3.5 Carbon Monoxide

7.3.5.1 Direct Toxic Effect

CO is best known for its affinity for hemoglobin, with which it combines to form carboxyhemoglobin (COHb), which has a very long residence time in the blood. The victim suffers asphyxiation. At COHb levels >9.5 MG/M^3 in 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 at lower levels among otherwise healthy persons is not well defined.

7.3.6 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 to 500 micrometers, the particulates from coal combustion appear in a more limited size range. These products tend to be found in the 0.01 to 10 micrometer range of equivalent aerodynamic diameters. Because this range neatly brackets the size defined for respirable particles, the coal combustion particulates pose a significant potential for adverse human health effects.

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 such that particles of 0.1 to 1 micrometer are created. Partial combustion can result in the formation of soot particles 0.01 to 1 micrometer in diameter. The energy available from combustion can also be responsible for the formation of condensation nuclei of 0.01 micrometers 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. The sulfates, nitrates, and hydrocarbons usually result from photochemical reactions. The size range associated with these particles is 0.01 to 1 micrometer.[15]

Virtually all of the naturally occuring elements can be found as contaminants in coal. The emission of these constituents is dependent on their chemical form prior to combustion and on their volatility.[9]

Most elements in coal, exclusive of carbon, come in the form of aluminosilicates, inorganic sulfides, and organic complexes. During combustion, the sulfides and organic compounds are decomposed to produce SO_2 and a number of oxides and other chemical species of varying volatility. The aluminosilicates, on the other hand, 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 which volatilize and adsorb on particulates are known to have adverse effects on human health,[28] and one of the most interesting of these is SO_2, which has been discussed in Sec. 3.3.1. When adsorbed on such surfaces, SO_2 is in many cases 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) may form aerosols of sulfuric acid or other acid sulfates. Particles containing vanadium are particularly likely to catalyze this reaction.

7.3.6.1 Mechanisms of Action

The effects that particulate emissions can have 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 constitute 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 is primarily a function of particle size. Those less than about .01 micrometers in diameter tend to behave like gases, and are generally not deposited at all. Particles with a diameter of .01 to around 1 micrometer are predominantly deposited in the alveolar or pulmonary region, while larger particles show a greater tendency to deposit in the nasopharyngeal and tracheobronchial regions.

Most airways are lined with ciliated and mucus-secreting cells which 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. There have been studies, however, which 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 absorbed into the bloodstream.

The rate at which particles are cleared from the pulmonary areas is variable. 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 succeed immediately in clearing the foreign particle, it may become sequestered in the lung. In this case 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 destory 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. The formation of the silicotic nodule is an example of the latter type of reaction.[17]

7.3.6.2 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.[18] The submicron fly ash particle presents a double threat to human health. Not only does this particle reach the pulmonary region of the lung and remain there for extended periods of time, but it also has the capability of deliverying relatively high concentrations of some of the effluents as the result of surface adsorbtion (see Sec. 3.3.6.1). A detailed breakdown of the known effects which might be attributed to each of the individual components would tend to be repetitive. We therefore present only a brief list of the major effects which can be anticipated and the important contributors in each.

Irritant Effect

Because they can adsorb SO_2 and other irritant gases and vapors, respirable particulates have the ability to magnify their effects by holding high concentrations of these irritants in close proximity to sensitive tissues for protracted periods of time.

The sulfate ion which is often associated with small particles and aerosols appears to be a far more potent irritant than any of the others discussed here. This is probably due in part to the fact that the ion forms a very strong and reactive acid and also to the fact that it is so strongly associated with particulates.[3]

The cations associated with the sulfates are important mediators of irritant potency.[19] Pure sulfuric acid (H_2SO_4) and ferric ammonium sulfate ($FENH_4SO_4$) are the most potent forms. Other ions tend to be weaker in proportion to their acidity.

Most particles which contain silica can, if they become permanently sequestered in the lung, induce various forms of fibrotic lung disease, such as silicosis, pneumoconiosis, etc.[6] In the amounts which are likely to be produced by power plants, however, this effect is likely to be unimportant.

Carcinogenic Effect

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

Direct Toxic Effects

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

7.4 QUANTITATIVE ESTIMATES OF RISK

While a great deal is known about the qualitative effects of many of the substances found in coal-related effluents in the pure state, most of this is based on short-run data at relatively high exposures. Properly measured dose-response data for long-term exposures at realistic levels to these substances is woefully lacking. Dose-response functions for combinations of substances broadly similar in composition to coal effluents may, however, be developed for some classes of outcomes from the available epedimiological literature. This is an application, however, for which most of these data are not well suited, as in many of these studies the exposure terms as they related to individuals were not well defined.

In the current literature there are three major efforts at a regression model of human health and air pollution.[21] Lave & Seskin have done an econometric type of analysis using health and air pollution data from 35 standard metropolitan statistical areas around the United States. Their measurement of air pollution was designed as a surrogate for the concept of "dirty air"; it is not really comparable across their sample as the same level of "dirtiness" might result in one case from automobile exhausts, in another case from petroleum refining or other heavy industry, and in a third case from coal effluents. Their indicators of economic status and health status suffered from similar kinds of difficulties. It is therefore not a very good model to use in projecting health effects.

The EPA has done a more detailed analysis on the basis of chess and other data which attempts to relate specific health effects to specific pollutants.[4] This study is oriented towards the kinds of pollutants produced by automobiles more than coal-fired power plants, and has particular problems with particulates. The suspended particulates used in this study were not comparable to those found in coal effluents. However, for what it does handle, the results are useful as a first approximation.

