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Energy Division

ENVIRONMENTAL ASPECTS OF DISTRICT HEATING/COGENERATION IN THE TWIN CITIES

by

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ABSTRACT

A study was made to assess some of the environmental impacts that might be expected to occur as the result of building a 2600 MW(t) city-wide district heating/cogeneration system in Minneapolis/St. Paul. The study focused on urban air quality impacts, power plant cooling water impacts, and disposal of solid wastes from a new cogeneration plant.

Estimates were made of the SO_2 and particulate emission rates and local concentrations without and with the district heating/cogeneration system. A methdology employing fuel use data was developed to estimate emission rates from sources not included in the National Emission Data System. Predictions were made on an annual average basis and 24 h average basis for five winter days and one late summer day. With the development of the district heating/cogeneration system, the total SO_2 emission rate could decrease (up to 3%) or increase (up to 11%) depending on the retrofitted power plant load factors. In all cases there would be reductions (up to 30%) in the predicted SO_2 concentrations in the urban area due to central facilities replacing many small heating units. The particulate total emission rates and concentrations were both predicted to be slightly reduced. Changes in the trace element concentrations and deposition rates were predicted to be very small.

Retrofitting existing power plants to cogeneration operation has generally positive impacts since these plants use once-through cooling. Much of the heat normally discharged into the Mississippi River would be diverted to the district heating system, thus greatly reducing the quantities of river water having temperatures above ambient. Solid wastes produced by the new cogeneration plant would be primarily ash and FGD wastes, and it is believed that they could be disposed in an environmentally safe manner.

1. BACKGROUND AND SCOPE OF STUDY

1.1 PURPOSE OF STUDY

The principal purpose for performing this study was to identify the types and magnitudes of major environmental impacts that could occur in an urban area if a large, modern district heating system was built there. District heating is used extensively in Europe and is being considered increasingly in the United States because it can be energy conserving and can allow the switch to cheaper fuels, such as coal. The resultant changes in the types of thermal energy sources in fuel consumption and in the type fuel used can all change the environmental impacts of space heating in an urban area.

The second purpose of this study was to develop a methodology for estimating the changes in space heating emissions that would occur. It can be difficult to estimate the magnitude of emissions from numerous existing space heating units and to project how these emissions will change once district heating has been implemented. In addition, if the district heating thermal energy sources are cogenerating power plants, as is the case in this study, there are additional complications due to time-varying demands for thermal and electrical power at each boiler. By working through a case study such as the one addressed here, a better insight can be obtained of how emissions estimates should be done.

To these ends, a conceptual city-wide district heating system using cogenerated heat for the Twin Cities of Minneapolis-St. Paul, Minnesota was investigated. A feasibility/economic study[1] concluded that such a system would be viable. The system was envisioned to use hot water technology and would have a thermal capacity of 2600 to 4000 MW(t). Most of the thermal energy would be provided by cogeneration units, which would be converted turbine-generator units at two existing coal-fired generating stations and one or two new coal-fired units. It should be noted that this particular investigation is not in support of any regulatory action.

A previous study[2] was made to determine the impact of this large hypothetical system on the annual average sulfur dioxide (SO_2) air quality. That study concluded that there would be a slight (~3%) increase in the total annual SO_2 emissions due to coal-fired cogeneration units replacing the individual furnaces using natural gas and oil. However, that study predicted that the annual average SO_2 concentrations in the urban area would decrease significantly (~15%). This reduction would be due to the use of tall stacks at the cogeneration plants, which would disperse the pollutants more effectively than could be realized for emissions from local heating units that typically have short stacks. These conclusions are consistent with those of a similar study done for Boston, Massachusetts.[3]

The study reported herein addresses the air quality impacts further as well as a number of other impacts. Specifically, topics being addressed are:

1. Changes in total fuel consumption,

2. Changes in emissions and ground level concentrations of SO_2 and total suspended particulates (TSP) for both annual and selected 24-h time frames,

3. Changes in trace metal emission inventory and concentrations,

4. Changes in water quality,

5. Impact of the new cogeneration unit (either a pulverized coal unit with a dry flue gas desulfurization scrubber or an atmospheric fluidized bed unit). For the new unit, the study considered:

   a. Air quality impacts,

   b. Disposal of solid wastes,

   c. Effect of coal storage on water quality.

A paper summarizing the air quality portion of the study was presented at the Air Pollution Control Association June 20-25, 1982 meeting.[4]

An analysis of the environmental regulatory requirements that are necessary to construct and operate this system was performed as a companion study to this one.[5] That study focused on the regulatory process of implementing this district heating/cogeneration system in the Twin Cities and evaluates its impact on the costs in terms of both money and time.

1.2 DISTRICT HEATING CONCEPT

District heating is generally defined as the distribution of thermal energy from a central source to residential, institutional, and commercial users. The central source is usually a heat-only unit or a cogeneration facility that produces both electricity and thermal energy. The most significant advantage of cogeneration power plants compared to conventional steam-electric generating stations is improved efficiency in fuel utilization. Figure 1.1 is a graph that compares efficiencies of electric-only vs. cogeneration units. The overall conversion efficiency of a typical electric-only plant is about 33%; two-thirds of the energy is rejected to the environment through the stack and through the plant cooling water system. (Water usually discharges from the plant condensers at about 35 to 40°C.) A cogeneration power plant, on the other hand, can operate at an overall efficiency as high as 85%, but this requires that some electric output be sacrificed. To supply thermal energy at a temperature high enough for district heating (120°C), steam is extracted from the turbine before it has expanded to its full potential, resulting in some reduction in the power output of the turbine. However, for each unit of electric energy sacrificed, 5 to 10 units of thermal energy are available for district heating.

An additional advantage of district heating systems is that they can utilize fuels that are more plentiful in the United States, such as coal

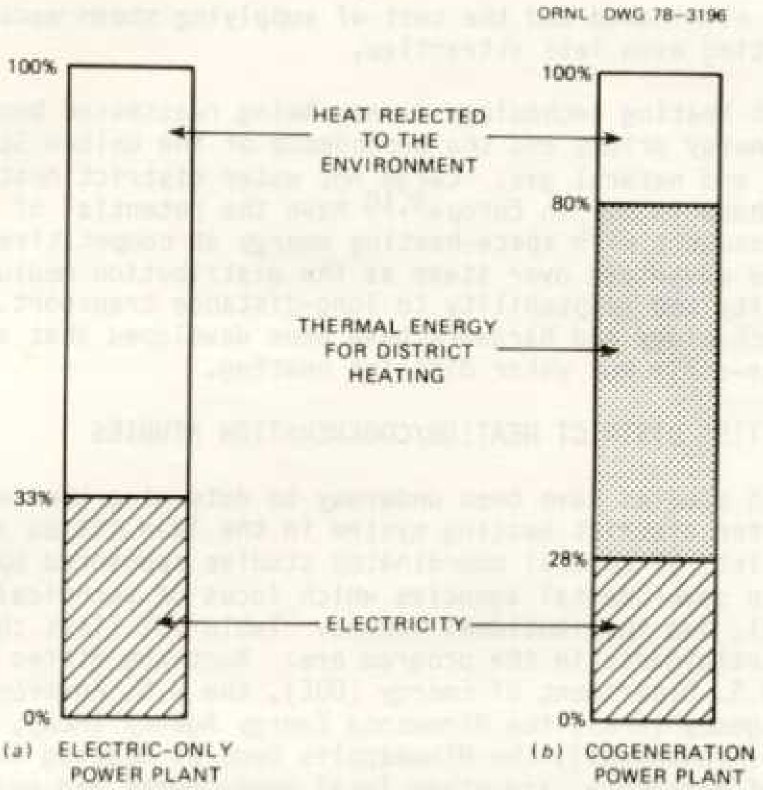

Fig. 1.1. Comparison of fuel utiliation of electric-only and cogeneration power plants.

and uranium. This reduces the use of fuels that are more limited in supply, such as natural gas and oil, which are commonly used in the smaller individual heating units. Moreover, municipal waste incineration is being used in some cases to furnish heat to district heating systems,[6] and the use of solar energy to furnish heat to these systems is being investigated.[7]

District heating has been in existence in the United States for approximately 100 years. In 1877, a short underground steam pipe was installed in Lockport, New York to transport thermal energy from a central source to heat a group of buildings.[8,9] However, it was not until the early part of the twentieth century that district heating/cogeneration systems came into existence. These systems utilized the exhaust steam from small, noncondensing steam-electric power plants to heat buildings in nearby business districts. After a period of rapid growth, the expansion of steam district heating systems slowed in the late 1940s when inexpensive oil and natural gas became available for heating purposes. At about the same time, utilities were introducing large condensing steam-electric power plants remotely located from urban areas; transporting steam over such distances would not have been economical. As the smaller, older cogeneration units were retired, sources for the steam district heating systems were eliminated and the cost of supplying steam escalated, making district heating even less attractive.

District heating technology is now being reassessed because of rapidly escalating energy prices and the dependence of the United States on imported oil and natural gas. Large hot water district heating systems similar to those in use in Europe[9,10] have the potential of providing consumers with space-heating energy at competitive prices. Hot water has the advantage over steam as the distribution medium because of its flexibility and adaptability to long-distance transport. Over the past 20 years, technology and hardware have been developed that successfully provide large-scale hot water district heating.

1.3 TWIN CITIES DISTRICT HEATING/COGENERATION STUDIES

In-depth studies have been underway to determine the feasibility of a large hot water district heating system in the Twin Cities area. The program consists of several coordinated studies sponsored by several companies and governmental agencies which focus on technical, economic, environmental, and institutional issues. Table 1.1 lists the various studies. Participants in the program are: Northern States Power Company (NSP), the U.S. Department of Energy (DOE), the U.S. Environmental Protection Agency (EPA), the Minnesota Energy Agency (MEA), the Minneapolis Gas Company (Minnegasco), the Minneapolis Central Heating Company, and University of Minnesota, and other local governments and private organizations.

TABLE 1.1 MINNEAPOLIS-ST. PAUL DISTRICT HEATING STUDIES

Studies	Sponsor
Distribution and building systems	
Studsvik district heating study (overall feasibility study outlining 20-year development)	DOE
Building conversion study (description of conversion techniques and estimation of costs)	DOE
Feasibility of expanding the St. Paul district heating system	NSP
Energy sources studies	
Retrofitting an existing coal plant (description of conversion techniques and costs for High Bridge Power Plant in St. Paul)	NSP
New coal cogeneration plant assessment (investigation of the possibility of locating a new coal-cogenerating unit near or in the Twin Cities)	NSP & DOE
Nuclear cogeneration plant assessment	DOE
Institutional issues	
Ownership option and barriers (identification and evaluation of nontechnical issues: ownership, financing, regulation, and marketability)	DOE & EPA
Environmental	
Air-quality modeling (prediction of the effect of district heating/cogeneration on Twin Cities air quality)	DOE & EPA

These studies concluded that a large hot water district heating/cogeneration system in the Twin Cities is feasible and economically attractive.[1] In addition, they concluded that the best way to start to implement such a system is to form a non-profit corporation.[11] The St. Paul District Heating Development Company, Inc. was formed in response to this conclusion. The company has constructed and started operation of the initial portion of the 200 MW(t) hot water district heating system.[12] The system will be expanded to serve most of St. Paul central business district and the State Capitol complex.[13] Presently, the Third Street Steam District Heating Plant is used to heat the water circulating in the hot water distribution system. It is planned to convert the newest turbine-generator at the nearby High Bridge Generating Plant (Figure 1.2) to provide cogenerated heat for the hot water system, replacing the Third Street plant as the primary source of energy for the system.[14]

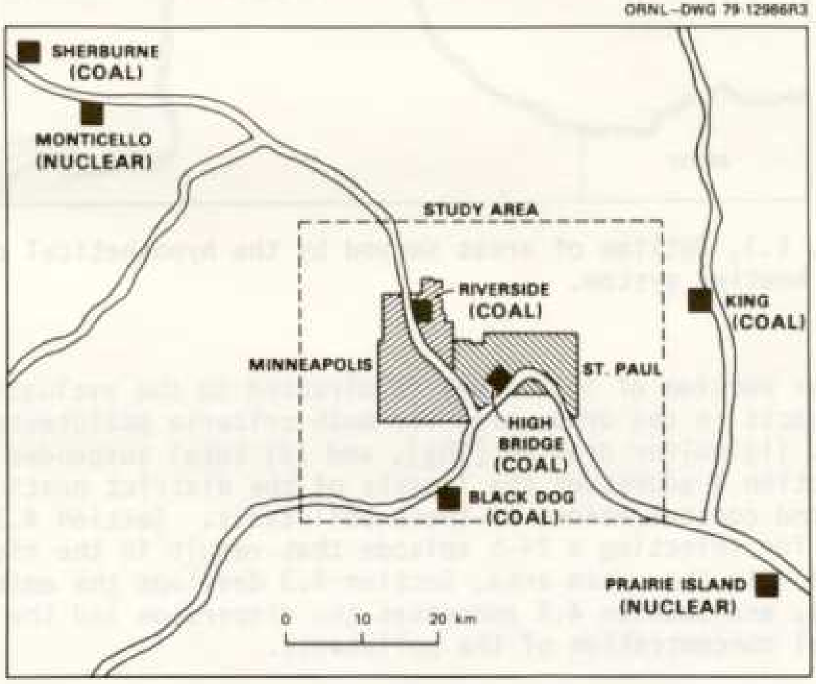

Fig. 1.2. Map of Minneapolis-St. Paul region showing study area (dashed line) and power plant locations.

1.4 SCOPE OF STUDY

The study herein focuses on the evaluation of the impacts within a 42 km (26 mi) by 50 km (31 mi) urban area outlined in Figure 1.2 It is assumed that areas served by the hypothetical city-wide district heating system are those indicated by the outlines in Figure 1.3. The system service area in Minneapolis is 64 km^2 (25 mi^2) and that in St. Paul is 26 km^2 (10 mi^2). Features of the district heating system along with the fuel savings that could be realized by the operation of the system are discussed in Section 3.

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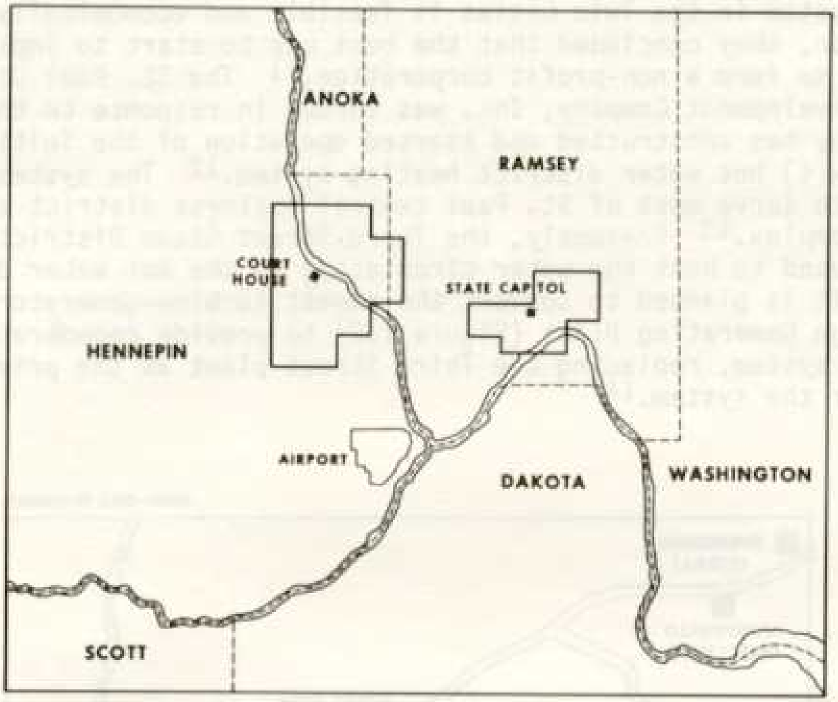

Fig. 1.3. Outline of areas served by the hypothetical city-wide district heating system.

A major portion of this study is directed to the evaluation of the air quality impacts in the urban area for both criteria pollutants selected for this study: (1) sulfur dioxide [SO_2], and (2) total suspended particulates [TSP]. Section 4 addresses the impacts of the district heating system on the emissions and concentrations of these pollutants. Section 4.2 addresses the procedures for selecting a 24-h episode that result in the highest SO_2 concentration in the urban area, Section 4.3 develops the emission source inventories, and Section 4.4 addresses the dispersion and the resulting ground level concentration of the pollutants.

The determination of the emission source strengths is a critical part of air quality impact evaluation procedures. It is envisioned that the development of city-wide district heating system would be over a 20-year period. During this time, it is anticipated that the types and amounts of fuels that would be available for heating needs in the area will change. The Twin Cities are large users of natural gas, but their supply is limited. In the winter months, alternate fuels, primarily fuel oil are used to supplement natural gas for heating needs. It is probable that the fuel mix will change in the future with increased use of alternate fuels. When this study was started, 1987 was the furthest into the future that extrapolation of the most recent (1976) fuel use data could be made with any confidence. The data as extrapolated to 1987, therefore, were used to generate the emission source strengths, recognizing that the situation at that time when the system is fully developed actually would be different.

This study does not investigate in any detail the impact of the city-wide district heating system beyond the limits of the boundaries of the study area. District heating systems generally replace several individual sources with short stacks with central heating or cogeneration plants having tall stacks. Tall stacks permit greater disperison of pollutants, but they potentially could increase the exposure of the population downwind of the urban area to the pollutants. It is recognized that such impacts could occur, but no effort was made to analyze them, as discussed in Section 1.5.

The impact of the district heating system on the trace metal emissions and concentrations is addressed in Sections 4.3.7 and 4.4.5, respectively. Treatment of this subject is limited to the evaluation of the impact on an annual basis.

Use of cogeneration facilities for district heating reduces the cooling water requirements for the power plants. The hypothetical district heating system study visualizes the conversion of the existing High Bridge and Riverside Generating Plants to cogeneration operation and the addition of a new cogeneration unit.[3] The existing plants located on the Mississippi River use once-through cooling. Estimation of the impacts of cogeneration operation on the river water temperatures are presented in Section 5. The new cogeneration unit would have close-cycle cooling, and therefore its impact on the river water temperature would be negligible. The effect of any close-cycle cooling system discharge on the river quality was not investigated.

The cogeneration plants for the city-wide district heating system use coal as the fuel. There are impacts due to runoff from coal storage piles and disposal of solid waste produced at those plants. For the study herein, it was assumed that there would be no significant changes in these impacts due to the conversion of the existing units to cogeneration operation. However, there will be additional impacts due to the construction of the new cogeneration unit, and these are addressed in Section 6.

1.5 STUDY LIMITATIONS

As stated above, this study was performed to evaluate the urban impacts of a large district heating system. To perform this study within the budgetary limitations of the project, several restrictions to the analysis were necessary. It is important to note some of the restrictions when interpreting the study results. First, environmental impacts were only considered in the vicinity of the system; just the most immediate impacts, those on a large urban population, were estimated. As a result, some long-range, possibly significant impacts may have been omitted. Shifting emissions to tall stacks can, as this study finds, result in pollutant concentration reductions within an urban area. These increased stack emissions will result in increased pollutant concentrations at greater distances from the source. It was beyond the scope of the study to determine the magnitude and significance of such long distance impacts.

Second, this analysis was done to identify important changes in pollution concentrations that might occur from district heating development, not to support any regulatory actions which must be undertaken in order to construct and operate such a system. Analytical models were chosen for this study based on their previous use in scientific research. They are not expected to supply the detailed precision and accuracy which are often required in environmental regulatory actions. Similarly, some data bases were used because they were adequate for the stated purposes of this project. Their use does not imply that better information could not be obtained if warranted in order to do an environmental impact analysis with different objectives.

Third, as stated in Section 1.1, this is a site-specific analysis with the consequent limitation in such important factors as existing and future fuel use and climatology. Such factors must be considered when the results of this study are used to estimate what the impacts might be of developing a district heating system in another community; the methodology developed here will be generally more applicable from site to site than the magnitudes of the calculated pollutant concentration changes.

Fourth, limitations in the scope of the study prevented the calculation of 3-h average pollutant concentrations on days when pollutant episodes were expected to occur. It is possible that for these conditions, localized increases in SO_2 concentrations could result under the district heating scenario studied here, because of the resultant increases in emissions from the power plants.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

2.1 FUEL SAVINGS

The development of a 2600 MW(t) city-wide district heating/cogeneration system in Minneapolis-St. Paul could result in significant fuel savings, particularly in the form of natural gas and oil. It is estimated that 19 PJ* (18×10^{12} Btu) of energy could be saved annually. Natural gas and oil energy savings by the district heating customers would be 26 PJ (25×10^{12} Btu) and 7 PJ (7×10^{12} Btu), respectively. These savings are equivalent to 7.1×10^8 m^3 (25×10^9 ft^3) of natural gas and 1.62×10^5 m^3 (1×10^6 bbl) of oil. The generation plants, however, will require additional fuel. About 4.0×10^5 Mg (4.4×10^5 tons) of additional coal having an energy content of 10 PJ (9.5×10^{12} Btu) would be required for replacement of electricity that was generated previously at the retrofitted power plants. The peak heat-only units need 4 PJ (4×10^{12} Btu) additional energy. This energy could be provided either by 1.2×10^8 m (4.1×10^9 ft^3) of natural gas or by 1.0×10^5 m^3 (6.4×10^5 bbl) of oil.

Much of the energy savings would be realized during the cold winter days, when the demand for thermal energy is the greatest. The 24-h net energy savings would be 112 TJ** (106×10^9 Btu) for a -5.8°C (21.5°F) average temperature day to 153 TJ (145×10^9 Btu) for a -17.2°C (1°F) average temperature day. These values compare to the annual average net energy saving of 52 TJ (49×10^9 Btu) per day. Since the use of oil for space heating purposes is greater during the colder days because of natural gas curtailment, the fraction of the net energy savings in the form of oil would be greater on the colder days. On the -5.8°C (21.5°F) day, 27% of the net energy saving would be in the form of oil, and on the -17.2°C (1°F) day, 55% of it would be in the form of oil. These values compare to the annual average value of 16% (assuming oil is used in the heat-only units).

2.2 CHANGE IN EMISSION RATES

With the full development of a 2600 MW(t) district heating/cogeneration system, this study projects that there would be a 2.6% increase in the total annual SO_2 emission rate. For the selected 24-h episodes during the winter season, the total SO_2 emission rate is projected to increase about 6 to 11%. The increases would be due to the addition of a new cogeneration plant and to the increased load factors of the retrofitted power plants. Increased SO_2 emissions at these plants are projected to be greater than the total decrease of SO_2 emissions from the sources connecting to the district heating system. Many of the sources that would connect to the district heating system now burn natural gas,

*PJ = petajoule = 10^{15} joules = 0.95×10^{12} Btu
**TJ = terajoule = 10^{12} joules = 0.95×10^9 Btu

which has extremely low sulfur content. During the very cold 24-h episode, [-17.2°C (1°F)], the increase in the total SO_2 emission rate would be somewhat lower than for some of the days not as severely cold. This would be due to the displacement of larger amounts of oil by the district heating customers.

Present air quality regulations do not require that power plants which are retrofitted for cogeneration operation meet the New Source Performance Standards (NSPS). If they did, the emission increase would be much less because of the emission controls that the plants would have to add. The total annual SO_2 emission rate would only increase about 0.8% and total 24-h episode SO_2 rate would increase in the range of 0.1 to 1.5%, except for the very cold days, when it would decrease about 1.2%.

The increase in the load factors of the retrofitted plants is the primary reason for the increase in the total SO_2 emission rates with the development of the district heating/cogeneration system. If there were no changes in the load factors at these plants, the total annual SO_2 emission rate would increase only about 0.4% due to the addition of the new cogeneration plant. For the selected 24-h episodes, the total SO_2 emission rates would decrease in the range of 0.5 to 3.3% for no changes in the retrofitted plant load factors.

In all cases, the total TSP emission rate would decrease. For the reference district heating/cogeneration system, it is estimated to decrease about 4% on an annual average basis, and from 7 to 24% during the 24-h episodes. This would be due to the small individual combustors having no particulate removal equipment being replaced with central plants (including the retrofitted plants) having high-efficiency particulate removal facilities.

The impact of having a reduced number of oil delivery trucks on the SO_2 and TSP emissions, if there is district heating, was found to be extremely small.

These changes in the total emission rates are generally consistent with those reported in the Boston, Massachusetts district heating/ cogeneration study.[3] In that study, it was predicted that the development of a 4000 MW(t) system would result in a 5.9% increase and a 2.5% increase in the total SO_2 and TSP emission rates, respectively. A direct comparison of the Boston study results with those reported herein is difficult, however. Although Boston uses a greater percentage of oil for the heating needs than does the Twin Cities, most of its power plants use oil instead of coal. Moreover, Boston has stringent restrictions on the sulfur content of the oil burned within the city. The Boston study considered an additional case where a large fraction of the major oil fired plants was converted to coal-fired operation. Assuming that the NSPS apply, that study predicted that there would be decreases of 0.8% and 0.5% in the total SO_2 and particulate emission rates, respectively. The Twin Cites predictions are consistent with these values.

It should be noted that 615 MW(t) of the 4044 MW(t) capacity in the Boston system would be from a nuclear power plant. Nuclear plants have essentially zero SO_2 and TSP emissions. Nuclear cogeneration was not included in the study herein. Prairie Island Nuclear Generating Plant could supply a large fraction of the energy for the Twin Cities system if it was converted to cogeneration operation. If it was, both the total SO_2 and TSP emission rates would decrease with the development of the system.

2.3 CHANGE IN AIR POLLUTANT CONCENTRATIONS

2.3.1 Annual Average SO_2 Concentrations

Dispersion calculations using the Climatological Dispersion Model (CDM) predicted annual average SO_2 concentrations in the Twin Cities area reasonably consistent with those measured for the base year 1976. In the downtown areas of Minneapolis and St. Paul, these concentrations were predicted to be 52 and 56 $\mu g/m^3$, respectively.* Most of the contributions to the SO_2 in the air in the downtown districts are due to the point sources and the commercial and industrial area sources. Each of these categories contributes about an equal amount to the SO_2 concentrations. The influence of the power plants is relatively small in spite of their large emission rates, primarily due to the use of tall stacks that encourages dispersion of the SO_2. The influence of the residences is also small, because, despite their short stacks, they primarily use natural gas as a fuel.

The annual average SO_2 concentrations were predicted to increase in 1987 without district heating due to the anticipated increased substitution of alternate fuels, primarily oil, for curtailed natural gas. The peak concentrations in downtown Minneapolis and St. Paul were predicted to increase to 60 and 62 $\mu g/m^3$, respectively. This represents about a 10 to 15% increase in the peak concentrations from 1976 to 1987.

If the city-wide district heating/cogeneration system was completely developed by that year, the SO_2 concentrations were predicted to be lower. The peak concentration in downtown Minneapolis would be 51 $\mu g/m^3$ and that in downtown St. Paul would be 53 $\mu g/m^3$. These values are about 15% lower than those for the same year if the system was not developed. They are also slightly lower than 1976 base year concentrations. About half of improvements in the SO_2 concentrations would be due to the displacement of the point sources by the district heating system, and the other half is due to the displacement of the commercial and industrial area sources having relatively short stacks. The increased contributions of the power plants to the SO_2 concentrations were predicted to be small because their tall stacks would result in greater dispersion of their emissions.

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*Absolute magnitudes of pollutant concentrations were calculated in this study only to provide a comparison of changes in the pollutant concentrations from one scenario to the next.

The 15% improvements in the SO_2 concentration is considerably lower than the 90% peak reductions predicted in the Boston study[3] and 98% peak reductions predicted by Moskowitz et al.[15] Much of this difference is due to the fact that those two studies did not consider the background SO_2 concentrations, which would be expected to reduce these percentages significantly.

2.3.2 Annual Average TSP Concentrations

For particulates, the peak TSP concentrations in the downtown areas were predicted to be 21 $\mu g/m^3$ in Minneapolis and 39 $\mu g/m^3$ in St. Paul. However, at these locations, much of the TSP in the air is due to sources other than those associated for energy needs, such as grain elevators. With the development of the district heating/cogeneration system, the greatest improvements in the annual average TSP concentrations would be at the locations of the peak improvement of the SO_2 quality. These locations are different from the locations of the existing peak TPS concentrations. In downtown Minneapolis at the location of peak improvement, the TSP concentration would only decrease from 13 to 12 $\mu g/m^3$. Similarly for St. Paul, it would decrease from 17 to 16 $\mu g/m^3$.

2.3.3 24-h Average SO_2 Concentrations

For the six selected 24-h episodes, SO_2 concentrations predicted by the Texas Episodic Model (TEM) in the downtown areas for the base year 1976 were reasonably consistent with the measured values, but not as close as for the average annual concentrations. Comparisons between predicted and measured values for short terms are not as meaningful as for the annual case because of the uncertainties in short-term source and meteorological data. The concentrations generally increased with decreasing temperatures for the four winter episodes having moderate winds generally blowing from between the east and the south. The predicted concentrations for the other winter episode, the coldest selected day, are somewhat lower than those for the next coldest selected day because this episode has a strong wind blowing from the northwest, which results in greater dispersion of the emissions.

The exact locations of the maximum SO_2 concentrations in the downtown areas vary for the different episodes because of the different meteorological conditions for each episode. However, these concentrations were predicted to be higher than the annual averages because of the increased demand for fuel and the increased substitution of oil for natural gas in the winter. For example, Episode 1 during 1976, having a temperature of -5.8°C (21.5°F), the peak concentration in downtown Minneapolis was predicted to be 101 $\mu g/m^3$ and that in downtown St. Paul was predicted to be 135 $\mu g/m^3$. For Episode 2, the episode having the highest concentrations and a temperature of -10.6°C (13°F), these peak concentrations were predicted to be 220 $\mu g/m^3$ and 143 $\mu g/m^3$, respectively.

The SO_2 concentrations were predicted to increase in 1987 without district heating because of the anticipated increased substitution of fuel oil for curtailed natural gas. For Episode 1, the peak SO_2 concentrations would increase 49% to 149 $\mu g/m^3$ in downtown Minneapolis and 29% to 174 $\mu g/m^3$ in downtown St. Paul. Similarly for Episode 2, they would increase 15% to 254 $\mu g/m^3$ in downtown Minneapolis and 11% to 159 $\mu g/m^3$ in downtown St. Paul. Most of the contributions to these concentrations would be due to the point sources other than the power plants and the commercial and industrial area sources, which typically have relatively short stacks. The contributions of these two source categories would be about equal. The power plant component of the concentrations would be small because of the use of the tall stacks, which results in relatively large dispersion of the pollutants. The residential area source contributions are low because of a high percentage of the residences in the study area use natural gas for their heating needs.

As with the case of the annual average concentrations, the 24-h SO_2 concentrations were found to decrease with the development of the 2600 MW(t) district heating/cogeneration system. Within the resolution of the dispersion models and the 1 Km receptor grid used in this study, no increases in the SO_2 concentrations were predicted anywhere in the study area for the episodes considered. The TEM calculations predicted greater than 20% decreases over large portions of the urban areas and 30 to 40% decreases in the downtown regions, where there are the highest population densities. It should be remembered that these predictions do not include any background concentrations. Including these will reduce these percentages, but decreases of 20 to 30% in the downtown areas would still be likely.

The magnitudes of the decreases with development of the system were found to be greatest for the days originally having higher SO_2 concentrations. These are generally the colder days when emission rates would be higher. For example, Episode 1, the peak concentration in downtown Minneapolis would be reduced 32% to 101 $\mu g/m^3$ and that in downtown St. Paul would be reduced 45% to 97 $\mu g/m^3$. For Episode 2, the episode having the highest concentrations, they would be reduced by 33% to 171 $\mu g/m^3$ and 35% to 104 $\mu g/m^3$, respectively.

The reductions were predicted to be primarily displacement of point sources and commercial and industrial area sources that would connect to the district heating system. As expected, the residences connecting to the system would have little effect since they primarily would be using natural gas prior to connection. Although the emission rates from the cogenerating power plants were assumed to be higher with cogeneration, the impact of this component on the total SO_2 concentrations were predicted to be small due to the relatively tall stacks.

The TEM predicted SO_2 concentrations in the downtown areas were checked by Multiple-Source Air Quality Algorithm (RAM) for Episode 2. The two models generally predicted the same impact, although RAM predicted a slightly greater influence of the power plants. This is believed to be due to the different dispersion coefficients used in the two models. In either case, the effect of the power plants was predicted to be small.

2.3.4 24-h Average TSP Concentrations

TSP concentrations for the winter episodes were predicted to be much higher than those for the annual case. The impact of the district heating/cogeneration system would be relatively small. The greatest reductions were predicted for Episode 2. Peak reductions of 8 $\mu g/m^3$ and 6 $\mu g/m^3$ were predicted for downtown Minneapolis and downtown St. Paul, respectively. These values compare to original peak concentrations of 161 and 249 $\mu g/m^3$ in downtown Minneapolis and 106 and 113 $\mu g/m^3$ in downtown St. Paul.

2.3.5 Trace Element Concentrations

The effect of the district heating/cogeneration system on the trace elements concentrations and deposition rates in the Twin Cities area was found to be negligible. Emissions of 17 trace elements from the coal-fired power plants were estimated, and the changes in their concentrations due to these emissions were predicted to be negligible compared to the typical concentrations of these elements in urban areas. Using a conservative particle settling velocity of 1 cm/s, the change in the predicted settling rates for these elements were predicted to be negligible compared to their natural abundance in soils. While concern over buildup of trace elements due to fossil fuel combustion, in general, cannot be dismissed, the impact of due to the development of the district heating/cogeneration system would be negligible.

2.4 WATER QUALITY IMPACTS

The conversion of High Bridge and Riverside Generating Plants to cogeneration mode of operation will substantially reduce the waste heat that is discharged into the Mississippi River. This will result in reductions in the portion of the river that will have temperatures in excess of the ambient due to the operation of the plant's once-through circulating water systems.

For High Bridge, conversion of Units 3, 5, and 6 to cogeneration operation would reduce the volume of water in the river having a given excess temperature by about an order of magnitude. Conversion of Unit 6 by itself would decrease the volume by a factor of 2. Similarly for Riverside, conversion of Units 6 and 8 to cogeneration operation would again reduce the volume of water in the river having a given excess temperature by about an order of magnitude.

For both plants, much of the dilution of the circulating water is predicted to be close to the points of discharge in the river. Thus, the size of the mixing zones (having greater than 5°C excess temperature) are small compared to the overall size of the main river channels at both plants. This means that there is no problem having adequate passage zones for the fish in the river.

There is a potential for a fish kill at the High Bridge plant if the retrofitted turbines are switched from straight condensing mode to cogeneration mode operation in the winter. This is because gizzard shad is part of the indigenous fish population in the river at this plant, and can be killed by sudden temperature changes of greater than 5°C at low water temperatures. However, it is not likely that this plant will operate in straight condensing mode during the winter since NSP's electrical loads peak during the summer, and the district heating heat demand would be the greatest during the winter. Such a fish kill potential is greatly reduced at the Riverside plant since the fish population there does not contain gizzard shad and is more cold tolerant.

2.5 NEW COGENERATION PLANT SOLID WASTE DISPOSAL

It appears that solid wastes produced at the new 190 MW(e)/335 MW(t) new cogeneration plant required for the new district heating system could be dispersed in an environmentally safe manner. The waste would be primarily ash and flue gas desulfurization (FGD) wastes. There would be also solid waste produced by the treatment of the coal storage pile treatment plant, but its volume would be very small compared to that of the ash and FGD wastes. The waste probably would have to be disposed offsite in landfills lined with an impervious material, such as bentonite.

If the new cogeneration plant is a pulverized coal unit equipped with a dry lime FGD system, a total of 114 Gg/y* (1.26×10^5 tons/y) of solid waste would be produced. If the plant is an atmospheric fluidized bed combustion (AFBC) unit, a total of 135 Gg/y (1.49×10^5 tons/y) of solid waste would be produced. The amount of waste that would be produced by the AFBC unit would be higher since at the present state of technology, these units greater quantities of limestone for sulfur removal.

2.6 RECOMMENDATIONS FOR FURTHER RESEARCH

It can be seen that a large district heating/cogeneration system in Twin Cities may have a number of urban environmental benefits. The study showed that there are likely to be improvements in the urban air quality and water quality. One of the major reasons for the improvement in the air quality is the displacement of the oil now being used by the commercial and industrial area sources that would connect to the district heating system. These sources generally have relatively short stacks and thus contribute significantly to the local pollutant concentrations.

Many assumptions were required to estimate the emission rates from the commercial and industrial area sources and the contribution of these to the pollutant concentrations. Considerable effort was devoted in this study to develop an accurate source inventory. However, this effort had to be limited to keep the scope of this study within reasonable limits. Subsequent to the time when the calculations were done for this study, the Metropolitan Council of the Twin Cities Area investigated the area sources

*Gg = Gigagrams = 10^9 grams = 1.1×10^3 tons in much more detail.[16] Individual sources including their stack heights accounting for 70% of the area sources were identified, and the Council was able to obtain good agreement between the measured and predicted average annual SO_2 concentrations for 1978.[17] It is recommended that impact of the city-wide district heating/cogeneration system be evaluated on an annual basis using the Metropolitan Council source data. This will indicate the sensitivity of the assumptions regarding the area source data on the predicted SO_2 concentrations.

In this study, a particular scenario defining the alternate fuels replacing curtailed gas and their displacement was selected. Although the prices of natural gas and oil have stabilized at this time (1983), it is likely that they will increase in the future and there will be an economic incentive to use cheaper fuels such as coal. Different scenarios evaluating the environmental impacts of using various alternate fuels in various cogeneration schemes should be investigated. Such a study would help to identify potential environmental problem areas as alternate fuels are substituted, as well as to possibly define efficiency credits for different energy utilization schemes.

As noted in Sections 1.4 and 1.5, this study is limited to the evaluation of the environmental impacts within the study area defined in Fig. 1.2. It was recognized at the beginning of the study that impacts could occur outside of the area and may have to be investigated. In particular, a major reason for the improvement in the urban air quality with district heating cogeneration in the use of tall stacks. However, tall stack emissions can measurably influence the environment downwind of the study area, and they should be investigated. SO_2 emissions from tall stacks could intensify any acid rain problems as well as intensifying the exposure of the population downwind of the study area. A regional study evaluating the impact of district heating/cogeneration in the Midwest or the Northeast would help to answer these questions.

SECTION 3

TWIN CITIES DISTRICT HEATING/COGENERATION SYSTEM

3.1 TWIN CITIES AREA

The Twin Cities area encompasses two concentrated municipalities about 11 km (7 miles) apart - Minneapolis and St. Paul (Figures 1.2 and 3.1). These areas are surrounded by regions of industrial and residential developments, which link the areas into one continuous metropolitan region. The total metropolitan population of over one million includes 0.8 million within the two city boundaries. This dense population, coupled with the cold climate [>4500 Celsius (8000 Fahrenheit) degree days], creates a large heat demand.

There are two relatively large, coal-fired electric generating plants within the city boundaries that can be converted to cogeneration operation - High Bridge for St. Paul and Riverside for Minneapolis. A third plant, Black Dog, is located about 16 km (10 miles) south of Minneapolis, and several newer coal-fired and nuclear plants exist outside the metropolitan area (see Figure 1.2).

The area selected for this study is outlined in Figure 1.2, and this is identical to the area selected for the previous air quality study.[2]

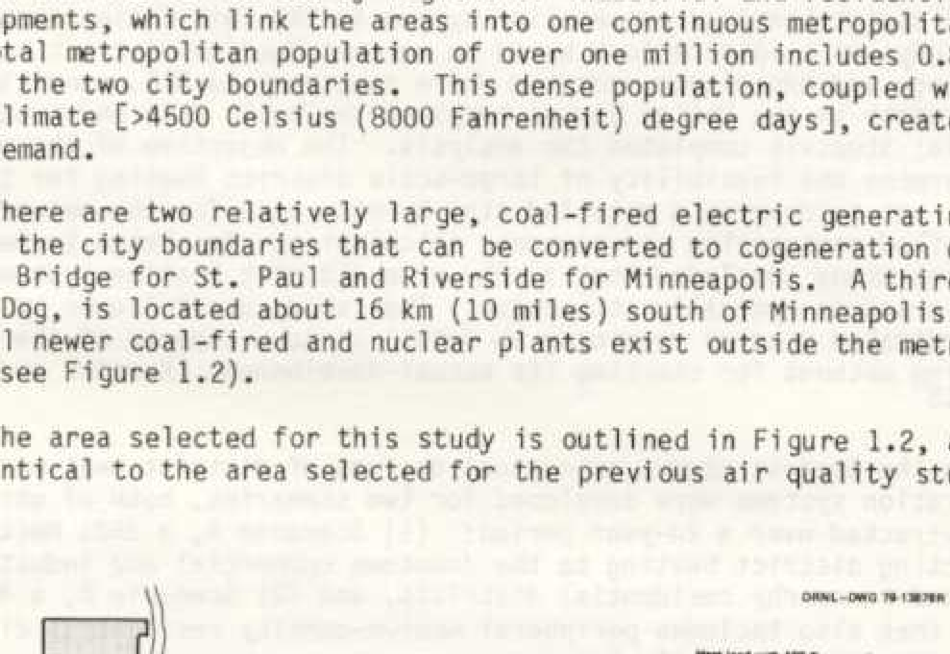

Fig. 3.1. Heat-load densities in the Twin Cities area and conceptual city-wide district heat piping systems.

This area includes the three existing power plants within the metropolitan area, but excludes the new fossil and nuclear plants outside the immediate area.

3.2 CITY-WIDE HOT WATER DISTRICT HEATING SYSTEM

3.2.1 Scope of Feasibility/Economic Study

The study done by Studsvik Energiteknik AB in Sweden was the initial indepth investigation of engineering and economic feasibility a large hot water district heating/cogeneration system in the Twin Cities area.[1] That study was a joint effort based on current Swedish district heating technology and experience, adapted where necessary to U.S. conditions. Participants in the United States supplied the basic data and economic criteria; Studsvik completed the analysis. The objective of the effort was to determine the feasibility of large-scale district heating for the Twin Cities, not to develop a detailed step-by-step plan for the network or to do detailed engineering and economic calculations. As stated in Section 1.3, that study concluded that a city-wide district heating system is feasible and economically attractive. That study was followed by a series of coordinated studies examining in detail various aspects of the system including methods for starting its actual development (Karnitz and Kolb).[18]

In the Studvik study, conceptual designs of district heating/cogeneration systems were developed for two scenarios, both of which could be constructed over a 20-year period: (1) Scenario A, a 2621 MW(t) system restricting district heating to the downtown commercial and industrial areas and to nearby residential districts, and (2) Scenario B, a 4042 MW(t) system that also includes peripheral medium-density residential districts having one- and two-family houses.