A third study conducted by Windelstein[9] in Buffalo, N.Y., regarding the effects of pollution in that area did deal with particulates more closely akin to those expected from coal burning.

While remaining acutely aware of the fact that existing dose-response functions are in a very preliminary stage, it is instructive for the purposes of defining potentially significant health effects to compare the projected air quality impacts from Sec. 6.0 with existing models. For this purpose health effects functions related to sulfates concentrations are reproduced in Table 7.1 based on a recently published report describing functions used by EPA researchers in a computerized model.[22] As an example, the threshold of

Table 7.1. Health Impacts of Sulfate Aerosol

Health Effect	Population at Risk	Assumed Baseline Frequency of Disorder within Population at Risk	Pollutant Concentration Threshold For Effect	Effect 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 symptom 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 $\mu g/m^3$

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. 6.13, Sec. 6.0. Further comparing the 0.5-1.5 $\mu g/m^3$ sulfate impact in the Northeast from the Illinois emissions in the high coal scenario (Fig. 6.12, Sec. 6.0) 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. Currently these calculations cannot be considered quantitative estimates of effects; however they do indicate qualitatively a high priority for further research to define these effects.

A more detailed evaluation of dose-response models is currently in progress and will be included in subsequent reports.

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8.0 WATER RESOURCES AND IMPACTS

8.1 INTRODUCTION

Water is a required input to all phases of the coal fuel cycle. In some areas, water may not be available to meet the requirements of coal utilization and conflicts may arise because of competing users in the agricultural, industrial, recreational, and other sectors. In addition, waste discharges from coal utilization bring additional pollutant loadings that may degrade existing water quality and affect the potential for use by man and the 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 pollutant loading from coal developments in the region.

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 in-stream uses.

2. To determine the water quality impacts associated with pollutant discharges from coal extraction and coal utilization facilities.

For each major river basin in the six-state area, an evaluation of water availability for future energy development was conducted. The evaluation includes a calculation of direct water consumptive requirements for the projected steam electrical power generation and coal gasification facilities and a comparison of requirements with natural availability. For the purposes of initial analysis, the 7 day/10-year low flow at river guaging 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 delineated in Section 4.0 and the characterization of effluent discharges of coal utilization facilities discussed in Section 3.0.

Impacts of water use and pollutant discharges on the quantity and quality of water resources are area and facility specific. In this initial analysis of water resource impacts, three river basins in the State of Illinois, including the Illinois, Rock, and Kaskaskia, were chosen as demonstrative example areas. These basins were selected because a relative intensive energy development was projected for each and a significant amount of water related data was available for these areas. Water use impacts were evaluated by comparing the quantity of surface and groundwater resources with the projected consumptive requirements of future energy development, and the projected consumptive needs of competing users that included municipal, industrial, agricultural and mining uses, as well as instream uses by hydroelectric power generation, navigation, recreation, fish and wildlife, and water quality management.

Water quality impacts of the selected rivers were represented by increments of pollutant concentration resulting from effluent discharges of projected coal utilization facilities. Concentration increments were subsequently compared with existing water quality levels as well as applicable water qualtiy standards to identify areas of adverse impacts.

The water requirements of the energy scenarios beyond the year 2000 will result in increasing pressure to use the Great Lakes water resources and to construct more reservoirs. The impacts and constraints associated with the use of the Great Lakes water resources and the impoundment of water in reservoirs are not considered in this analysis.

Drainage and runoff from coal mines and seepage from waste disposal sites and holding ponds, created for coal utilization and coal extraction, could cause serious pollution problems for surface and groundwaters. 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.

The following subsections present Regional Water Profile (8.2); Water Requirements for the Projected Coal Utilization (8.3); Water Pollutant Loadings from Coal Utilization (8.4); and Impacts of Water Requirements and Pollutant Loadings (8.5).

8.2 REGIONAL WATER PROFILE

The six-state study area includes three Water Resource Council (WRC) regions:[1] the Ohio River basin, the Upper Mississippi River basin, and the Great Lakes basin. The following paragraphs present brief descriptions of these regions in terms of water availability and quality. The regional boundary and surface waters included in the region are shown on the map presented as Fig. 8.1.

8.2.1 Geographic Description of the Region

The Ohio Region

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

The section of the Ohio River basin WRC Region contained 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 stateline 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 inches annually. Precipitation is usually greatest in June or July and least in October, and the average seasonal variation is small. Geographically, average annual rainfall

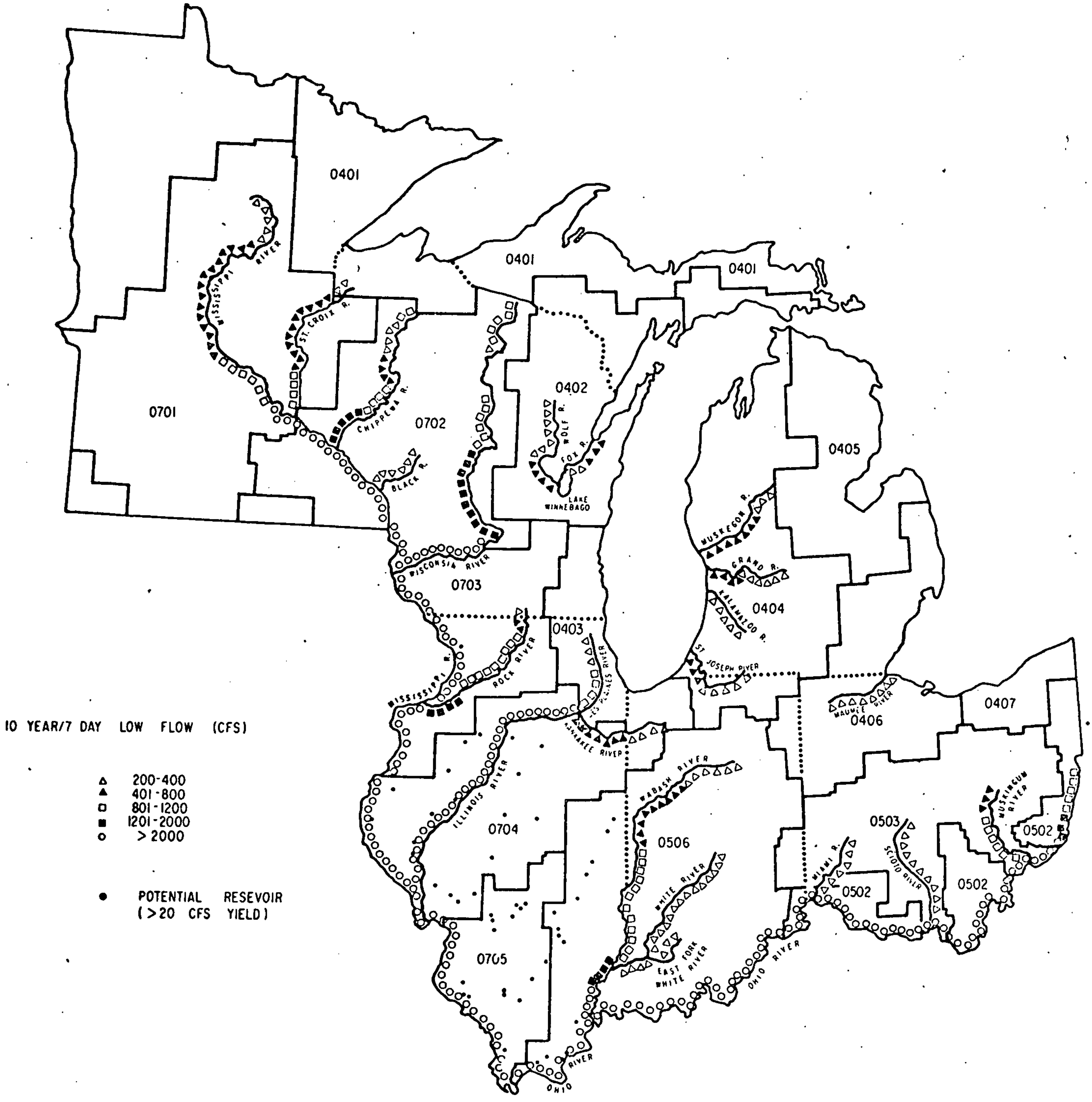

Fig. 8.1 Regional Water Resources Represented by 10 year/ 7 day Low Flows in Major Rivers

ranges from about 36 inches in the northern plains area to about 44 inches 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.

The 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 north-central United States. The watershed area of the basin is 189,000 square miles or about 121 million acres.

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

The basin extends in a north-south direction for some 700 air miles, from the mouth of the Ohio River to a line about 700 miles south of 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: ASA 701 contains the Minnesota and St. Croix Rivers plus the Mississippi from its source to Minneapolis; ASA 702 includes the Chippewa and Wisconsin Rivers and the Mississippi from Minneapolis to Wyalusing, Wisconsin; ASA 703 contains the Rock River and the Mississippi from Wyalusing, Wisconsin to Burlington, Iowa; ASA 704 includes the Illinois River and the Mississippi from Burlington, Iowa to Alton, Illinois; and ASA 705 contains the Kaskaskia River and the Mississippi from Alton, Illinois to Cairo, Illinois.

The Great Lakes Region Basin

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 Midwest study area: ASA 402 contains the Fox and Wolf rivers of Wisconsin: ASA 404 includes the St. Joseph, the Kalamazoo, the Grand and Muskegon Rivers: the Saginaw River drains ASA 405; and the Maumee River drains ASA 406.

8.2.2 Surface and Groundwater Availability

The amount of flow, and the seasonal, annual, and long-term fluctuations in flow in a river are important limiting considerations in coal conversion assessment. Stream and ground water, water quality and availability, type and quantity of aquatic and terrestial biota, and river use potentials are all affected by river flow.

For this study, the flow measurement used for characterization and projection purposes is the 7-day/10-year low flow. This parameter provides a measure of worst-case flow conditions that coal conversion facilities will have to deal with, and provides a maximum boundary for siting considerations. Table 8A.1 in the appendix to Sec. 8 contains, for each WRC aggregated subarea, the 7-day/10-year low flow information at designated river miles. This information is also summarized in Fig. 8.1. These data were gathered from published reports available from federal and state agencies, including U.S.G.S., Corps of Engineers, EPA, and State Water Resources Boards.

Groundwater varies considerably between and within river basins. Availability and quality of groundwater are dependent upon recharge rates, types of substrata that convey and contain the water and the 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 ground-water supplies are available throughout most of the glacial till areas and the alluvial valleys of other portions of the basin. The unconsolidated deposits to the north of the Ohio River contain large groundwater storage reservoirs in buried flow channels framed by preglacial drainage systems. For the most part, groundwater 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 large concentrated municipal and industrial water supply needs. However, the effect on streamflow of groundwater withdrawal may prove a restraining factor in groundwater use.

The mineral content of groundwater is generally higher than that of surface water. Significant problems of excessive chloride exist in several areas and problems associated with excessive mineral concentrations and hardness are also encountered. High iron content is also 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. There are also large areas of limestone and dolomite aquifers of extremely variable yield. Unconsolidated aquifers of good to excellent yield line most present-day river systems and are also found in ancient river bed systems. Groundwater availability is generally good, except in areas of large municipal and industrial locations where use exceeds recharge.