The service areas for both scenarios are shown in Figure 3.1. Scenario A design was selected for the environmental analysis reported herein as being typical of a system that would be installed in the Twin Cities by the year 2000. It was concluded by Studsvik that this system is economically viable, as shown in Figure 3.2.

3.2.2 Principal Features of the City-Wide District Heating Concept[1]

The development of the district heating system load capacities for the two scenarios was assumed to be the rates shown in Figure 3.3. Geographical areas that would be served by this system and the hot water trunk lines are outlined in Figure 3.1. For Scenario A, it was assumed that all the potential customers with the exception of those now connected to steam systems in Minneapolis and certain large industries would subscribe to the hot water service. (A modern 80 MW steam system serves part of downtown Minneapolis and a 126 MW system serves the University of Minnesota Minneapolis campus.) For Scenario B, only 70% of the additional potential customers were assumed to subscribe to the system, since these are predominately residential. It should be noted that these loads do not include loads of any new customers.

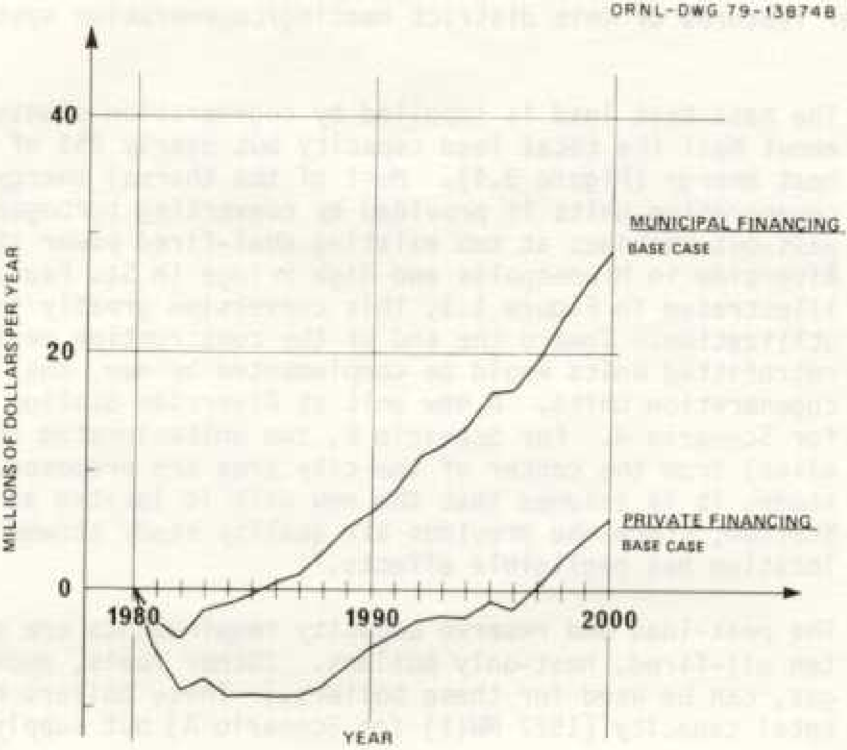

Fig. 3.2. Annual net savings in 1978 dollars for Scenario A district heating/cogeneration system.

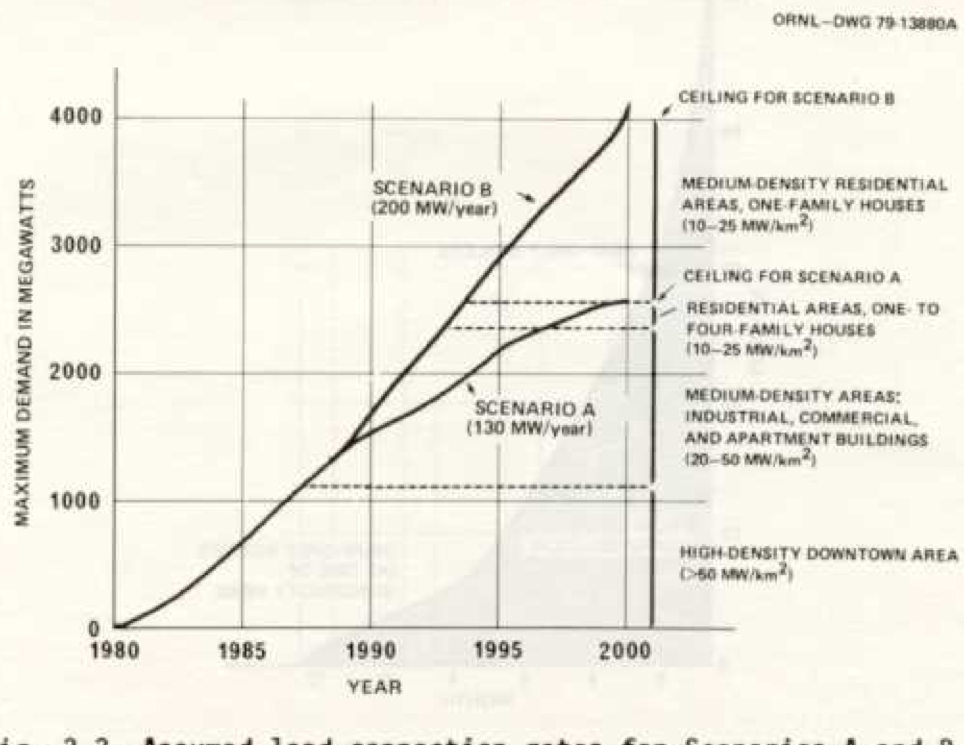

Fig. 3.3. Assumed load connection rates for Scenarios A and B.

Other features of this district heating/cogeneration system concept are:

1. The base heat load is supplied by cogeneration plants that provide about half the total load capacity but nearly 85% of the annual heat energy (Figure 3.4). Most of the thermal energy from cogeneration units is provided by converting turbogenerators to pass-out machines at two existing coal-fired power stations - Riverside in Minneapolis and High Bridge in St. Paul. As illustrated in Figure 1.1, this conversion greatly improves fuel utilization. Toward the end of the construction period, the retrofitted units would be complemented by new, coal-fired cogeneration units. A new unit at Riverside Station is assumed for Scenario A. For Scenario B, two units located about 27 km (17 miles) from the center of the city area are proposed. (For this study, it is assumed that the new unit is located at High Bridge Station, since the previous air quality study showed that its location has negligible effects.[2])

2. The peak-load and reserve capacity requirements are supplied by ten oil-fired, heat-only boilers. (Other fuels, such as natural gas, can be used for these boilers.) These boilers have a large total capacity [1527 MW(t) for Scenario A] but supply only a small

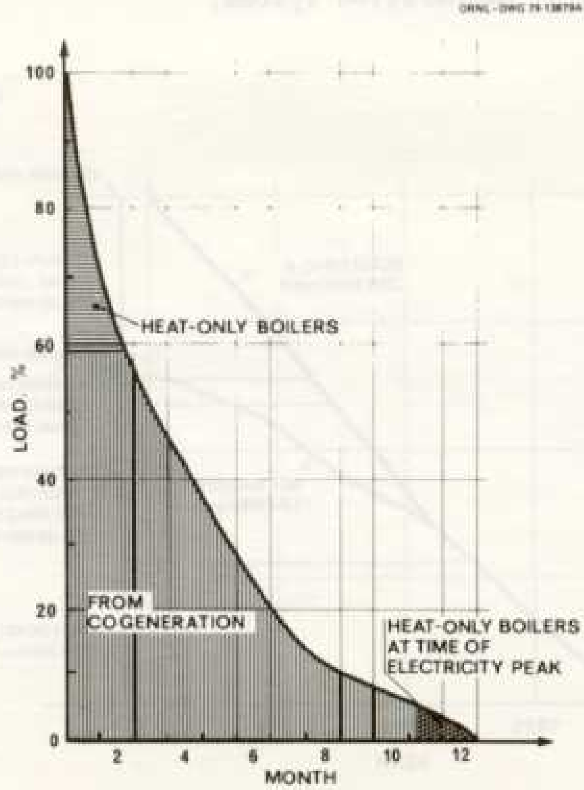

Fig. 3.4. Heat-load duration curve and load distribution.

percentage of the annual heat energy. They are located at various points in the supply area, thus reducing the size of pipes necessary between the central cogeneration plant sites and the supply areas.

3. The heat is transported from the production plants to the various parts of the supply area by hot water mains (Figure 3.1) in accordance with modern European district heating technology.

4. The heat is distributed from the regional system to individual buildings and houses by a hot water distribution system that runs under pavements, under streets, and, where possible, through cellars.

5. The heating systems of existing buildings are adapted so that they can be connected to the district heating system through heat exchangers. Different conversions are used for buildings and houses currently supplied by hot water, steam, or hot air.

6. The demand for thermal energy to power air conditioning units is ignored because it is estimated to be very small.

3.3 GENERATING PLANTS

3.3.1 Cogeneration Plants

As stated in Section 3.2.2, the bulk of the thermal energy for the city-wide heating system would be furnished by the cogeneration plants. These units would consist of a new unit and the retrofitted units at the High Bridge and Riverside Generating Plants. For the study reported herein, it was assumed that the new unit would be located at the High Bridge plant site. The previous annual air quality study[2] concluded that the new unit did not significantly affect the air quality impacts of the district heating system. Therefore, its location is not expected to affect the conclusions reached in the present report.

The new cogeneration unit would have a net capacity of 235 MW(e) in cold condensing mode of operation and 178 MW(e)/342.2 MW(t) in cogeneration mode of operation.* It would be either a pulverized-coal boiler with a dry flue gas desulfurization (FGD) system or an atmospheric fluidized bed (AFB) boiler with sulfur absorbed in the bed material.[19] For the purposes of the environmental assessment reported here, a pulverized-coal boiler unit with dry FGD system was assumed.

The new cogeneration unit would have to adhere to the present (1978) New Source Performance Standards (NSPS)[20,21] In the conceptual design

*These capacities are somewhat different than those used in the original feasibility/economic study,[1] where values of 190 MW(e)/335 MW(t) were used.[1] The new values are based on a more recent detailed conceptual study of the new cogeneration plant.[19]

of this unit, it was assumed that it would use Western sub-bituminous coal, which has a 0.9% sulfur content and 193 MJ/kg (8300 Btu/lb) heating value. For this coal, the NSPS states that the SO_2 and TSP emission factors would have to be limited to 260 ng/J (0.60 lb/million Btu) and 13 ng/J (0.03 lb/million Btu), respectively.

The turbine generators that would be converted to cogeneration operation at High Bridge and Riverside are relatively old units. High Bridge Generating Plant now has four operating turbine-generator units, designated as Units 3, 4, 5, and 6. The initial investigation of these units[1] indicated that they could provide 631 MW(t) generating capacity for the district heating system, as shown in Table 3.1. These values were used in the air quality impact analysis discussed in this report. Revised values of the electrical and thermal capacities, based on later detailed studies,[14] were used in the water quality analysis, as is described later in this section.

The High Bridge plant is now using a mix of 75% Western and 25% Illinois coal as its fuel.[22,23]. A single stack serves all four boilers, and there is no FGD system at the plant.

At Riverside Generating Plant three operating boilers (Boilers 6, 7 and 8) are furnishing steam to the turbine-generators, Units 1, 2, 6 and 8. The Unit 7 turbine was retired because of mechanical problems. If Unit 7 turbine was replaced, the feasibility economic study[1] indicated that this

TABLE 3.1. ELECTRICAL AND THERMAL CAPACITIES OF HIGH BRIDGE AND RIVERSIDE GENERATING PLANTS (MW)

	High Bridge Generating Plant				Riverside Generating Plant			
	Unit 3	Unit 4	Unit 5	Unit 6	Units 1&2	Unit 6	Unit 7[a]	Unit 8
Values Used in Feasibility Economic Study and in Present Air Quality Analysis[1]								
Present Electrical	62	62	102	156	-	62	-	216
Cogeneration								
Electrical	48	48	64	98	-	48	52	127.5
Thermal	117	117	157	240	-	110	110	330
Updated Electrical Capacities[22,23]	55	33	98	163	44	67	-	227
Values Assumed for Water Quality Analysis (Sect. 5)								
Present Electrical	55	33	98	163	-	62	-	216
Cogeneration[b]								
Electrical	49	-	66	109	-[c]	48	-	127.5
Thermal	120	-	138	186	-[c]	110	-	330

[a]Present Unit 7 turbine retired. A new unit would be required for cogeneration.

[b]Revised capacities for the High Bridge converted units are based on data in Reference 14.

[c]New turbine on Unit 7 is assumed to have a closed cycle cooling water system, which will not have significant temperature impact on the Mississippi River.

plant could provide 550 MW(t) generating capacity for the district heating system, as shown in Table 3.1. Each operating boiler at Riverside has its own stack, and until recently, none of the boilers were equipped with a FGD facility. However, a demonstration FGD system for Boilers 6 and 7 started operation recently.[24] The plant presently uses a mix of 88% Western coal and 12% petroleum coke as its fuel.[23]

For the air quality impact analysis in Section 4, it was assumed that the retrofitted plants would have the thermal capacities stated by the feasibility/economic study,[1] and the FGD system does not exist at Riverside. This was done to be consistent with the previous annual air quality impact analysis[2] and to provide a conservative estimate of the air quality impacts by the district heating/cogeneration system. The 1979 Minnesota air quality regulations[25] state that the SO_2 and TSP emission limits for these existing plants are 1.3 μg/J (3.0 lb/million Btu) and 170 ng/J (0.4 lb/million Btu), respectively.

The second set of information in Table 3.1 (Updated Electrical Capacities) shows the electrical generating rates of the High Bridge and Riverside plants as determined about four years after the original feasibility/economic study[22,23]. The total electrical rating from both plants differs by less than 5 percent over this four-year period and is not expected to significantly alter the conclusions of this study. The variation in output between different units does show the difficulty in pinpointing electrical capacities at existing plants.

For the water quality impacts addressed in this study (Section 5), the revised set of electric and thermal generating capacities were used. These were also based on a recent, detailed investigation of the High Bridge plant[14] which concluded that Unit 4 turbine should not be converted because of balance and alignment problems. The new study found that High Bridge could provide 444 MW(t) generating capacity for the district heating system. These values were selected over the other data presented in the table to provide reasonable estimates of the present situation at these plants and of the impact of converting the turbine generators. Here it was assumed that High Bridge Unit 4 would not be converted and that the new Riverside Unit 7 would have a closed-cycle circulating water system.

3.3.2 Other Electrical Plants

Two other electrical generating plants are included in this study, but their operation would not be impacted directly by the district heating/cogeneration system. They are the Black Dog Generating Plant and the Inver Hills Generating Plant. The Black Dog Plant has four operating boiler-turbine generator units having a total percent day capacity of 424 MW(e).[23] These boilers again have to adhere to the Minnesota air quality regulation for existing units.[25] A single stack serves all four boilers. The Inver Hills Plant has six oil-fired turbine-generators having a total capacity of 414 MW(e).[1] The Minnesota air quality regulation limits the emissions from this plant to 690 μg/J (1.6 lb/million Btu) SO_2 and 170 μg/J (0.4 lb/million Btu) TSP.[25] Neither the Black Dog Plant or the Inver Hills Plant have FGD systems.

3.3.3 Heat-Only Plants

Heat only plants would supply energy to the district heating system during periods when the system's demands exceed the capacity of the cogeneration units. In this study, it was assumed that these units would consist of ten 153 MW(t) capacity oil-fired boilers located at the junctions of main pipelines in the district heating network. It was further assumed that 1.9% sulfur residual oil would be used for these units.[2,26] In this case, the SO_2 and TSP emissions were assumed to be limited to 85 μg/J (0.20 lb/million Btu) and 13 μg/J (0.03 lb/million Btu), respectively. If these heat-only units were to use natural gas instead of oil, these emission rates would be considerably smaller.

The present coal-fired boilers at the Third Street Generating Plant are capable of generating steam at rates up to 150 MW(t). For the city-wide district heating/cogeneration system, it was assumed that the St. Paul district heating system would be absorbed into the large system and that the Third Street Plant would be retired.

3.4 POTENTIAL FUEL SAVINGS

3.4.1 Annual Fuel Savings

Energy savings that could be realized by the installation of the large city-wide district heating/cogeneration system are tabulated in Table 3.2. On an annual basis, 19 PJ(19 x 10^{15} joules) of energy would be saved.

TABLE 3.2 ENERGY CONTENT OF FUELS ASSOCIATED WITH DISTRICT HEATING/COGENERATION SYSTEM[a]

Case	Celsius Heating Degree Days[b]	Oil Savings in District Heating Zones	Natural Gas Savings in District Heating Zones	Oil Required for Heat-Only Units	Coal Required for Electrical Makeup	Net Energy Savings
Annual, PJ[d]	4359[c]	7	26	4	10	19
24 h Episode 1, TJ[e]	24.2	30	133	0	51	112
24 h Episode 2, TJ	28.9	77	113	2	59	129
24 h Episode 3, TJ	28.1	56	129	0	58	127
24 h Episode 4, TJ	25.3	43	126	0	53	116
24 h Episode 5, TJ	35.6	101	128	17	59	153
24 h Episode 6, TJ	0.0	17	4	0	5	16

[a]The energy units associated with the values in Columns 3 through 7 are listed in Column 1.

[b]Based on 18.3°C reference temperature.

[c]Value for the year 1976 assumed in the feasibility/economic study.[1] For comparison, a typical year has a value of 4533

[d]PJ = petajoules = 10^{15} joules = 0.95 x 10^{12} Btu.

[e]TJ = terajoules = 10^{12} joules = 0.95 x 10^{9} Btu.

Energy savings in the form of oil and natural gas would be 29 PJ, but 10 PJ additional energy in the form of coal would be required each year to replace the electricity that would have been generated by the cogeneration plant steam if it had not been diverted to the district heating system. The quantities of fuel corresponding to these values of energy are presented in Table 3.3. It was assumed here that the heating value of oil is 35.3 MJ/m^3, that of natural gas is 37.3 MJ/m^3 and that of coal is 24.7 MJ/kg. Annual oil and natural gas savings would be 16.2×10^4 m^3 (1.0×10^6 bbl) and 7.1×10^8 m^3 (25×10^9 ft^3), respectively, but an additional 4.0×10^5 Mg (0.44×10^6 tons) of coal would be required each year for electrical makeup.

The values of the annual energy savings that could be realized by the city-wide system were determined in most part in the Studsvik feasibility/economic study.[1] In developing these numbers, that study used 1976 Twin Cities energy use data and assumed that the efficiency of the gas-fired and oil-fired heating units is 0.7. It further assumed that the efficiency of peak load boilers is 0.9, and that of the coal-fired electrical plants is 0.4.

The Studsvik study does not differentiate between the use of natural gas and oil, however. To find the difference, annual oil savings were first determined from the information used to generate the gaseous pollutant emission rates, discussed in Section 4.3. Values of these savings are shown in Table 3.4. The natural gas savings were then assumed

TABLE 3.3 QUANTITIES OF FUELS ASSOCIATED WITH DISTRICT HEATING/COGENERATION SYSTEM

Case	Celsius Heating Degree Days[a] m^3	Oil Savings in District Heating Zone[b] m^3	Natural Gas Savings in District Heating Zones m^3	Oil Required for Heat-Only Units m^3	Coal Required for Electrical Makeup Mg
Annual	4359[c]	16.2×10^4	7.1×10^8	1.0×10^5	4.0×10^5
24 h Episode 1	24.2	7.0×10^2	3.6×10^6	0	2.0×10^3
24 h Episode 2	28.9	18.3×10^2	3.0×10^6	0.5×10^2	2.4×10^3
24 h Episode 3	28.1	13.2×10^2	3.5×10^6	0	2.4×10^3
24 h Episode 4	25.3	10.2×10^2	3.4×10^6	0	2.1×10^3
24 h Episode 5	35.6	23.9×10^2	3.4×10^6	4.0×10^2	2.4×10^3
24 h Episode 6	0.0	0.4×10^2	0.5×10^6	0	0.2×10^3

[a]Based on 18.3° reference temperature.

[b]From Table 3.4.

[c]Value for the year 1976 assumed in the feasibility/economic study.[1] For comparison, a typical year has a value of 4533.

1 m^3 = 35.3 ft^3 = 264 gal = 6.3 bbl.
1 Mg = 1.1 Tons

TABLE 3.4 COMPONENTS OF OIL SAVINGS IN DISTRICT HEATING ZONES[a], m^3

Case	Celsius Heating Degree Days[b]	Point Source Savings	Commercial-Industrial Area Source Savings	Residential Area Source Savings	Total Sources
Annual	4359[c]	7.4×10^4	5.9×10^4	2.9×10^4	16.2×10^4
24-h Episode 1	24.2	2.3×10^2	3.1×10^2	1.6×10^2	7.0×10^2
24-h Episode 2	28.9	8.4×10^2	8.0×10^2	1.9×10^2	18.3×10^2
24-h Episode 3	28.1	7.6×10^2	3.8×10^2	1.8×10^2	13.2×10^2
24-h Episode 4	25.3	5.7×10^2	2.9×10^2	1.6×10^2	10.2×10^2
24-h Episode 5	35.6	10.5×10^2	11.2×10^2	2.3×10^2	23.2×10^2
24-h Episode 6	0.0	0.4×10^2	0.0	0.0	0.4×10^2

[a]Sources extrapolated to the year 1987 were used to make these estimates.

[b]Based on 18.3°C reference temperature.

[c]Value for the year 1976 assumed in the feasibility/economic study.[1] For comparison, a typical year has a value of 4533.

$1 \text{ m}^3 = 35.3 \text{ ft}^3 = 264 \text{ ft}^3 = 6.3 \text{ bbl}$.

to be the difference between the total energy savings reported in the feasibility/economic study and the oil savings.

To determine the reduction in the annual oil consumption, data used for estimating emission sources for air quality impacts, discussed in Section 4.3, were utilized. Although the impact of the district heating system is evaluated using source data extrapolated to the year 1987, the difference for the overall oil consumption in the regions of interest for the years 1976 and 1987 is not great. Cole and Kinnear[27] (Appendix D) estimated that the difference would be less than 5%. Therefore, use of these 1987 data to evaluate the oil consumption impact is reasonable here.

Three different categories of emission sources used in evaluating the air quality impacts were used to estimate the oil consumption impact: (1) the relatively large point sources, (2) the relatively small commercial-industrial area sources, and (3) the relatively small residential area sources. The methods using the source data presented in Section 4.3 to estimate the oil use reduction for each of these categories are summarized below.

For the point sources that would connect to the district heating system, the oil savings were estimated by first identifying those sources using oil from the Source Classification Code (SCC) number[28] included in the data in the National Emissions Data System (NEDS) file. The oil saved by each of these sources in the district heating zones was then assumed to be the oil throughput multiplied by the percentage of the source energy requirement used for space heating. Table 3.4 shows that

7.4×10^4 m^3 oil each year would be saved by the point sources connecting to the district heating system. Of this, the residual oil saving is 6.6×10^4 m^3 and the distillate oil savings is the remainder.

For the commercial and industrial area sources, the annual amount of oil used in the district heating zones was determined in each county from the difference of the total oil use determined by Cole and Kinnear[27] (Appendix D) and the total point source oil use. These differences were then assumed to be distributed within each county according to the proportions of natural gas curtailed (demand minus supply) throughout the county. On an annual basis, it was estimated that 45% of distillate oil and 35% of residual oil used by the commercial and industrial area sources located in the district heating zones would be replaced by the district heating system.[2,26] This is equivalent to 5.9×10^4 m^3 of oil, of which 3.3×10^4 m^3 is residual oil. The remainder is distillate oil.

Cole and Kinnear's total oil data do not include the residential oil use. The residential oil use was estimated from 1970 census data for the Twin Cities region extrapolated to the year 1987 and the average oil use in each residence determined by MEA.[26] For the residences located within the district heating zones, it was assumed that all of oil used would be replaced by the district heating system. This is 2.9×10^4 m^3 per year as shown in Table 3.4, and it is primarily distillate oil.

For the heat only units, it was assumed in Tables 3.2 and 3.3 that they use oil for fuel. Natural gas could be just as easily used and this would result in a substantial increase in the net oil savings. Use of large insulated tanks for short-term heat storage, such as is done in Europe, would reduce the need for heat-only units. This would then reduce the oil and natural gas requirements to operate the system.

3.4.2 24-h Episode Fuel Savings

Six 24-h episodes were selected for detailed air quality analysis, as discussed in Section 4.2. The first five episodes are for winter days having -17.3 to -5.9°C average temperatures, and the sixth episode is a fall day when there is no space heating demand. The quantities and energy contents of the fuels associated with the district heating/cogeneration systems for these episodes are presented in Tables 3.2, 3.3, and 3.4. District heating is used for hot water (process) heating and space heating. It is assumed that the space heating demands are proportional to the values of the heating degree days, which are listed in Tables 3.2 through 3.4.

It can be seen in Tables 3.2 and 3.3 that for the colder winter days, there is an increase in the oil savings with an increase in the heating degree days. The saving in the natural gas is about the same in all of the selected winter episodes. As will be discussed in Section 4.3, this reflects the fact that the demand for natural gas has reached the limit of its availability and oil is being used to provide the additional energy. This is done by curtailing the gas supply to lower priority users, which are primarily in the point source and commercial-industrial area source categories, as shown in Table 3.4. The greatest fuel and energy savings is realized for Episode 5, which has 35.6 Celsius heating degree days. It is doubtful that much greater energy savings could be realized for days colder than this, since the district heating system heat demand reached the limit of the cogeneration units capacities and since any additional heat demand would have to be met by the heat-only units.

The episodic fuel use data presented in Tables 3.2 and 3.3 were derived by first noting that the feasibility/economic study concludes that 23.4% of the 23.3 PJ annual energy demand of the district heating system would be for water heating (process) purposes.[1] It was assumed that this portion of the demand remains constant throughout the year. It was further assumed that remainder of the annual energy demand is for space heating equivalent to 4359 Celsius degree days. (This is the year 1976 value used in the feasibility/economic study, which is lower than the value of 4533 Celsius degree day for a typical year.) The total 24-h episode energy demands were then determined by summing the hot water energy demands, assumed to be constant, and the space heating demands, assumed to be proportional to the number of heating degree days. The sum of the daily oil and natural gas savings in the district heating zones can then be determined from the annual saving multiplied by the ratio of the daily energy demand to the annual energy demand.

The point source oil savings (except the heat-only units) for the 24-h episodes were estimated in essentially the same manner as was done for the annual case. The difference for the episodes is that the annual point source data base was modified to account for the change in the oil use rate, during the 24-h episodes. These modifications are discussed in Appendix A.

For the commercial and industrial area sources, the total oil use and the portion of it used for space heat in each county for each selected 24-h episode were determined by Cole and Kinnear[27] (Appendix D). As for the annual case, the amount of oil used in the district heating zones was calculated by simply substracting the total point source oil use from the total oil use. The differences were then again assumed to be distributed within each county according to the proportion of the natural gas that is curtailed. The amount of oil that would be saved in the district heating zones was assumed to be the oil used in these zones multiplied by the portion of the oil used for space heating. This is discussed further in Appendix A.

The residential oil use for the 24-h episodes was estimated by assuming that all of the annual residential oil use is for space heating; thus, the daily oil use is proportional to the degree days. This is discussed in more detail in Appendix A.

In only two of the episodes, the cogeneration plants would have insufficient capacity to meet the district heating systems demands. The heat-only units would then have to be used in these cases.

Additional coal requirements for the 24-h episodes were determined noting that the reduction of the electrical power at the cogeneration plants at full load would be 229.5 MW(e) at the retrofitted plants and 44 MW(e) at the new plant.[1]* It was assumed that the new unit would have the highest priority in meeting the district heating system's needs, and that the efficiency of plant producing the makeup electricity is 0.4.

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*A later, detailed study of the new cogeneration plant concluded that the electrical power capacity would actually be reduced 57 MW(e).[19]

SECTION 4

AIR QUALITY IMPACTS

Air quality calculations for the Twin Cities area were done for three cases: (1) a base-year case (1976), (2) a future-year case (1987) without a district heating/cogeneration system, and (3) a future-year case (1987) with a fully developed regional district heating/cogeneration system. These are the same scenarios that were addressed in the previous annual SO_2 air quality study.[2] The year 1976 was selected for the base case since it was the most recent year that data were available for at the time the previous study was started. During 1976, most of the heating needs in the Twin Cities area were met by using natural gas, which resulted in relatively low pollutant emission rates. On colder days, the availability of natural gas was insufficient to meet the demand, and alternate fuels were used to make up the difference. The alternate fuels, such as oil, have higher pollutant emission rates.

During the time when the regional district heating/cogeneration system is developed, it is anticipated that the amounts and types of fuel available for heating needs will change. It is probable that natural gas use will be curtailed further in the future years, and alternate fuels will have to be substituted. At the time the previous air quality study was started, the furthest into the future that a prediction of fuel use and availability could be made with confidence was 1987. The study reported herein used the same year in order to be consistent. Thus, the impact of a fully developed district heating/cogeneration system was evaluated for the year 1987, even though it is likely that it will be at least the year 2000 before the system is actually developed.

4.1 CRITERIA POLLUTANTS

This study focuses on two atmospheric pollutants: sulfur dioxide (SO_2), and total suspended particulates (TSP). These are two of the primary pollutants included in the National Ambient Air Quality Standards.[29] Nitrogen oxides (NOx) were not included in this study although it is recognized that they are primary pollutants. However, these oxides are relatively fast reacting materials, and the nonreactive dispersion models used in this study are not applicable.[30]

A limited effort was made to assess the impact of the trace element emission from the major coal-fired plants. The trace elements selected for this study are listed in Table 4.1. They were selected on the basis of detriment to human health, and because there is an existing data base for these elements.[31]

4.2 EPISODE SELECTION

To determine the 24-h episodes that would have the highest air pollutant concentrations, it was recognized that the concentrations are dependent on both the pollutant emission rates and the meteorological conditions. The procedure used in this study was to first identify the 24-h episodes having mete-

TABLE 4.1 TRACE ELEMENTS CONSIDERED IN THE EMISSIONS FROM COAL-FIRED PLANTS

Antimony	Mercury
Arsenic	Molybdenum
Beryllium	Nickel
Cadmium	Scandium
Cobalt	Selenium
Chromium	Uranium
Copper	Vanadium
Fluorine	Zinc
Lead	

orological conditions resulting in the highest pollutant concentrations if the pollutant emission rates are assumed to be constant throughout the year. For these identified episodes, the emission rates were then estimated recognizing that they are dependent on the daily space heating needs and on the substitution of alternate fuels, such as oil, for the curtailed natural gas on the colder days. Using these estimated emission rates and the meteorological conditions for these episodes, the SO_2 and TSP concentrations in the area were then predicted, as discussed in Section 4.4.4.

The 24-h episodes were identified by using the Multiple-Source Air Quality Algorithm (RAM)[32,33] for the 25 point sources in the Twin Cities area having the highest annual SO_2 emission rates. This steady-state Gaussian plume model is discussed further in Section 4.4.1. The RAMF version of this model, which calculates the pollutant concentration each hour and then averages these concentrations for each 24-h period, was used here. These calculations were based on hourly meteorological data obtained at Minneapolis-St. Paul Airport[34] for the years of 1975 and 1976 and the annual source emission data for 1976 (Section 4.3). The receptors were assumed to be located on a 5-km square grid over approximately the study area shown in Figure 1.2.

The 24-h episodes that were selected for further study on the basis of these calculations are identified in Table 4.2. Five of these episodes are during the winter season and the sixth is in late summer. Comments regarding the SO_2 concentrations based on these initial RAMF calculations are presented in Table 4.2. The highest SO_2 concentration was predicted for the late summer day, Episode 6, but this is not expected to be true in reality. As will be seen in Section 4.3, there was no demand for space heat and thus use of fuels other than natural gas were at their minimum levels during this day.

Five winter episodes were selected with the intent that the day having the highest SO_2 concentration due to the combination of emission rates and meteorological conditions would likely be included in this study. Analysis of these episodes is expected to indicate how the city-wide district heating/cogeneration system may improve air quality when adverse pollution conditions are anticipated. (As will be seen in Section 4.4.4, Episode 2 has the highest

TABLE 4.2. SELECTED 24-h EPISODES[a]

Episode	Date	Celsius Heating Degree Days[b]	Comments
1	Jan. 7, 1975	24.2	High SO_2 concentrations for long periods.
2	Dec. 21, 1975	28.9	Very high SO_2 concentration for 1 hour.
3	Jan. 4, 1975	28.1	Highest SO_2 concentration for 1 hour.
4	Mar. 8, 1976	25.3	High SO_2 concentrations for 2 nonconsecutive hours.
5	Jan. 19, 1975	35.6	Very high SO_2 concentration for 1 hour. Very cold day.
6	Sept. 3, 1975	0.0	Highest SO_2 concentration for entire day. Warm day.

[a]Based on the initial RAMF calculations using 1976 annual average point source emission rates.

[b]Defined as: Heating Degree Days

$$= 18.3 - \frac{T_{high} + T_{low}}{2}; \quad \text{for } \frac{T_{high} + T_{low}}{2} \leq 18.3°C$$

$$= 0; \quad \text{for } \frac{T_{high} + T_{low}}{2} > 18.3°C$$

where

T_{high} = high temperature for 24-h period, °C;

T_{low} = low temperature for 24-h period, °C.

SO_2 concentration of selected episodes.) Episode 6 is included in the analysis to indicate the expected air quality improvements during a non-heating season day having very adverse pollution conditions.

4.3 EMISSION SOURCE INVENTORY

In this study, the sources of the SO_2 and TSP emissions were classified into four categories:

(1) generating plant sources,
(2) point sources,
(3) commercial and industrial area sources, and
(4) residential area sources.

These categories were selected primarily on the basis that a different method was used to estimate emission rates for each of them. The starting point in making these estimates was the emission data developed for the previous annual air quality study.[2] Modifications and additions were made to this data base because of information that became available after that study was completed. The emission rates for the 24-h episodes were then estimated from the revised annual data; noting the increased demand for energy and the increased substitution of alternate fuels for curtailed natural gas on the colder days. These methods and estimates are discussed in detail below.

It is important to note at this point that in estimating the emissions for 1987, many assumptions had to be made in extrapolating the situation to 1987. In reality, the situation is changing continuously. For example, emissions per unit heat input from some of the existing generation plants have been reduced to meet air quality regulations.[24,35] In this study, the reported 1976 values were used since these modifications could not be anticipated at the time the study was started. The effects of the reduction in this particular case will be to improve the air quality benefits of the district heating/cogeneration system.

For the major coal burning plants, the trace element emissions were estimated primarily based on the type of coal that is presently used in each of these plants. This will be discussed in Section 4.3.7.

4.3.1 Generating Plant Emission Sources

4.3.1.1 Annual Emissions

For 1976, the annual SO_2 and TSP emission rates from the electrical power plants in the area and from NSP's Third Street Heating Plant were obtained from the NEDS file.[26] These data are presented in Tables 4.3

TABLE 4.3. POWER AND HEATING PLANTS SO_2 EMISSION RATES, g/s

Plant	Annual	Episode 1	Episode 2	Episode 3	Episode 4	Episode 5	Episode 6
1976 and 1987 without district heating/cogeneration							
Third Street	14	136	162	158	142	200	0
High Bridge	590	937	865	937	865	937	577
Riverside	617	937	865	937	865	937	577
Black Dog	810	1167	1078	1167	1078	1167	718
Inver Hills	18	4	4	4	4	4	4
Total	2049	3181	2974	3203	2954	3245	1876
1987 with district heating/cogeneration							
Third Street	0	0	0	0	0	0	0
Oil-fired Heat Only Units	12	0	2	0	0	32	0
High Bridge							
Retrofitted units	649	1198	1442	1422	1263	1442	0
New unit	118	181	181	181	181	181	130
Riverside	678	1198	1442	1422	1263	1442	577
Black Dog	810	1167	1078	1167	1078	1167	718
Inver Hills	18	4	4	4	4	4	4
Total	2273	3748	4147	4196	3789	4236	1429
1987 Change	224	567	1173	993	835	991	-447
% Change	10.9	17.8	39.4	31.0	28.3	30.5	-23.8

TABLE 4.4. POWER AND HEATING PLANTS TSP EMISSION RATES, g/s

Plant	Annual	Episode 1	Episode 2	Episode 3	Episode 4	Episode 5	Episode 6
1976 and 1987 without district heating/cogeneration							
Third Street	3.2	18.1	26.6	21.0	18.9	26.6	0
High Bridge	1.8	2.7	2.5	2.7	2.5	2.7	2.7
Riverside	29.8	55.8	51.5	55.8	51.5	55.8	34.4
Black Dog	7.4	9.7	8.5	9.7	8.5	9.7	6.0
Inver Hills	1.2	0.3	0.3	0.3	0.3	0.3	0.3
Total	43.4	86.6	89.4	89.5	81.7	95.1	42.4
1987 with district heating/cogeneration							
Third Street	0	0	0	0	0	0	0
Oil-fired Heat Only Units	1.8	0	0.3	0	0	4.9	0
High Bridge							
Retrofitted units	2.0	3.4	4.1	4.1	3.6	4.1	0
New unit	5.9	9.0	9.0	9.0	9.0	9.0	6.5
Riverside	32.8	71.4	85.9	84.7	75.2	85.9	34.4
Black Dog	7.4	9.7	8.5	9.7	8.5	9.7	6.0
Inver Hills	1.2	0.3	0.3	0.3	0.3	0.3	0.3
Total	51.1	93.8	108.1	107.8	96.6	113.9	47.2
1987 Change	7.7	7.2	18.7	18.3	14.9	18.8	4.8
% Change	17.7	8.3	20.9	20.5	18.2	19.8	11.3

and 4.4. It was assumed that for 1987, without the development of a regional district heating/cogeneration system, the emission rates from these plants would be identical to those for 1976.

With the full development of the district heating/cogeneration system in 1987, the annual load factors for the retrofitted units at High Bridge and Riverside Generating Plants were estimated to be about 10% higher than those without the installation of the system.[2] This increase was determined by comparing the historical load factors for those plants with the annual projected load demand for the district heating system. The annual emission rates for these two retrofitted plants thus were assumed to be 10% higher than the 1976 values. It was assumed that the Third Street Plant would be retired with the development of the new district heating/cogeneration system. This, of course, implies that there would be no emissions from this plant in 1987.

For the new cogeneration unit to be built for the 2600 MW(t) district heating system, a detailed conceptual design study[19] stated that the boiler heat rate would be 702 MW(t) and that the plant would use Western subbituminous coal. As stated in Section 3.3.1, it was assumed that this coal has an 0.9% sulfur content and a 19.3 MJ/kg (8300 Btu/lb) heating value. Using the NSPS emission factor of 260 ng/J (0.60 lb/million Btu) for SO_2 and 13 ng/J (0.03 lb/million Btu) for TSP,[20,21] the emission rates from this unit at full load would be 181 g/s for SO_2 and 9.0 g/s for TSP. Assuming an annual load factor of 65%, these rates would be the values shown in Tables 4.3 and 4.4.

For the oil-fired heat-only units, it was assumed that they would be fired with 1.9% sulfur residual oil and that their efficiency would be 0.9.[2,26] Using emission factors of 86 ng/J (0.20 lb/million Btu) for SO_2 and 13 ng/J (0.03 lb/million Btu) for TSP, the annual average emission rates for each of the 10 units are 1.18 g/s SO_2 and 0.18 g/s TSP.

It can be seen in Table 4.3 that there would be about an 11% increase in the total SO_2 emission rate from the power plants with the development of the 2600 MW(t) district heating/cogeneration system. This would be due to the increased load factor of the retrofitted units and the addition of a new cogeneration unit. This is addressed further at the end of this section.

4.3.1.2 24-h Episode Emissions

For the selected 24-h episodes, emission rates from the electric and heat generating plants were determined from the products of the full load emission rates and the plants' 24-h load factors. For the existing plants, the 1976 full load emission rates were obtained from the Minnesota Pollution Control Agency (MPCA),[36] and they are presented in Table 4.5.

TABLE 4.5. 1976 FULL LOAD EMISSION RATES FOR STEAM ELECTRICIAL AND HEATING PLANTS, g/s[36]

Plant Name [1976 Capacity]	SO_2 Emission Rate	TSP Emission Rate
Third Street [150 MW(t)]	262	34.9
High Bridge [349 MW(e)]	1442	4.1
Riverside [338 MW(e)]	1442	85.9
Black Dog [421 MW(e)]	1796	15.0

The estimated 24-h load factors for these plants are listed in Table 4.6. The 1976 load factors for the existing steam electric plants were estimated from the historical data for High Bridge and Riverside Generating Plants shown in Figure 4.1 and noting that peak electrical loads in the Twin Cities are during the summer season. The Third Street Heating Plant was assumed to operate at full load when the temperature is at the Twin Cities winter dimension temperature* of -28.3°C (equivalent to 46.7 Celsius degree days).[1] The load factor for this plant was then assumed to be proportional to the ratio of the selected episode degree days to the degree days for the dimension temperature. As stated above, the load factors for 1987 without the development of the district heating/cogeneration system are assumed to be identical to those for 1976.

For 1987 with the full development of the district heating/cogeneration system, it was assumed that the load factors for the Black Dog Generating Plant would be the same as for 1976 and those for the Third Street Plant would

*The winter dimension temperature is the outdoor temperature used to size building heating systems.

TABLE 4.6. ESTIMATED STEAM GENERATING PLANTS' LOAD FACTORS FOR THE 24-h EPISODES

	1976 and 1987 without district heating/cogeneration		1987 with district heating/cogeneration			
Episode	Black Dog High Bridge Riverside	Third Street	New Cogeneration Unit	Black Dog	High Bridge Riverside	Third Street
1	0.65	0.52	1.00	0.65	0.83	0.0
2	0.60	0.62	1.00	0.60	1.00	0.0
3	0.65	0.60	1.00	0.65	0.99	0.0
4	0.60	0.54	1.00	0.60	0.88	0.0
5	0.65	0.76	1.00	0.65	1.00	0.0
6	0.40	0.0	0.72	0.40	0.40[a]	0.0

[a]Riverside Plant only. High Bridge Plant load factor is 0.0.