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

In the Lake Michigan area of the Great Lakes basin, groundwater occurs in several formations throughout the basin. It is probable that more than one aquifer will be encountered at any well site. Although the Lake Michigan basin has the most bountiful groundwater supplies in the entire Great Lakes basin, there are areas where natural or man-made conditions create problems. In some places the groundwater resource 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, prohibiting major groundwater use. Extensive lowering of bedrock aquifer water levels often occurs in metropolitan areas. This condition results in increased pumping costs and depletion of future water availability. Contaminations of shallow aquifers by waste disposal and of deep aquifers by leakage from water in multi-aquifer wells have also occurred.

In the Lake Huron area, the groundwater varies greatly in amount and quality. Water occurs in aquifers in glacial deposits, which vary considerably in permeability and potential water yield. The bedrock contains aquifers generally yielding moderate to small amounts of water. The chemical quality of this water may be poor. Moderate and large supplies adequate for industry and municipalities are restricted to the western and southern sections of the basin.

In the Lake Erie basin, major aquifers are found in unconsolidated sediments and in near-surface bedrock formations. However, in contrast to the three upper Great Lakes basins, the Lake Erie basin has less significant unconsolidated aquifers and fewer consolidated aquifers. Chemical quality of the groundwater has been a limiting factor in its development. Water from surficial sand and gravel aquifers is generally good to fair in quality. Iron is usually present. The water can be hard and contain appreciable amounts of dissolved solids. Bedrock aquifers consistently yield hard to very hard water with quantities of dissolved solids often above the recommended limit of 1,000 mg/l. Saline water is present locally, and increasingly with depth. Iron and sulfate contents may be relatively high in local areas and increase treatment costs.[4]

General groundwater resource studies 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 that lie in glacial drift to under .01 cfs in the southern portions where glacial deposits diminish and Devonian or Mississippi shale predominate. In Minnesota, in the Minnesota River basin, groundwater 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 groundwater availability in the six-state study.

8.2.3 Existing Water Quality

Throughout the region each state has developed a system of river use classification. These classifications vary from state to state and from river reach to river reach. Typical classifications include public drinking supply, industrial use, agricultural use, fish and wildlife, and recreation. For each of the classification categories, acceptable concentration levels have been developed for a variety of water quality parameters that vary with use classification. Typical parameters include Dissolved oxygen (DO), Fe, Cl, Phenols, pH, Biological Oxygen Demand (BOD), fecal coliform, Mg, Pb, Cr, Cd, and Cu.

Figure 8.2 shows areas that presently violate water quality standards for DO, pH, Fe and heavy metals, including Cd, Cv, Pb, Mg and Cu. This baseline map was compiled by calculating background river concentrations for water quality parameters available through STORET. STORET, the United States Environmental Protection Agencies water quality data storage base, contains data from field tests conducted by state and federal agencies, such as geology surveys, environmental protection agencies, departments of natural resources, and water surveys, as well as eductional 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 to standards applicable to the river reaches. As indicated in Fig. 8.2 standard violations occur frequently throughout the region for these parameters.

The reasons behind these violations are both natural and anthropogenic. However, since the standards are based on health criteria, even natural violations indicate problem areas.

High Fe concentrations commonly occur due to natural sources such as springs, groundwater interface and geological substrata. However, erosion from excavations, mine tailings, and industrial effluent may also contribute to high Fe concentrations in rivers.

The amount of DO in a stream is a function of water temperature, water depth and surface area, bottom contour, organic loading, and type and amount of biological organisms in the water. Each of these functions may be modified by both natural and man-made sources. Man-induced problems most often occur in heavily poluated areas and stem from increased organic loading due to municipal and industrial effluents.

Low pH concentrations can occur naturally due to springs, geological substrata, and runoff; however, such readings are more often an indication of anthropogenic contributions to water quality. Acid mine drainage from surface tailing and deep mines and effluent from industrial sources are common sources of man-induced Pow pH levels.

Although high heavy-metal concentrations occasionally result from natural situations, they most often result from anthropogenic sources. Mining, agriculture, textiles, chemical, electrical, and refining industries can all contribute to high concentration of heavy metals in water systems through runoff and effluent discharges.

8.3 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; namely; coal conversion plants, and electric power plants, including nuclear and oil, gas and coal burning facilities.

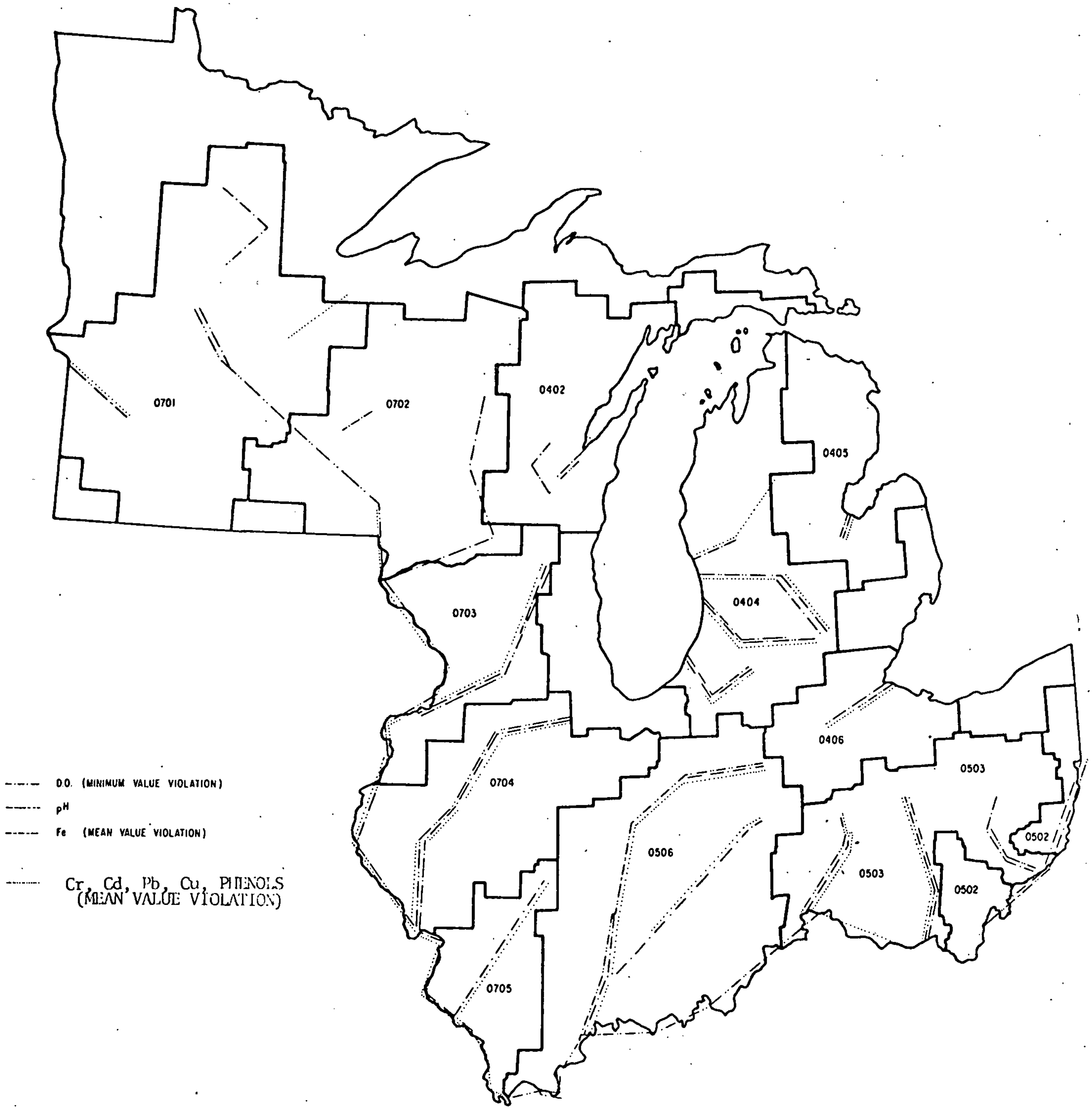

Fig. 8.2 Recorded Regional Water Quality Standards Violations in Major Rivers

As discussed in Sec. 3.0, it was assumed that relatively stringent water consumption controls would be utilized, resulting in 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.

Megawatt generation and water requirements for electrical generation and coal gasification for the years 1985 and 2020 have been computed and presented in Table 8.1 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 percent consumption of 7-day/10-year low flow by 2020 energy development are also presented for each applicable water resource area.

Based solely upon water consumption by electrical power generation and coal gasification, surface water availability problems will develop in several sections of the study area. 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 Ohioa and 30% of the White River in Indiana, 40% of the Minnesota River in Minnesota, and 40% of the Kaskaskia River in Illinois. In addition, problem areas 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.

In these problem areas, if consumptive water demand is to be met, lower water- intensive technologies will have to be introduced, available water supplies augmented, or siting patterns changed.

Two potential methods of water augmentation are the use of lakes and creation or reservoirs. Though these two solutions may be available on a site-specific basis, assessment of their impacts on water availability requires further analysis.

Groundwater is a third method of water augmentation. Groundwater availability is a more site-spedific parameter than surface water availability, the former being dependent upon the thickness, depth, recharge rate, quality and type of aquifers used as well as the extent to which the aquifer potential is already developed by competing users. As limited by the scope of this study, only generalizations, as presented in Sec. 8.2.2, can be made as to overall regional groundwater availability for conversion facilities.

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. 8.5, additional water resources and effects of other competing users will be considered in evaluating the water availability problems for the sample areas in Illinois.

8.4 WATER POLLUTANT LOADINGS FROM COAL UTILIZATION

In coal-related energy facilities, waste streams are generated from cleaning of stack gases; softening, neutralization and demineralization of boiler water; blowdown from various plant processes; cooling and cleaning of crude gases; quenching of gasifier ash and removal of slurry; runoff from coal storage

Table 8.1. 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 River	-	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)	11.5 (21.6)	7,000
	Reservoir	2,966	-	2,966	2,966	-	37.4	-	-

Table 8.1. (Cont'd.)

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	
503	Muskingum River	4,163	-	27,610	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 R.	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 R.	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 R.	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 R.	-	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 R.	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	-	-

( ) Numbers in parenthesis indicate Total water requirements, tributary plus mainstem.

piles; and/or other sources. The makeup and degree of water pollutants possible from power generation plants and coal conversion facilities are dependent on the size and types of processes and pollution control and water conservation practices involved in the various facilities; these have been discussed in detail in Sec. 3.0 of this report.

Based on the loading rates given in Tables 3.7 and 3.1, and siting development 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 8.2 is a summary of data by river basins. High effluent control following New Source Performance Standards (NSPS) for power generation, and "treated" option for coal gasification, were used where given; otherwise the uncontrolled values were used.