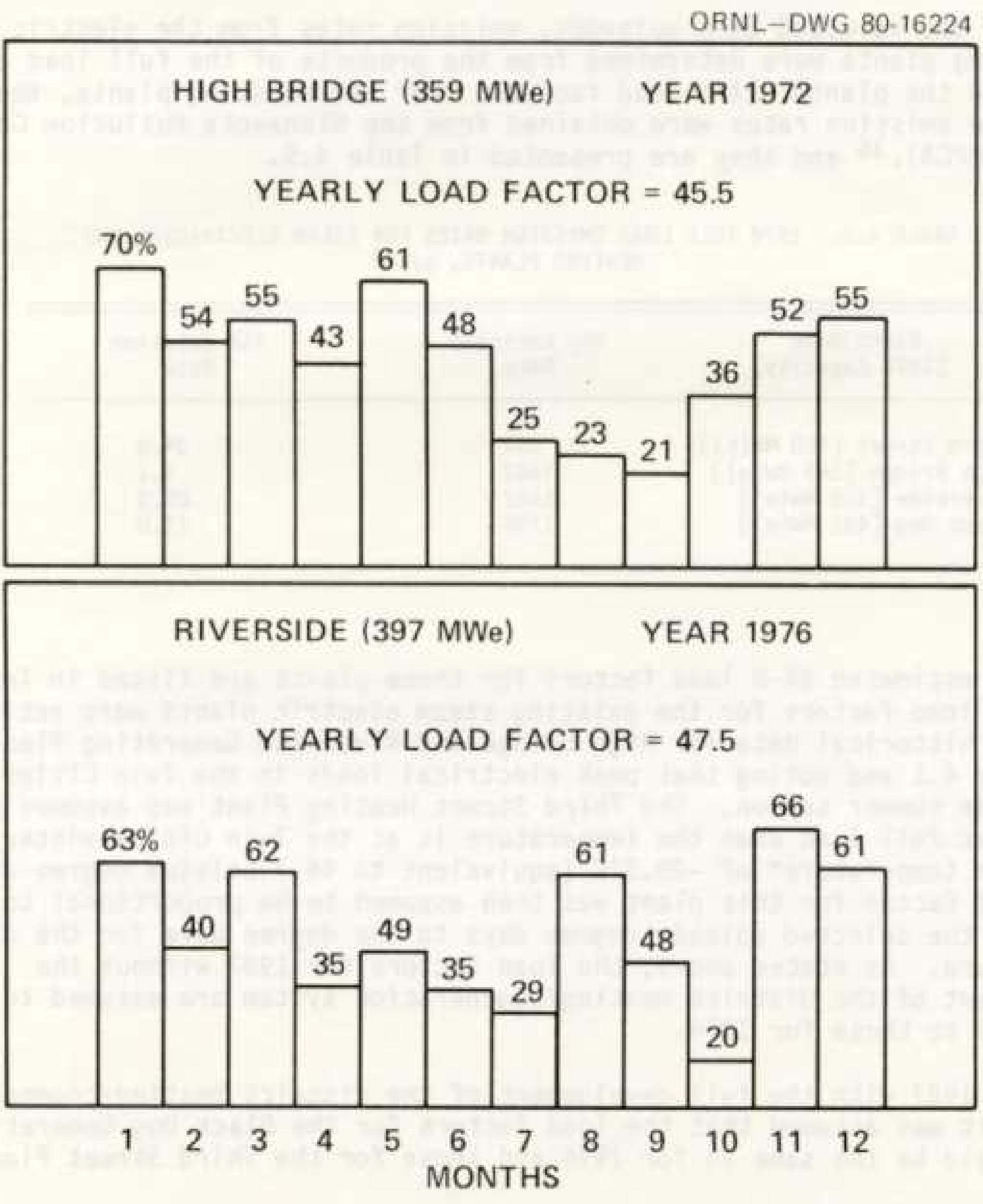

Fig. 4.1. Historical load factors for High Bridge and Riverside Generation Plants.

be zero. It was further assumed that the dispatch priority for the units to furnish heat to the district heating system would be: (1) the new 190 MW(e)/335 MW(t) cogeneration unit would be used first, (2) the retrofitted units at High Bridge and Riverside would be used next, and (3) the ten heat-only boilers would be used last.

The 24-h episodes load demands by the district heating system were determined by first noting that 23.4% of the 23.3 PJ annual demand would be for water (process) heating purposes.[1] It was assumed that this portion of the load demand would be constant throughout the year. The remaining 76.6% of the annual demand would be for space heating equivalent to 4359 Celsius degree days. (This is the value used in the feasibility/economic study,[1] which is lower than the value of 4533 Celsius degree days for a typical year.) The daily energy demands were then determined by summing the daily water heating demands and the daily space heating demand; the latter assumed to be proportional to the number of heating degree days for the episode. The load factors listed in Table 4.6 for the first five episodes were then calculated from these demands and the assumed priority of plant operation. For the sixth episode, all of the district heating needs could be met by the new cogeneration unit operating at a load factor of 0.52. However, the electrical demand at High Bridge during this day would be higher, and thus it was assumed that the new unit would operate at an 0.72 load factor and the Riverside Plant would operate at an 0.4 load factor.

The need for using the heat-only units was found to exist during only two episodes. These units would have to provide 23 MW(t) energy for Episode 2 and 339 MW(t) energy for Episode 5. This results in the emission rates shown in Tables 4.3 and 4.4. The total annual SO_2 emission rates for Episode 6 decreases in the district heating/cogeneration scenario. This is because the operation of the steam plants are governed by the electrical demand on this minimum heat demand day, and the new cogeneration plant is assumed to be used in place of the existing units at High Bridge to meet the electrical demand. The new unit has a lower SO_2 emission factor, as discussed above, and thus this scenario has lower SO_2 emissions.

For NPS's Inver Hills Generating Plant, the 1976 annual emission rates were obtained from the NEDS file. The emission rates for all 24-h episodes were assumed to be about one-fourth of the average annual rates. This was done because this plant operates primarily as a peak electrical load plant, and the peak load occurs in the summer for the Twin Cities. Since this plant is not likely to be impacted by the district heating/cogeneration system, it was assumed that the emission rates are the same in 1987 with and without district heating/cogeneration as for 1976.

4.3.1.3 Sensitivity Analysis

As mentioned previously, there would be a significant (approximately 11%) increase in the total annual SO_2 emission rates from the power and heating plants with the full implementation of a district heating/cogeneration system. As shown in Table 4.3, this increase is very large (18 to 39%) for the five winter 24-h episodes. For Episode 6, the late summer episode, Table 4.3 shows a decrease in the total emission rate. This is due to the assumption that the new cogeneration unit will be dispatched before the retrofitted units at High Bridge, as discussed above.

Two scenarios were investigated to gain some insight into the effect which assumptions about power plant pollution control efficiencies and load factors have on differences in emissions with or without district heating in 1987. In Table 4.7 the net changes in emissions obtained using these two scenarios are compared with the net change calculated in the base case scenario.

TABLE 4.7. EFFECT OF THE EMISSION FACTOR AND LOAD FACTOR ON CHANGE OF SO_2 EMISSION RATES FROM THE POWER AND HEATING PLANTS, g/s

	Base Case[a]	Sensitivity Scenario 1	Sensitivity Scenario 2[b]
Annual	224	154	127
Episode 1	567	260	154
Episode 2	1173	381	151
Episode 3	993	343	149
Episode 4	835	313	153
Episode 5	991	375	173
Episode 6	-447	0	0

[a]From Table 4.3.

[b]Emission factor for Third Street Plant without district heating/cogeneration assumed to be 260 ng/J (0.6 lb/million Btu).

In Scenario 1 it is was assumed that all power plants were fitted with controls by 1987 which limited their SO_2 emissions to 260 ng/J (0.6 lb/MBtu), equivalent to the emission factor of the new cogeneration plant. Annual and 24-h load factors are the same as those in the base case scenario. Results of these calculations, as presented in column 2 of Table 4.7, show that the increase in the total generating plant emissions would not be as large. The increase is dramatically lower for the 24-h episodes. This is because the retrofitted plants would be operating at much higher load factors (Table 4.6), and their SO_2 emission factors would be reduced from 1.3 µg/J (3.0 lb/million Btu) to 260 ng/J (0.61 lb/million Btu) in this scenario. For Episode 6, the change in emission rates would be zero, since there would be no difference in the emission factors between the retrofitted and the new cogeneration plants.

In Scenario 2 it was assumed that the load factors of the power plants would be the same with or without district heating. Emission factors remained the same as in the base case scenario with the exception of that for the Third Street plant, which was assumed to be 260 ng/J (0.6 lb/MBtu). The objective in leaving the load factors unchanged in the second scenario is to determine how emissions are affected if it is assumed that the load schedule of the cogenerating power plants is determined by electricity demand and not by district heating demand. Some European systems have found there is no significant increase in the load factors when plants are retrofitted to cogenerate.

In short, when the second scenario is considered in conjunction with the base case scenario, one brackets the range where the actual plant load factor is expected to fall if the 2600 MW city-wide system is actually put into operation. It can be seen from Table 4.7 that district heating development results in even less of an increase in SO_2 emissions under this scenario than it did under Scenario 1. Most of the increase which does occur is due to the addition of the new cogeneration unit.

4.3.2 Point Emission Sources

4.3.2.1 Annual Emissions

The point emission source inventories were developed from the 1976 NEDS data for the region and the natural gas curtailment plans developed by Northern Natural Gas Company, the supplier for the Twin Cities area. Point sources are generally defined as those sources emitting greater than 907 kg (100 tons) per year of a criterion pollutant, which is sufficiently large for it to be included in the NEDS data base. The locations of these sources within the study area are shown in Figure 4.2.

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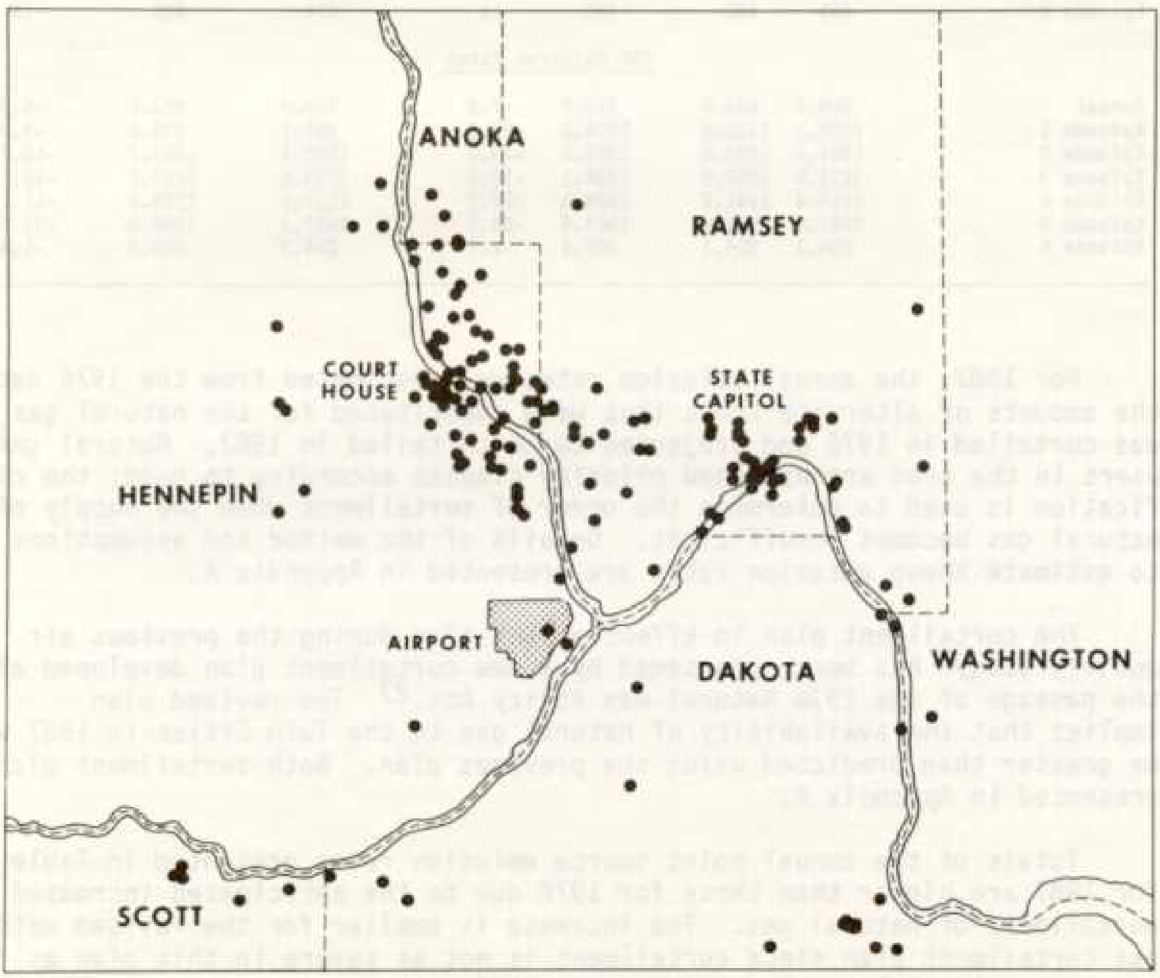

Fig. 4.2. Point emissions source locations in the study area.

The 1976 annual data in the NEDS file were reviewed and updated by MEA.[2,26] Totals of the 1976 annual average emission rates from these sources, excluding the power and heating plants, are listed in Table 4.8.

TABLE 4.8. TOTAL EMISSION RATES FROM POINT SOURCES EXCLUDING POWER AND HEATING PLANTS, g/s

	Old Natural Gas Curtailment Plan				New Natural Gas Curtailment Plan		
	1976	1987 Without District Heating/ Cogeneration	1987 With District Heating/ Cogeneration	1987 Change	1987 Without District Heating/ Cogeneration	1987 With District Heating/ Cogeneration	1987 change
			SO_2 Emission Rates				
Annual	1048	1236	1158	-78	1127	1054	-73
Episode 1	2053	2350	2192	-158	1953	1850	-103
Episode 2	2588	2701	2514	-187	2685	2503	-182
Episode 3	2506	2637	2457	-180	2515	2350	-165
Episode 4	2123	2432	2268	-164	2147	2028	-119
Episode 5	3191	3191	2969	-222	3191	2969	-222
Episode 6	465	465	450	-15	471	456	-15
			TSP Emission Rates				
Annual	558.7	583.6	575.8	-7.8	559.9	553.0	-6.0
Episode 1	1075.1	1110.5	1094.0	-16.5	946.1	936.8	-9.3
Episode 2	1265.3	1283.8	1264.6	-19.2	1282.4	1263.7	-18.7
Episode 3	1231.9	1252.9	1234.1	-18.8	1233.6	1217.5	-16.1
Episode 4	1114.4	1151.2	1134.0	-17.2	1117.1	1105.5	-11.6
Episode 5	1527.9	1527.9	1504.4	-23.5	1527.9	1504.4	-23.5
Episode 6	204.1	204.1	202.4	-1.7	204.3	202.9	-1.4

For 1987, the annual emission rates were estimated from the 1976 data and the amounts of alternate fuels that were substituted for the natural gas that was curtailed in 1976 and projected to be curtailed in 1987. Natural gas users in the area are assigned priority classes according to need; the classification is used to determine the order of curtailment when the supply of natural gas becomes insufficient. Details of the method and assumptions used to estimate these emission rates are presented in Appendix A.

The curtailment plan in effect at the time during the previous air quality study[2] has been superseded by a new curtailment plan developed after the passage of the 1978 Natural Gas Policy Act.[27] The revised plan implies that the availability of natural gas in the Twin Cities in 1987 will be greater than predicted using the previous plan. Both curtailment plans are presented in Appendix A.

Totals of the annual point source emission rates presented in Table 4.8 for 1987 are higher than those for 1976 due to the anticipated increased curtailment of natural gas. The increase is smaller for the revised natural gas curtailment plan since curtailment is not as severe in this plan as it was in the previous plan. For this study, it is assumed that the emission rates are those predicted using the revised curtailment plan.

Point source emission rates will decrease with the development of the district heating/cogeneration system, as shown in Table 4.8. The sources that would connect to such a system were identified by MEA in the previous annual air quality study.[2,26] It was assumed that for these sources, the reduction in the annual average emission is equivalent to that portion of the plant's energy requirement used for space heating.[2]

4.3.2.2 24-h Episode Emissions

To estimate the point source emissions for the 24-h periods, the fuel mix for each source during each episode had to be determined. This variable is a function of the ambient temperature because of the natural gas curtailment schedules. A number of assumptions had to be made in the procedure for estimating the temperature at which natural gas is curtailed for different classes of point sources. Details of the procedure and assumptions are described in Appendix A. The episodic emission rate for each point source was then determined using the curtailment temperature plus additional assumptions regarding the partitioning of fuel used for space heat and process heat and the source emission factor. Details of this procedure are also described in Appendix A.

The total 24-h point source emission rates are also presented in Table 4.8, and they are higher for those episodes having the lower average ambient temperatures. This, of course, is due to increase of fuel used to meet the increase in the space heating needs and the greater substitution of alternate fuels having higher emission rates for natural gas at the lower temperatures. Except for Episode 5, there is an increase in the emission rates in 1987 compared to 1976 due to the anticipated decrease in the availability of natural gas. For Episode 5, the average temperature is -17.2°C, which is below the gas curtailment temperature for all classes of point sources. Thus, there would be no changes in the future emission rates between 1976 and 1987. Episode 6 emission rates are very low since this is a late summer condition with no space heating demands and minimal gas curtailment.

With the development of the district heating/cogeneration system, Table 4.8 shows that there would be a reduction in the total point source emission rates. The magnitude of the reduction is greater for the episodes having the higher value degree days. As for the annual case, it was assumed that the reduction in the emission rate for each of the point sources connecting to the district heating system is equivalent to that portion of the fuel required for space heating.

Again for this study, the 24-h emission rates predicted using the new natural gas curtailment plan were used for the dispersion analysis (Section 4.4). Table 4.8 shows that the predicted overall impacts will be slightly smaller for the scenario based on the new curtailment plan.

4.3.3 Commercial and Industrial Area Sources

For emissions from the relatively small combustion units, a data base similar to NEDS is not available. Rather than try to calculate the emissions from each of these units individually, an indirect approach based on fuel use in the area was used. These sources are thus defined as area sources. The commercial and industrial area sources were treated separately from the residential area sources, since the methods of estimating the distribution of the emissions from these sources within the study area are different. Estimates of the emissions from the commercial and industrial area sources are treated here and emissions from the residential area sources are treated in Section 4.3.4.

It was assumed for the commercial and industrial area sources that the SO_2 and TSP emissions are primarily due to the distillate and residual fuel oils burned by these sources. Emissions of these pollutants from natural gas combustion at these sources are small compared to the emissions from the fuel oils. The effect of ignoring these natural gas combustion emissions is to make the estimate of the impact of the district heating/cogeneration system slightly conservative.

4.3.3.1 Annual Emissions

The annual commercial and industrial area source emissions were estimated by a two-step procedure described in detail in Appendix A. Briefly, the totals of the distillate oil and the residual oil used in the study area during 1976 were estimated from data collected by the State of Minnesota and the U. S. Department of Commerce.[27] These totals were then extrapolated to 1987 considering changes in energy demand and natural gas availability. From these totals, the total point source distillate and residual oil use was subtracted to yield the annual area source oil use.

Knowing the total oil use, the total emissions in the study area were calculated and are presented in Table 4.9. It was assumed that distillate oil

TABLE 4.9. TOTAL EMISSION RATES FROM COMMERCIAL AND INDUSTRIAL AREA SOURCES (NEW NATURAL GAS CURTAILMENT PLAN), g/s

	1976	1987 Without District Heating/Cogeneration	1987 With District Heating/Cogeneration	1987 Change
		SO_2 Emission Rates		
Annual	429	617	573	-44
Episode 1	450	983	889	-94
Episode 2	1,188	1,510	1,338	-172
Episode 3	800	1,013	917	-96
Episode 4	446	984	899	-85
Episode 5	1,288	1,812	1,581	-231
Episode 6	171	353	353	0
		TSP Emission Rates		
Annual	27.4	42.1	39.1	-3.0
Episode 1	28.4	65.0	58.7	-6.3
Episode 2	70.4	91.9	81.6	-10.3
Episode 3	47.6	64.9	58.7	-6.2
Episode 4	28.6	64.2	58.4	-5.8
Episode 5	75.8	109.2	95.7	-13.5
Episode 6	12.6	25.9	25.9	0

has an 0.5% sulfur content and residual oil has 1.9% sulfur content.[2,22] For TSP emissions, it was assumed that the emission factor is 240 g/m^3 (2 lb/1000 gal.) for distillate oil and 2.54 kg/m^3 (22 lb/1000 gal.) for residual oil.[28]

It was assumed that the commercial and industrial area source emissions are distributed in the study area in proportion to the distribution of natural gas curtailment in the area. Curtailment data for each of the natural gas billing districts were used first to estimate the emissions in the billing districts. The gas billing district area sources were then reapportioned into the Computer Assisted Area Source Emissions (CAASE) grid.[37] This is a square grid system that uses the Universal Transverse Mercator (UTM) coordinates[38] used in the dispersion model calculations described below.

A typical plot of the commercial and industrial area SO_2 source strengths is shown in Figure 4.3. The grid size associated with this figure varies with location. The smallest grids are near the downtown area, where grid squares of 1 to 4 km^2 are appropriate. In the outer areas, the grid size is larger, essentially because the gas billing districts in the outer regions are larger.

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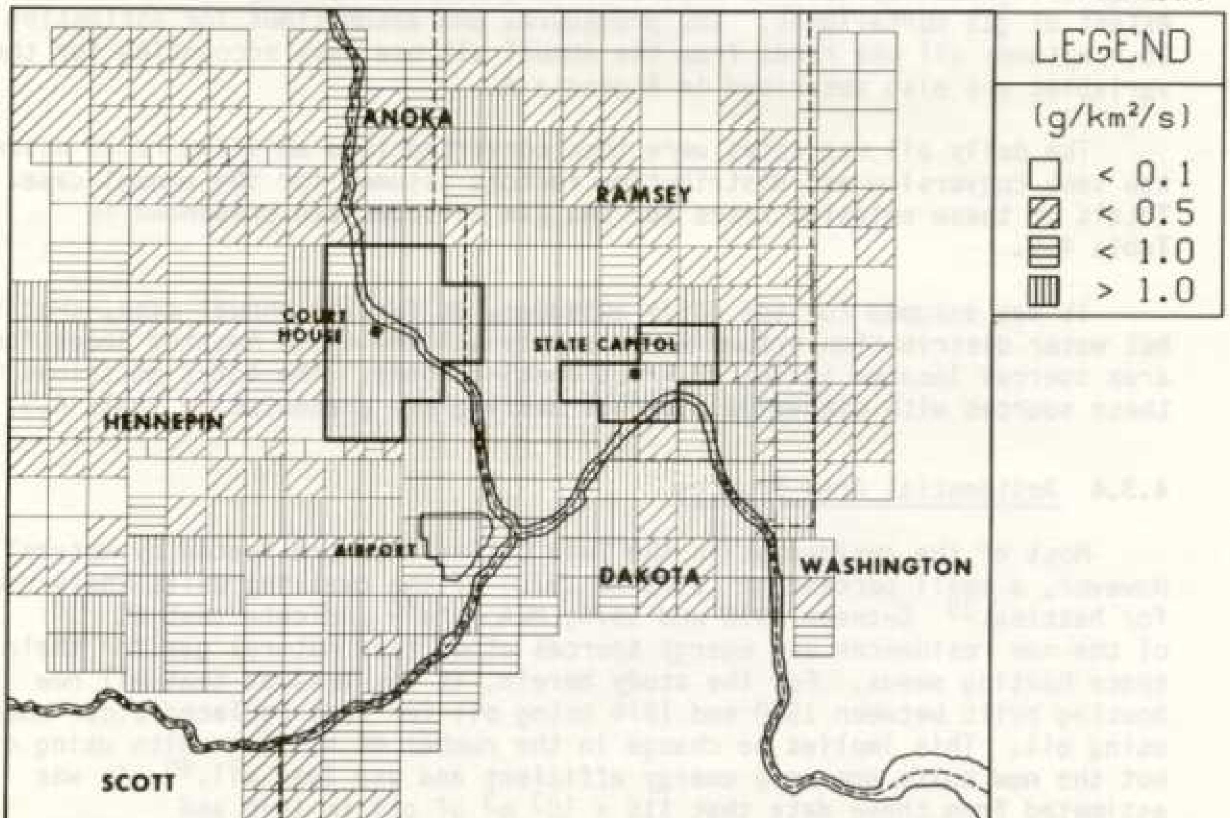

Fig. 4.3. Estimated annual averaged commercial and industrial area source SO_2 emissions for 1987 without district heating/cogeneration (g/km^2/s). (Heavy outlines are the district heating zone boundaries).

For 1987 with district heating/cogeneration, it was assumed that the district heating system would replace all the area sources used for space heating in the district heating zones. MEA estimated that 45% of the distillate oil and 35% of the residual oil consumed annually by the area sources are used for space heating purposes.[2,26] This implies that about 37% of the oil used by the commercial and industrial area sources in the district heating zones would be eliminated and the total area source emissions would be reduced by the amounts shown in Table 4.9.

4.3.3.2 24-h Episode Emissions

For the 24-h episodes, the procedure for estimating the commercial and area source emissions is the same as that for the annual emissions; first estimate the oil use rates, then convert these values to emissions using the appropriate emission factors. Details of the procedures for the episode emissions are also described in Appendix A.

The approach for determining the episode area source oil use is the same as that for the annual oil use; first estimate the total oil use in the area, and then subtract the total point source oil use. The volume of oil that is used during each episode is dependent on the space heating needs and the extent of gas curtailment. The procedures and assumptions for estimating the 24-h episode oil use rates from the annual oil use data accounting for these variables are also described in Appendix A.

The daily oil use rates were then converted into emission rates assuming the same conversion and distribution factors assumed for the annual case. Totals of these emission rates for the six episodes are presented in Table 4.9.

It was assumed for the daily episodes, as for the annual case, that the hot water distribution system would supply all the space heating needs for the area sources located in the district heating zones. The total emissions for these sources with city-wide district heating are presented in Table 4.9.

4.3.4 Residential Area Sources

Most of the residences in the Twin Cities area are heated by natural gas. However, a small percentage (9.7% in 1970) of the dwelling units there use oil for heating.[39] Between 1970 and 1976, MEA data[40] indicate that 6% of the new residences use energy sources other than natural gas for their space heating needs. For the study herein, it was assumed that all new housing built between 1970 and 1976 using oil for fuel replaced older housing using oil. This implies no change in the number of housing units using oil, but the new units are more energy efficient and use less oil.[40] It was estimated from these data that 116×10^3 m^3 of oil in 1976 and 76×10^3 m^3 of oil in 1987 are used for residential heating in the Twin Cities. The method and assumptions used to calculate these quantities are described in Appendix A.

To determine the SO_2 and TSP emission rates from the residences, use of fuels for purposes other than space heating were ignored. It was assumed that the housing units burning oil use 0.5% sulfur distillate oil. It was further assumed that the TSP emission factor for the oil use in these units is 300 g/m^3 (2.5 lb/1000 gal) and that for natural gas is 0.16 g/m^3 (10 lb/10^6 ft^3).[28] Using these assumptions, the total annual emissions rates were calculated and are presented in Table 4.10.

TABLE 4.10. TOTAL EMISSION RATES FROM RESIDENTIAL AREA SOURCES, g/s

	1976	1987 Without District Heating/Cogeneration	1987 With District Heating/Cogeneration	1987 Change
		SO_2 Emission Rates		
Annual	31	30	22	-8
Episode 1	61	58	43	-15
Episode 2	73	69	51	-18
Episode 3	71	67	49	-18
Episode 4	64	60	44	-16
Episode 5	90	85	62	-23
Episode 6	0	0	0	0
		TSP Emission Rates		
Annual	6.8	7.7	5.6	-2.1
Episode 1	13.2	15.0	10.9	-4.1
Episode 2	15.8	17.9	13.0	-4.9
Episode 3	15.3	17.4	12.7	-4.7
Episode 4	13.8	15.7	11.4	-4.3
Episode 5	19.5	22.1	16.1	-6.0
Episode 6	0	0	0	0

For the dispersion calculations, it was assumed that the emissions are distributed in the study area in proportion to population density in the area as reported in 1970 census data.[39] With the development of the district heating/cogeneration system, it was assumed that all the housing units heated in the district heating zones would connect to the system and their emission rates would be reduced to zero. The predicted magnitudes of the reduction of the emission rates and the total residential emission rates in the area are given in Table 4.10.

For the 24-h episodes, the emission rates were assumed to be proportional to the number of heating degree days, assuming that there are 4533 Celsius heating degrees per year. The emission rates thus determined are listed in Table 4.10.

4.3.5 Total Emissions

Totals of the SO_2 and TSP emission rates for all of the sources considered for the Twin Cities area are listed in Table 4.11. These are the

TABLE 4.11. TOTAL EMISSION RATES (NEW NATURAL GAS CURTAILMENT PLAN), g/s

	1976	1987 Without Heating/ Cogeneration	1987 With Heating/ Cogeneration	1987 Change	Per cent Change
			SO_2 Emission Rates		
Annual	3557	3823	3922	99	2.6
Episode 1	5745	6175	6530	355	5.8
Episode 2	6823	7238	8039	801	11.1
Episode 3	6580	6798	7512	714	10.5
Episode 4	5587	6145	6760	615	10.0
Episode 5	7814	8333	8848	515	6.2
Episode 6	2512	2700	2238	-462	-17.1
			TSP Emission Rates		
Annual	636.3	653.1	648.8	-4.3	-0.7
Episode 1	1203.3	1112.7	1100.2	-12.5	-1.1
Episode 2	1440.9	1481.6	1466.4	-15.2	-1.0
Episode 3	1384.3	1405.4	1396.7	-8.7	-0.6
Episode 4	1238.5	1278.7	1271.9	-6.8	-0.5
Episode 5	1718.3	1754.3	1730.1	-24.2	-1.4
Episode 6	259.1	272.6	276.0	3.4	1.3

sums of the values for different categories of sources presented in Tables 4.3, 4.4, 4.8, 4.9, and 4.10. It can be seen in Table 4.11 that the development of this city-wide district heating/cogeneration system would result in noticeable (3 to 11%) increases in the total SO_2 emission rates. The only exception is for Episode 6, the late summer episode. Here the electrical current generated by the High Bridge retrofitted units was assumed to be displaced by current generated by the new cogeneration unit. This would result in a net decrease in the SO_2 emissions because the new plant has a lower emission factor.

The increases in the SO_2 emission rates are due to the increased load factors assumed for retrofitted power plants and to the addition of a new cogeneration power plant. These actions would result in relatively large increases in the power plant emission rates, as was seen in Table 4.3. These increases more than offset the decreases in the SO_2 emission rates from the sources connecting to the district heating system. Many of these sources now burn natural gas, which has an extremely low sulfur content.

To gain some idea of the importance of these assumptions on the total net emission rates, the change in the total emission rates was predicted for three alternative scenarios. These are: (1) all power plants use western coal and adhere to the NSPS emission rates, (2) no change in the power plant load factors with the implementation of the district heating/

cogeneration system, and (3) same as the previous scenario, but with the new cogeneration plant electrical capacity to match the electrical capacity loss in the retrofitted plants. The changes in the predicted SO_2 emission rates from the power plants for the first two scenarios are addressed in Section 4.3.1.3. The effect of these on the changes in the total SO_2 emission rates in the Twin Cities area is shown in Table 4.12.

TABLE 4.12. EFFECT OF POWER PLANTS' EMISSION FACTOR AND LOAD FACTOR ON CHANGE OF TOTAL SO_2 EMISSION RATE

	Base Case		Scenario 1: Emission Factor of Existing Coal Plants Changed to 260 g/J (0.6 lb/million Btu)		Scenario 2: Loads Factor of Retrofitted Plants Assumed to be the Same With or Without District Heating/Cogeneration[a]		Scenario 3: Same as Scenario 2 but with the New Cogeneration Plant Electrical Capacity to Match the Retrofitted Plants' Capacity Loss	
	Change,[b] g/s	Per cent Change	Change, g/s	Per cent Change	Change, g/s	Per cent Change	Change, g/s	Per cent Change
Annual	99	2.6	29	0.8	2	0.1	17	0.4
Episode 1	355	5.8	48	0.8	-58	-0.9	-33	-0.5
Episode 2	801	11.1	9	0.1	-221	-3.1	-191	-2.6
Episode 3	714	10.5	64	0.9	-130	-1.9	-100	-1.5
Episode 4	615	10.0	93	1.5	-67	-1.1	-40	-0.7
Episode 5	515	6.2	-101	-1.2	-303	-3.6	-273	-3.3
Episode 6	-462	-17.1	-15	-0.6	-15	-0.6	-15	-0.6

[a]Emission factor for Third Street Plant with district heating/cogeneration assumed to be 260 ng/J (0.6 lb/million Btu).

[b]From Table 4.11.

If it is assumed that the emissions from the retrofitted plants are limited to that specified by NSPS for a plant using western coal, 260 ng/J (0.6 lb/million Btu), the net change in total emission rate would be much less than for the base case. The values presented in Table 4.12 assume that the power plant emissions would be limited by these standards in 1987, whether or not the development of the district heating/cogeneration system takes place.

If there is no change in the load factors of the power plants after the implementation of the district heating/cogeneration system, Table 4.12 indicates that there generally would be a small decrease in total SO_2 emission rates. In this case, the total decrease in the emission rate of the sources connecting to the district heating system would be greater than the total increase in the power plant emission rate. Most of the increase in the total power plant emission rate would be due to the addition of the new cogeneration unit.

It can be argued that the change in emission rates in Scenario 2 does not reflect the true situation since the 190 MW(e) capacity of the new cogeneration plant does not completely replace the 229.5 MW(e) capacity lost by retrofitting the existing units. If the new cogeneration plant had 39.5 MW(e) additional capacity, its SO_2 emission rate would increase by (39.5/235) 181 or 30.4 g/s at full load. Using an 0.50 annual load factor and Table 4.6 retrofitted plants' load factors for the 24-h episodes, the change in the total emission rates would be the values shown in Table 4.12. In this case, the increase in the total annual SO_2 emission rate would be still less than 0.5% and the selected 24 h episode total SO_2 emission rates would still decrease.

It is beyond the scope of this study to speculate on exactly how the district heating/cogeneration system would develop in the Twin Cities area. However, the base case in Table 4.12 probably is, or is close to being, the worst case regarding SO_2 emissions from the cogeneration plants. In this case, all the operating units at High Bridge and Riverside Generating Plants would be retrofitted for cogeneration operation. The NSPS would not be applied to the retrofitted plants since the modifications would be made to the turbine, not the boiler itself. Moreover, the NSPS does not consider an increased plant load factor as a boiler modification. The other extreme would be compliance with NSPS and no change in the load factors of the retrofitted plants with the development of the district heating/cogeneration system. At this extreme, Table 4.12 shows that there would be a net decrease in the total SO_2 24-h emission rates in the Twin Cities area. The actual change in the total SO_2 emission rates probably would be somewhere between the extreme values given in Table 4.12. If the trend is toward building new cogeneration units instead of retrofitting existing units, however, the NSPS would apply and there could be a decrease in the total SO_2 emission rate.

For TSP, Table 4.11 shows that there would be a decrease of the total emission rate in the area with the development of the district heating/cogeneration system. This is because the power plants are equipped with controls, primarily electrostatic precipitators, to limit the TSP emissions. Many of the existing sources that would connect to the district heating system do not have TSP emission control devices. Thus, the displacement of these sources by the central power plants would result in a net decrease in the TSP emissions.

It should be remembered that many assumptions were made to derive the values in Tables 4.11 and 4.12. Therefore, care must be taken in interpreting these data. However, it appears that the development of a large district heating/cogeneration system could in the long run result in a minimal increase or even a decrease in the total SO_2 and TSP emission rates. Reductions in the total TSP emission rates can be expected because of the installation of high efficiency collection equipment at the power plants.

4.3.6 Effect of Mobile Emission Sources (Oil Transport)

In Section 3.4.1, it was concluded that the sources that would connect to the district heating system use 7.45×10^5 m^3 residual oil and 4.67×10^5 m^3 distillate oil. Since the fuel oils are usually delivered to the users by truck, an estimate was made of the reduction of the SO_2 and TSP emissions associated with these quantities of oil. Smaller fuel oil users usually use distillate oil, which is generally delivered in smaller gasoline powered trucks. The larger users use both types of fuel oil, and they are generally delivered to them in diesel powered trucks. In the Twin Cities, a heavy duty truck typically travels 56 km (35 m) to deliver 30 m^3 of oil.[41]

A conservative approximation of the SO_2 and TSP emissions is to assume that all the oil is delivered in 30 m^3 capacity diesel powered trucks. Diesel trucks have emission factors of 2.8 g SO_2 and 1.5 g particulates for each mile traveled.[28] These factors are much higher than the values of 0.18 g/m of SO_2 and 0.54 g/m of particulates for gasoline powered trucks,[28] and more than compensate for the increased mileage required by the smaller trucks. Using this approximation, the total annual SO_2 and TSP emissions would be reduced by 348 kg and 186 kg respectively.

Assuming conservatively that fuel oil deliveries are made only during the six-month heating season and then only during a 5-day, 40-h week, the total average emission rates from these trucks during these hours are 0.19 g/s and 0.1 g/s for SO_2 and TSP respectively. Comparing these values with the total emission rates for the commercial and industrial area sources, Table 4.9, it can be concluded readily that they are insignificant.

4.3.7 Trace Element Emissions

The combustion of coal releases a multitude of chemical elements to the atmosphere. Called trace elements because of their relatively low concentrations in coal, some of these may be toxic to flora and fauna even in low concentrations. There is a possibility that deposition of some trace elements may be sufficient to increase their background concentrations to potentially hazardous levels. While more than 60 elements have been found in coal, 17 elements known or suspected to be hazardous, have been selected for this study (Table 4.1).

Trace element emissions are associated with the fly ash from coal combustion, either as ash, or as vapor which may later adsorb to the fly ash. The emission rates of these elements and the average settling rate of the ash particles are used for deriving annual deposition rates, the rates at which these elements accumulate on a surface. This section addresses the emission rates, and Section 4.4.5 addresses the dispersion and settling rates.

As stated in Section 3.3, the primary coal-fired plants in the Twin Cities area are the Black Dog, High Bridge, and Riverside Generating Plants. Black Dog and High Bridge presently use a mixture of 75% western and 25% Illinois coals, and Riverside uses a blend of 88% western coal and 12% petroleum coke.[23] It was assumed for this analysis that the new 190 MW(e)/335 MW(t) cogeneration unit would burn western coal.[19] The estimated quantities of fuel that would be used by these plants after the city-wide district heating/cogeneration system is developed are given in Table 4.13. The values for the existing plants were estimated from NSP

TABLE 4.13. ESTIMATED ANNUAL COAL CONSUMPTION AT ELECTRICAL GENERATING PLANTS WITH DISTRICT HEATING/COGENERATION, Gg

Plant	Annual Coal Throughput
Black Dog	972
High Bridge	841
New Cogeneration Unit	745
Riverside[a]	973

[a]Riverside uses a mixture of coal and petroleum coke.

data for fuel use at these plants[23] in 1977 plus 10% increase for the retrofitted plants, as discussed in Section 4.3.1. The value for the new cogeneration plant was determined from the conceptual design of the plant[19], assuming a 65% load factor.

Chemical composition of coal varies with the location of the source of coal, and even can vary within a given coal seam. Trace element content of typical western and Illinois coals was obtained from the U.S. Geological Survey,[42] and are listed in Table 4.14. It was assumed that the coals being used in the Twin Cities generating plants are of these compositions. It was further assumed that the petroleum coke used in the Riverside plant has the same trace element content as the Montana coal shown in Table 4.14.

TABLE 4.14. AVERAGE CONCENTRATIONS OF TRACE ELEMENTS IN TYPICAL WESTERN AND ILLINOIS COAL USED AT NORTHERN STATES POWER STEAM PLANTS,[42] ppm

Element	Western Coal (Rosebud/McKay bed, Colstrip, Montana)	Illinois Coal (Herrin bed)
Antimony	0.950	
Arsenic	2.72	5.44
Beryllium	0.742	1.94
Cadmium	0.117	1.51
Chromium	28.6	88.3
Cobalt	10.7	15.1
Copper	7.01	10.3
Fluorine	50.8	70.1
Lead	4.30	19.8
Mercury	0.0871	0.0925
Molybdenum	2.03	6.54
Nickel	1.72	14.8
Scandium	1.15	2.55
Selenium	0.732	2.27
Uranium	0.980	1.93
Vanadium	6.73	21.7
Zinc	43.2	162.

Given the amounts of each trace element for each particular coal, the next step in determining trace element emissions is to determine the fractions of these amounts actually released. Ideally, each coal boiler's trace element emission potential could be calculated knowing the element abundance in the coal burned, the annual coal throughput, the particle size dependent enrichment factor for each element, and the size spectra of particles both produced and actually emitted. Size dependence is a critical factor because of the enhanced adsorption of volatile elements on small particles due to the greater surface area-to-mass ratio for small particles than for larger ones. However, because size spectra data for the plants of interest are not available and because of the other assumptions made in this analysis, calculations of this detail are not warranted. Edwards et al.[43] have determined the collection efficiencies of trace elements in a number of coal-fired electrical generating plants. On the basis of these determinations, it was assumed that the trace element collection efficiencies of the NSP generating plants are the values listed in Table 4.15. These values reflect the fact that all the existing units except Riverside Boilers 6 and 7 have electrostatic precipitation systems. Riverside Boilers 6 and 7 have cyclone particulate removal systems. (The recent addition of the dry scrubber FGD system to these two boilers was ignored in this analysis.) The new cogeneration unit is visualized to have a dry scrubber-baghouse flue gas cleanup system.

TABLE 4.15. TRACE ELEMENT COLLECTION EFFICIENCIES ASSUMED FOR THE ELECTRICAL GENERATING PLANTS

Element	Black Dog, High Bridge, Riverside Boiler 8	Riverside Boilers 6 & 7	New Cogeneration Unit
Antimony	96	7	99
Arsenic	95	75	99
Beryllium	99	84	99
Cadmium	95	44	99
Chromium	98	28	99
Cobalt	98	45	99
Copper	99	57	99
Fluorine	92	25	99
Lead	97	30	99
Mercury	0	3	99
Molybdenum	95	25	99
Nickel	99	19	99
Scandium	99	33	99
Selenium	94	33	99
Uranium	97	61	99
Vanadium	98	36	99
Zinc	97	39	99

Using these collection efficiencies with the total amount of each element in the annual coal throughput for each plant, the annual net emission of each element from each plant can be estimated. Values of these emissions are presented in Table 4.16.