Different pollutants may influence the quality of water and of stream biota in different ways. Biological oxygen demand (BOD), which has been used as an indicator of the strength of exidizable compounds, reveals a potential for removing dissolved oxygen (DO) from water. A high BOD may use all available (DO), thus turning 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; nitrite and nitrate are in turn nutrients for biological growth. Ammonia is a good indicator of stream quality as it originates primarily from anthropogenic sources, including gasification and power plants.

Chlorides occur in most surface waters, and sources of chlorides may be natural or anthropogenic, including energy related coal activities. High chloride levels may be hazardous to people with kidney and heart disease. Chlorides impart an undesirable taste to the water and may combine with heavy metals to form toxic salts.

Suspended solids directly affect the turbidity level, which has a profound effect upon the stream biota. Increased turbidity increases cost and decreases effectiveness of water disinfection.

Sulfate may be a limiting factor in algae growth in various 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 affects the taste of drinking water and tends to precipitate and agglomerate on pipe surfaces causing economic problems in water usage. Iron may, under unbuffered circumstances, lower the pH to a toxic level. Iron precipitates may also clog fish gills and smother eggs and larvae of aquatic animals.

Table 8.2. 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 where data for both baseline and high coal use scenarios are presented.

Table 8.2. (Cont'd)

Pollutant	Muskingum River	Scioto River	Miami River	White River	Wabash River[a]	Ohio River[b]	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

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

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

Table 8.2. (Cont'd)

Pollutant	Minnesota River	Wisconsin River	Rock River[a]	Illinois River[b]	Illinois River[c]	Kaskaskia River[a]	Mississippi River[d]
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

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

[b] Represents Baseline Scenario.

[c] Represents High Coal Use Scenario.

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

Copper, another effluent from power plants and gasification processes, is frequently found in surface waters and in small amounts is beneficial to humans and water biota. However, large doses may affect water taste, and in high prolonged doses it 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 concentration. 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 and damaging fish gills. Low levels of zinc are found in coal-related energy activities.

Mercury, lead, chromium, and cadmium, cyanide and phenols are all highly toxic to human and aquatic communities. All have acute and chronic effects, and all concentrate through food chains. They affect the cardio vascular, nervous and excretory systems, and have potential carcinogenic and teratogenic effects. Primary sources for environmental concentrations of all these substances are anthropogenic and include coal mining, power generation, and gasification.

Impacts of pollutant loadings on stream water quality are area-specific, depending on the nature and extent of pollutant as well as the quality and hydrologic characteristics of the receiving water. Specific impacts of three demonstrative example areas are delineated in the subsection that follows.

Discharge of water heat constitutes one other 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, currently restrict the discharge of heated effluents to the aquatic environment. To evaluate the impacts of thermal discharges beyond the year 2000, it is assumed that closed-cycle cooling, such as mechanical draft towers, natural draft towers, and/or cooling ponds, will be used in coal utilization facilities and that no heated effluents will be discharged warmer than EPA standards established for maintenance of propagation and protection for a balanced, indigeneous population of shellfish, fish, and wildlife in or on the receiving water body.

8.5 IMPACTS OF WATER USES AND POLLUTANT LOADING

In this section, 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. Sec. 8.5.1 deals with the water requirement impacts, and Sec. 8.5.2, the pollutant loading impacts.

There are water quality impacts relative to coal developments, which are not quantified in this study, including (1) surface water quality degradation by sediment, acids, and heavy metals carried into streams by coal mine drainage and runoff and (2) groundwater degradation from water percolation through mined areas, spoil piles, and waste disposal sites of utilization facilities. These potential impacts are discussed briefly in Sections 8.5.3 and 8.5.4.

8.5.1 Water Use Impacts

In this section, impacts of water use by the 2020 energy development was evaluated to include considerations of competing water users. Data on the projected withdrawal uses by 2020 for municipal, industrial, agriculatural, and 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 consumptive use fractions from total withdrawal uses. These results are shown in Table 8.3, 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 groundwater.

Illinois River

The Illinois is the largest tributary of the Mississippi above the mouth of the Missouri, with a median flow of 15,480 cfs and 7-day/10-year low flow of 3600 cfs. Minimum potential available groundwater, including that now being used, is 5750 cfs. Yields from lakes and reservoirs in the basin amount to 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 at 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 $33^{1}/_{3}$% of the projected total use. The residential, commercial, agricultural and mining users, together, account for 1117 cfs. The projected energy developments call for power plants at 64,600 MW under the high coal use scenario, and 42,500 MW under the baseline scenario, which will consume 815 and 573 cfs, respectively. These uses account for less than 26% of the projected total consumptive use in the basin.

Based on the data on Table 8.3, it is apparent that apart from instream 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 the period of extreme low flow, the demand by energy development could rise to 16% of the 7-day/10-year low flow, however.

For the Illinois River basin, water use conflicts 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. At the present time, a minimum of 6500 cfs is needed for instream uses in the basin, and it has been estimated that at least 25% of the time these needs will not be satisfied.[7] Furthermore, the 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 Rock River basin is 10,710 square miles.

Table 8.3 Summary of Water Availability and Requirements for 2020 Energy Developments and Competing Users

Users	Illinois	Rock	Kaskaskia
Consumptions by Withdrawal Uses (cfs)			
Municipal & 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 (cfs)[a]			
Hydropower	9366	14210	0
Commercial Navagation	3140	0	337
Recreation, and fish & wildlife	10680	3452	542
Water Quality Management	510	1594	25
Water Availability (cfs)			
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 Reference (7).

[b]Estimated from siting development projected in Sec. 4.0 of this report, also see Table 8.1.

[c]From Table 8A.1.

[d]From Reference (8).

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

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

The projected total consumptive use by 2020, including those by energy sources and nonenergy sources, is equal to about 1434 cfs. The primary consumers are agricultural users, which account for 73.5% of the projected total uses. More than 50% of agricultural water uses are (and will be) dependent on the groundwater sources.[7]

The plan for 2020 energy development, for both baseline and high coal use scenarios, contemplates the 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 power plant water demands represent less than 14% of the 7-day/10-year low flow, and about 5% of the median flow in the Rock River.

Based on flow rates alone, the water supply in the basin apparently will be sufficient to meet the requirements of the 2020 energy development. Similar to the Illinois River, use conflicts between the withdrawal users and instream users are presently existing 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 in a southwesterly direction 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. Groundwater in the basin is quite limited; 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 groundwater, 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 self-supplied industrial users, combined, will require 600 cfs, or 85% of the projected total demand. The projected energy developments by the year 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.

Based on the data given on Table 8.3, water supply in the Kaskaskia River basin will be a problem due to high demand and low availability. The data indicates that during the low flow period the projected total water consumption will amount to approximately 94% of available supplies from all known sources in the basin, including natural stream flow, lakes and reservoirs, and groundwater. It is apparent that serious conflicts can arise among different users.

The conflicts may be reduced somewhat by increasing use of groundwater, 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 less intensive water use energy technology or alternative siting be developed for the Kaskaskia River basin.

8.5.2 Water Quality Impacts

Impacts on the water quality of the Illinois river, Kaskaskia river and Rock rivers in the State of Illinois were evaluated for the projected coal utilization of 2020. The impacts are represented by the pollutant concentration increments due to waste discharges from coal-burning power generation and coal gasification facilities. Simple material balances were performed to incorporate the pollutant loadings and streamflow of each river reach to calculate concentration increments. The 7-day/10-year low flow was used to provide a worst-case situation where effluent loading would be least diluted. It was assumed for the purposes of this study that (1) high effluent controls are implemented 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 8.4 is a summary of background water quality and the projected concentration increments due to 2020 coal developments. Results for the baseline scenario and 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 quality generally indicates a condition of 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 origins. The river water in this area has generally high chloride, phosphate, and nitrogen values, low dissolved oxygen content, and extremely high coliform counts. Long reaches of the stream are devoid of fish, and toxic metals of various kind 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 shown some recovery of its quality as rough fish begin to appear followed by some sport species in successive sectors downstream.

The entire Illinois River has been classified as aquatic life use, and agricultural, industrial, food processing and public water supply and primary contact uses. The Illinois water quality standards applicable for public watersupply, which has the most stringent standard requirements among the different uses, are tabulated in Table 8A.2.

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 mg/l, 0.01 mg/l, and 50 mg/l, respectively, for parts of the river, particularly the upper and middle reaches. The STORET data, which are not given in Table 8.4, also indicate violation of standards in the maximum

Table 8.4. Background Water Quality and Impacts of 2020 Coal Development

Reach	Pollutants[a]														
	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	-	-	-	(mg/l)
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 Scenarios															
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 8.4. (Cont'd)

Reach	Phenols[a] B	Phenols I	Cadmium B	Cadmium I	Chromium B	Chromium I	Copper B	Copper I	Iron B	Iron I	Zinc B	Zinc I	Lead B	Lead 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	(μg/l)
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	-	-	0.006	-	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 and increment due to projected coal utilization: B, I.

readings of ammonia, dissolved solids, mercury, copper, zinc, cadmium and chromium, and the minimum value of DO, for the entire length, (or part) of the Illinois River.

The 2020 baseline scenario includes plans for the construction of eleven coal-burning thermal electric power plants, on the Illinois River and its tributaries, and, in comparison, the 2020 high coal use scenario includes plans for four more of these plants similarly located.

Data on Table 8.4 indicate a relatively insignificant impact of 2020 coal developments on the water quality of the Illinois River. This situation is due mainly to relatively high streamflow with its consequent high-dilution effect on the river and low pollutant loadings from power plants.

For both baseline and high coal use scenarios, the estimated increments of pollutant concentrations, with the exception of chromium, represent only a small percentage of background readings. Thus, assessments indicate that effluent discharges from these future power plants would probably not cause variations in the status of standards violations.

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

Rock River

The Rock River in Illinois has been classified as aquatic life use, agricultural, industrial, food processing, public water supply and primary contact use. Presently, water quality standards are being violated. The STORET data in Table 8.4 indicate that mean values of iron and copper exceed their respective standard. Maximum readings of ammonia, dissolved solids, iron, copper, mercury, 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 represent the major waste loads. The large number of livestock and the large tonnages of applied fertilizers are also causes of water quality degradation in the basin.

Both baseline and high coal use scenarios contemplate the construction of a coal-burning power plant on the Rock River. Water quality impacts by the waste discharge from this plant will be insignificant due to low pollutant loadings, and high streamflow.

Kaskaskia River

Like the Illinois and Rock Rivers, the Kaskaskia is classified as aquatic life use, and agricultural and industrial supply, food processing and public water supply and primary contact use. Although with minor inputs from municipalities and industries, water quality problems still exist in the Kaskasia River due to (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, ranging from 160-575 mg/l in the northern part of the basin and from 140-365 mg/l in the southern part. Concentration of dissolved solids are lower during high flow than during low flow, ranging from 350-1300 mg/l. In addition, measurements for nitrate at Shelbyville and Vandalia exceed 10 mg/l standard for food processing and public water supply. Maximum chloride readings exceed the 250 mg/l standard during summer and fall months 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 Kaskaskia River basin includes the construction of two gasification plants and one power plant. Results of impact analysis indicate a pronounced effect from these coal utilization facilities on the quality of the Kaskaskia River. This impact is in part due to the low flow volume of the river, and in part to the high effluent loadings from coal utilization facilities, particularly the gasification plants.* The most pronounced effects are with phenols, lead, iron, cyanide, and ammonia. The estimated concentration increments indicate that, during the low flow, waste discharges from these future plants will definitely cause violation of standards for the above parameters. Discharges from these plants may also cause problems in other parameters, including copper, chromium, cadmium, and TSS.