Given the net annual total TSP and trace element emissions (Tables 4.4 and 4.16), an enrichment factor can be developed for each element, which is merely the mass of an element per unit mass of TSP. Then, using the TSP concentrations and deposition rates determined through the use of a numerical dispersion model, the concentrations and deposition rates can be easily calculated for each element. This will be addressed in Section 4.4.5.

TABLE 4.16. ANNUAL TRACE ELEMENT EMISSIONS ESTIMATES FOR THE GENERATING PLANTS WITH DISTRICT HEATING/COGENERATION, kg

Element	Black-dog	High Bridge	New Cogeneration Unit	River-side 8	River-side 6 & 7	Total
Antimony	34	29	4	26	224	317
Arsenic	145	126	12	87	172	542
Beryllium	9	8	3	5	30	55
Cadmium	20	17	1	4	17	59
Chromium	758	659	128	376	5,290	721
Cobalt	183	158	48	125	1,510	2,020
Copper	53	46	31	36	774	940
Fluorine	4,140	3,610	227	394	9,700	18,100
Lead	253	220	19	100	770	1,360
Mercury	86	74	1	64	22	247
Molybdenum	156	135	9	76	389	765
Nickel	22	19	8	6	358	413
Scandium	14	13	5	8	124	164
Selenium	64	55	3	32	358	512
Uranium	29	25	4	17	92	167
Vanadium	172	150	30	83	1,100	1,540
Zinc	1,970	1,740	193	883	6,700	11,500

4.4 DISPERSION OF POLLUTANTS

The effluents entering the atmosphere from various sources undergo advection and diffusion. The purpose of this section is to estimate the ground level pollutant concentrations due to the emissions estimated in Section 4.3. Both SO_2 and TSP concentrations were calculated on an annual average basis and on a 24 h average basis for the six episodes identified in Section 4.2. Trace element concentrations (and deposition rates) were calculated on an annual average basis.

4.4.1 Dispersion Models

There are a multitude of prediction models for calculating pollutant concentrations in urban atmospheres.[44] They vary from being very simple to very elaborate and specialized. Although there are differences in the results calculated by the different models, often these differences are within the error expected, if allowances are made for the known inaccuracies in predicting atmospheric dispersion.

Three multi-source atmospheric dispersion models were used in this study to predict surface level pollutant concentrations.* The

*The choice of models in this study does not imply that they reflect an approach that is acceptable for regulatory actions. That was not the intent of this study.

Climatological Dispersion Model (CDM)[45,46] is a long-term model used to predict annual average concentrations, and the Multiple-Source Air Quality Algorithm (RAM)[32,33] and the Texas Episodic Model (TEM)[47] are short-term models used to predict the 24-h average concentrations. All three models use the steady-state Gaussian plume relation for predicting the ground level concentrations of essentially non-reactive pollutants emitted from point and area sources in quasi-level terrain. Despite the basic similarity, several important differences among these models must be considered before interpreting the predicted results. These differences are discussed in Sections 4.4.1.1 through 4.4.1.3.

The CDM is a program developed by the U. S. Environmental Protection Agency (EPA)[30] that was used in this study to predict the annual average pollutant concentrations on a 2-km square grid over the entire study area, shown in Fig. 4.4. The TEM program was used to predict the 24-h average pollutant concentrations on a 1-km square grid over the entire study area. TEM was developed by the Texas Air Control Board.[48] The model developed by EPA for predicting the 24-h average concentration is RAM.[30] However, in the form used in this study, it was limited in the number of sources and receptors that can be simulated at one time. In order to check the assumptions that were applied in using TEM, RAM was used to predict the pollutant concentrations on a 1-km square grid for a limited

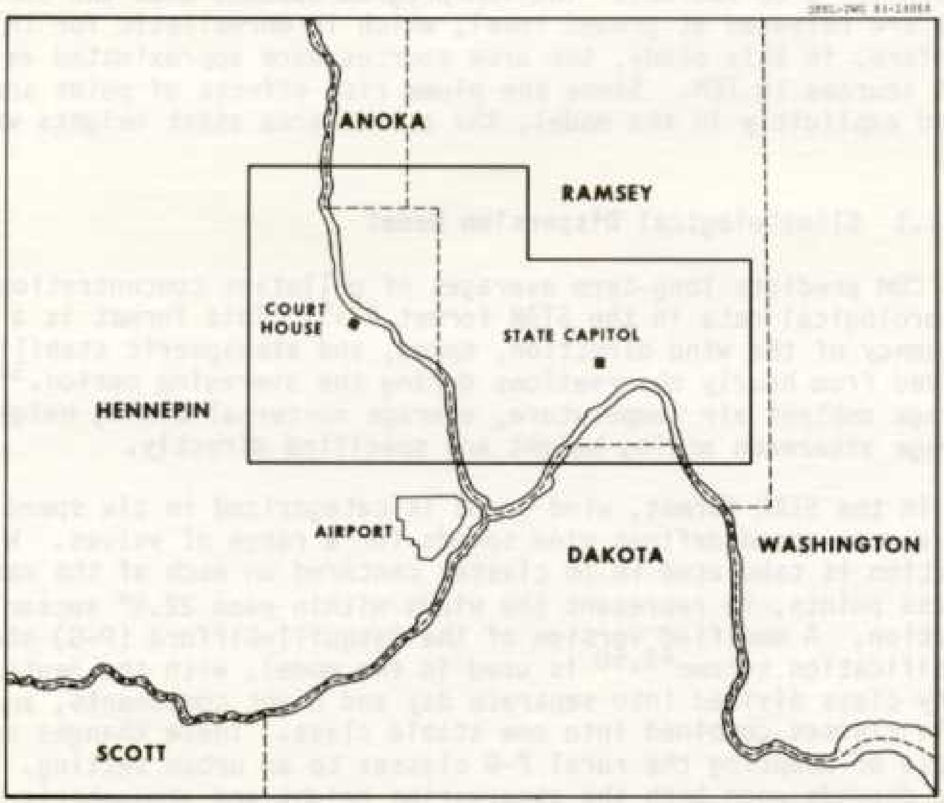

Fig. 4.4. Air quality study areas. Full 42 x 50 km area used for CDM and TEM calculations. Smaller 16 x 27 km area used for RAM calculations.

area outlined in Fig. 4.4. Some of the RAM-predicted concentrations are presented in Appendix C. Recognizing the differences between RAM and TEM, the impacts predicted by the two models were approximately equivalent.

In Sections 4.4.3 and 4.4.4 and in Appendix C, the predicted pollutant concentrations are presented in the form of contour plots. All these plots were computer-generated using the concentrations predicted by the models for the rectangular grids.

The stack heights of the point sources were assumed to be those listed in the NEDS data base as updated by MEA.[2,26] The stack height of the commercial and industrial area sources was assumed to be 10 m except for the downtown areas. In most of the downtown areas, it was assumed to be 15 m, and in the central downtown areas, it was assumed to be 20 m. For the residential area source, the stack height was assumed to be 5 m.

All three of these dispersion models consider the plume rise of the point sources due to the momentum and buoyancy of the gases leaving the stacks. However, these models treat the plume rise of the area sources differently. CDM and RAM do not consider the plume rise of the area source emissions. To account for the plume rise of these emissions, the effective stack heights in these two programs were assumed to be 14.75 m, 19.3 m, and 24.0 m for the commercial and industrial area sources, and 8.0 m for the residential area sources. The TEM program assumes that the source emissions are released at ground level, which is unrealistic for this study. Therefore, in this study, the area sources were approximated as a number of point sources in TEM. Since the plume rise effects of point sources are tested explicitly in the model, the actual area stack heights were used here.

4.4.1.1 Climatological Dispersion Model

CDM predicts long-term averages of pollutant concentrations using meteorological data in the STAR format.[45,46] This format is a joint frequency of the wind direction, speed, and atmospheric stability class derived from hourly observations during the averaging period.[34] Average ambient air temperature, average nocturnal mixing height, and average afternoon mixing height are specified directly.

In the STAR format, wind speed is categorized in six speed classes, so that a mean speed defines wind speeds for a range of values. Wind direction is tabulated in 16 classes centered on each of the cardinal compass points, to represent the winds within each 22.5° sector by a mean direction. A modified version of the Pasquill-Gifford (P-G) stability classification scheme[49,50] is used in the model, with the neutral stability class divided into separate day and night components, and the two stable classes combined into one stable class. These changes are for the purpose of adapting the rural P-G classes to an urban setting. Since wind speed depends upon both the observation height and atmospheric stability, a power law wind profile is used to extrapolate the data to the height of the emission source. Directional wind shear with height is not considered. The mixing height tends to decrease with increasing stability, which is accounted for in the model by slight modifications of the mixing height with stability.

CDM uses a simplified Gaussian relation to represent the plume dispersion in the atmosphere. A plume is assumed to homogeneously disperse in the horizontal direction within one of the 16 sectors, allowing only the vertical component of dispersion to vary with range and stability. The function describing vertical dispersion has been empirically derived from the P-G dispersion curves. Values of the dispersion function at the point of emission release are assumed to be 30 m for area sources and for point sources with stacks up to 20 m, zero for point source stacks 50 m and above, and a linearly interpreted value for stacks between 20 and 50 m. This is to account for the enhanced mixing occurring at lower elevations in an urban setting. A Briggs plume rise relationship, which considers the momentum and buoyancy of the gas leaving the stack, is used to estimate point source plume rise.[51] Area sources are assumed to have only the specified emission release heights for describing emission characteristics. The method of images is used to deal with plume reflections from the ground and a stable atmospheric layer.

The CDM program has a calibration option to adjust the predicted concentrations to be consistent with measured concentrations using a linear regression relation.[46] This option was not used directly in this study. However, the predicted SO_2 concentrations for 1976 were compared with the measured values obtained from the MPCA, as discussed in Section 4.4.3.

4.4.1.2 RAM

The Multiple-Source Air Quality Algorithm, commonly called RAM, consists of a meteorological data preprocessor program and four model versions which can be used for predicting episodic air quality for urban or rural settings.[32,33] The two urban versions, RAM and RAMF, have been used in this study. RAM is appropriate for analyzing air quality during an episode of 24 h, while RAMF is a truncated form of the general algorithm for calculating 24-h average concentrations for each day of the year. RAMF is useful for identifying days of high predicted concentrations from a long record, as was done in this study (Section 4.2). All versions of RAM are based upon the same Gaussian plume method used in CDM, but there are some data format changes in RAM.

RAM requires more detailed meteorological data than does CDM. Hourly wind speed and direction, ambient temperature, atmospheric stability class, and mixing height data representative of the study area are required. The hourly mixing height data requirement usually requires interpolation of morning and evening sounding data. The power law approach for estimating changes of wind speed with height is used in RAM as in CDM, although RAM uses larger exponents than does CDM. The wind speeds in these classes will therefore be higher than in CDM, and thus will predict greater dispersion of pollutants.[33,45] Since RAM uses hourly wind data, horizontal, as well as vertical, dispersion coefficients are in the Gaussian dispersion relation. The coefficients used in this program were recommended for urban areas by Briggs, and were derived from observations taken during non-winter months of the 1963-65 St. Louis, Missouri, study.[44,52]

As for CDM, the Briggs plume rise relationship is used to predict the plume rise of point sources in RAM. However, RAM uses a later version of Briggs relations, making distinction between plumes dominated by buoyancy and those dominated by momentum and considering stack tip downwash.[33]

For area sources, RAM uses specified effective emission heights as stated above. RAM considers the influence of wind speed on the effective height and permits the use of up to three heights to represent variation of height across the source region. The Gifford-Hanna narrow plume simplification[53] in RAM, for calculating dispersion of pollutants from area sources, in essence ignores all emissions except those coming from the narrow sector upwind of a given receptor. This assumption requires that emission rates be quite uniform across the study region, an assumption which is reasonable for the area sources in the Twin Cities.

4.4.1.3 Texas Episodic Model

The Texas Episodic Model (TEM) is a dispersion model designed for the same episodic applications as RAM and is very similar from a meteorological standpoint.[47] However, there are differences in formatting and on substantive points of dispersion theory and the assumptions used in the two programs.

As the computer programs were written at the time of the study, the TEM program was dimensioned to accept a larger number of sources and a far greater number of receptors than does RAM. This was the primary reason that TEM was used to predict the bulk of the 24-h pollutant concentrations in Section 4.4.4. At that time, RAM was dimensioned to handle up to 250 point sources, 100 area sources, and 150 receptors, whereas TEM was initially dimensioned to handle up to 300 point and 50 area sources, and 2500 receptors in a 50 by 50 array.[33,47] Moreover, the dimensions on the number of sources and arrays could be easily changed in TEM, which was done with the receptor array in this study.

For area sources, TEM assumes that the release heights are at ground level. This assumption would result in unrealistically high pollutant concentrations in this study. Therefore in this study, each area source was approximated as a point source having a single stack. A stack with characteristics representative of those in the area is assigned to the area center, and an emission rate equivalent to the entire area emission rate is then assigned to the stack. Since the stack was assumed to be a point source, the actual stack heights were specified in the input data as discussed in Section 4.4.1.1.

A primary difference between TEM and RAM is the dispersion coefficients used in the Gaussian plume relation. TEM uses the same P-G dispersion coefficient curves[49,50] to derive the dispersion coefficients as are used in CDM. TEM uses both horizontal and vertical dispersion coefficients. It is beyond the scope of this study to determine which set of coefficients is most applicable here, since neither set was derived from atmospheric conditions directly corresponding to the urban winter setting of the Twin Cities.

4.4.2 Meteorological Conditions

The surface meteorological conditions in the Twin Cities were assumed to be those measured at the Minneapolis-St. Paul Airport. Mixing heights were assumed to be those measured at St. Cloud, Minnesota.[34]

For the annual average conditions, the STAR data based on hourly observations at the airport during 1960-1964[34] were assumed to be representative. Figure 4.5 is the annual windrose generated from these data, where it can be seen that the wind is predominantly from the southwest. The average ambient air temperature is 6.5°C. The average nocturnal mixing height is 411 m, and the average afternoon mixing height is 1173 m.

Hourly meteorological data for the six selected 24-h episodes (Section 4.2) are presented in Appendix B. The mixing height data were determined by interpolating the mixing height measurements made every 12 h. The five winter episodes had cold temperatures and relatively poor dispersion characteristics while the summer episode was a warm day when space heating demand was at a minimum. These five winter days can be placed in two markedly different meteorological categories. The first four episodes are similar because during each day the winds were light to moderate in strength, generally blowing from between east and south, the atmosphere was

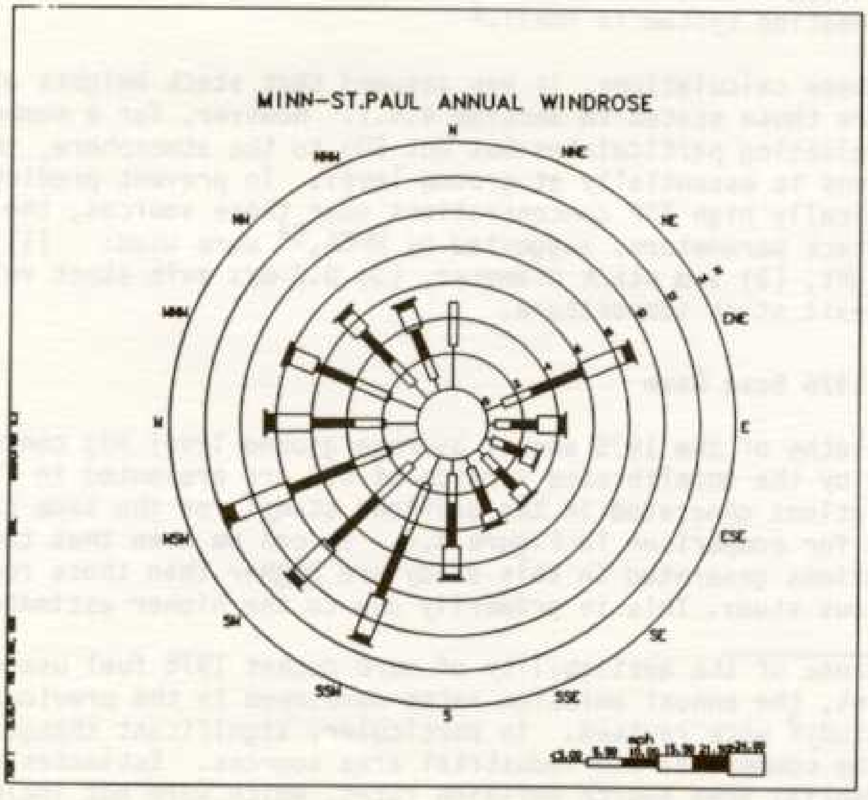

Fig. 4.5. Annual windrose for Minneapolis-St. Paul.

usually neutral to stable, the mixing heights were quite low, and the temperatures were well below freezing. Episode 5 contrasts with the first four days by having strong northwesterly winds, neutral atmospheric stability, comparatively high mixing heights, and cold temperatures dropping throughout the day to very low readings. By comparison, Episode 6 a late summer episode, had moderate to moderately strong west to northwesterly winds, generally neutral stability, mixing heights higher by a factor of 2 or 3 than those of the winter episodes, and mild temperatures. Thus, Episodes 1 through 4 represent days of large space heating demand and fairly poor atmospheric dispersion, while Episode 5 is a day of very large heating demand but fairly good dispersion.

4.4.3 Annual Average Pollutant Concentrations

Annual average ground level SO_2 and TSP concentrations were calculated using the uncalibrated version of CDM (Section 4.4.1.1).* The pollutant concentrations were determined on a 2-km square grid, and from these, computer-generated isopleths were produced.

For this study, the only large electrical power plants considered were Black Dog, High Bridge, and Riverside. The King and Sherbourne plants, located outside of the study area (Fig. 1.2), were not included in this analysis. Furthermore, it was assumed that the new 190 MW(e)/335 MW(t) cogeneration unit would be located at the High Bridge site. The previous study showed that the effects of those plants external to the study area and the effect of the new cogeneration plant location on the impact of the district heating system is small.[2]

In these calculations, it was assumed that stack heights of the sources are those stated in Section 4.4.1. However, for a number of point sources releasing particulates but not SO_2 to the atmosphere, the release of emissions is essentially at ground level. To prevent prediction of unrealistically high TSP concentrations near these sources, the following default stack parameters, suggested by MPCA,[54] were used: (1) 13.7-m stack height, (2) 1-m stack diameter, (3) 0.2-m/s exit stack velocity, and (4) 10°C exit stack temperature.

4.4.3.1 1976 Base Case

Isopleths of the 1976 annual average ground level SO_2 concentrations predicted by the uncalibrated version of CDM are presented in Figure 4.6. The predictions generated in the previous study[2] for the same case are presented for comparison in Figure 4.7. It can be seen that the predicted concentrations generated in this study are higher than those reported in the previous study. This is primarily due to the higher estimates of fuel

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*Because of the availability of more recent 1976 fuel use data for the Twin Cities, the annual emission rates developed in the previous air quality study[2] were revised. In particular, significant changes were made in the commercial and industrial area sources. Estimates were made of the residential area source emission rates, which were not included in the previous study.

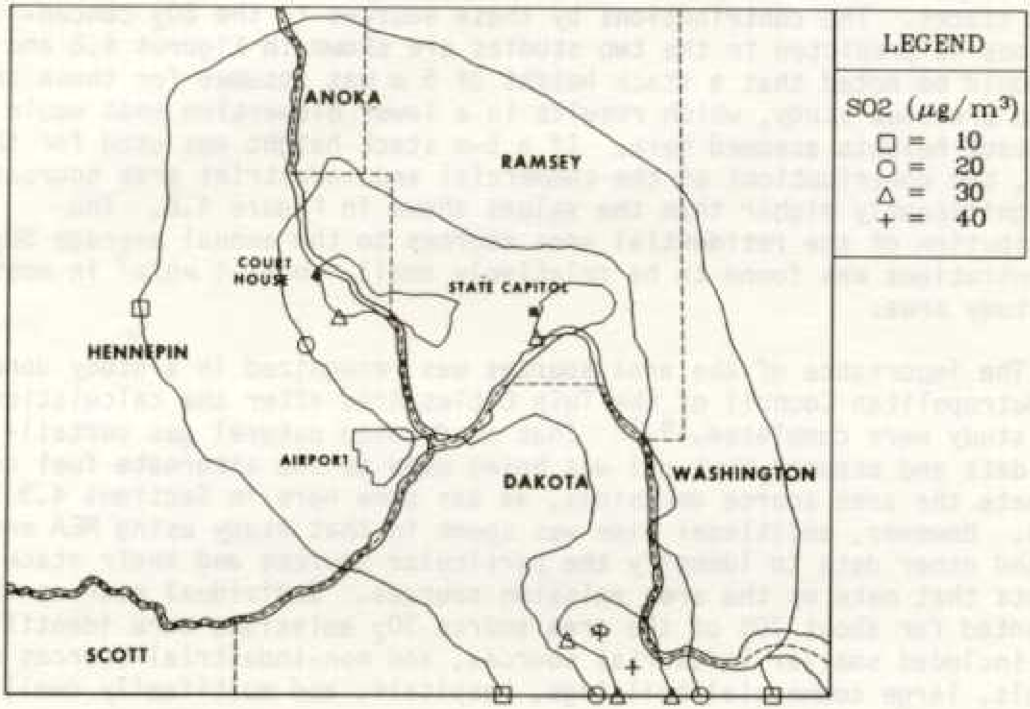

Fig. 4.6. Annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the base year 1976.

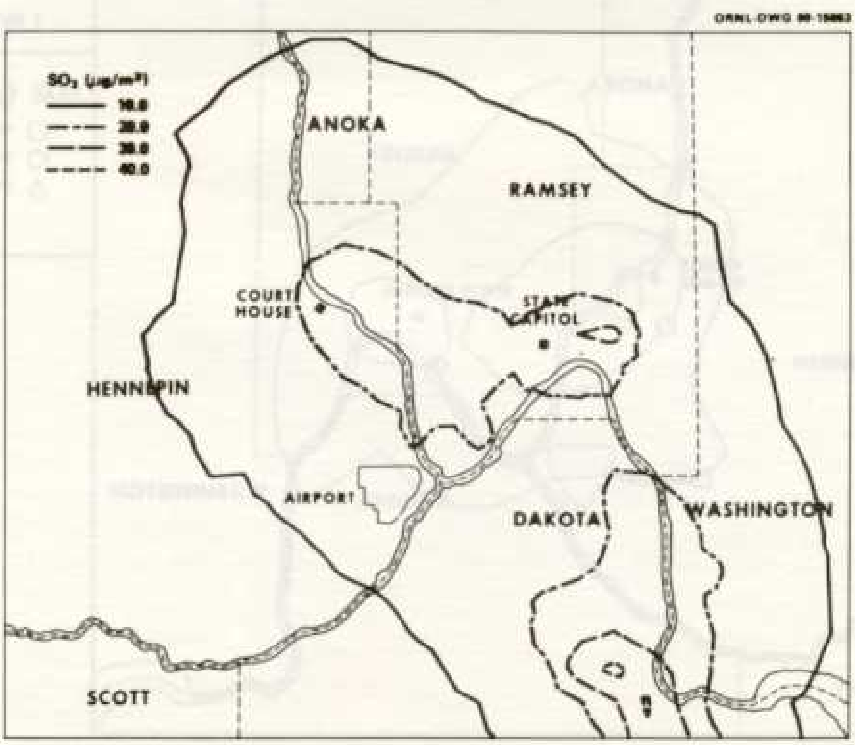

Fig. 4.7. Annual average SO_2 concentrations predicted in the previous study[2] by the uncalibrated version of CDM for the base year 1976.

oil use by the commercial and industrial area sources that generally have short stacks. The contributions by these sources to the SO_2 concentrations as predicted in the two studies are shown in Figures 4.8 and 4.9. It should be noted that a stack height of 5 m was assumed for these sources in the previous study, which results in a lower dispersion than would be for the stack heights assumed here. If a 5-m stack height was used for this study, the contributions of the commercial and industrial area sources would be significantly higher than the values shown in Figure 4.8. The contribution of the residential area sources to the annual average SO_2 concentrations was found to be relatively small, about 1 $\mu g/m^3$ in most of the study area.

The importance of the area sources was recognized in a study done by the Metropolitan Council of the Twin Cities Area after the calculations for this study were completed.[16,17] That study used natural gas curtailment data and assumed that oil was being used as the alternate fuel to estimate the area source emissions, as was done here in Sections 4.3.3 and 4.3.4. However, additional time was spent in that study using MEA energy use and other data to identify the particular sources and their stack heights that make up the area emission sources. Individual sources that accounted for about 70% of the area source SO_2 emissions were identified. They included smaller industrial sources, and non-industrial sources such as schools, large commercial buildings, hospitals, and multifamily dwellings.

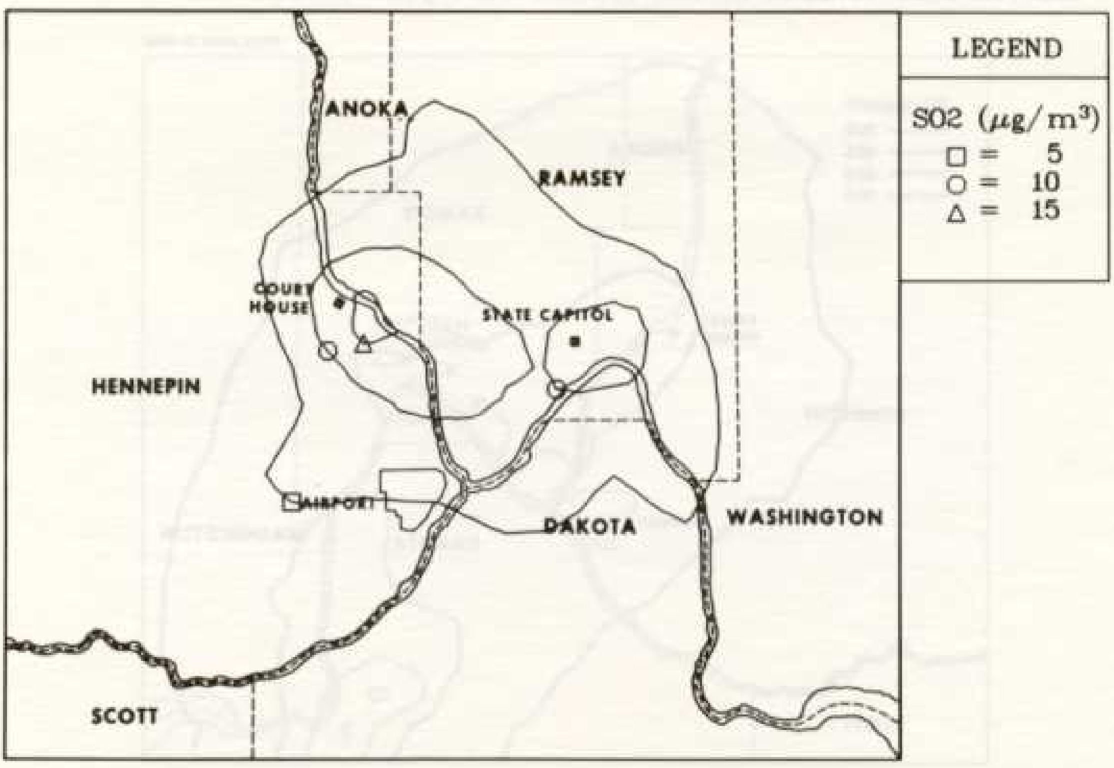

Fig. 4.8. Predicted commercial and industrial area source component of the annual average SO_2 concentrations for the base year 1976.

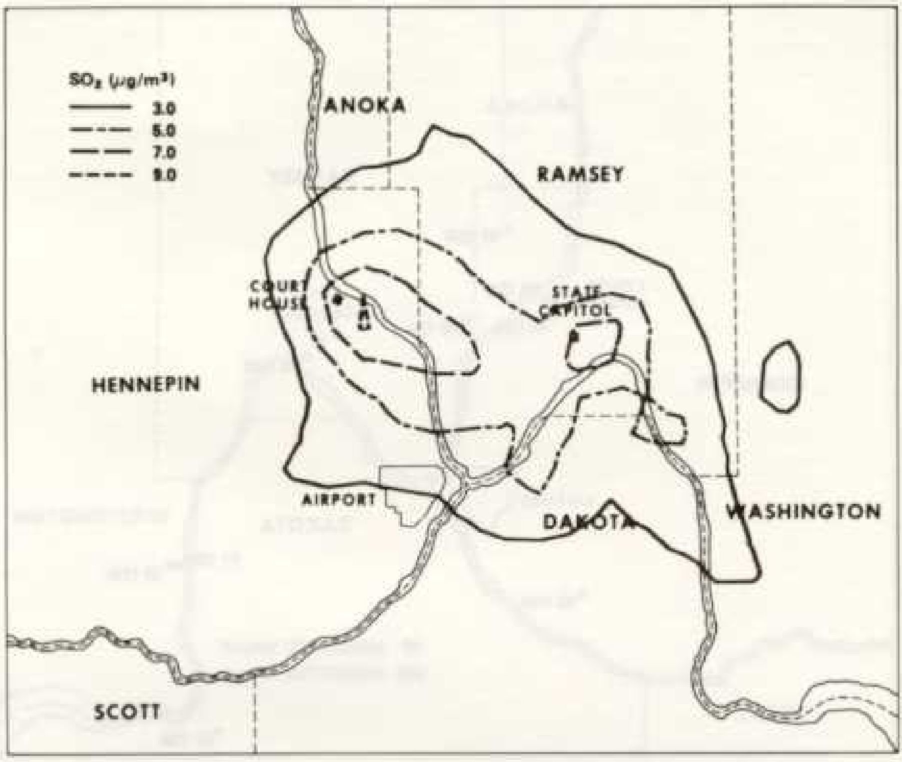

Fig. 4.9. Commercial and industrial area source component of the annual average SO_2 concentrations predicted in the previous study[2] for the base year 1976.

Using 1978 data in the CDM program, the Metropolitan Council study predicted annual SO_2 concentrations in good agreement with the measured data.[17] The general patterns of that study's predicted concentrations are the same as those predicted here, shown in Figures 4.6 and 4.8. The area sources were predicted in both studies to be the greatest in the North Minneapolis area.

The SO_2 concentrations predicted in this study were compared with annual averages of measured data measured by MPCA.[55] The comparisons shown in Figure 4.10 are reasonably consistent in the central part of the area, but the predicted concentrations in the southern part of area were low. This is primarily due to ignoring oil use by the area sources in this part of the study region, which is several kilometers from the district heating zones. At all of the measured points, the predicted concentrations are lower than the measured concentrations. It was beyond the scope of this study to investigate the reasons for these differences, but it is likely that they are partially due to the assumptions used in developing the area sources and ignoring the background SO_2 concentrations.

The data in Figure 4.10 are insufficient to develop a meaningful linear least-square regression relation between the predicted and measured SO_2 concentrations. However, the relation developed for the Minnesota SIP,[56]

$$C = 0.81\, C_{calc} + 25.3\ , \qquad (10)$$

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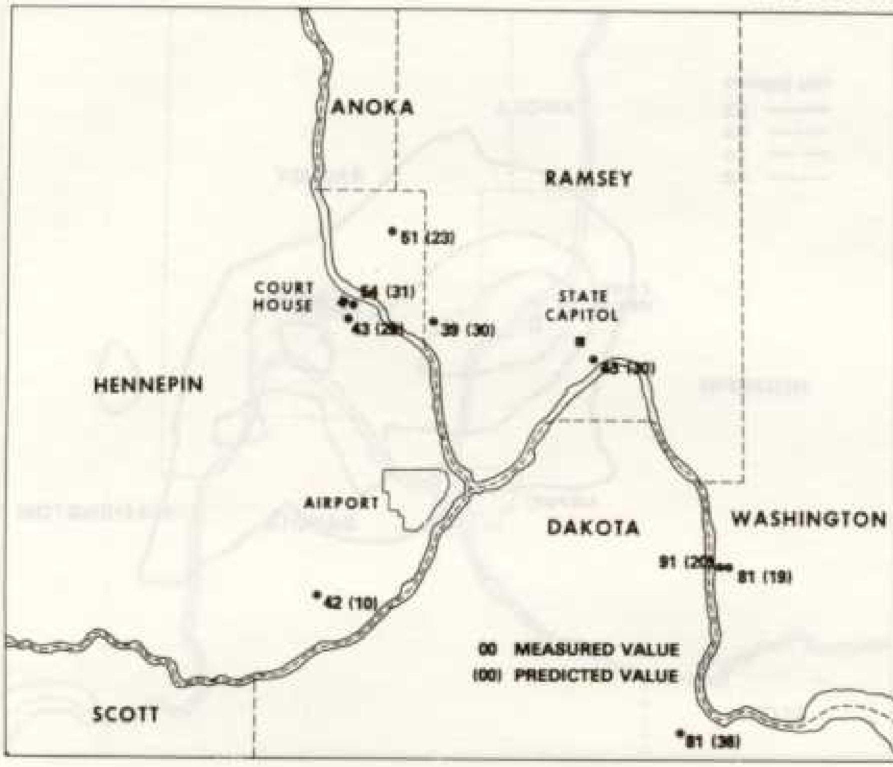

Fig. 4.10. Comparison of predicted and MPCA-measured annual average SO_2 concentrations for the base year 1976.

where

C = measured SO_2 concentration, $\mu g/m^3$;

C_{calc} = calculated SO_2 concentration, $\mu g/m^3$;

is generally consistent with the comparisons in the central part of the study region. This relation gives some idea of the magnitude of the error associated with the uncalibrated CDM program in evaluating the impact of the district heating/cogeneration system (Section 4.4.3.3).

The CDM calculations predicted that the peak SO_2 concentration in the downtown Minneapolis area was 33 $\mu g/m^3$ and that in the downtown St. Paul area was 38 $\mu g/m^3$. Equation (10) indicates that these concentrations were 52 and 56 $\mu g/m^3$, respectively.

Isopleths of the total predicted TSP concentrations in the study region are presented in Figure 4.11.* Almost all of the contribution to the TSP concentrations are from the point sources. The peak concentration is located in Scott County, which is a considerable distance from the district heating zones in the downtown areas. This peak is primarily due to the industrial operations in the area, and would not likely be changed by the district heating/cogenera-

*Note that the particulate emission inventory here does not include particulates from numerous fugitive sources.

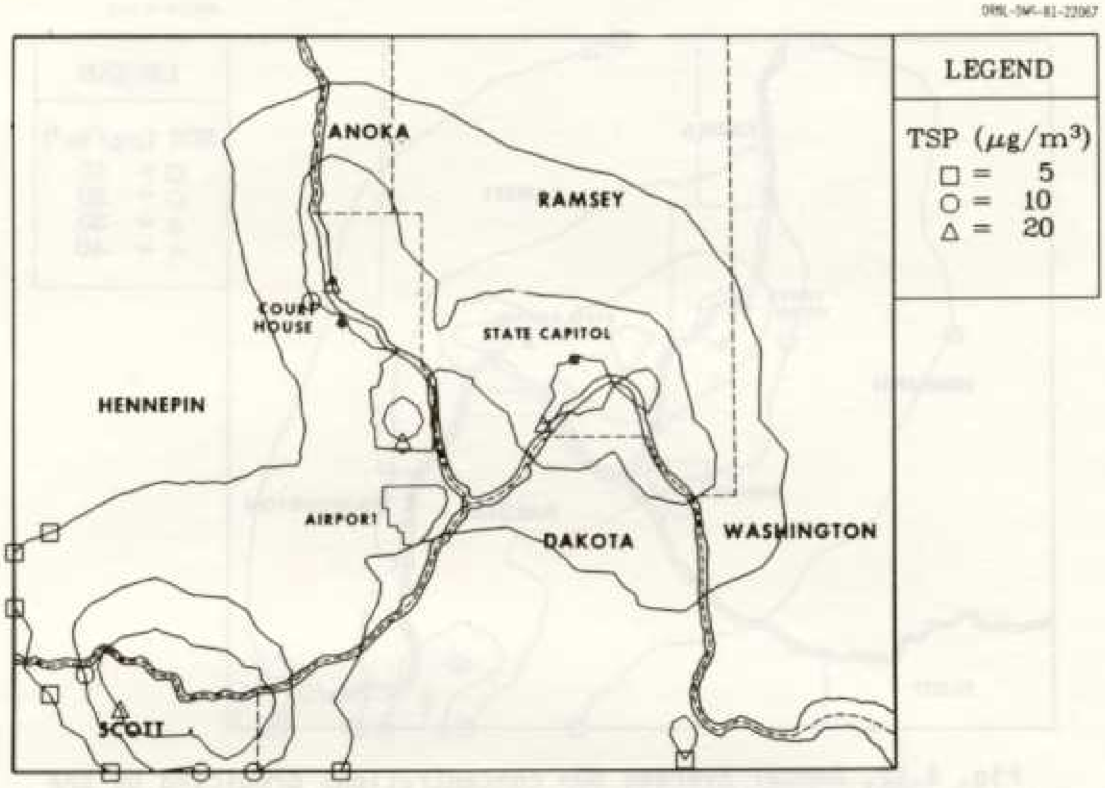

Fig. 4.11. Annual average TSP concentrations predicted by the uncalibrated version of CDM for the base year 1976.

tion system. In Minneapolis and St. Paul, the peak TSP concentrations were predicted to be 21 and 39 $\mu g/m^3$, respectively.

No effort was made in the study reported herein to compare the predicted TSP concentrations with the measured concentrations. This was not done because, as will be shown below, the predicted impact of the development of a regional district heating/cogeneration system on these concentrations is relatively small.

4.4.3.2 1987 Future Year Case Without District Heating/Cogeneration

In 1987 the predicted SO_2 emission rates from the point sources and commercial and industrial area sources would be significantly higher than the 1976 emission rates because of the projected increased use of fuel oil to replace the curtailed natural gas. These will result in higher SO_2 concentrations in the area if the district heating system is not developed.

Isopleths of the CDM-predicted total SO_2 concentrations for this case are presented in Figure 4.12. It can be seen that these concentrations are higher than those calculated for 1976, as shown in Figure 4.6. The magnitudes of the differences in these predicted concentrations are presented in Figure 4.13. Much of the increase would be due to the increase in the emissions from the commercial and industrial area sources. Predicted peak concentrations in downtown Minneapolis and downtown St. Paul in this case are 43 and 46 $\mu g/m^3$, respectively. Assuming that the linear

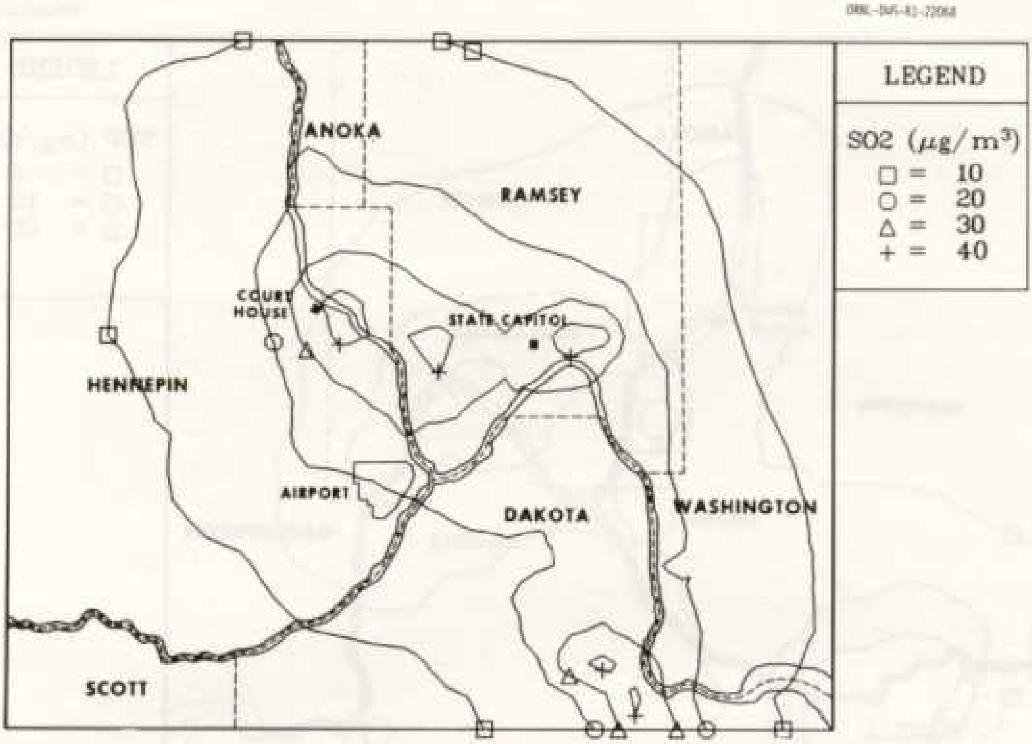

Fig. 4.12. Annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

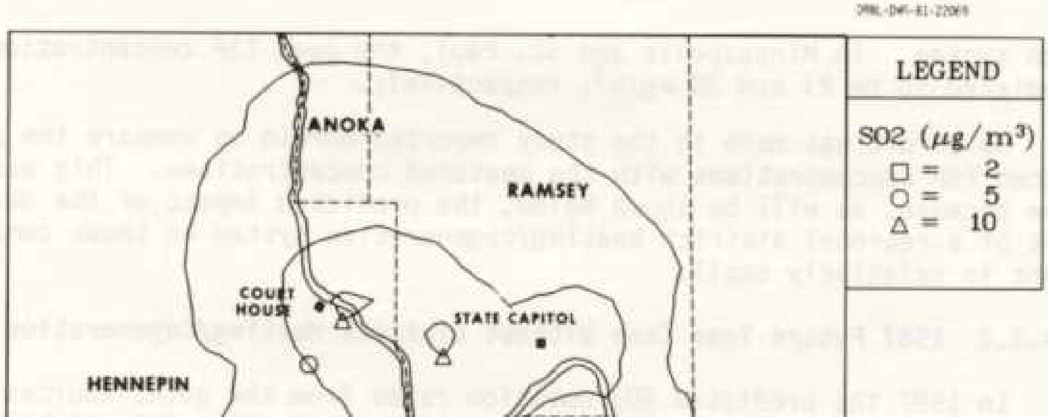

Fig. 4.13. Increases in the annual average SO_2 concentrations predicted by the uncalibrated version of CDM from the base year 1976 to the future year 1987 without district heating/cogeneration.

calibration relation for 1976, Equation (10), is valid, these peak concentrations would be 60 and 62 $\mu g/m^3$, respectively.