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

8.5.3 Surface Water Pollution by Coal Mining

Water pollution by coal mining operations have been studied quite extensively. 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 that caused by exposing minerals to oxidation or leaching, resulting in undesirable concentrations of dissolved materials.

Pollutants from mine sites can be carried in runoff or mine drainage. Pollutant parameter concentrations that most frequently exceed acceptable levels in waste water from coal production facilities are: acidity, total iron, dissolved iron, manganese, aluminum, nickel, zinc, total dissolved solids, total suspended solids, sulfate, ammonia, fluorides, and strontium.[9]

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*Reference is made to Section 3.0 of this report. The New Source Performance Standards for coal gasification have not been published. For the purposes of this analysis, approximate loading values for gasification facilities were used.

A recent EPA report indicates that from a total of 3000 active and abandoned mines in the state of Illinois, at an average of 24,000 lb 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 surface mines in Illinois.[10]

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

Pollutants from coal mines can generally be categorized by differences between acid or ferruginous drainage and alkaline drainage, which in turn reflects local or regional coal and overburden conditions. Alkaline drainage is most frequently found in the Western coal fields and is generally characterized by total dissolved solids and suspended solids in excess of acceptable levels. Acid or ferruginous drainage, typically found in the Appalachian and Eastern Interior Coal Regions, exhibits high concentrations of all of the critical parameters indicated previously.

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

From available historical data generated in the past decade on waste water quality from coal mines, EPA established waste characteristics for thirteen pollutants for both acid and alkaline drainage from underground and surface mines.[9] The established waste characteristics are presented in the EPA report and will not be repeated here.

The EPA study concluded that technologies have been developed to abate mining waste water problems at reasonable costs. They include neutralization of acidity with concurrent reduction of other pollutants to safe concentrations, and utilization of settling basins and coagulants to remove excessive total suspended solids. Neutralization of acidity can usually be achieved with lime followed by aeration and sedimentation. Other neutralization reagents occasionally used include limestone, caustic soda, soda ash, and anhydrous ammonia. In addition to acidity, neutralization treatment of mine drainage can successfully remove iron, manganese, aluminum, nickel, zinc and total suspended solids.

In order to successfully achieve the control of water pollution from coal mines, waste water treatment techniques discussed above are implemented in conjunction with effective mining, regrading, water diversion, erosion control, soil supplementation, and revegetation techniques.

Coal production operations have been included in point source categories and are currently regulated by federal and state environmental conservation agencies. Waste discharges from these operations are controlled via NPDES 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 8.5 presents the New Source Performance Standards of Coal Mining operations recommended by EPA.

8.5.4 Groundwater Pollution by Waste Disposal

Minimization of pollutant discharges from conversion facilities to surface waters can be achieved by extensive reuse of water in these plants, and evaporation of waste water in ponds. However, the designing of 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 potentially may be chosen by many plants, is to bury the residuals, possibly at the mine site. The procedure is quite effective in areas where the groundwater level is deep and rainfall sparse, but could cause groundwater pollution in areas where coal seams, through which contaminants could leak, compose parts of local aquifers. Little information is available on the mechanism, as well as the nature and extent, of groundwater pollution by waste disposal and more such research is needed.

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

Table 8.5. 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: Reference 9.

APPENDIX TO SECTION 8.0

Table 8A.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
	Muskegon	1	20	660
		2	53	450
		3	87	307

Table 8A.1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow (cfs)
404 (Cont'd)	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
702	Chippewa	1	16	1900
		2	48	775
		3	76	500
		4	109	285
		5	150	200

Table 8A.1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow (cfs)
702 (Cont'd)	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
	Mississippi	18	635	11000
		19	670	8500
		20	717	7000
		21	774	4500
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
		5	160	15
		6	196	10
		7	231	3

Table 8A.1. (Cont'd)

Water Resource Council Aggregated Subarea	River	River Reach	Midpoint River Mile	7-day/10-year Low Flow (cfs)
705 (Cont'd)	Mississippi	1	18	48500
		2	54	47750
		3	85	47250
		4	108	47000
		5	135	46500
		6	175	45500

Table 8A.2. Public Water Supply Quality Standards for the Illinois, Rock, and Kaskaskia Rivers[a]

Parameters	Limiting Conditions or Concentrations
pH	6.5–9.0
P	0.05 mg/l
D.O.	6.0 mg/l
Radioactivity	
β	100 pci/l
RA 226	1
Sr 90	2
Fecal Coliform (5 sample/30 day)	200 per 100 ml
NH_3	1.5 mg/l
As	0.01
Ba	1.0
Bo	1.0
Cd	0.01
Cl^-	250.0
Cr^{+6}	0.05
Cr^{+3}	1.0
Cu	0.02
Cyanide	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
T.D.S.	500
Zn	1.0
C.C.E.	0.2

Table 8A.2 (Cont'd)

Parameters	Limiting Conditions or Concentrations
MBAS	0.5 mg/l
Oils	0.1 |
N (NO_2, NO_3)	10.0 |
T.S.S.	15.0 |

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

REFERENCES FOR SECTION 8.0

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