Isopleths of the contributions of: (1) point sources, (2) power plants, (3) commercial and industrial area sources, and (4) residential area sources to the total predicted SO_2 concentration are presented in Figures 4.14, 4.15, 4.16, and 4.17, respectively. It can be readily seen that most of the SO_2 present in the air in the Twin Cities is due to the point sources and the commercial and industrial area sources. Although the emissions from the point sources are much higher than those from the area sources, as shown in Tables 4.8 and 4.9, the taller stacks generally used by the point sources result in greater dispersion of the emissions. As a result, the ground level SO_2 concentrations from these two source categories are comparable. For the generating plants which have relatively tall stacks and high emission rates, as shown in Table 4.4, the contribution to the SO_2 concentrations is low. The residential sources have very little contribution since their emissions are very low, as shown in Table 4.10.

For the particulates, isopleths of the total predicted TSP concentration are presented in Figure 4.18. The increase in these concentrations over 1976 would be very slight, as shown in Figure 4.19. Most of the

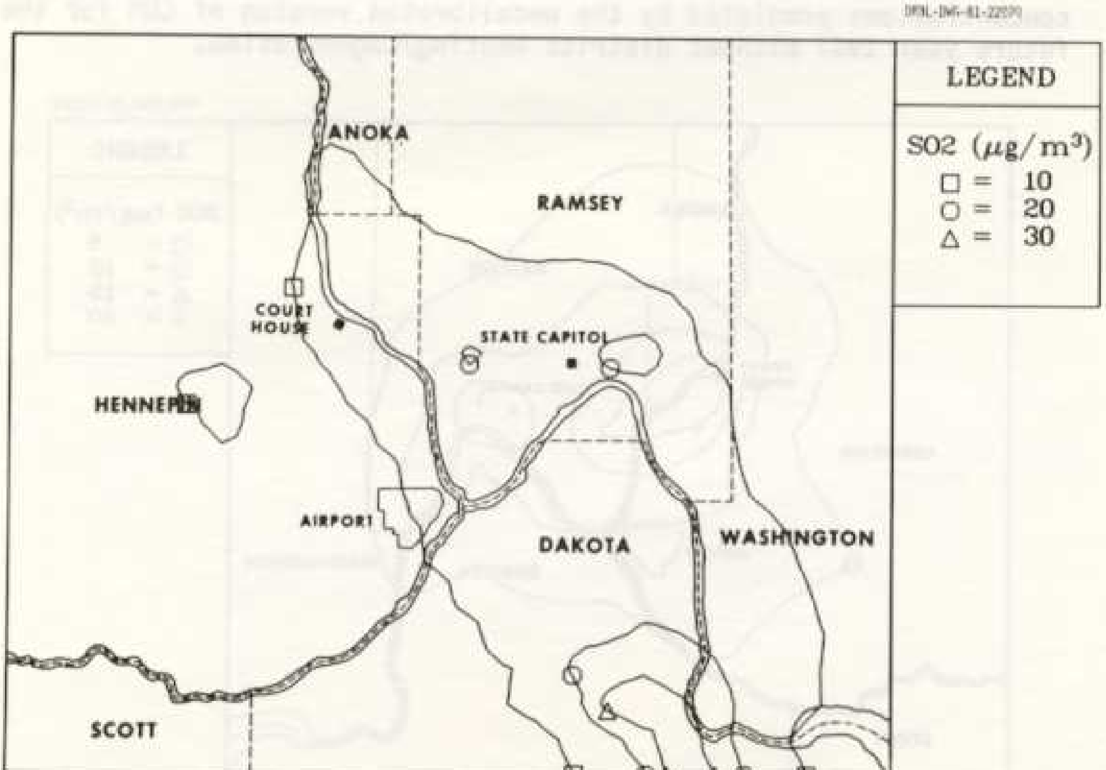

Fig. 4.14. Point source component of the annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

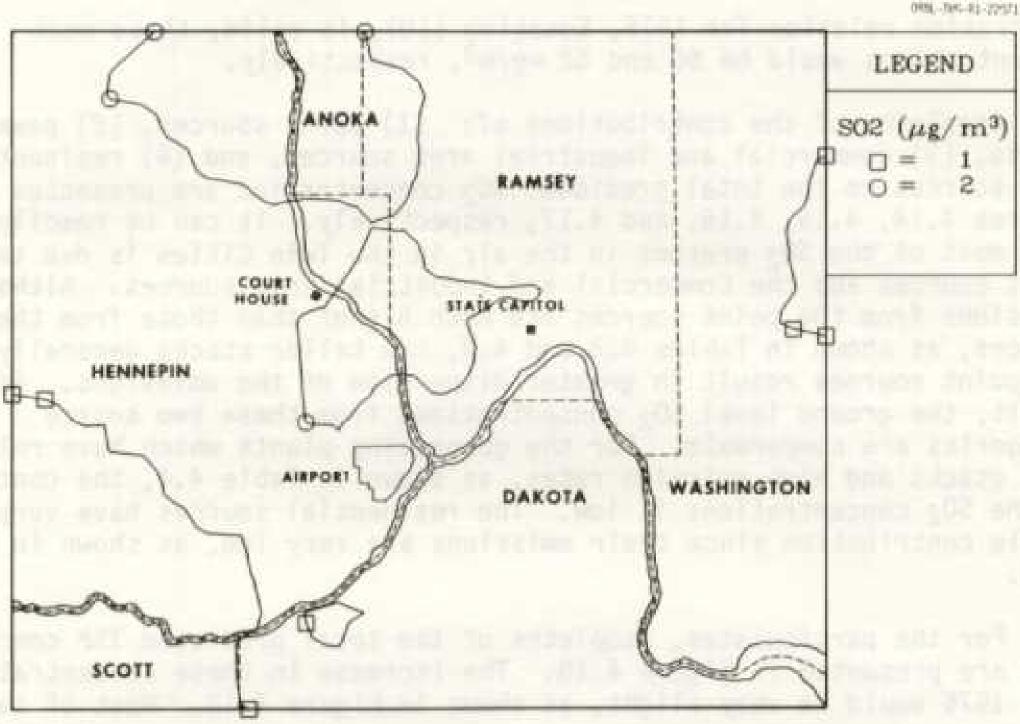

Fig. 4.15. Power plant component of the annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

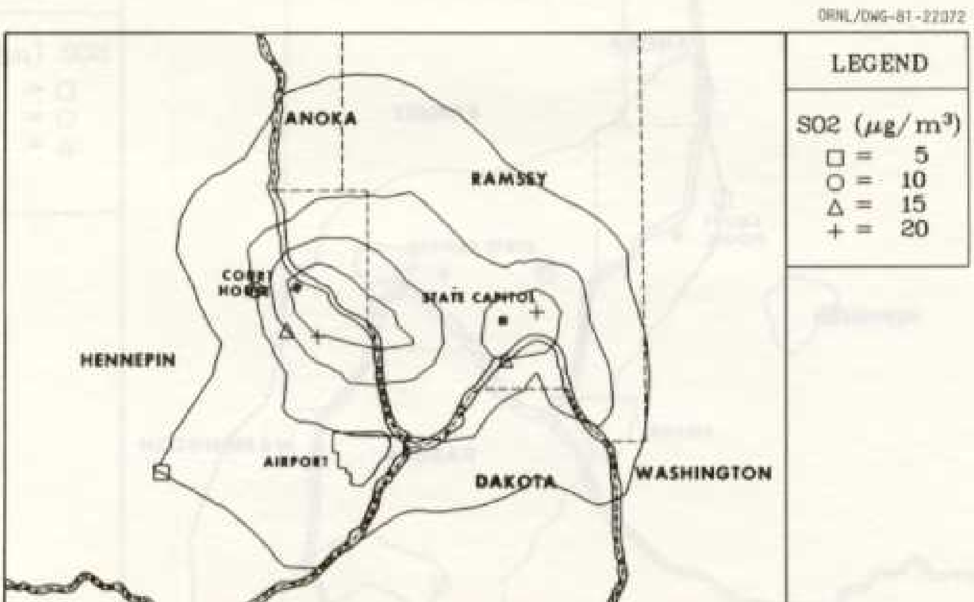

Fig. 4.16. Commercial and industrial area source component of the annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

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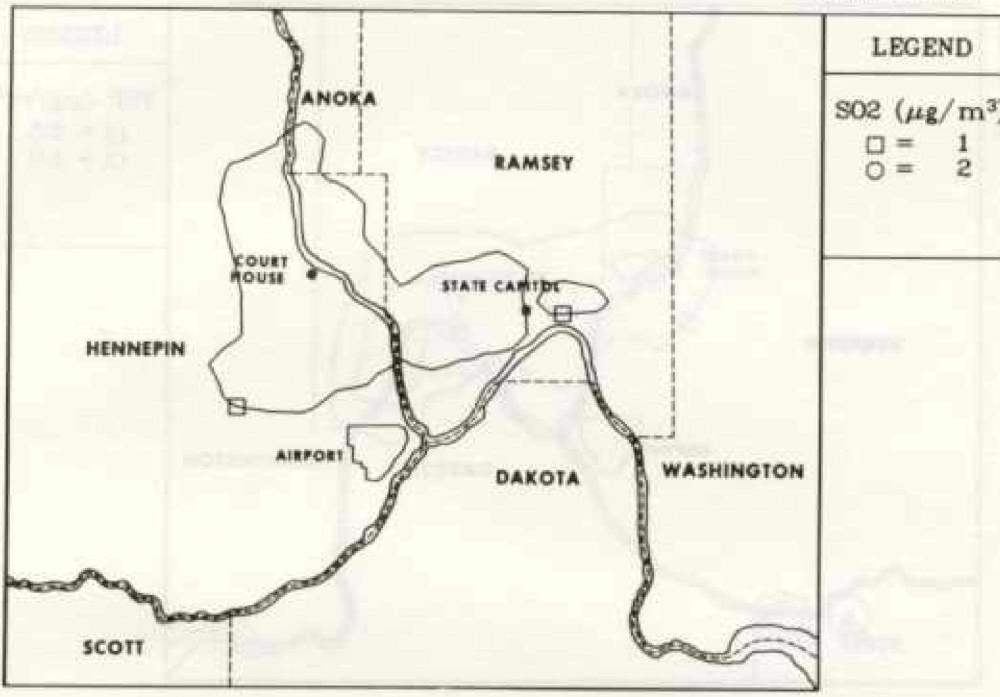

Fig. 4.17. Residential area source component of the annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

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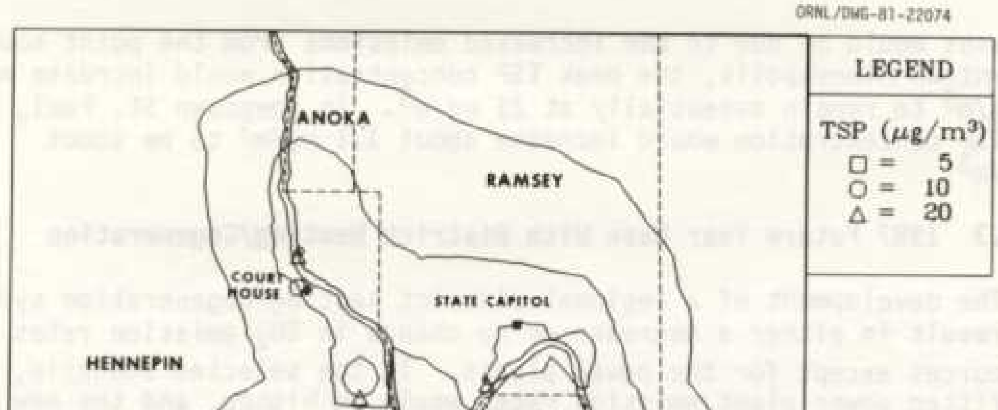

Fig. 4.18. Annual average TSP concentrations predicted by the uncalibrated version of CDM for the future year 1987 without district heating/cogeneration.

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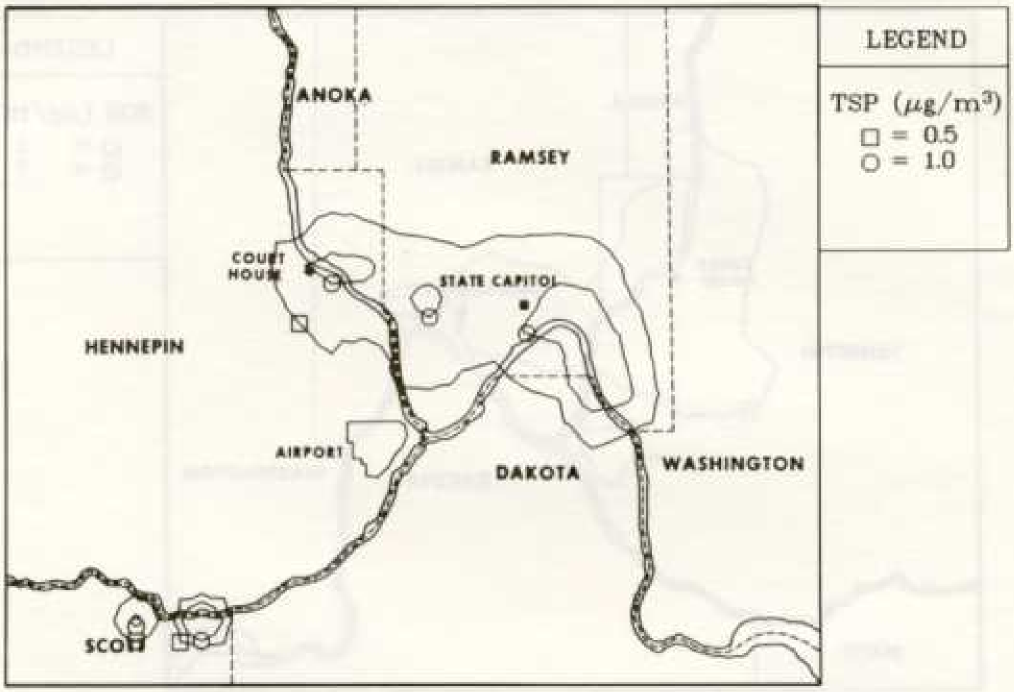

Fig. 4.19. Increase in the annual average TSP concentrations predicted by the uncalibrated version of CDM from the base year 1976 to the future year 1987 without district heating/cogeneration.

increases would be due to the increased emissions from the point sources. In downtown Minneapolis, the peak TSP concentration would increase about 0.4 $\mu g/m^3$ to remain essentially at 21 $\mu g/m^3$. In downtown St. Paul, the peak TSP concentration would increase about 1.1 $\mu g/m^3$ to be about 40 $\mu g/m^3$.

4.4.3.3 1987 Future Year Case With District Heating/Cogeneration

The development of a regional district heating/cogeneration system will result in either a decrease or no change in SO_2 emission rates from all sources except for the power plants. In the selected scenario, the retrofitted power plant emission rates would be higher, and the new cogeneration plant at the High Bridge site would be a large additional SO_2 emission source.

Isopleths of the total annual average SO_2 concentrations predicted by the uncalibrated version of CDM for this case are presented in Figure 4.20. By comparison with Figure 4.12, it can be seen that the impact of the district heating/cogeneration system will be a reduction in the SO_2 concentrations. Although it was shown in Table 4.11 that there would be an increase in the SO_2 emissions for the selected scenario, the SO_2 concentrations will be lower due to the use of relatively tall stacks at the power plants. The tall stacks permit relatively large dispersion of the SO_2 emissions.

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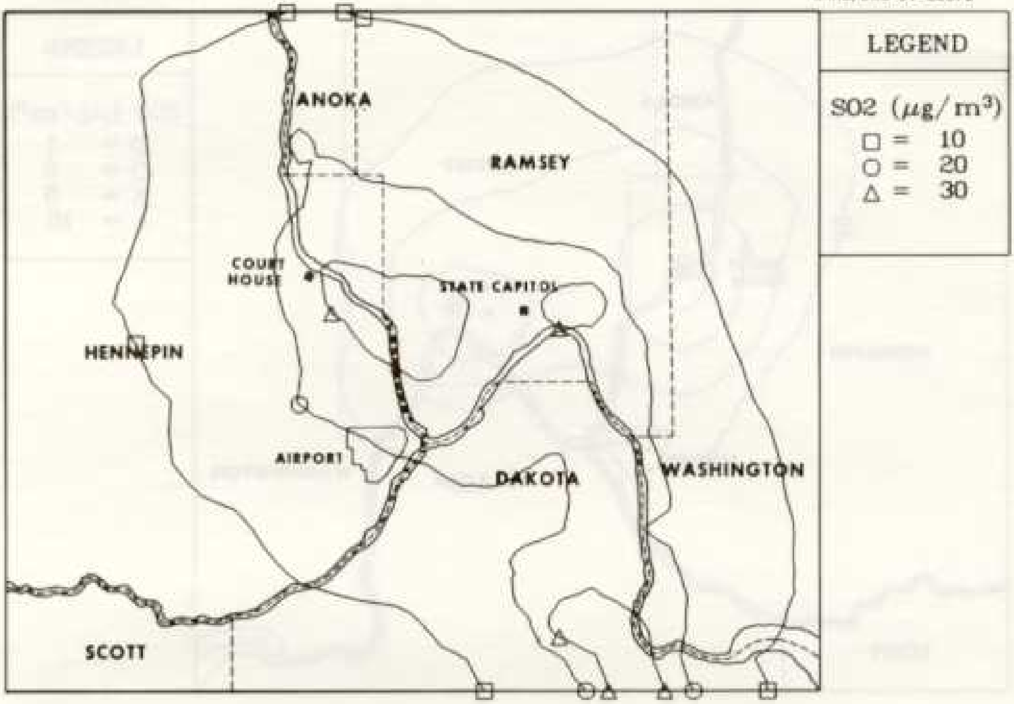

Fig. 4.20. Annual average SO_2 concentrations predicted by the uncalibrated version of CDM for the future year 1987 with district heating/cogeneration.

The magnitudes of these calculated decreases are shown in Figure 4.21. It can be seen that the greatest reductions in the SO_2 concentrations would be in the more populated downtown areas. At the location of the peak concentrations, shown as the darkened squares in Figure 4.21, CDM predicted that the peak concentration would be reduced from 43 to 32 $\mu g/m^3$ in downtown Minneapolis and from 46 to 34 $\mu g/m^3$ in St. Paul. If it is assumed again that the linear calibration for 1976, Equation (10), is valid, these peak concentrations would be reduced from 60 to 51 $\mu g/m^3$ in downtown Minneapolis and from 62 to 53 $\mu g/m^3$ in downtown St. Paul. At both locations, the reduction is about 15%.

The contributions of the various classes of sources to the reduction in the SO_2 concentrations at these peak locations are listed in Table 4.17. It can be seen that the point sources (excluding the generating plants) and the commercial and industrial area sources contribute about equally to the reduction in the concentrations. The influence of the generating plants is very small because of the relatively tall stacks, but there are very slight increases in the concentrations near the plants. The contribution of the residential area sources is very small, and thus they have little influence on the results.

Isopleths of the total predicted TSP concentrations are presented in Figure 4.22. Again, there would be a decrease in the concentration due to the development of the regional district heating/cogeneration system. Figure 4.23 shows the magnitude of these reductions. The locations of the

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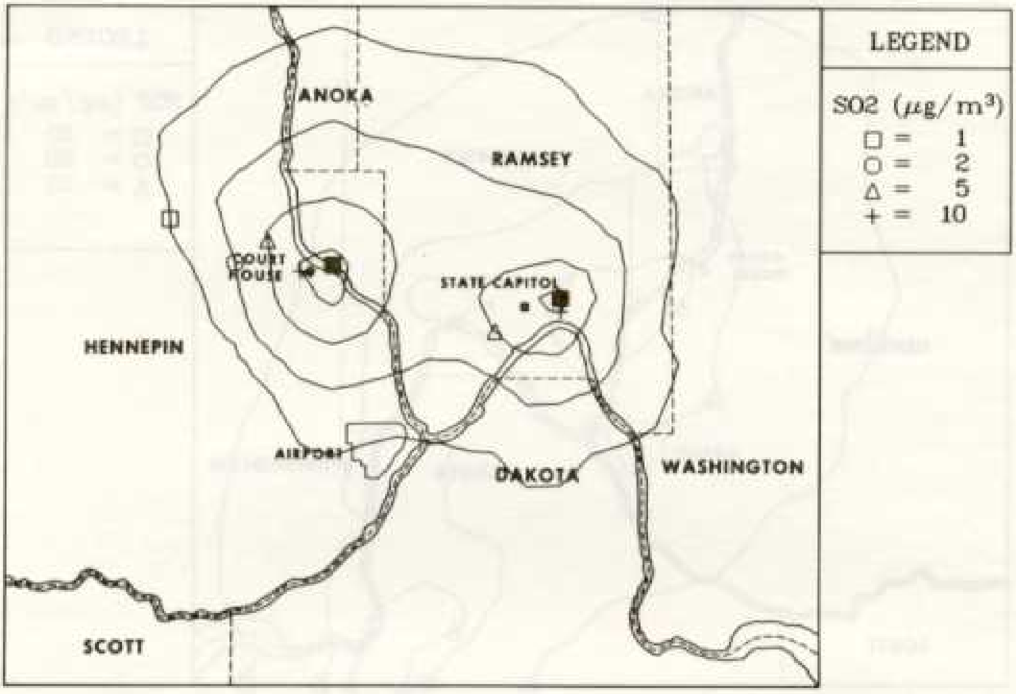

Fig. 4.21. Decreases in the annual average SO_2 concentrations for the future year 1987 resulting from the development of the district heating/cogeneration system as predicted by the uncalibrated version of CDM.

greatest reductions in the downtown area are also shown in this figure. These are the same locations as the greatest reduction in SO_2 concentrations in the downtown area, shown in Figure 4.21, but the magnitude of the TSP reductions is much smaller. At this location in Minneapolis, the TSP concentration would be reduced from 13 to 12 $\mu g/m^3$. Similarly for St. Paul, it would be reduced from 17 to 16 $\mu g/m^3$.

The contributions of the various types of sources to the reduction of the TSP concentration are presented in Table 4.17. Again, it can be seen that the point sources (excluding the generating plants and the commercial and industrial area sources) contribute about equally to the reduction in these concentrations. The influence of the generating plants is too small to detect because they have particulate removal devices and relatively tall stacks.

4.4.4 24-h Average Pollutant Concentrations

For each 24-h episode defined in Table 4.2, the time average SO_2 and TSP concentrations were calculated using TEM (Section 4.4.1.3). The pollutant concentrations were calculated each hour at receptors located on a 1-km square grid over the entire study area. The 24-h average concentrations were then calculated simply by summing the predicted concentrations at each receptor and dividing by 24. From these average concentrations, computer-

TABLE 4.17. DECREASES IN THE ANNUAL AVERAGE SO_2 AND TSP CONCENTRATIONS AT LOCATIONS OF PEAK CONCENTRATIONS[a] RESULTING FROM THE DEVELOPMENT OF THE DISTRICT HEATING/COGENERATION SYSTEM (PREDICTED FOR THE FUTURE YEAR 1987 BY THE UNCALIBRATED VERSION OF CDM), $\mu g/m^3$

	SO_2		TSP	
	Minneapolis	St. Paul	Minneapolis	St. Paul
Total				
Without system	43.5	45.6	13.1	16.6
With system	31.7	33.8	11.9	15.4
Difference	11.8	11.8	1.2	1.2
Point Sources				
Without system	16.0	22.6	11.0	14.8
With system	11.9	16.7	10.5	14.1
Difference	4.1	5.9	0.5	0.7
Commercial and Industrial Area Sources				
Without system	24.1	20.0	1.6	1.4
With system	17.2	14.9	1.1	1.0
Difference	6.9	5.1	0.5	0.4
Residential Area Sources				
Without system	1.3	1.2	0.3	0.3
With system	.4	0.4	0.1	0.1
Difference	0.9	0.8	0.2	0.2
Power Plants				
Without system	2.0	1.8	0.1	0.1
With system	2.2	1.9	0.1	0.1
Difference	-0.2	-0.1	0.0	0.0
Heat Only Plants				
Without system	0.0	0.0	0.0	0.0
With system	0.04	0.03	0.01	0.00
Difference	0.0	0.0	0.0	0.0

[a]Shown as darkened squares in Figures 4.21 and 4.23.

generated isopleths were produced. It will be seen that the isopleths here are somewhat more irregular than those for the annual average concentrations because of the shorter averaging time.

As indicated in Section 4.4.1.3, TEM was selected for this study since it is dimensioned to accommodate a relatively large number of sources and receptors. However, as discussed in Section 4.4.1, there are some differences between this program and the RAM program, a model commonly used to predict 24-h pollutant concentrations. Furthermore, the area sources were approximated as point sources on a 1-km grid in this analysis using TEM. To compare the two models and assumptions in this study, RAM, in addition to TEM, was used to predict the SO_2 concentrations for Episode 1 during 1976 and for Episode 2 during 1987. The analysis using RAM is described in Appendix C. It was shown that, although there are some minor differences in the concentrations predicted by the two models, the overall results are consistent. The fact that there is agreement in the predictions using the two models does not, of course, imply in itself that the results are

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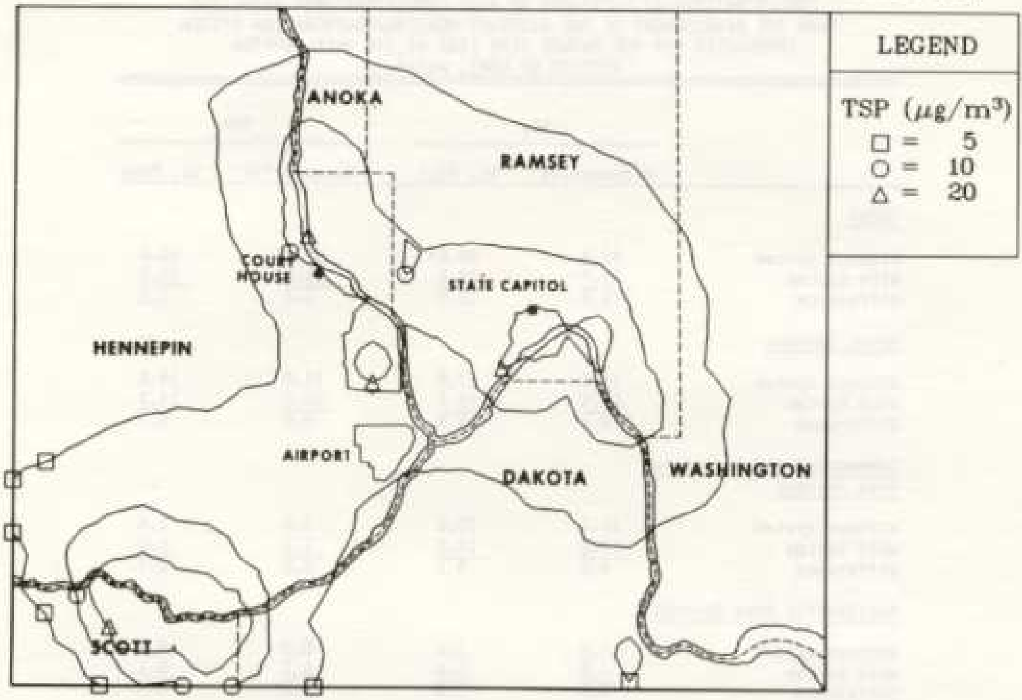

Fig. 4.22. Annual average TSP concentrations predicted by the uncalibrated version of CDM for the future year 1987 with district heating/cogeneration.

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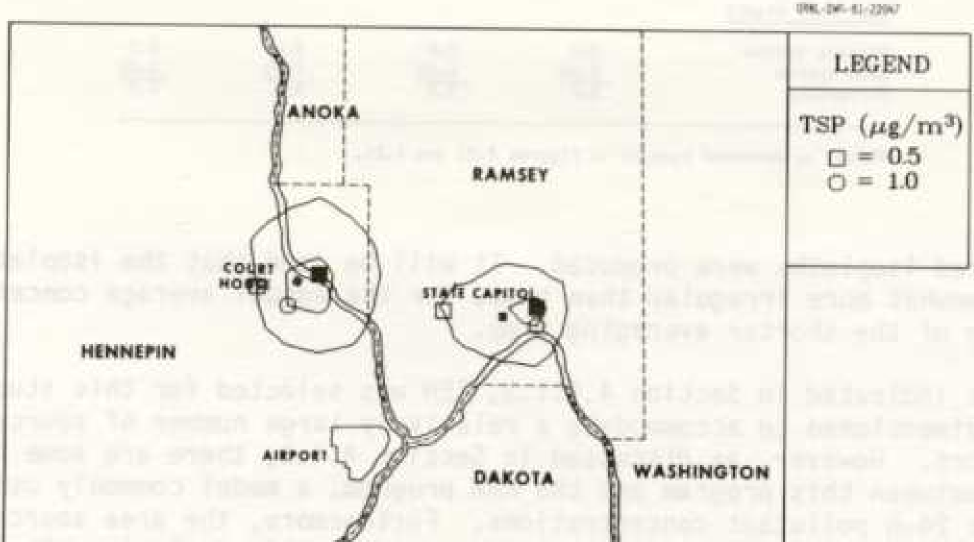

Fig. 4.23. Decreases in the annual average TSP concentrations for the future year 1987 resulting from the development of the district heating/cogeneration system, as predicted by the uncalibrated version of CDM.

accurate. Only comparison with measurements can confirm the accuracy of the predictions.

The stack parameters assumed for the 24-h episode analysis are those given in Section 4.4.1. The default values of the TSP emission stack parameter were assumed to be those used for the prediction of the annual concentrations in Section 4.4.3.

4.4.4.1 1976 Base Case

The 24-h average ground level SO_2 concentrations were calculated using TEM for all six episodes. It was found that the SO_2 concentrations are the highest during Episode 2. Isopleths of the concentrations for Episodes 1 and 2 are presented in Figures 4.24 and 4.25. (Isopleth plots are

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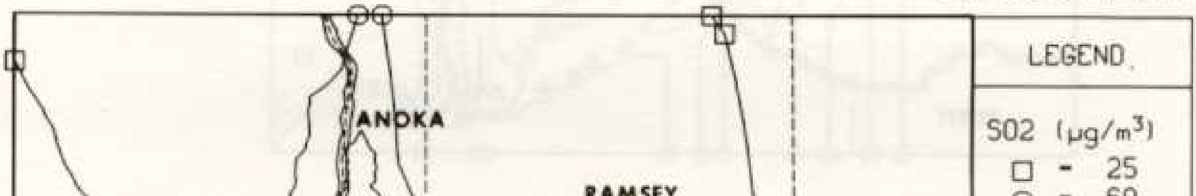

Fig. 4.24. Total SO_2 concentrations predicted by TEM for 1976 - Episode 1.

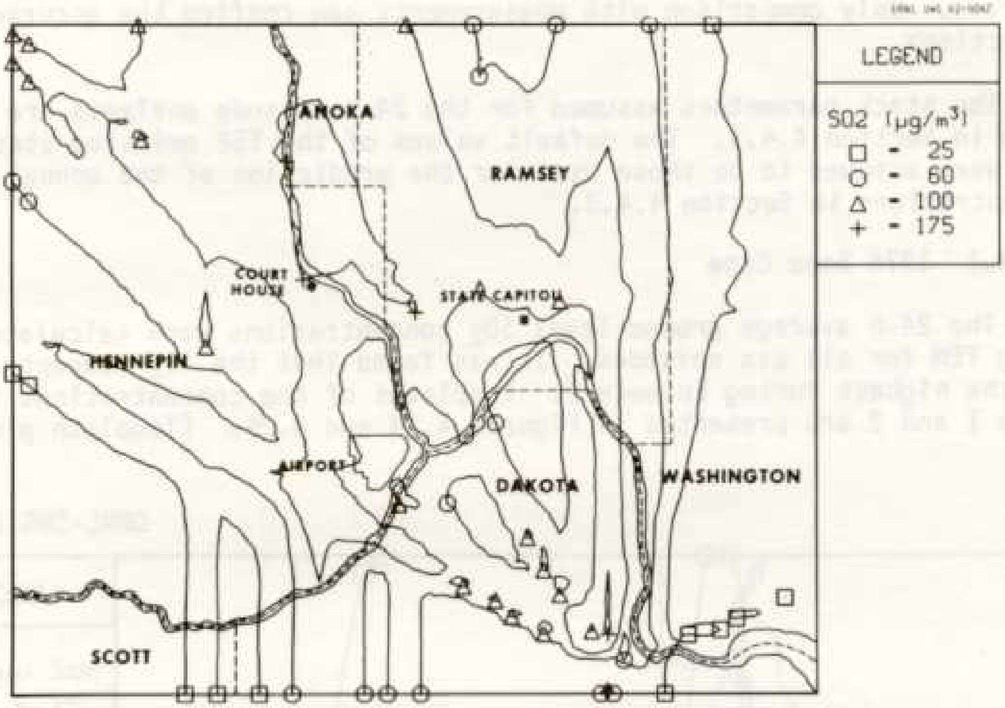

Fig. 4.25. Total SO_2 concentrations predicted by TEM for 1976 - Episode 2.

presented for all six episodes for the 1987 future year case, Section 4.4.4.2.) The plot for Episode 1 is included here for comparison since the wind conditions and stability condition for the two episodes are similar, as discussed in Section 4.4.2. It can be seen at once that the concentrations for Episode 2 are considerably higher than for Episode 1. This reflects that Episode 2 is a colder day than Episode 1, having 28.9 compared to 24.2 Celsius degree days. The emission rates for Episode 2 are therefore higher because of the increased demand for space heating and the increased substitution of oil for curtailed natural gas.

It should be noted that the vertical isopleths at the bottom of Figure 4.25 are more artifacts of the simulation routine than reality. It was assumed that no sources exist outside of the boundary and the wind was predominantly from the south during this 24-h period.

As for the annual case, both of these plots show high SO_2 concentrations southeast of St. Paul, where there is a relatively heavy concentration of industry. In the downtown areas, which would be most impacted by district heating, the maximum TEM predicted concentrations are 101 and 220 $\mu g/m^3$ for Episodes 1 and 2 for Minneapolis, and 135 and 143 $\mu g/m^3$ for St. Paul.

SO_2 monitoring data were obtained by MPCA at the locations shown in Figure 4.26.[55,57] Observed and predicted SO_2 concentrations at these locations for the six selected episodes are presented in Table 4.18. In the calculations, 1975 meteorological data were used for all episodes except for

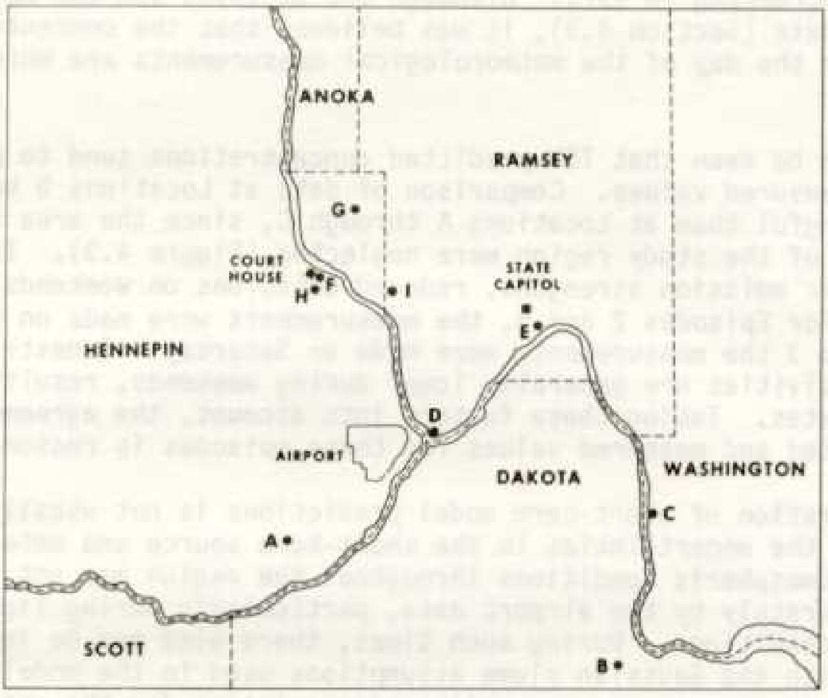

Fig. 4.26. Locations of SO_2 sample stations.

TABLE 4.18. OBSERVED AND PREDICTED SO_2 CONCENTRATIONS AT MONITORING SITES, (predicted values given in parentheses) $\mu g/m^3$

Location (from Figure 4.26)	Episode No. and Measurement Date					
	1 1/7/75	2 12/21/75	3 1/4/75	4 3/8/76	5 1/19/75	6 9/3/75
A	52 (35)	24 (65)	34 (72)	26 (63)	-- (26)	21 (3)
B	34 (29)	21 (45)	44 (68)	18 (50)	-- (104)	191 (28)
C	-- (10)	26 (63)	-- (49)	-- (32)	-- (121)	209 (14)
D	31 (65)	52 (71)	10 (62)	-- (62)	-- (109)	5 (14)
E	24 (78)	29 (66)	-- (74)	50 (53)	-- (99)	34 (22)
F	60 (83)	178 (157)	63 (138)	65 (96)	-- (90)	21 (22)
G	55 (59)	52 (184)	65 (118)	92 (79)	-- (74)	21 (15)
H	26 (85)	47 (141)	21 (123)	44 (87)	-- (106)	29 (7)
I	60 (63)	26 (170)	34 (141)	94 (76)	-- (100)	-- (22)

Episode 4 occurring in 1976. Although the emission sources were estimated from 1976 data (Section 4.3), it was believed that the concentrations measured on the day of the meteorological measurements are more representative.

It can be seen that TEM-predicted concentrations tend to be higher than the measured values. Comparison of data at Locations D through I is more meaningful than at Locations A through C, since the area sources at the lower part of the study region were neglected (Figure 4.3). In estimating the episodic emission strengths, reduced emissions on weekends were not considered. For Episodes 2 and 5, the measurements were made on Sunday, and for Episode 3 the measurements were made on Saturday. Industrial and commercial activities are generally lower during weekends, resulting in lower emission rates. Taking these factors into account, the agreement between the predicted and measured values for these episodes is reasonable.

Calibration of short-term model predictions is not usually done because of the uncertainties in the short-term source and meteorological data.[30] Atmospheric conditions throughout the region may not be represented accurately by the airport data, particularly during light and variable wind conditions. During such times, there also may be inherent problems with the Gaussian plume assumptions used in the models. Therefore no effort was made to use any calibration relation for the episodes.

TEM was also used to predict the TSP concentrations for the base year, 1976. Comparison of these predicted values with those predicted for the future year 1987 without district heating/cogeneration revealed that there would be only a minimal increase in these concentrations. Therefore they will not be discussed in more detail until the next section.

4.4.4.2 1987 Future Year Case Without District Heating/Cogeneration

Isopleths of the 24-h average ground level SO_2 concentrations in 1987, as predicted by TEM for Episodes 1 through 6, are presented in Figures 4.27 through 4.32. The general patterns of these concentrations are the same as those for the 1976 base case, but the magnitudes are higher, particularly in the downtown areas. Figures 4.33 and 4.34 show the increases in the SO_2 concentrations for Episodes 1 and 2. In the downtown areas for Episode 1, the peak concentrations are predicted to increase from 101 to 149 $\mu g/m^3$ in Minneapolis and from 135 to 174 $\mu g/m^3$ in St. Paul. Similarly for Episode 2, they are predicted to increase from 220 to 254 in Minneapolis and from 143 to 159 $\mu g/m^3$ in St. Paul. The location of these peak concentrations would shift somewhat in the downtown areas, reflecting a change in the distribution of the SO_2 emission rates. The higher concentrations, of course, reflect the projected increase in oil use.

For all six episodes, Figures 4.27 through 4.32 show a general increase in SO_2 concentrations with decreased temperatures. This again reflects the increased emission rates (Table 4.11) due to the increased demand for fuel and the increased substitution of oil for natural gas on the colder days. The dispersion pattern for SO_2 is different for all six episodes due to differences in the meteorological characteristics (Section 4.4.2).

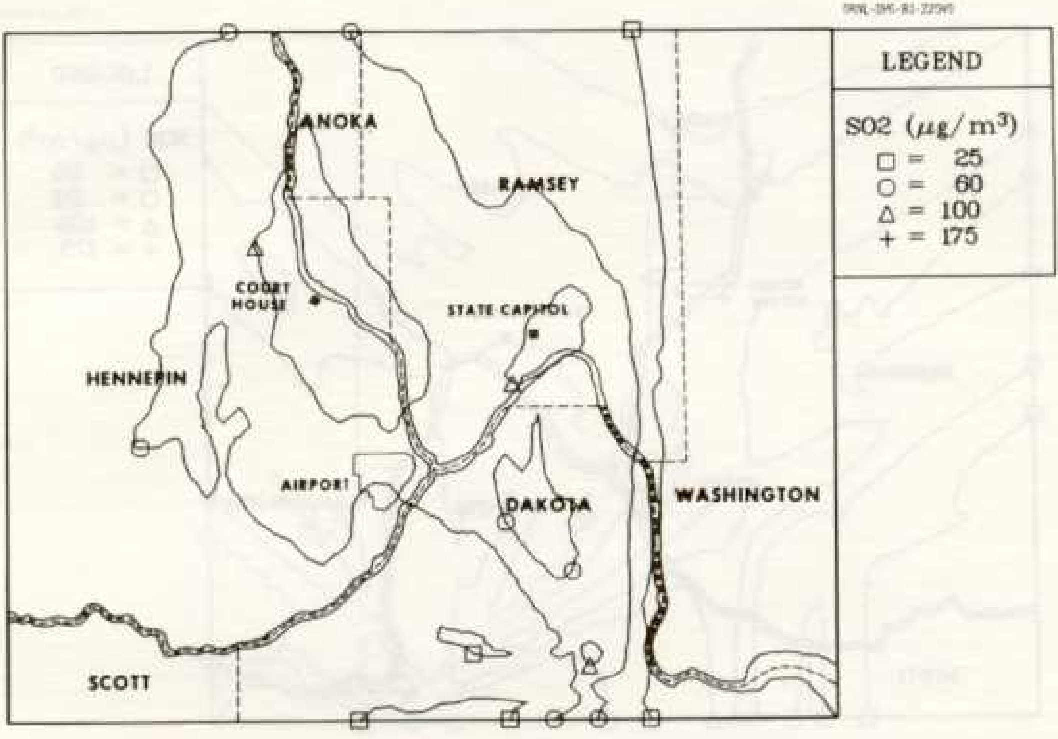

Fig. 4.27. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 1.

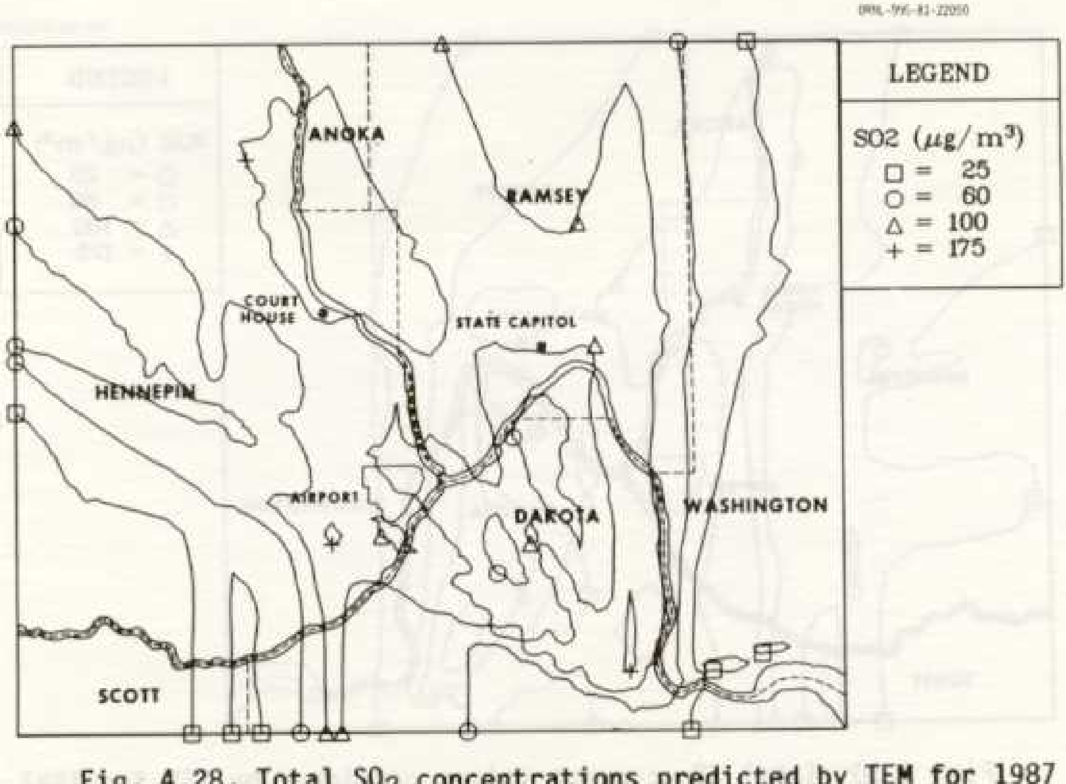

Fig. 4.28. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 2.

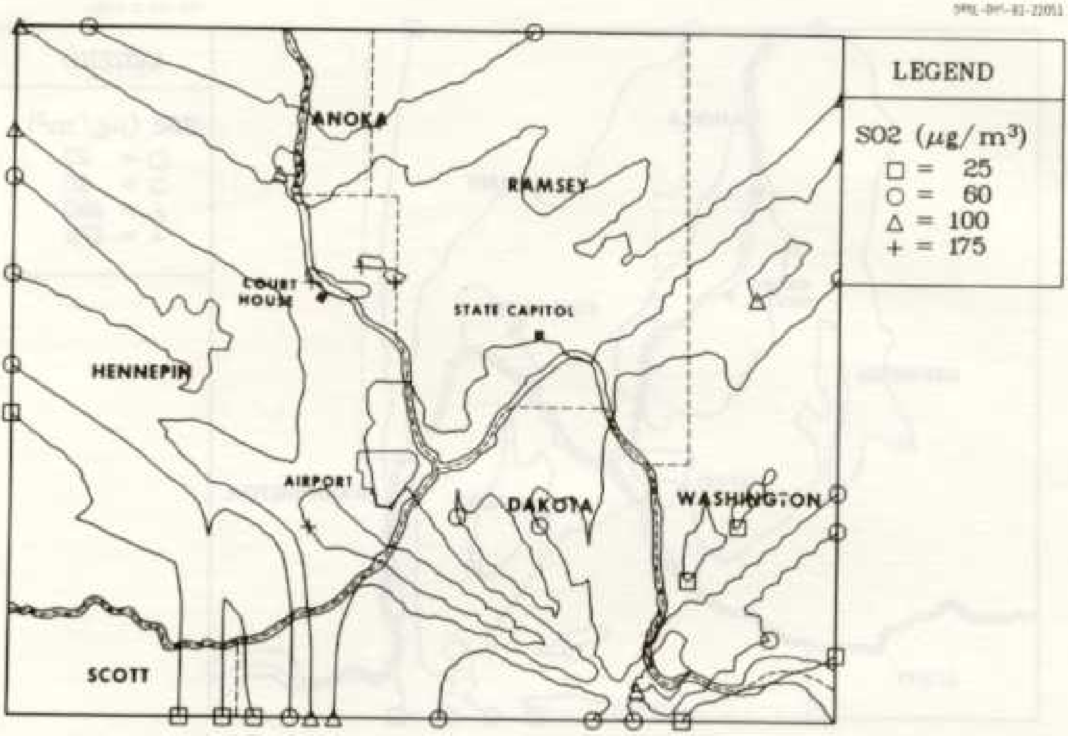

Fig. 4.29. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 3.

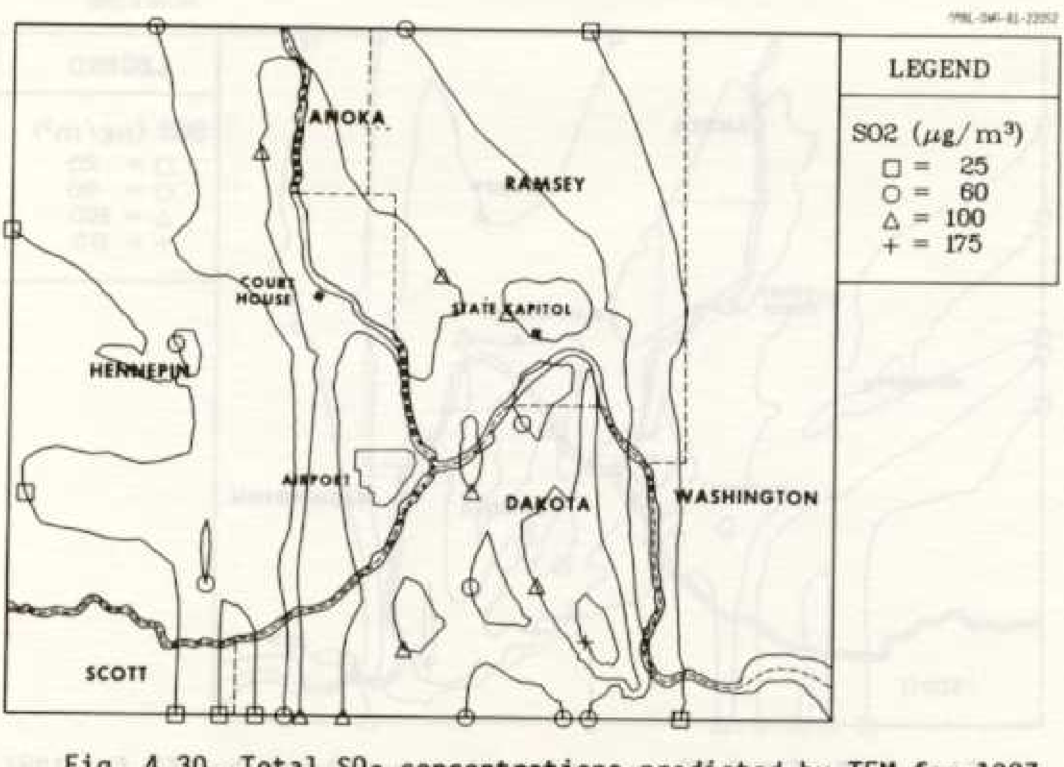

Fig. 4.30. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 4.

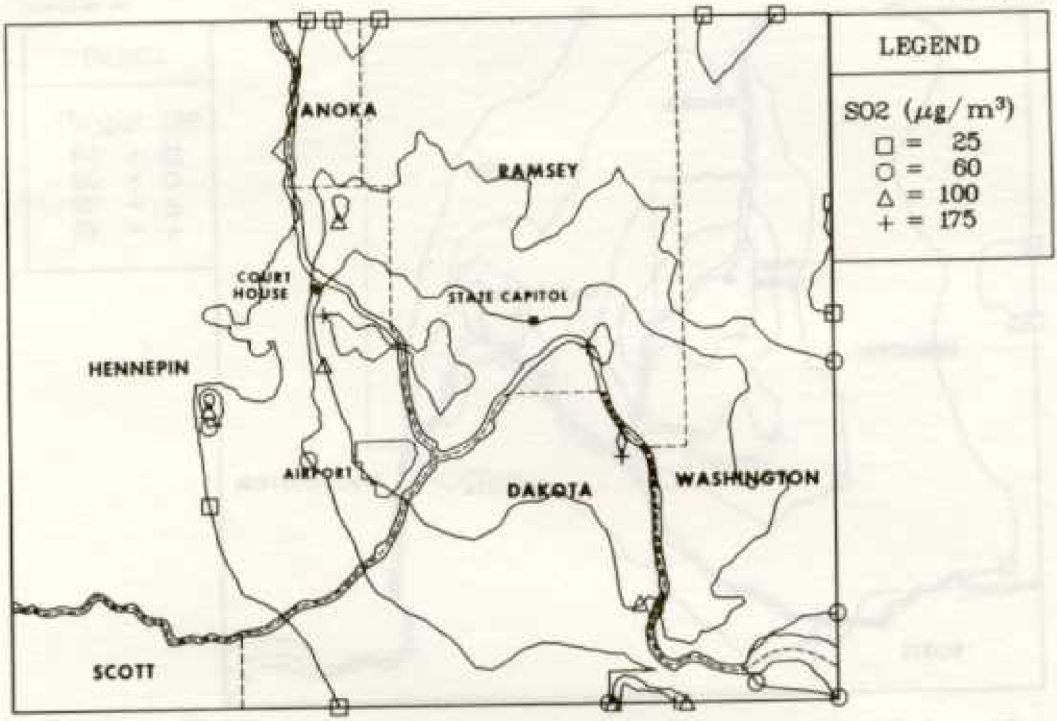

Fig. 4.31. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 5.

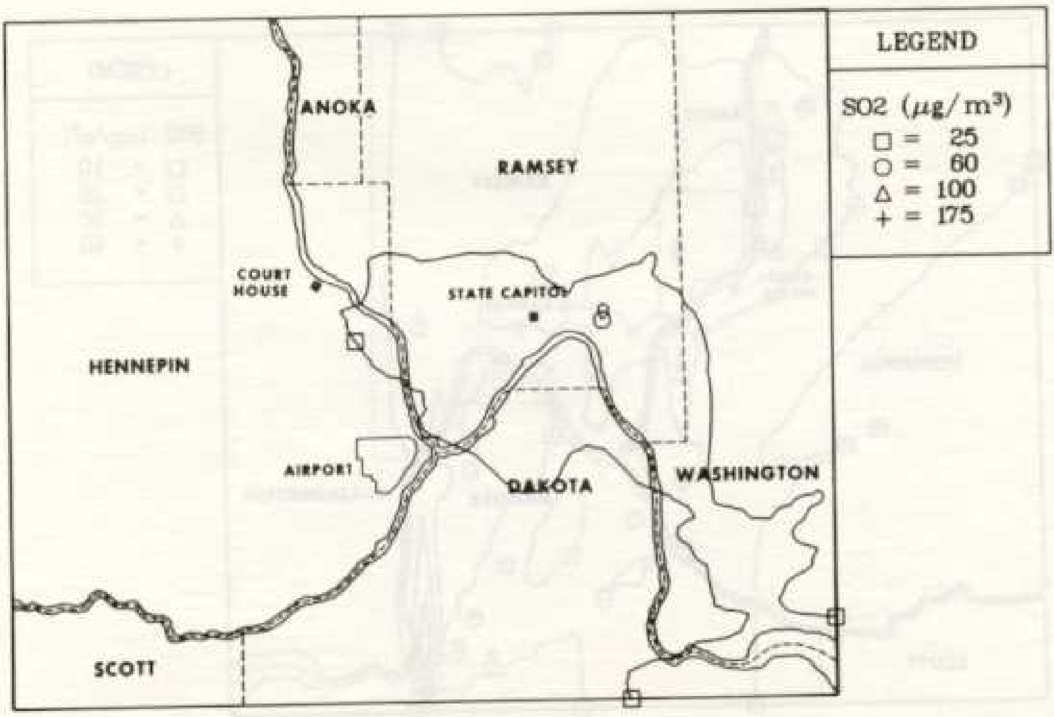

Fig. 4.32. Total SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 6.

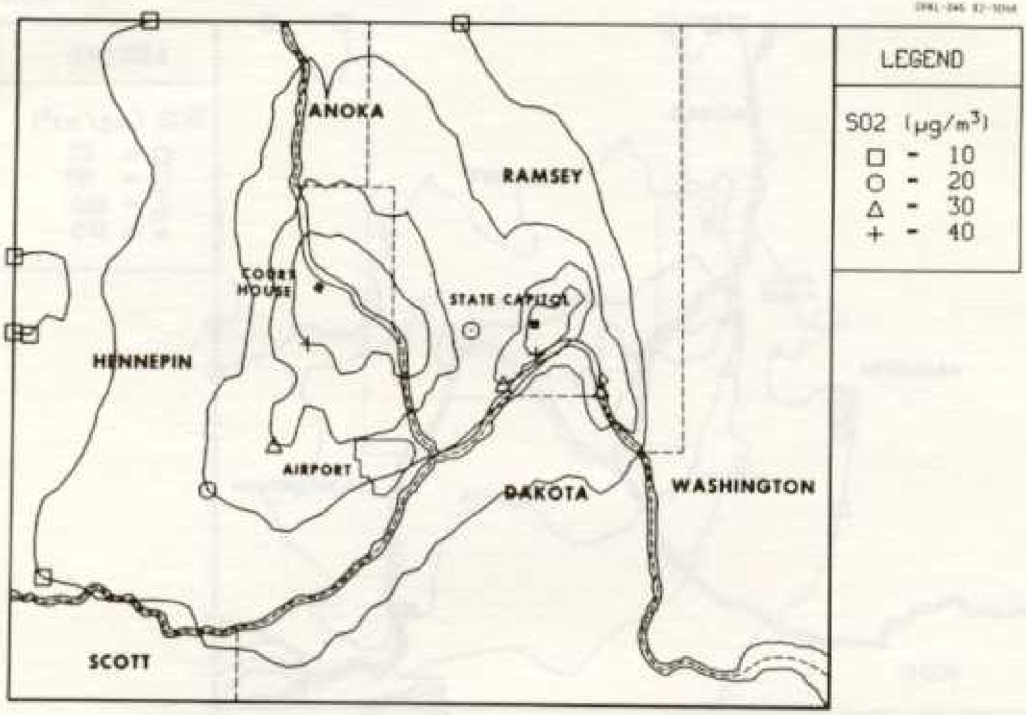

Fig. 4.33. Increases in the 24-h SO_2 concentrations predicted by TEM from 1976 to 1987 without district heating/cogeneration - Episode 1.

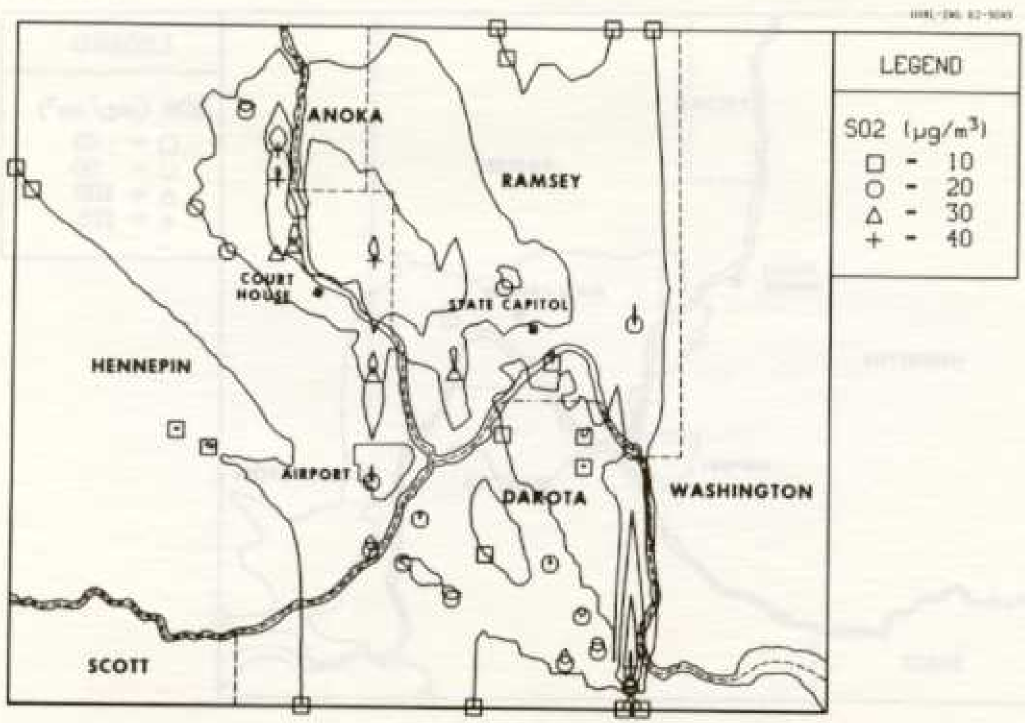

Fig. 4.34. Increases in the 24-h SO_2 concentrations predicted by TEM from 1976 to 1987 without district heating/cogeneration - Episode 2.

The patterns for the first four episodes are quite similar since the winds and other meteorological conditions were similar. The atmospheric dispersion characteristics for these four episodes were relatively poor. As discussed in Section 4.4.3, Episode 5 had strong northwest winds with relatively high mixing heights. The SO_2 concentration patterns for this episode, shown in Figure 4.31, reflect these better dispersion conditions. Episode 6 had moderately strong west to northwesterly winds together with lower emission rates, which result in the lower SO_2 concentrations, shown in Figure 4.32.

As for 1976, these figures show high SO_2 concentrations fanning out from the industrial region located southeast of St. Paul. Even for Episode 5, where the strong northwest winds tend to carry the pollutant out of the area, Figure 4.31 shows that there could be high concentrations near the southern border of the study area.

The next highest SO_2 concentrations are predicted to be in downtown areas. The exact locations of these concentrations vary due to different meteorological conditions for each episode. However, Figures 4.27 through 4.32 show that the maximum predicted concentrations in downtown Minneapolis are in the vicinity of the Hennepin County Courthouse, and in downtown St. Paul, in the vicinity of Minnesota State Capitol. Some typical maximum SO_2 concentrations in these areas predicted by TEM are listed in Table 4.19. It

TABLE 4.19. TYPICAL TEM-PREDICTED 1987 MAXIMUM SO_2 CONCENTRATIONS AND CHANGES WITH DISTRICT HEATING/COGENERATION IN THE DOWNTOWN AREAS ($\mu g/m^3$)

	Minneapolis			St. Paul		
Episode	Original Concentration	Change with District Heating	Per cent Change	Original Concentration	Change with District Heating	Per cent Change
1	144	-48	-33	131	-47	-36
	149	-48	-32	174	-79	-45
				131	-56	-43
2	202	-57	-28	152	-70	-46
	194	-60	-31	159	-55	-35
	243	-82	-34	122	-54	-44
	254	-83	-33			
3	188	-61	-32	143	-65	-45
	165	-65	-39	134	-54	-40
	171	-68	-40	143	-51	-36
4	183	-48	-26	132	-50	-38
	156	-47	-30	115	-39	-34
				136	-66	-49
5	194	-77	-40	159	-79	-50
	175	-64	-37	160	-75	-47
	176	-65	-37	176	-80	-45
				142	-75	-39
6	26	-11	-42	57	-6	-11
	33	-12	-36	48	-4	-8
	35	-12	-34	46	-7	-15

can be seen that these concentrations in downtown Minneapolis generally are higher than those in downtown St. Paul. As will be seen later, this is due to the higher predicted source strengths in Minneapolis, particularly the commercial and industrial area sources.

In both downtown areas, the SO_2 concentrations generally were predicted to increase with decreasing temperatures, as for the 1976 base case. The only exception is Episode 5 in downtown Minneapolis. Here the SO_2 concentrations were predicted to be lower than those for Episode 2, because of the strong northwest wind in Episode 5.

In contrast to the five winter episodes, Episode 6 is predicted to have much lower SO_2 concentrations, as shown in Figure 4.32. Despite the lower concentrations in Episode 6, there are signs of the same concentration peaks as observed for the winter episodes. The presence of the peak concentrations near the downtown areas of both Minneapolis and St. Paul during the summer suggests that a substantial amount of SO_2 is emitted near these sites for non-space heating purposes.

Of the selected episodes, Episode 2 is predicted to have generally the highest SO_2 concentrations in the study area. Isopleths of the contribution of: (1) point sources, (2) power plants, (3) commercial and industrial area sources, and (4) residential area sources to the Episode 2 SO_2 concentrations are presented in Figures 4.35, 4.36, 4.37, and 4.38, respectively. As with the annual average concentrations (Section 4.4.3.2), the predicted primary contributions are due to the point sources and the commercial and industrial area sources. The contribution of the commercial and industrial area sources are particularly significant in Minneapolis because of their relatively high use of fuel oil there. The contributions of the point sources (Figure 4.35) generally have the same pattern as the total SO_2 concentrations (Figure 4.28). The power plant contributions are generally small. However, they are significant near the plants, particularly in North Minneapolis (maximum value of 26 $\mu g/m^3$). The residential area sources, of course, again have low contribution due to their low emission rates (Table 4.10).

Contributions of these sources to the SO_2 concentration at the location of maximum concentrations in the downtown areas are presented in Table 4.20. At these locations, the major portion of the SO_2 are predicted to be from the point and commercial and industrial area sources.

Predictions of the TSP concentrations were made using TEM. Isopleths of the predicted concentrations for Episodes 2 and 4 are presented in Figures 4.39 and 4.40 respectively. The patterns in these two plots are similar to those for the SO_2 concentrations shown in Figures 4.28 and 4.30, except for large quantities of TSP in Scott County. These are due to the industrial operations in that county. The concentrations for Episode 2 are predicted to be generally higher than those for Episode 4 due to the higher emission rates for Episode 2 (Table 4.11). Most of the contributions to the TSP concentrations are from the point sources, and there are many peaks in the concentrations throughout the study area. For Episode 2, two predicted peak concentrations near the Hennepin County Courthouse are 161 and 244 $\mu g/m^3$, and near the Minnesota State Capitol, 168 and 210 $\mu g/m^3$.

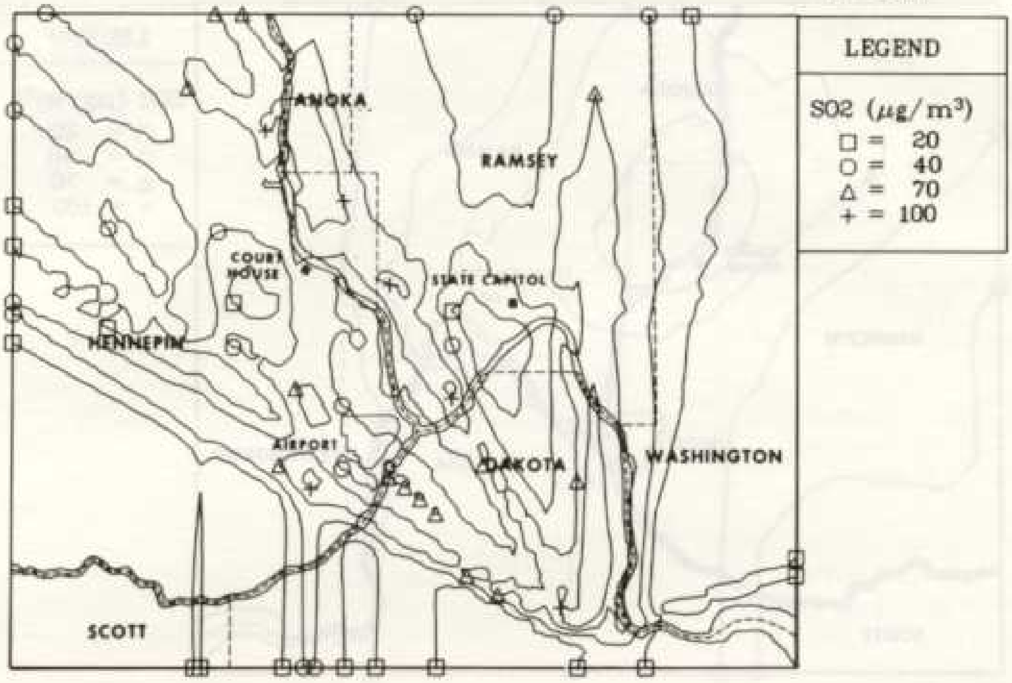

Fig. 4.35. Point source component of the SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 2.

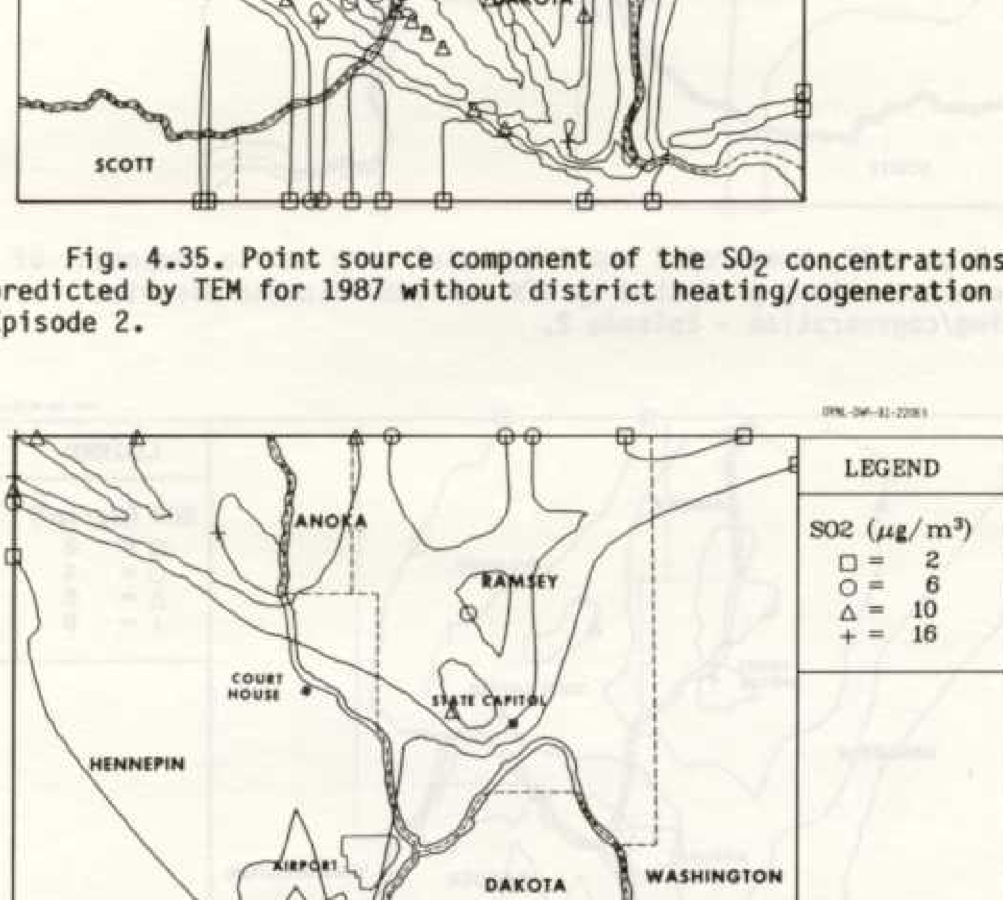

Fig. 4.36. Power plant component of the SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 2.

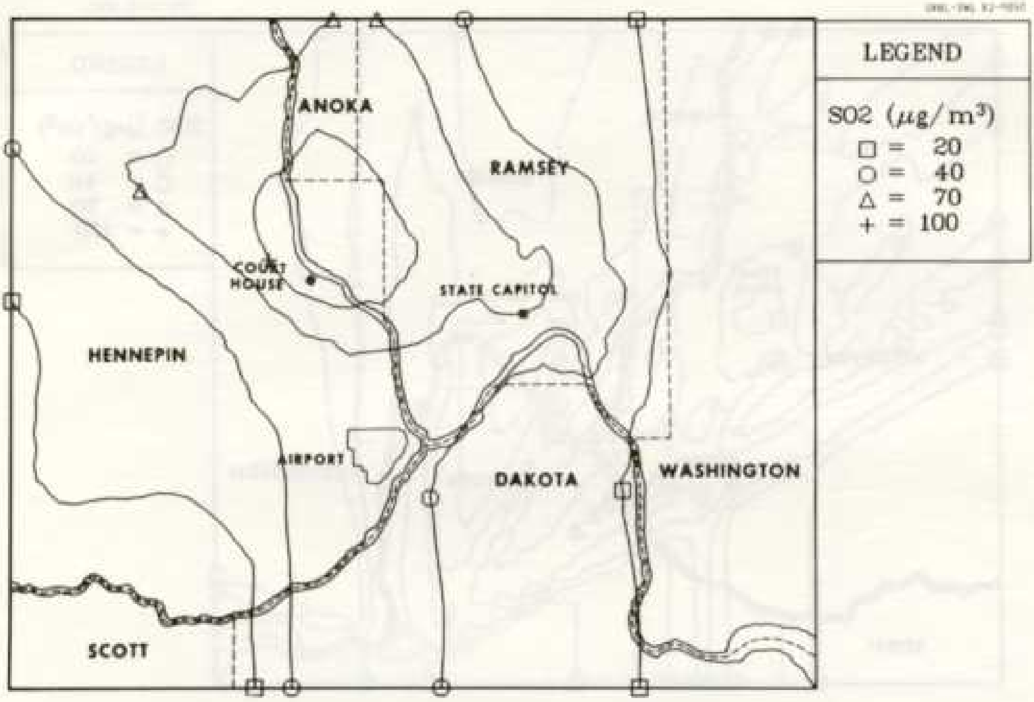

Fig. 4.37. Commercial and industrial area source component of the SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 2.

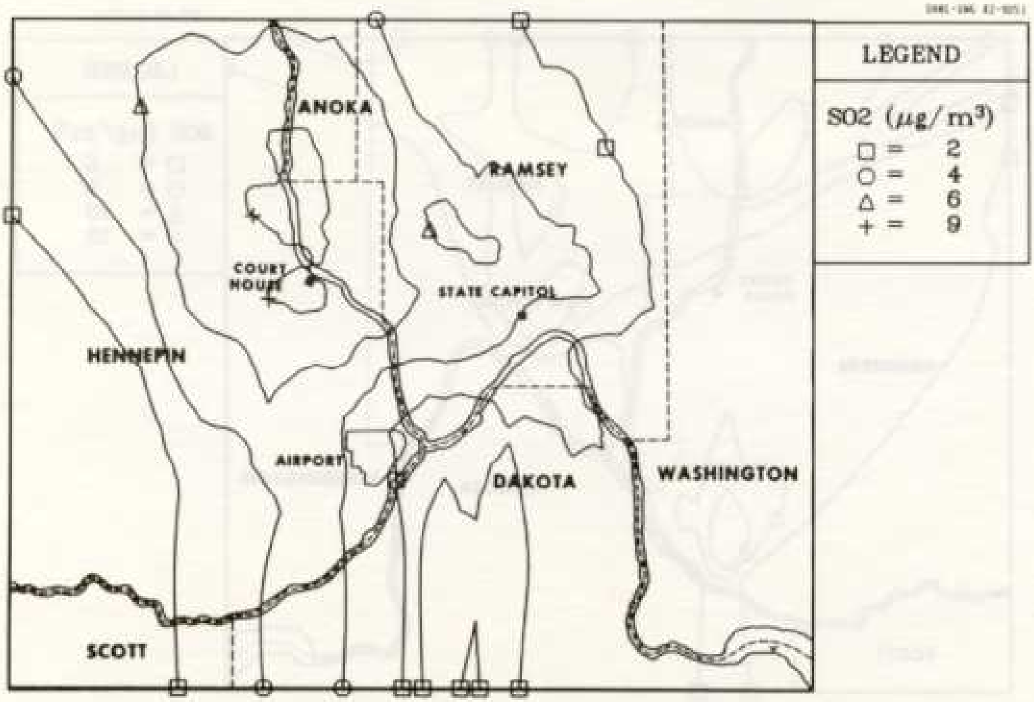

Fig. 4.38. Residential area source component of the SO_2 concentrations predicted by TEM for 1987 without district heating/cogeneration - Episode 2.

TABLE 4.20. COMPONENTS OF 1987 EPISODE 2 MAXIMUM SO_2 CONCENTRATIONS AND THEIR CHANGES PREDICTED BY TEM ($\mu g/m^3$)

Component	Original Concentration	Change with District Heating	Per cent Change
	Downtown Minneapolis		
Total	202 194 243 254	-57 -60 -82 -83	-28 -31 -34 -33
Point Sources	72 58 99 109	-10 -9 -24 -21	-14 -16 -24 -19
Power Plants	3 3 5 7	0 0 -1 -1	0 0 -20 -14
Commercial and Industrial Area Sources	117 124 129 127	-43 -48 -53 -55	-37 -39 -41 -43
Residential Area Sources	9 8 9 9	-4 -3 -5 -6	-44 -38 -55 -67
	Downtown St. Paul		
Total	152 159 122	-70 -55 -54	-46 -35 -44
Point Sources	74 70 54	-40 -19 -27	-54 -27 -50
Power Plants	6 6 3	1 2 1	17 33 33
Commercial and Industrial Area Sources	69 77 62	-29 -35 -20	-42 -45 -40
Residential Area Sources	4 5 3	-2 -3 -1	-50 -60 -33

For Episode 4, they are predicted to be less, 143 and 162 $\mu g/m^3$ near the Hennepin County Courthouse and 106 and 113 $\mu g/m^3$ near the Minnesota State Capitol.

The predicted 1976 TSP concentrations were only slightly lower than those predicted for 1987 without district heating/cogeneration. For all six episodes, the patterns of the 1976 and 1987 TSP concentrations were predicted to be essentially the same. The 1987 values would be slightly higher due to the anticipated increased substitution of alternate fuels for natural gas. Episode 2 was predicted to have one of the higher increases for 1987, and these are shown in Figure 4.41. The maximum increase would be in North Minneapolis, and the maximum predicted increase was 8 $\mu g/m^3$. This is relatively small compared to the average predicted concentration of about 100 $\mu g/m^3$ in that area. Predicted increases throughout the rest of the study area were much lower.

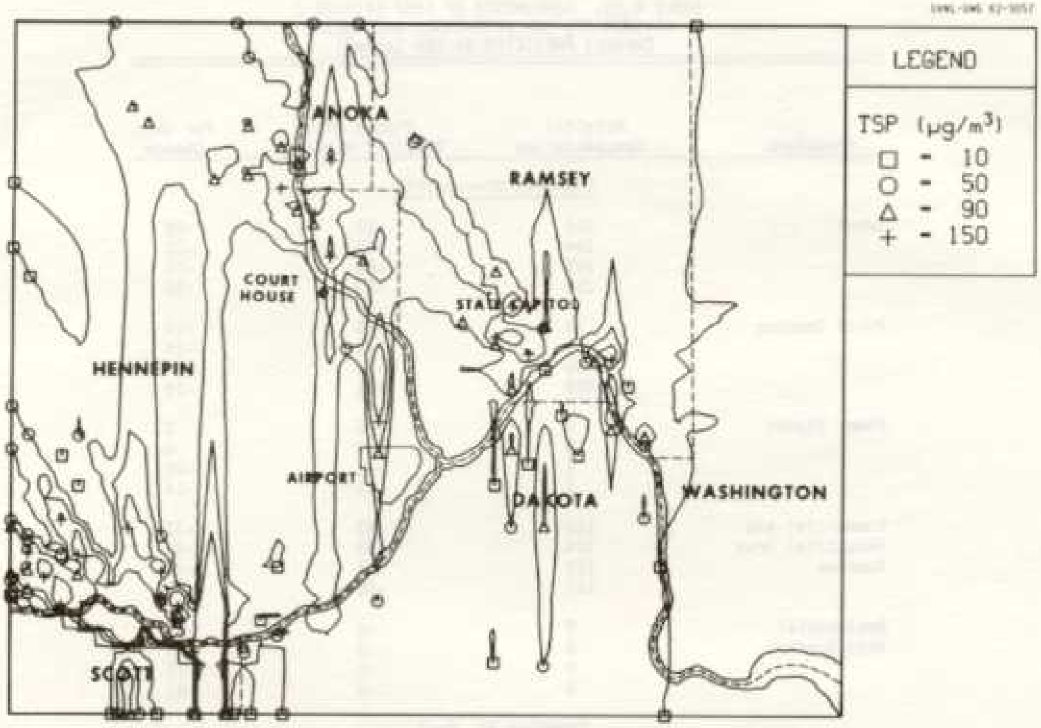

Fig. 4.39. Total predicted TSP concentrations for 1987 without district heating/cogeneration - Episode 2.

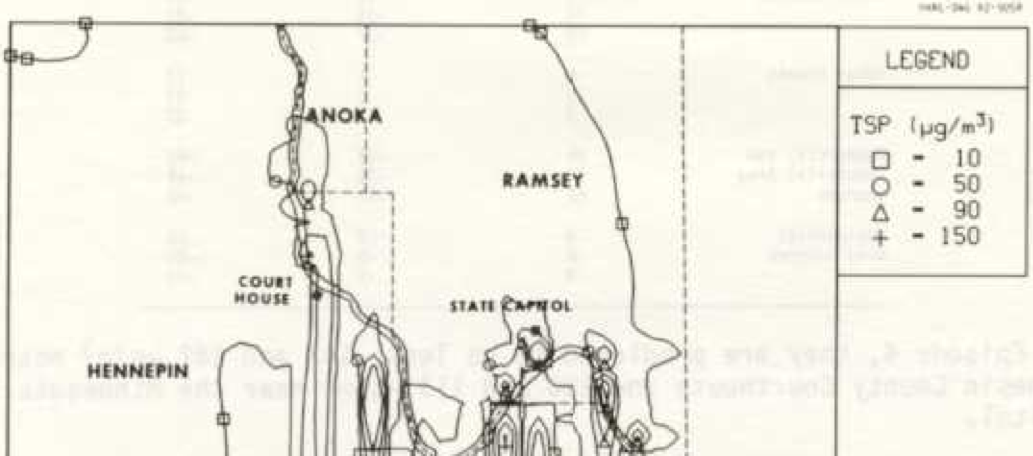

Fig. 4.40. Total predicted TSP concentrations for 1987 without district heating/cogeneration - Episode 4.

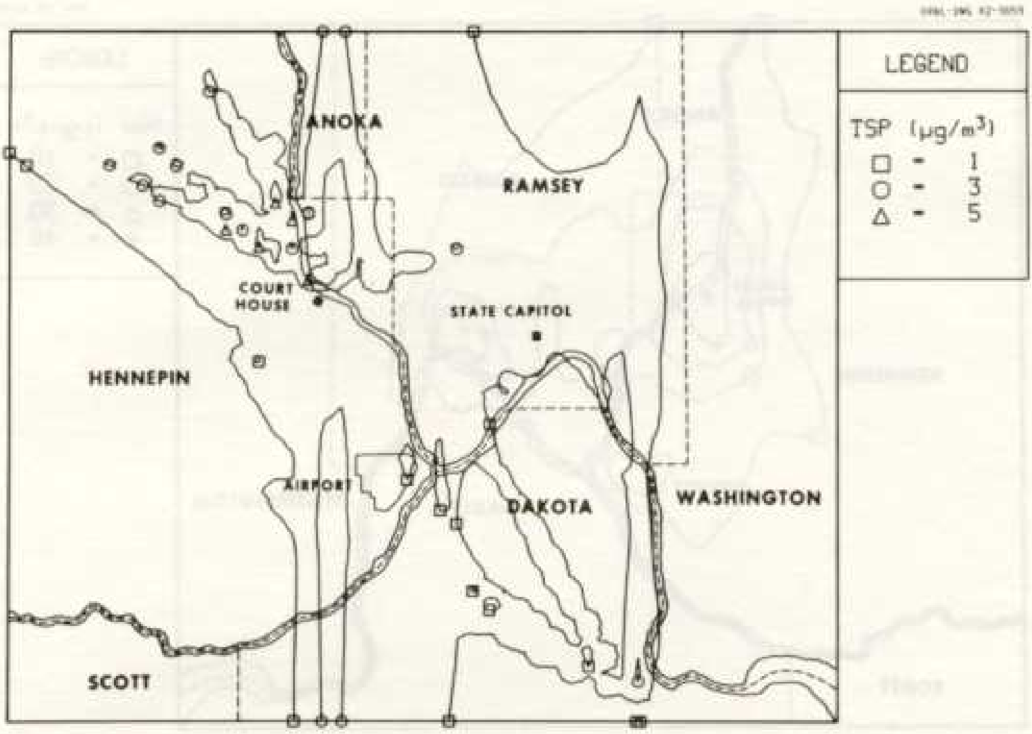

Fig. 4.41. Predicted increases in total TSP concentrations from 1976 to 1987 without district heating/cogeneration - Episode 2.

4.4.4.3 1987 Future Year Case With District Heating/Cogeneration

As expected, it is predicted that the development of the regional district heating/cogeneration system will result in decreases in the ground level SO_2 concentrations, particularly in the downtown areas. Figures 4.42 through 4.47 are isopleths of TEM-predicted difference in the SO_2 concentrations in 1987 with and without the district heating/cogeneration system. All these figures predict that the largest decreases would be in the downtown areas, where the district heating system would be located. These decreases reflect that, except for the power plants, all the SO_2 emission rates from the sources would be equal or lower with the development of the district heating system.

The magnitude of decreases will be larger for the colder days. This is, of course, due to the fact that the sources that would be displaced by the district heating system would have higher emission rates on these days, as discussed in Section 4.3. Due to the different meteorological conditions for each of the episodes, the patterns of these decreases would be different. However, all episodes are consistent in showing that the greatest benefit would be in the district heating zones.

The changes in SO_2 concentrations at the locations in the downtown areas that are predicted have the highest concentrations in 1987 without the development of the system are listed in Table 4.19. It can be seen that

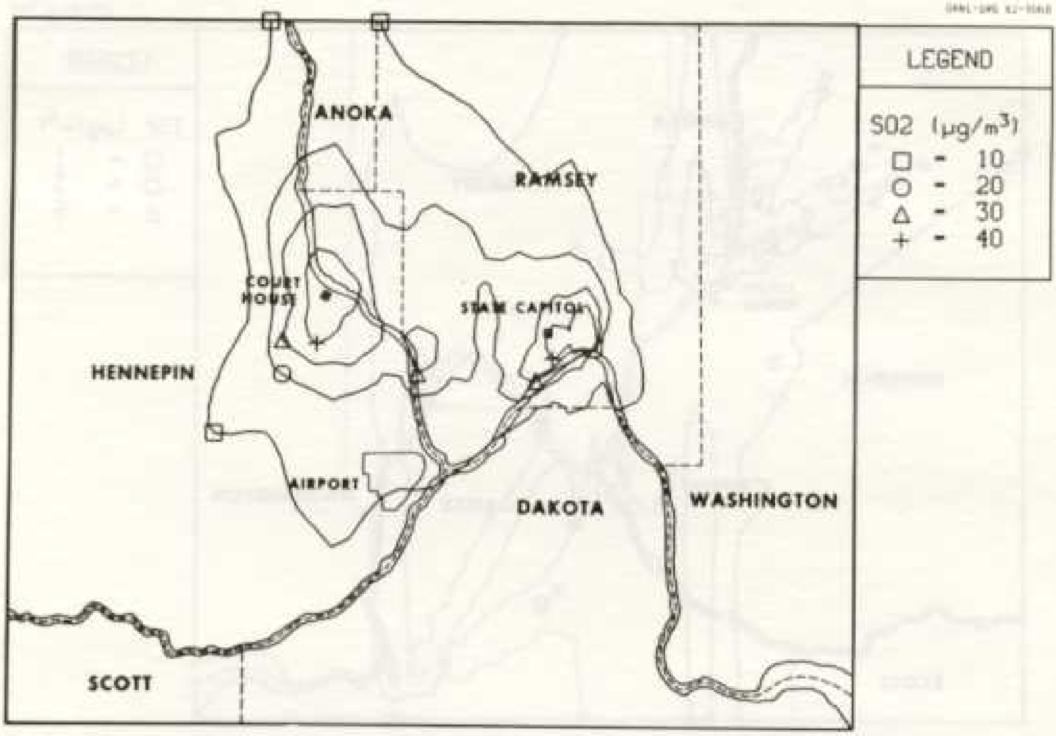

Fig. 4.42. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 1.

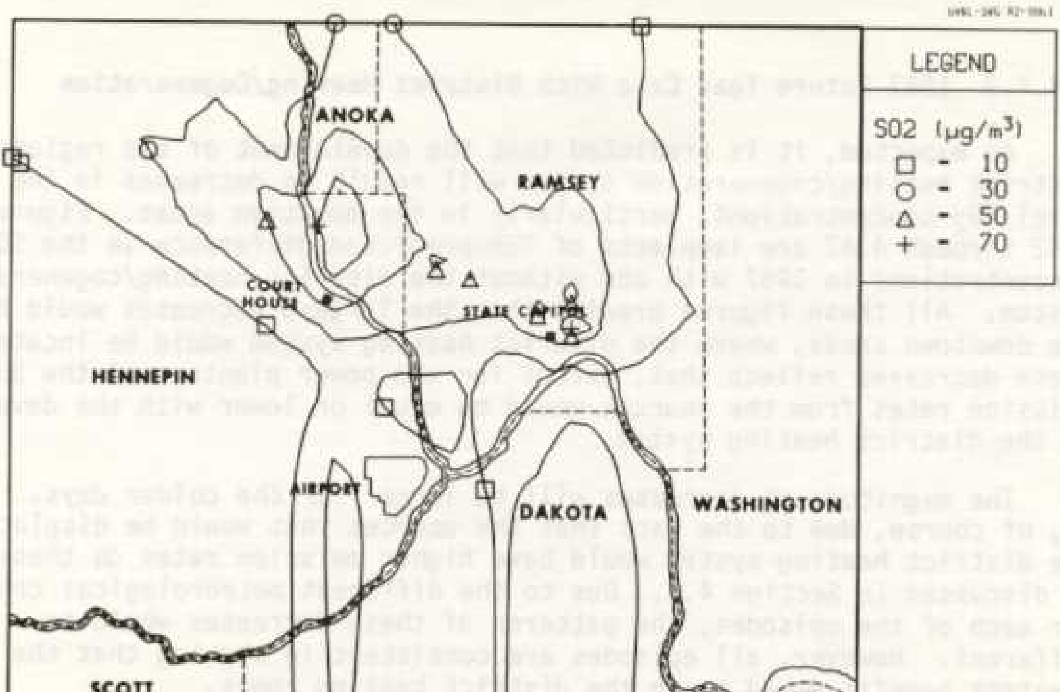

Fig. 4.43. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 2.

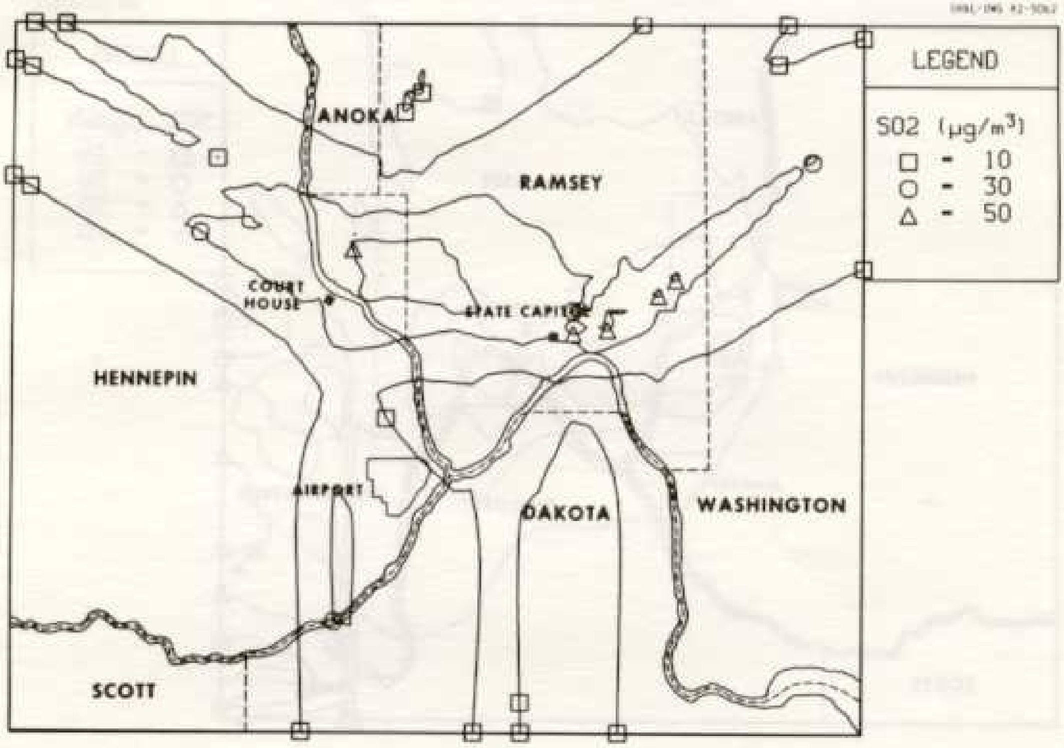

Fig. 4.44. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 3.

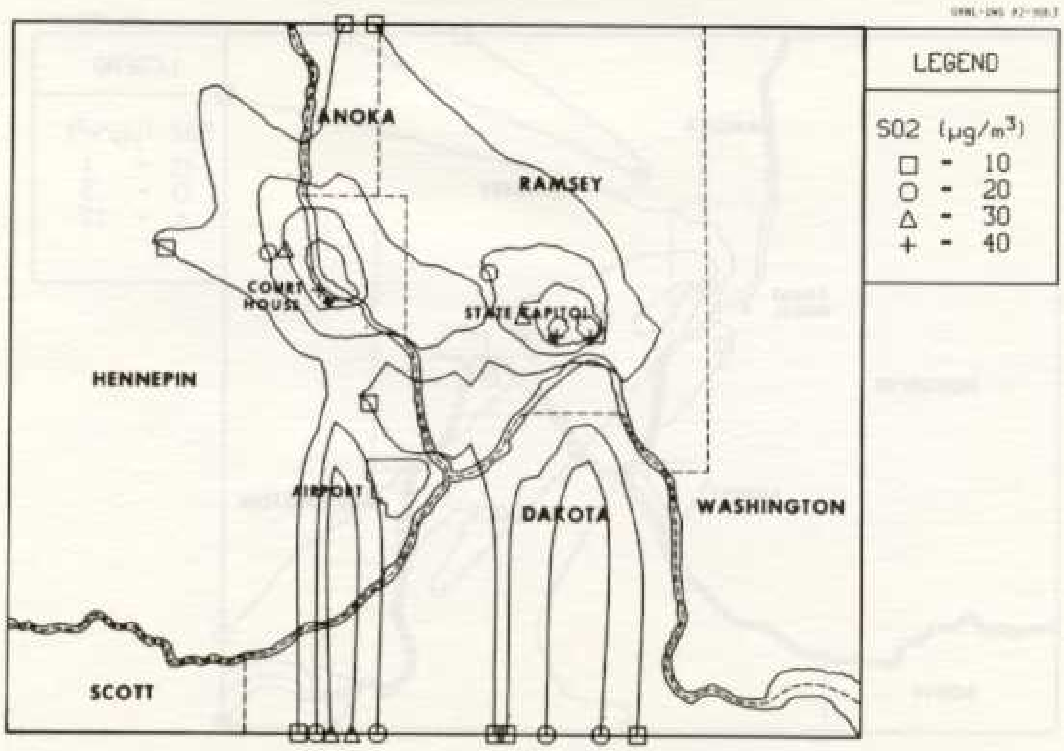

Fig. 4.45. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 4.

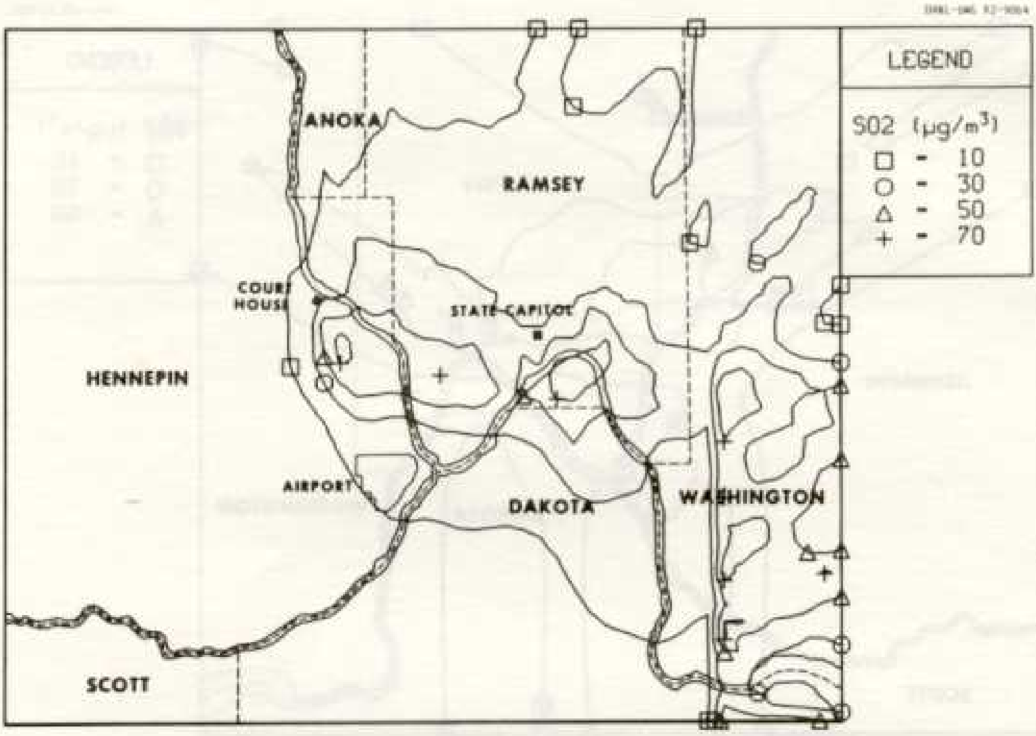

Fig. 4.46. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 5.

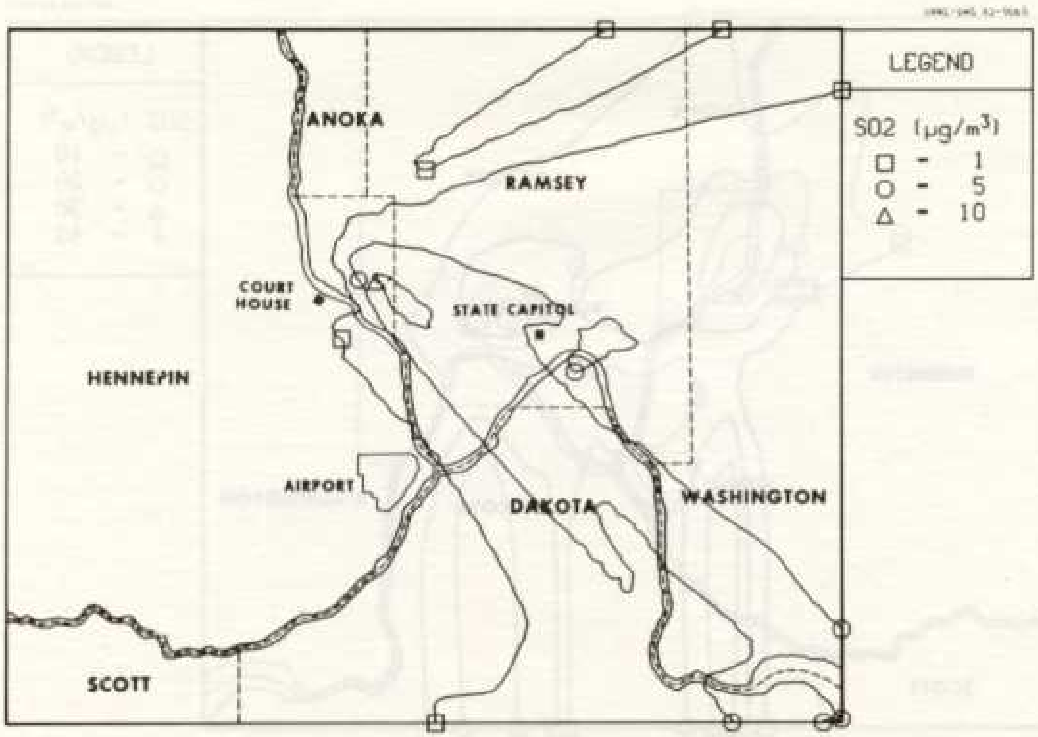

Fig. 4.47. Decrease in total SO_2 concentrations predicted by TEM with development of district heating/cogeneration in 1987 - Episode 6.

decreases of 30 to 40% probably would be realized at these locations. A 50% decrease was predicted at one location in downtown St. Paul for Episode 5. It should be remembered that the background SO_2 was not considered in the episodic predictions. Therefore, the values predicted here are expected to represent the upper limits of the percentage decreases.

Plots of the ratios (normalization) of the predicted SO_2 concentrations with and without the district heating/cogeneration system in 1987 are presented in Figures 4.48 through 4.53. It can be seen that large portions of the metropolitan region are predicted to have improved air quality due to the district heating system. Much of the area within the Twin Cities boundaries (shown in Figure 1.2) would have a reduction in SO_2 greater than 20%. These figures again show generally that the greatest improvement would be on the colder days. In no case was an increase in the total SO_2 concentration predicted at the level of modeling precision used in this study.

As for the annual case, the reductions in the SO_2 concentrations would be due primarily to the displacement of point sources and commercial and industrial area sources by the district heating system. The contribution of these components to the reductions in Episode 2 at the locations that are predicted to have the highest concentrations in the downtown areas are listed in Table 4.20. In downtown Minneapolis, the displacement of the area sources would contribute most to the improvement, the reduction in this component being about 40%. In downtown St. Paul, displacement of both the point sources and commercial and industrial area sources was predicted to contribute about equally to the improvement. The difference due to the power plants was predicted to be small. Use of tall stacks by these plants results in relatively great dispersion of the pollutants.

Figures 4.54 through 4.57 are isopleths of the ratios (normalization) of the TEM-predicted Episode 2 SO_2 concentrations with and without district heating in 1987 for the following components: (1) point sources, (2) power plants, (3) commercial and industrial area sources, and (4) residential area sources. For the point sources, the greatest relative change in the SO_2 concentrations is predicted to be in the downtown St. Paul area. This is consistent with the data presented in Table 4.20. The location of the next highest change would be in downtown Minneapolis.

The contribution of the power plants to the SO_2 concentrations will increase due to the retrofit and assumed load factors of these plants. Figure 4.55 predicts that the greatest percentage increase (greater than 70%) would be just west of St. Paul, due primarily to the assumed addition of a new cogeneration unit at the High Bridge Generating Plant. Significant areas possibly would have an increase greater than 30% in this component, particularly in the northwest part of St. Paul and in the northern part of Hennepin County. There would be some small pockets of decreases of this component, primarily due to the assumed retirement of the Third Street Plant. Within the resolution of this analysis, the overall impact of these increases would be small since the power plant component of the total SO_2 concentrations are predicted to be small (Figure 4.36). Table 4.20 predicts that at the locations in the downtown areas that would have the highest

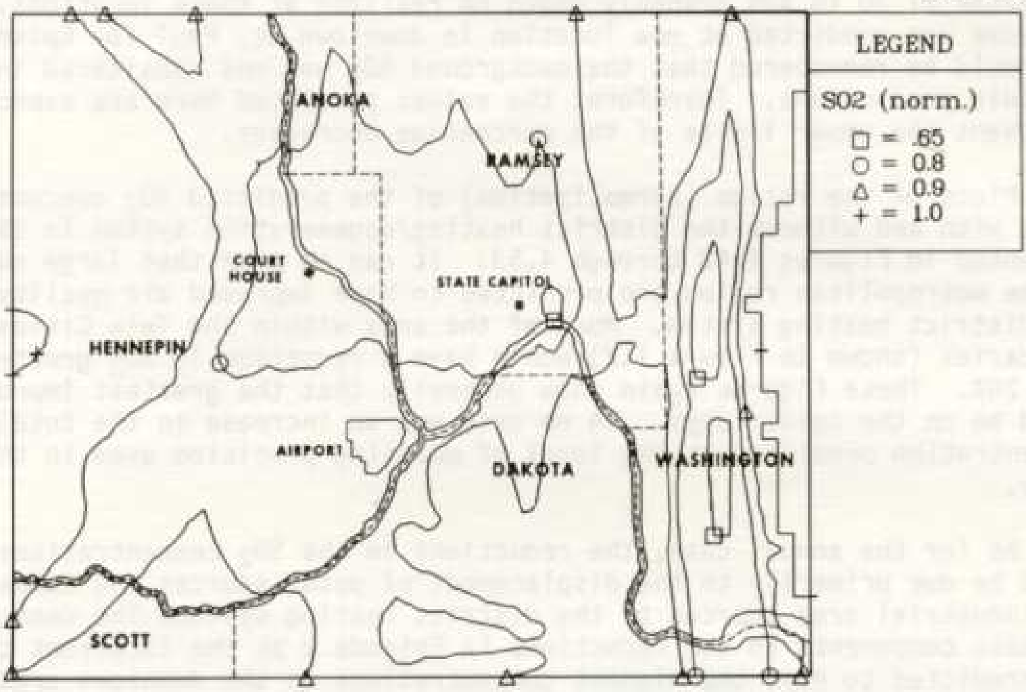

Fig. 4.48. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 1.

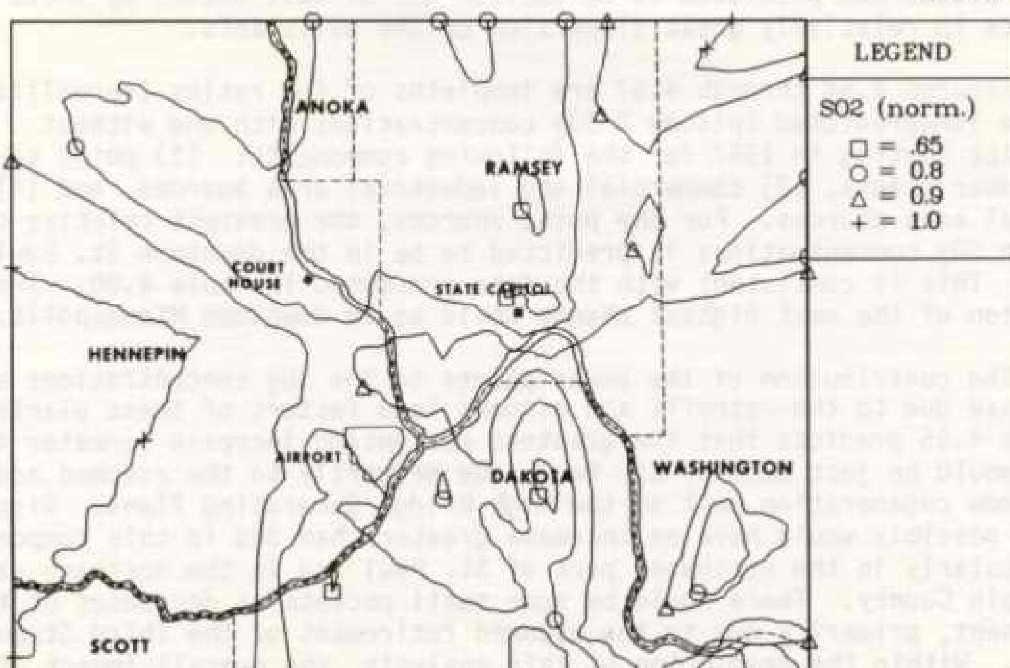

Fig. 4.49. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 2.

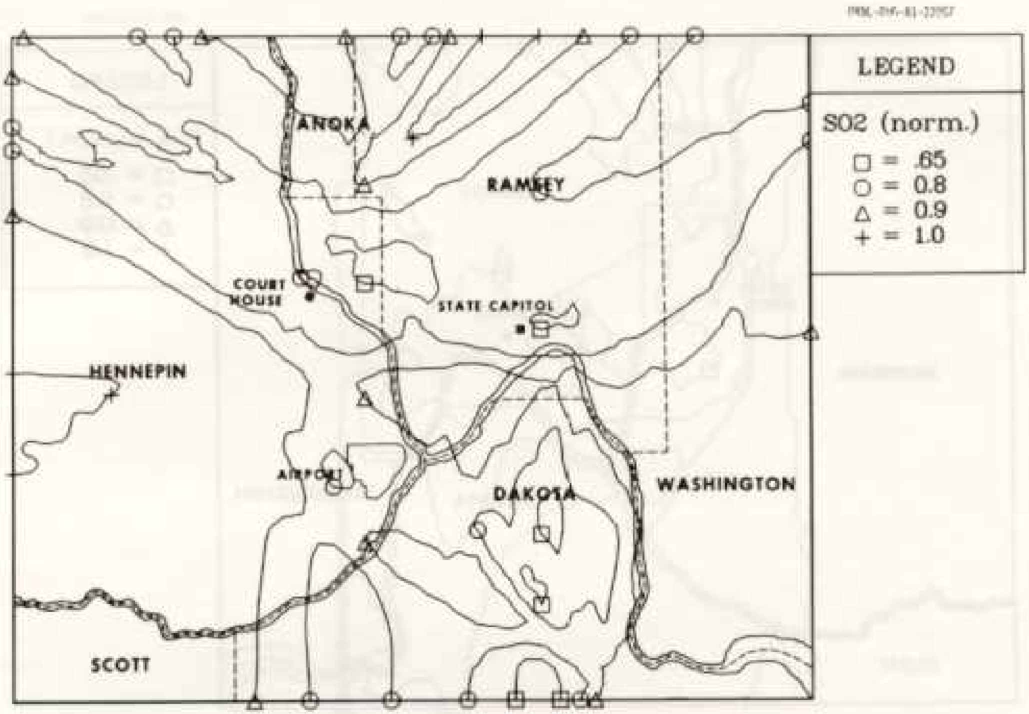

Fig. 4.50. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 3.

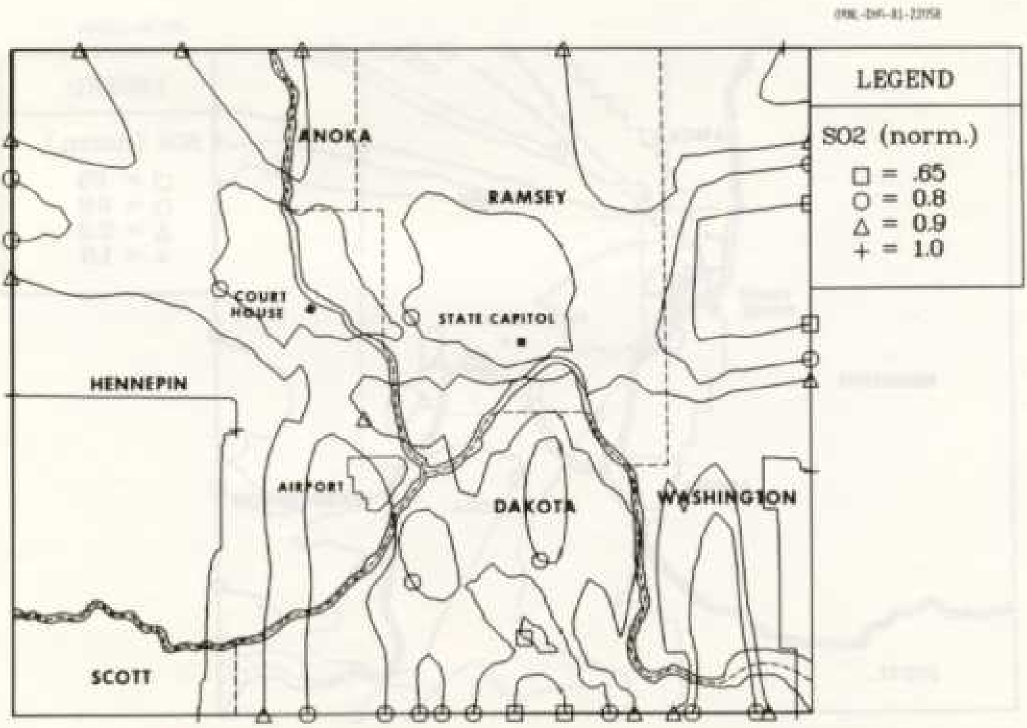

Fig. 4.51. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 4.

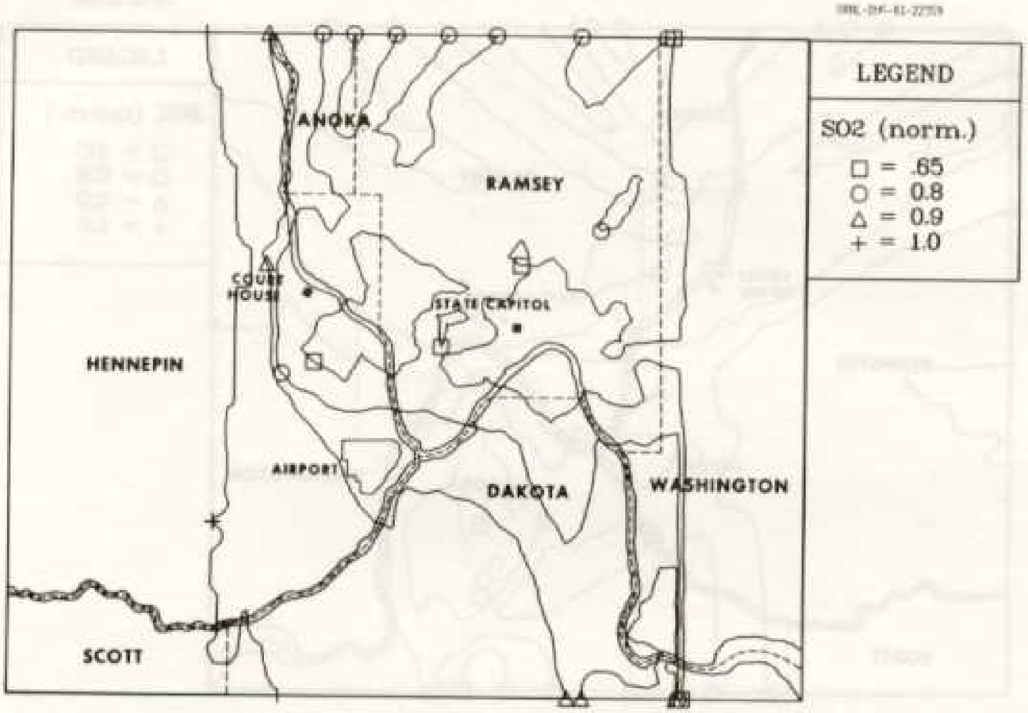

Fig. 4.52. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 5.

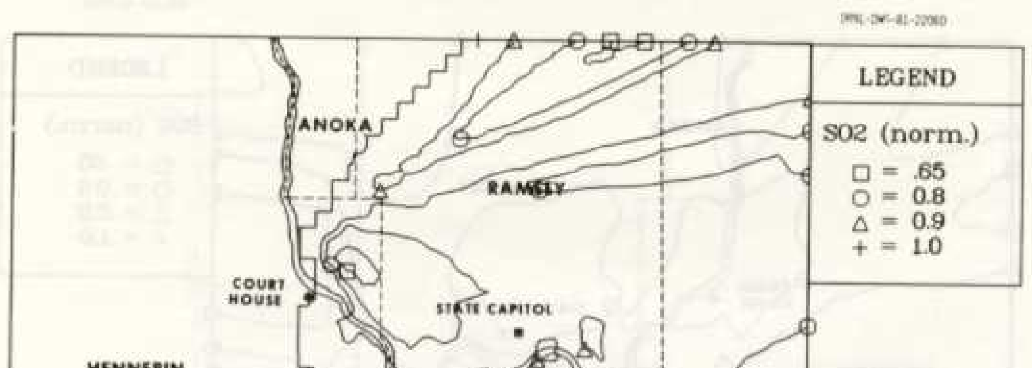

Fig. 4.53. Ratio (normalization) of TEM predicted SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 6.

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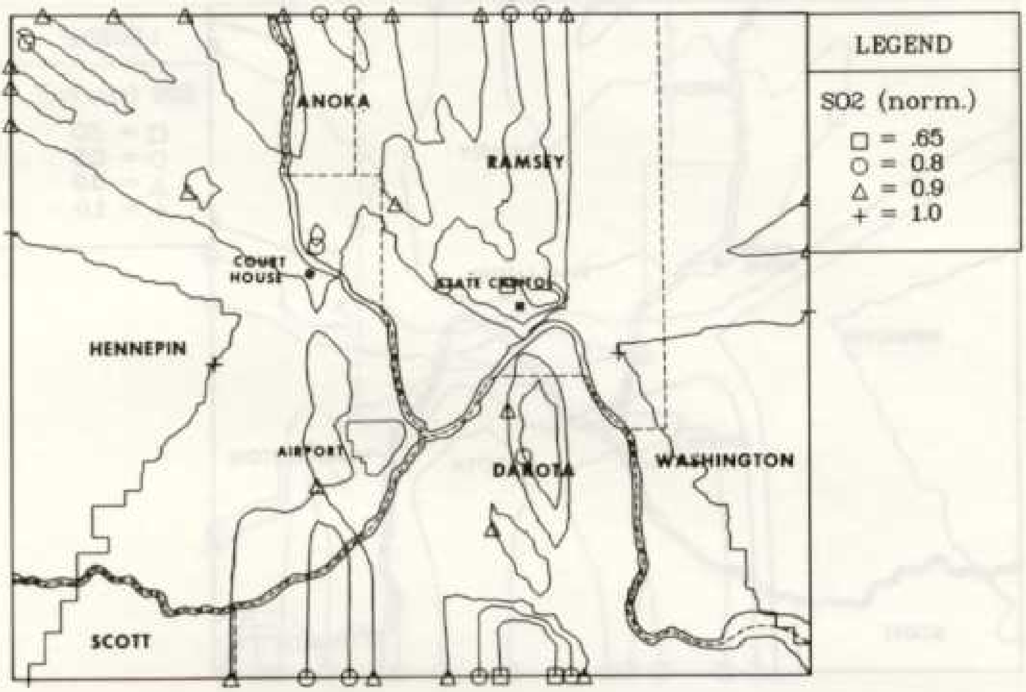

Fig. 4.54. Ratio (normalization of TEM predicted point source components of SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 2.

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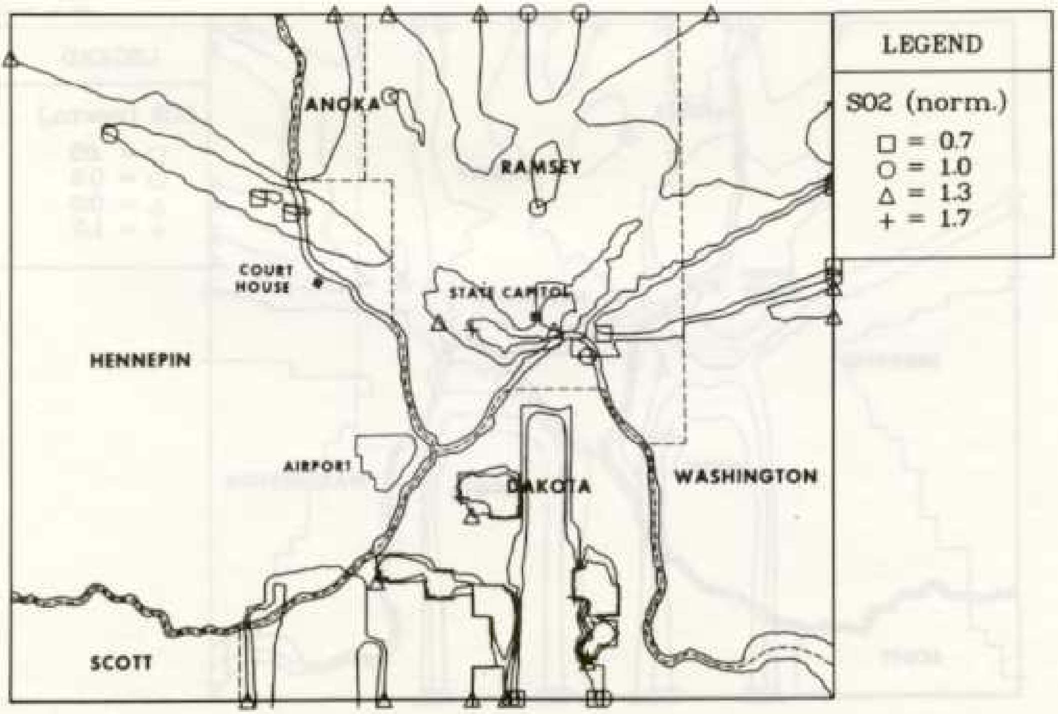

Fig. 4.55. Ratio (normalization) of TEM predicted power plant source components of SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 2.

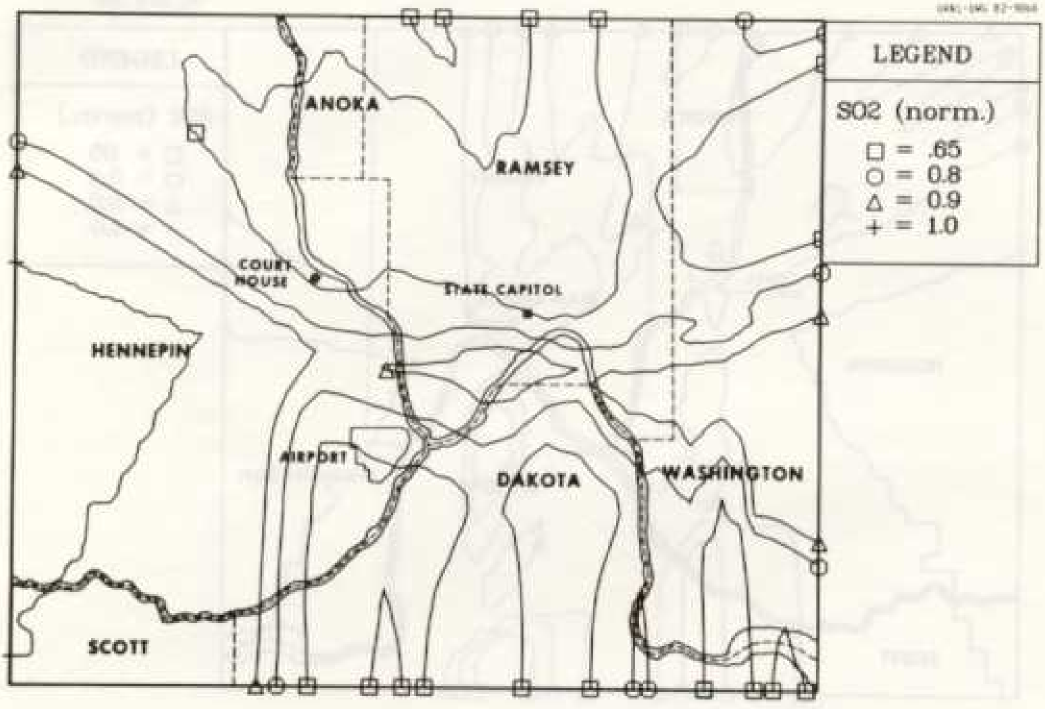

Fig. 4.56. Ratio (normalization) of TEM predicted commercial and industrial area source components of SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 2.

Fig. 4.57. Ratio (normalization) of TEM predicted residential area source components of SO_2 concentrations in 1987 with and without development of district heating/cogeneration - Episode 2.

SO_2 concentrations, the increase in the contributions from the power plants would be small. However, at other locations, the power plant contributions could be more significant.

A major portion of the improvement in the SO_2 concentrations would be due to the displacement of the short stack commercial and industrial area sources by the district heating system. In the urban area, particularly in the north central part, where this component of the SO_2 concentrations are predicted to be high (Figure 4.37), the greatest percentage improvement would occur (Figure 4.56). Table 4.20 shows that up to a 40% reduction of this component could be realized with the development of the district heating/cogeneration system. Figure 4.56 shows that large portions of the urban area are predicted to have a reduction of this component greater than 35%. These findings are typical of the other selected episodes, and it can be concluded that displacement of these sources would have the largest impact on air quality. As shown in Section 4.3.3, the concentration of the commercial and industrial area sources is generally higher in areas of higher population densities. Thus the displacement of these sources by the district heating system generally would have greater benefits for the higher populated areas.

Figure 4.57 shows that similar percentage reductions of the residential area sources component of SO_2 concentration would be realized with the development of the district heating/cogeneration system. However, the absolute magnitude of this component would be small due to the extensive use of natural gas for residential heating in the Twin Cities (Figure 4.38). Therefore the contribution to air quality improvement of the residential units connecting to the district heating system would be small. If fuel oil was used for a much larger portion of the residential heating needs in the area, this benefit would be much more important.

There would also be a slight decrease in the predicted TSP concentrations in the area with the development of the city-wide district heating/cogeneration system. This would again be due to the anticipated decrease in the emission rates, as shown in Table 4.11. Figures 4.58 and 4.59 show the decrease in the 1987 TSP concentrations predicted by TEM for Episodes 2 and 4. The predicted decreases are greater for Episode 2, which is the colder day and originally had the higher emission rates. The highest peak decrease of 8 $\mu g/m^3$ for this episode would be near the Hennepin County Courthouse. The next highest peak decrease is in downtown St. Paul, where it is about 6 $\mu g/m^3$. For Episode 4, these peaks would be slightly less, predicted to be about 6 $\mu g/m^3$ in both downtown Minneapolis and downtown St. Paul. Compared to the original concentrations in Figures 4.39 and 4.40, the predicted decreases in Figures 4.58 and 4.59 are small.

4.4.5 Trace Element Dispersion

The atmospheric dispersion of trace elements was assumed to be solely a function of particulate dispersion, just as the emission of trace elements is associated with particulate emissions (Section 4.3.7). Both the annual average atmospheric concentrations and the annual depositions of the 17 elements listed in Table 4.1 were estimated. This analysis has been

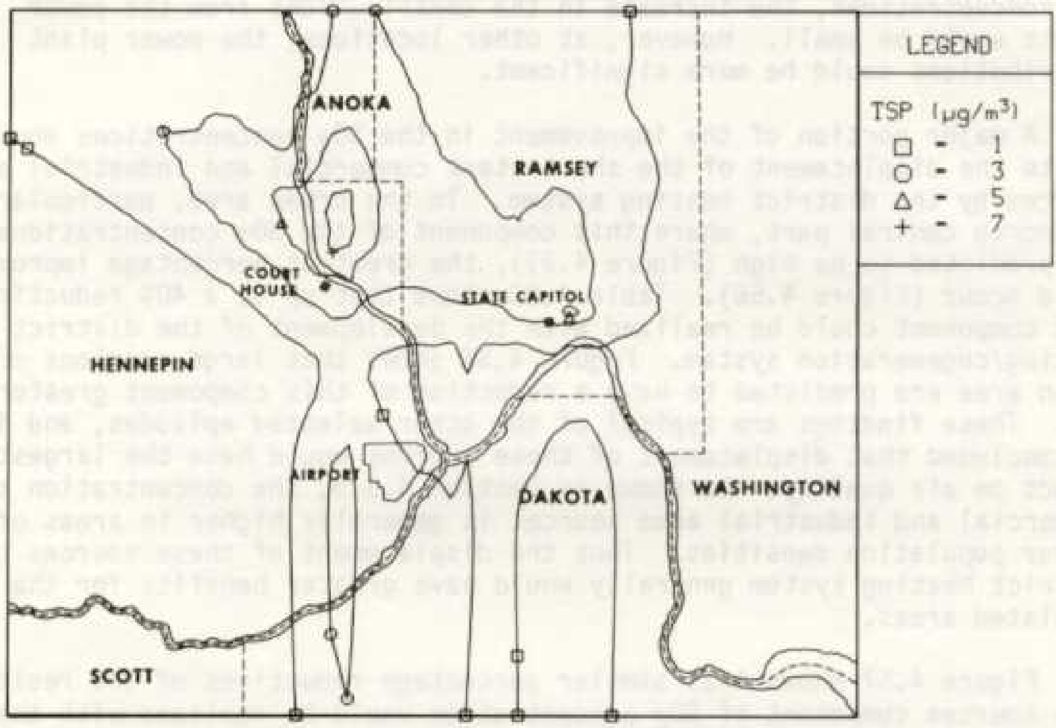

Fig. 4.58. Decrease in the total predicted TSP concentrations with the development of district heating/cogeneration in 1987 - Episode 2.

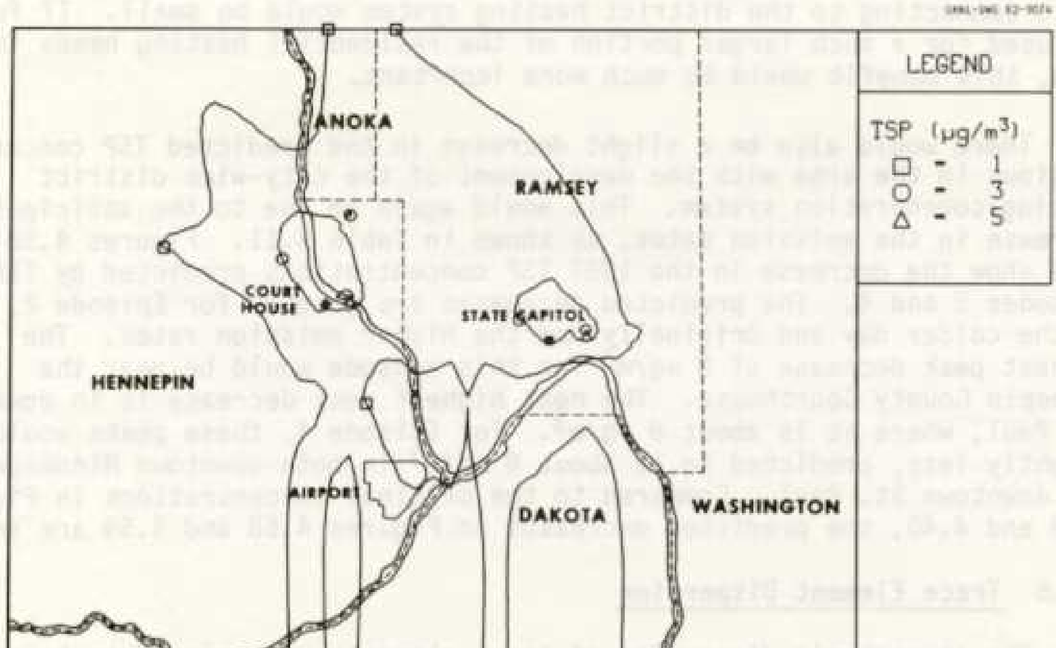

Fig. 4.59. Decrease in the total predicted TSP concentrations with the development of district heating/cogeneration in 1987 - Episode 4.

limited to an annual average study because trace element accumulation is primarily a chronic rather than an acute concern.

The specific method for estimating mean annual concentrations and annual depositions of the trace elements was to use CDM to predict the annual TSP concentrations due to the emissions from each power plant. The TSP emission rates for 1987 with district heating/cogeneration listed in Table 4.4 were used since the plant load factors and thus the concentrations are higher than for the other cases. Knowing the TSP concentration component from each power plant, the trace element concentration component was estimated by multiplying the TSP concentration by the ratio of trace element emission to the TSP emission from that plant, listed in Tables 4.16 and 4.4 respectively. The concentration at each model receptor point is simply the sum of the contributions from each power plant. When the atmospheric concentration of an element is known, the deposition rate of the element can be estimated by multiplying by the settling velocity of the particles. A settling velocity of 1 cm/s was assumed for this study.

The predicted results are summarized in Tables 4.21 and 4.22, together with representative values of observed trace element concentrations. Table 4.21 displays the predicted area averaged deposition rates of the 17 trace

TABLE 4.21. PREDICTED TRACE ELEMENT DEPOSITION RATES AND TYPICAL AMBIENT CONCENTRATIONS FOR THE TWIN CITIES AREA

Element	Crustal Abundance[58] (g/m^2-cm)	Maximum Annual Deposition (g/m^2-yr)	Study Area Average Annual Deposition (g/m^2-yr)
Antimony	3.5×10^{-3}	1.7×10^{-5}	1.5×10^{-6}
Arsenic	3.2×10^{-2}	1.5×10^{-5}	1.6×10^{-6}
Beryllium	4.9×10^{-2}	2.4×10^{-6}	2.2×10^{-7}
Cadmium	3.5×10^{-3}	1.5×10^{-6}	1.9×10^{-7}
Chromium	1.8	4.4×10^{-4}	3.7×10^{-5}
Cobalt	4.4×10^{-1}	1.1×10^{-4}	1.0×10^{-5}
Copper	9.7×10^{-1}	5.8×10^{-5}	5.1×10^{-6}
Fluorine	1.1×10	7.7×10^{-4}	7.1×10^{-5}
Mercury	1.4×10^{-3}	3.5×10^{-6}	4.4×10^{-7}
Molybdenum	2.6×10^{-2}	3.1×10^{-5}	3.0×10^{-6}
Nickel	1.3	2.7×10^{-5}	2.7×10^{-6}
Scandium	3.9×10^{-1}	9.4×10^{-6}	8.6×10^{-7}
Selenium	8.8×10^{-4}	2.7×10^{-5}	2.3×10^{-6}
Uranium	4.8×10^{-2}	7.2×10^{-6}	6.8×10^{-7}
Vanadium	2.4	8.3×10^{-5}	7.8×10^{-6}
Zinc	1.2	5.2×10^{-4}	5.1×10^{-5}

TABLE 4.22. PREDICTED ATMOSPHERIC TRACE ELEMENT CONCENTRATIONS FOR THE TWIN CITIES AND TYPICAL URBAN TRACE ELEMENT CONCENTRATION, $\mu g/m^3$

Element	Average Atmospheric Concentration[59]	Max. Annual Atmospheric Concentration	Study Area Average Atmospheric Concentration
Antimony	3×10^{-2}	5.4×10^{-5}	4.8×10^{-6}
Arsenic	7×10^{-3}	4.8×10^{-5}	5.1×10^{-6}
Beryllium	2×10^{-1}	7.6×10^{-6}	7.0×10^{-7}
Cadmium	3×10^{-3}	4.8×10^{-6}	6.0×10^{-7}
Chromium	1.4×10^{-2}	1.4×10^{-3}	1.2×10^{-4}
Cobalt	3×10^{-3}	3.5×10^{-4}	3.2×10^{-5}
Copper	1.5×10^{-1}	1.8×10^{-4}	1.6×10^{-5}
Fluorine	1	2.4×10^{-3}	2.3×10^{-4}
Lead	1	1.9×10^{-4}	1.9×10^{-5}
Mercury	n/a	1.1×10^{-5}	1.4×10^{-6}
Molybdenum	1.2×10^{-3}	9.8×10^{-5}	9.5×10^{-6}
Nickel	6×10^{-3}	8.6×10^{-5}	8.6×10^{-6}
Scandium	n/a	3.0×10^{-5}	2.7×10^{-6}
Selenium	2×10^{-2}	8.6×10^{-5}	7.3×10^{-6}
Uranium	n/a	2.3×10^{-5}	2.2×10^{-6}
Vanadium	8×10^{-3}	2.6×10^{-4}	2.5×10^{-5}
Zinc	2×10^{-1}	1.6×10^{-3}	1.6×10^{-4}

elements, as well as the deposition rates at the location receiving the greatest annual accumulation. Table 4.22 shows the atmospheric concentrations of the 17 elements corresponding to the mean and maximum depositions.

Comparisons of the annual deposition rates to the average crustal abundance of the 17 elements indicates that the annual accumulation of these elements is very small when compared to typical ambient levels. Only selenium appears to have any possibility of accumulating in noticeable amounts, and this possible accumulation lies well within the range of uncertainty for the ambient level measurements. The predicted atmospheric concentrations of trace elements are at least an order of magnitude lower than levels observed in the Twin Cities.

The concentrations and deposition rates listed in Tables 4.21 and 4.22 are about 10% higher than the predicted rates in 1987 without district heating/cogeneration since the load factors for TSP emission rates are about 10% higher for the district heating/cogeneration case. Therefore, the impact of the city-wide district heating system would be an order of magnitude lower than the values shown in the two tables. Moreover, trace element emissions from sources that would be displaced by the district heating system were ignored in this study. Thus, the steam plants' additional contributions of trace elements to the soil, water, and air in the Twin Cities with the development of the district heating system appear to be comparatively trivial even with the conservatively large trace element emission estimates used here. While the concern over the buildup of potentially harmful trace elements due to fossil fuel combustion cannot be dismissed by virtue of this study, the impact of the Twin Cities district heating/cogeneration system alone is inconsequential.

SECTION 5

WATER QUALITY IMPACTS

Estimates were made of the impact of retrofitting the High Bridge and Riverside Generating Plants on water temperatures in the Mississippi River. Both of these plants presently use river water for once through cooling. Converting the turbine-generator units to cogeneration mode of operation will reduce the amount of waste heat deposited in the river. This will result in reduced areas of the river having excess temperatures (temperatures above the normal ambient river temperature). In this study, estimates were made of the water temperatures near the circulating water discharge. Here the discharging water mixes with the ambient river water to reduce its excess temperature. The waste heat ultimately is dissipated from the river to the atmosphere, and much of it is dissipated downstream of the mixing zone.

The predictions of the water temperatures were made for the plants operating at full load in their present condition using straight condensing made electrical generation. These predictions were then repeated for the plants generating at full load with the turbine-generators converted into cogeneration units. Since the retrofitted turbine-generators could operate either as straight condensing units or as cogeneration units, the effect of switching modes of operation on the indigenous fish populations at the two plants was investigated briefly.

5.1 MISSISSIPPI RIVER HYDROLOGY

The High Bridge Generating Plant is located on the Mississippi River at River Mile 840.5 (miles upstream from the Mississippi River-Ohio River confluence).[60] The Riverside Generating Plant is located on the Mississippi River at River Mile 857.[61] St. Anthony Falls is located between these two plants at River Mile 854.1. These falls have been an effective geological barrier to upriver fish migration for about 10,000 years until 1963. At that time, a navigation lock was installed there, which at least has partially removed this barrier.

The river drains approximately 49,500 km^2 (19,100 mi^2) upstream of the Anoka gauging station, located at River Mile 864.8 and approximately 95,300 km^2 (36,800 mi^2) upstream of the St. Paul gauging station, located at River Mile 839.3. The river flow is modified through a series of dams and lock and dams located in the river. Normal water surface elevations at High Bridge and Riverside are 212 and 244 m (695 and 799.2 ft) above mean sea level (MSL), respectively. The flow rates are usually the highest in the spring and early summer and the lowest in the winter. Typical monthly average flow rates at the Anoka and St. Paul gauging stations are presented in Figures 5.1 and 5.2.[60,61]

The water temperature impacts were predicted for both typical winter and summer ambient conditions. The conditions at each plant location selected for this study are listed in Table 5.1. The flow rates selected

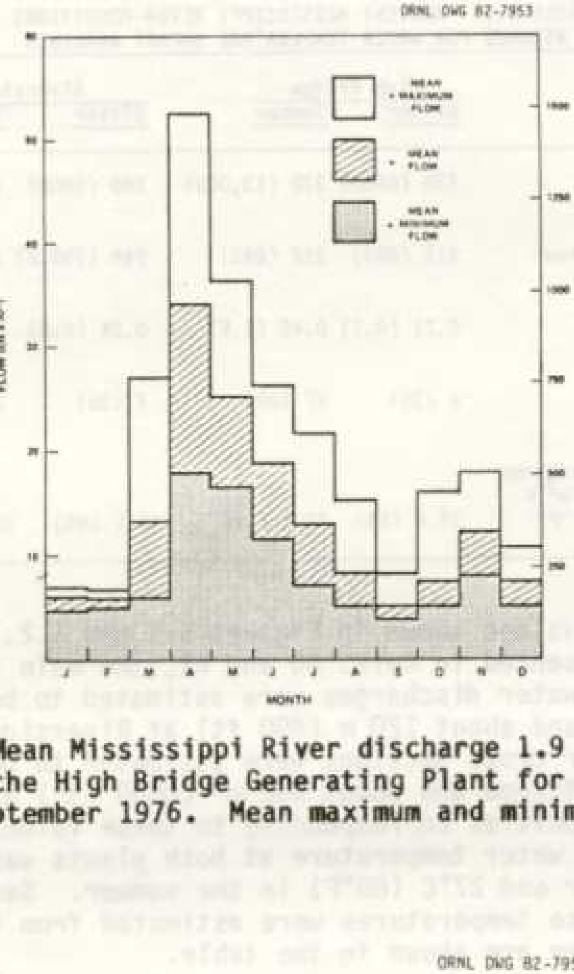

Fig. 5.1. Mean Mississippi River discharge 1.9 km (1.2 mi) downriver from the High Bridge Generating Plant for the period October 1966 through September 1976. Mean maximum and minimum flows are also shown.[60]

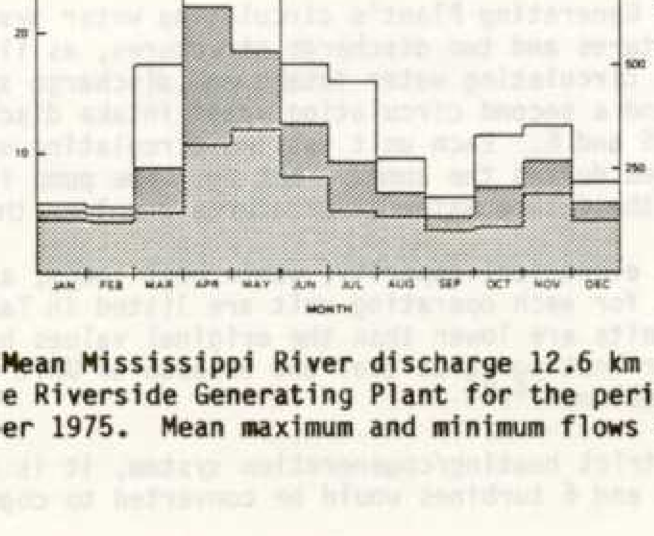

Fig. 5.2. Mean Mississippi River discharge 12.6 km (7.8 mi) upriver from the Riverside Generating Plant for the period October 1966 through September 1975. Mean maximum and minimum flows are also shown.[61]

TABLE 5.1. AMBIENT MISSISSIPPI RIVER CONDITIONS ASSUMED FOR WATER TEMPERATURE IMPACT ANALYSIS

	High Bridge		Riverside	
	Winter	Summer	Winter	Summer
Flow Rate, m^3/s (ft^3/s)	170 (6000)	370 (13,000)	140 (5000)	283 (10,000)
Surface Elevation m(ft) MSL	212 (695)	212 (695)	244 (799.2)	244 (799.2)
Velocity, m/s (ft/s)	0.21 (0.7)	0.45 (1.5)	0.24 (0.8)	0.52 (1.7)
Temperature, °C (°F)	2 (35)	27 (80)	2 (35)	27 (80)
Surface Heat Exchange Coefficient $W/m^2 \cdot °K$ ($Btu/day \cdot ft^2 \cdot °F$)	15.4 (65)	33.1 (140)	15.1 (65)	33.1 (140)

are typical of the values shown in Figures 5.1 and 5.2. On the basis of the information presented in Refs. 60 and 61, the main river channel widths at the circulating water discharges were estimated to be about 210 m (700 ft) at High Bridge and about 120 m (400 ft) at Riverside. At the same locations, the river cross sections were estimated to be about 810 m^2 (8800 ft^2) at High Bridge and about 550 m^2 (6000 ft^2) at Riverside. The river water velocities corresponding to these values are shown in Table 5.1. Ambient water temperature at both plants was assumed to be 2°C (35°F) in the winter and 27°C (80°F) in the summer. Surface heat exchange coefficients at these temperatures were estimated from the data of Thackston,[62] and they are shown in the table.

5.2 HIGH BRIDGE GENERATING PLANT

5.2.1 Circulating Water Discharge System

High Bridge Generating Plant's circulating water system presently has two intake structures and two discharge structures, as illustrated in Figure 5.3. One circulating water intake and discharge system provides for Units 3 and 4, and a second circulating water intake discharge system provides for Units 5 and 6. Each unit has two circulating water pumps. Both pumps are operated during the summer, but only one pump is operated during the winter when the intake water temperatures are less than 10°C (50°F).

The present electrical capacity, waste heat loads, and circulating water flow rates for each operating unit are listed in Table 5.2. Ratings of some of the units are lower than the original values because of the change to a lower heating value coal and because of Unit 4 turbine balance and alignment problems.[14,22]

For the district heating/cogeneration system, it is now visualized that Units 3, 5, and 6 turbines would be converted to cogeneration

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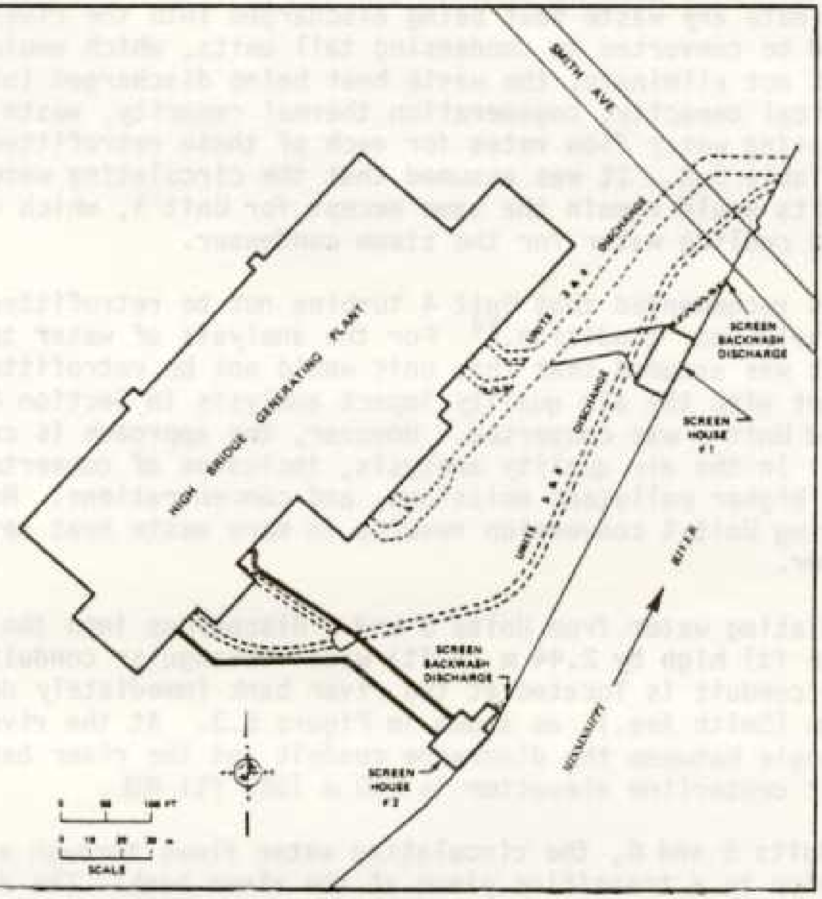

Fig. 5.3. Schematic of High Bridge Generating Plant showing location of intake structures, plant, and discharges.[60]

TABLE 5.2. HIGH BRIDGE GENERATING PLANT ELECTRIC CAPACITIES, COGENERATION THERMAL CAPACITIES, WASTE HEAT LOADS, AND CIRCULATING WATER FLOW RATES[14,22,63]

	Electrical Capacity MW(e)	Cogeneration Thermal Cap. MW(t)	Waste Heat Load MW(t)	Circulating Water Flow Rate m^3/s (ft^3/s) Winter	Summer
Unit 3	55	0	91	19.2 (62.9)	28.2 (92.5)
Unit 4	33	0	53	18.7 (61.3)	27.5 (90.2)
Unit 5	98	0	152	27.0 (88.7)	42.1 (138.1)
Unit 6	163	0	243	34.9 (114.5)	52.6 (172.7)
Unit 3 Cogeneration	49	120	0	0 (0)	0 (0)
Unit 5 Cogeneration	66	138	46	27.0 (88.7)	42.1 (138.1)
Unit 6 Cogeneration	109	186	111	34.9 (114.5)	52.6 (172.7)

machines.[14] Unit 3 would be converted to a back pressure unit, which would eliminate any waste heat being discharged into the river. Units 5 and 6 would be converted to condensing tail units, which would greatly reduce, but not eliminate, the waste heat being discharged into the river. The electrical capacity, cogeneration thermal capacity, waste heat load, and circulating water flow rates for each of these retrofitted units are listed in Table 5.2. It was assumed that the circulating water flow rates for all units would remain the same except for Unit 3, which would no longer need cooling water for the steam condenser.

It was recommended that Unit 4 turbine not be retrofitted because of its relatively poor condition.[14] For the analysis of water temperature impacts, it was assumed that this unit would not be retrofitted. This is inconsistent with the air quality impact analysis in Section 4, where it was assumed Unit 4 was converted. However, the approach is conservative in each case. In the air quality analysis, inclusion of converted Unit 4 results in higher pollutant emissions, and concentrations. Here it will be seen ignoring Unit 4 conversion results in more waste heat being discharged to the river.

Circulating water from Units 3 and 4 discharges into the river through a 1.83 m (6 ft) high by 2.44 m (8 ft) wide rectangular conduit.[22] The end of the conduit is located at the river bank immediately downstream of High Bridge (Smith Ave.), as shown in Figure 5.3. At the river bank, the included angle between the discharge conduit and the river bank is 68° and the conduit centerline elevation is 210 m (688 ft) MSL.

For Units 5 and 6, the circulating water flows through a 2.13 m (7 ft) diameter pipe to a transition piece at the river bank. The discharge opening of the transition piece is a rectangle measuring 0.91 m (3 ft) high and 2.50 m (8.19 ft) wide. The centerline of this opening is located 6.28 m (20.62 ft) upstream of the centerline of Units 3 and 4 discharge at an elevation of 210.8 m (691.5 ft MSL). The included angle between Units 5 and 5 discharge centerline and the river bank is 39°.

5.2.2 Analysis and Results

The analysis was done for four different scenarios with the plant operating at full load during the winter and the summer. They are:

1. Present plant with all four units operating.

2. Unit 6 operating as a condensing tail cogeneration unit and Units 3, 4, and 5 operating in their present condition.

3. Unit 3 operating as a back-pressure cogeneration unit and Units 4, 5, and 6 operating in their present condition.

4. Unit 3 operating as a back-pressure cogeneration unit and Units 5 and 6 operating as condensing tail units. Unit 4 operating in its present condition.

Scenarios 1, 3, and 4 were selected to evaluate the full impact of the plant conversion to cogeneration on the water quality. Since the condensing tail cogeneration units, Units 5 and 6, can operate either as straight condensing electrical generation units or as cogeneration units, both scenarios were investigated. In either scenario, Unit 3, retrofitted for back-pressure operation, would not operate in a condensing electrical mode. Scenario 2 was selected in recognition that only Unit 6 will be converted to cogeneration for the demonstration hot water district heating system that now has started operation in St. Paul.[13]

The circulating water flow rates, velocities, and excess temperatures at the end of the discharge water structures for these scenarios are listed in Table 5.3. When Unit 3 is converted to a back-pressure cogeneration turbine, only the circulating water from Unit 4 will be discharged through the structure for Units 3 and 4. This, of course, will result in reduced discharge flow rate and velocity. For Units 5 and 6, conversion to condensing tail cogeneration turbines will not reduce the circulating water flow rate, but will reduce the excess temperatures of the discharging water.

TABLE 5.3. CIRCULATING WATER PARAMETERS AT THE HIGH BRIDGE GENERATING PLANT

	Units 3-4 Discharge	Units 5-6 Discharge
Flow Area, m^2 (ft^2)	4.46 (48.0)	2.28 (24.56)
Flow Rate, m^3/s (ft^3/s)		
Present		
Winter	37.9 (124.2)	61.9 (203.2)
Summer	55.7 (182.7)	98.7 (310.8)
Unit 3 Cogeneration		
Winter	18.7 (61.3)	
Summer	27.5 (90.2)	
Velocity, m/s (ft/s)		
Present		
Winter	0.79 (2.59)	2.52 (8.27)
Summer	1.16 (3.81)	3.86 (12.66)
Unit 3 Cogeneration		
Winter	0.39 (1.28)	
Summer	0.57 (1.88)	
Excess Temperature, °C (°F)		
Present		
Winter	9.8 (17.6)	16.5 (29.6)
Summer	6.6 (11.9)	10.7 (19.3)
Unit 3 Cogeneration		
Winter	7.3 (13.1)	
Summer	4.9 (8.9)	
Unit 6 Cogeneration		
Winter		10.9 (19.7)
Summer		7.2 (12.9)
Units 5 & 6 Cogeneration		
Winter		6.6 (11.8)
Summer		4.3 (7.7)

The water discharging into the river through the structures can be considered as buoyant jets. As the water flows into the river, it passes through a number of physical regimes in which the river water mixes with it. The regimes that are most commonly classified are as follows:[64,65]

1. Zone of flow establishment (ZFE): In ZFE, the velocity profile of the discharge water is visualized to transform from a flat profile at the discharge structure to a bell-shaped Gaussian profile by entraining river water. The centerline water velocity remains constant in ZFE.

2. Zone of established flow (ZEF): In ZEF, the discharge continues to have a Gaussian velocity profile, but mixing continues due to the momentum and buoying of the jet. The centerline water velocity as well as the excess temperature continues to decay due to the mixing action.

3. Field zone: In the field zone, the jet momentum has been dissipated and further mixing is due to ambient currents and turbulence in the water body.

The nature of the buoyant jets at the two discharge structures are different because of the difference in the discharge structure designs and the circulating water characteristics. Because of the proximity of the two discharges, they will interact with one another. Since this relatively complex situation does not lend itself to simple analysis, a heuristic approach was used to predict the discharging water behavior.

The approach used was first to treat each of the discharges as a single submerged jet. It was found generally for High Bridge that discharging water reaches the river surface at the end of the ZFE. At this point, the water jets were treated as surface discharges. Next, the location where the two surface jets meet was determined. At this location, it was assumed that the two jets combine to form a single surface jet.

The behavior of the discharging water in ZFE was predicted by the model for round submerged discharges developed by Hirst.[64,65] This model uses integral equations of mass, energy, and momentum to describe the jet behavior in the ZFE. Since the Gaussian temperature profile develops before the Gaussian velocity profile in ZFE, the centerline temperature at the end of the ZFE is lower than the initial discharge temperatures. For these calculations, it was assumed that the diameter of Units 3-4 discharge is 1.8 m (6 ft) and that of Units 5-6 discharge is 0.9 m (3 ft). The initial excess temperatures and the predicted excess temperatures at the end of the ZFE are presented in Table 5.4. The same calculations indicated that the discharges reach or nearly reach the river surface at the end of ZFE.

Next, the behavior of the two discharges was predicted using the Shirazi-Davis surface discharge model[66] assuming that the initial excess temperatures are those calculated at the end of ZFE. This model again uses the integral equation of mass, energy, and momentum to describe the jet behavior in the ZEF. It is further assumed in this model that the temperature and velocity profiles in ZEF are Gaussian. The results

TABLE 5.4. ESTIMATED EXCESS TEMPERATURES IN THE HIGH BRIDGE GENERATING PLANT DISCHARGES °C (°F)

	At Discharge	At End of ZFE	At Point of Discharge Jet Interference	
Units 3-4 Discharge				
Present				
Winter	9.8 (17.6)	8.5 (15.3)	9.8 (17.6)	
Summer	6.6 (11.9)	5.6 (10.1)	6.6 (11.9)	
Unit 3 Cogeneration				
Winter	7.3 (11.8)	6.1 (11.0)	7.3 (11.8)	
Summer	4.9 (8.9)	4.3 (7.8)	4.9 (8.9)	
Units 5-6 Discharge				
Present				
Winter	16.5 (29.6)	14.3 (25.5)	12.1 (21.8)	11.8 (21.3)*
Summer	10.7 (19.3)	9.2 (16.6)	7.7 (13.8)	7.4 (13.5)*
Unit 6 Cogeneration				
Winter	10.9 (19.7)	9.4 (16.9)	7.7 (13.8)	
Summer	7.2 (12.9)	6.6 (11.9)	5.4 (9.8)	
Units 5 and 6 Cogeneration				
Winter	6.6 (11.8)	5.8 (10.4)	4.4 (7.9)*	
Summer	4.3 (7.7)	3.8 (6.8)	2.8 (5.0)*	

*With Unit 3 in Cogenerating Mode of Operation.

predicted for the two discharges were plotted to determine where the boundaries (location where the ratios of local temperature to the centerline temperature is 1/e) coincide. It was found that the discharges started to "merge" about 1-1.2 m (3-4 ft) downstream of Unit 3-4 discharge and 5-5.5 m (16-18 ft) downstream of Unit 5-6 discharge. This location is well within the ZFE for Units 3-4 discharge, but downstream of the ZFE for the Units 5-6 discharge. It was assumed, therefore, that the temperature of Units 3-4 discharge at this point is the same as that at the discharge structure. The temperature of the Units 5-6 discharge stream at this point is lower than that at the end of the ZFE. Values for these temperatures are given in Table 5.4.

Downstream of the point where the jet boundaries coincide, it was assumed that the two discharges merge into a single surface discharge jet. For the initial condition of the combined jet, it was assumed the discharge velocities are the vectorial sums of the weighted initial velocities of the individual discharge jets and that the excess temperatures are the sums of the weighted temperatures at the point where the discharge boundaries coincide. It was assumed that the initial discharge depth is 1.83 m (6.0 ft) on the basis of the depth of the two discharges at the point of coincidence. Values of these initial parameters are presented in Table 5.5. The excess temperatures in the combined surface discharge region were again predicted using the Shirazi-Davis Model.[66]

The predicted excess temperatures in the Mississippi River are presented in Figures 5.4 and 5.5. Figure 5.4 shows the surface areas in the river having excess temperatures greater than the indicated values for the winter conditions. Figure 5.5 shows the same for the summer conditions.

TABLE 5.5. ASSUMED INITIAL PARAMETERS FOR COMBINED SURFACE DISCHARGE AT HIGH BRIDGE GENERATION PLANT

	Flow Rate m^3/s (ft^3/s)	Velocity m/s (ft/s)	Excess Temperature °C (°F)	Depth m (ft)	Angle* Degrees
Present					
Winter	9.27 (327.4)	1.83 (6.00)	11.2 (20.2)	1.83 (6.0)	43
Summer	13.97 (493.5)	2.79 (9.16)	7.3 (13.1)	1.83 (6.0)	43
Unit 3 Cogeneration					
Winter	7.49 (264.5)	2.01 (6.61)	10.8 (19.4)	1.83 (6.0)	40
Summer	11.37 (401.0)	3.10 (10.18)	6.9 (12.5)	1.83 (6.0)	40
Unit 6 Cogeneration					
Winter	9.27 (327.4)	1.83 (6.00)	8.4 (15.2)	1.83 (6.0)	43
Summer	13.97 (493.5)	2.79 (9.16)	5.9 (10.6)	1.83 (6.0)	43
Units 3, 5, and 6 Cogeneration					
Winter	7.49 (264.5)	2.01 (6.61)	5.1 (9.1)	1.83 (6.0)	40
Summer	11.36 (401.0)	3.10 (10.18)	3.3 (5.9)	1.83 (6.0)	40

*Relative to river bank.

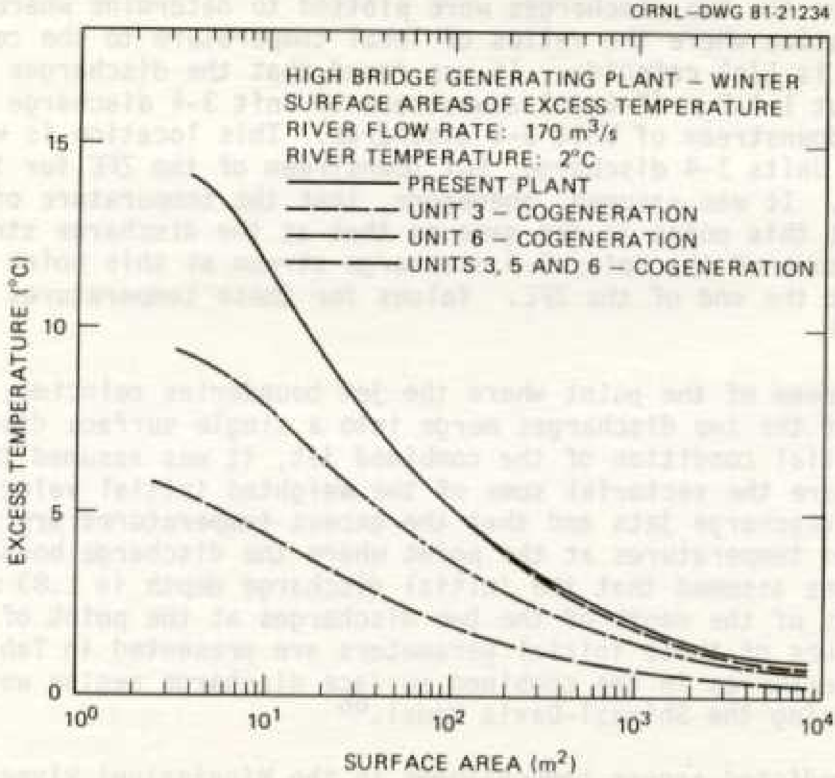

Fig. 5.4. River surface areas of excess temperatures at High Bridge Generating Plant - winter.

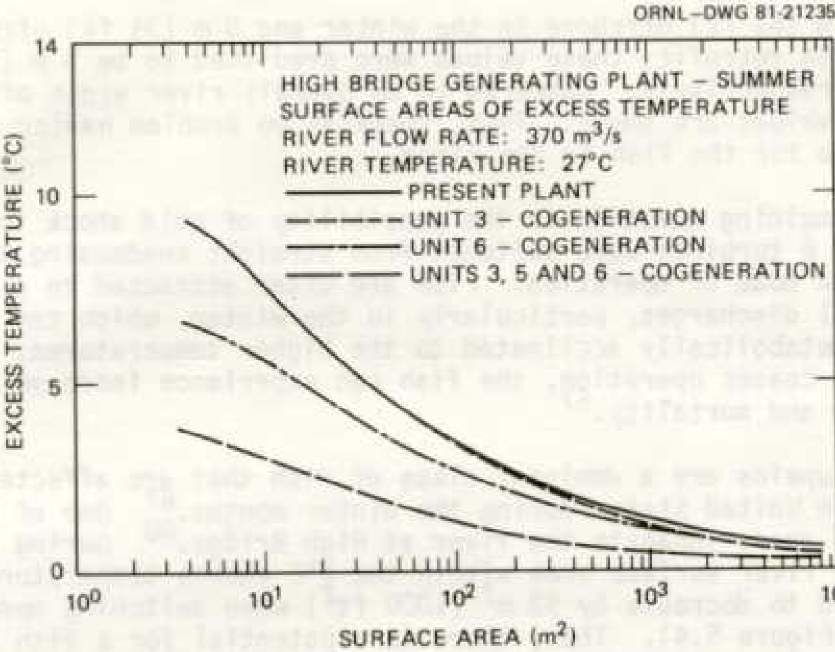

Fig. 5.5. River surface areas of excess temperatures at High Bridge Generating Plant - summer.

As expected, conversion of Units 3, 5, and 6 at High Bridge to cogeneration operation reduces the impact of the plant on the river temperatures. The initial temperatures of the discharging water would be much lower with cogeneration and smaller portions of the river would be exposed to the higher temperature water. Since Unit 5-6 discharge generally would have a higher temperature than Unit 3-4 discharge, most of higher excess temperatures in the river would be due to the Unit 5-6 discharge.

Because of the geometries and velocities of the two discharges, there appears to be considerable dilution of Units 5-6 discharge water before it mixes very much with Units 3-4 discharge water. However, the dilution of Units 3-4 discharge water at this point appears to be very limited. Thus removing Unit 3 circulating water from Units 3-4 discharge due to conversion to back-pressure cogeneration would have a very limited impact on the river temperature.

Conversion of Units 5 and 6 turbines to condensing tail cogeneration units would have significant impacts on the river temperature. Conversion of Unit 6 would result in a factor of 2 to 2.5 reduction in the area of the river that would be exposed to significant excess temperature. Conversion of units 5 and 6 would reduce this area by about an order of magnitude.

The areas of the river within the discharge mixing zones (having greater than 5°C excess temperatures) are calculated to be small compared to the overall size of the river at the plant. At the present time at the point where the discharge water thermal plume centerline excess temperature is reduced to 5°C, it was predicted that the outer boundary of the plume is located 19 m (61 ft) offshore in the winter and 9 m (31 ft) offshore in the summer. With retrofit, these values were predicted to be 5 m (15 ft) and 3 m (10 ft), respectively. Compared to an overall river width of 210 m (700 ft), these values are small. Thus, there is no problem having an adequate passage zone for the fish in the river.

The remaining question is the possibility of cold shock to the fish if Units 5 and 6 turbines were switched from straight condensing mode to cogeneration mode of operation. Fish are often attracted to power plant warm thermal discharges, particularly in the winter, which can cause them to become metabolically acclimated to the higher temperatures. If the power plant ceases operation, the fish can experience increase loss of equilibrium and mortality.[67]

The clupeids are a dominant class of fish that are affected by cold shock in the United States during the winter months.[67] One of these, the gizzard shad, inhabits the river at High Bridge.[60] During the winter, the river surface area within the 5°C excess temperature isotherm is predicted to decrease by 93 m^2 (1000 ft^2) when switching modes of operation (Figure 5.4). Thus, there is a potential for a fish kill if this were to happen. Fortunately, NSP's peak electrical demand is in the summer when the cold shock effects during the warmer period is minimal.[67,68] During the winter months, it is likely that the plant would not switch modes of operation, but operate only in the cogeneration mode, which would minimize the adverse cold shock effects at that time. Other fishes that are predominant in the High Bridge river area are walleye, northern pike, channel catfish, river shiner, smallmouth bass, and carp.[60] These species are more tolerant of the cold than gizzard shad, and thus are less susceptible to adverse effects from cold shock.[67,68]

5.3 RIVERSIDE GENERATING PLANT

5.3.1 Circulating Water Discharge System

Riverside Generating Plant presently utilizes three once-through circulating water systems, as illustrated in Figure 5.6. Circulating water for Units 1 and 2 turbines is withdrawn from the river through #400 screen house and is discharged to the river through pipes terminating at the river bank. For Unit 6 turbine, the circulating water is withdrawn through #900 screen house and is discharged through a pipe terminating in the middle of the river. Similarly for Unit 8 turbine, the circulating water is withdrawn from the river through #2400 screen house and is discharged through a separate pipe terminating in the middle of the river. (The fourth intake structure, designated as #225 screen house in Figure 5.6, was used for now retired Units 3, 4, and 5.) The circulating water system for each turbine has two pumps. Both pumps are operated during the summer, but only one pump is operated during the winter [intake temperature less than 10°C (50°F)].[61]

Boilers 6 and 7 provide steam for Units 1, 2, and 6 turbines. (Unit 7 turbine has been retired.) Boiler 8 is dedicated to the Unit 8 turbine, ORNL DWG 82-7956

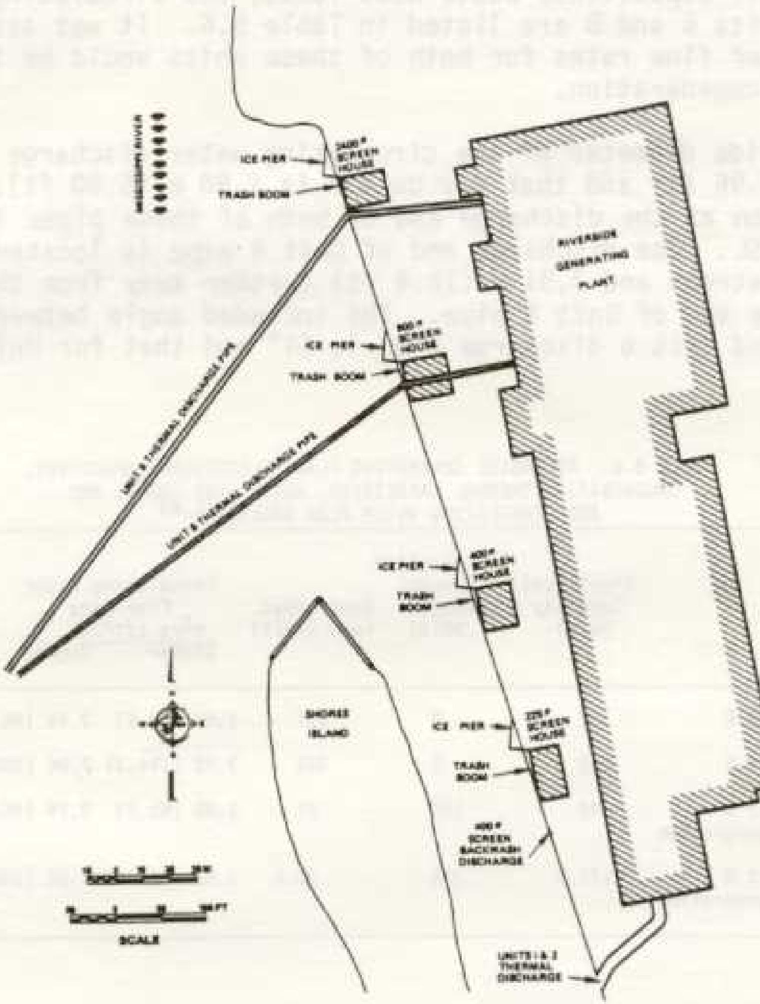

Fig. 5.6. Schematic of Riverside Generating Plant showing location of intake structures, plant, and discharges.[61]

the newest and largest unit at the plant. At full load conditions, the plant is limited to discharging 527 (MW(t) (1.8×10^9 Btu/hr) of heat to the river.[63] Of this 322 MW(t) (1.1×10^9 Btu/hr) is from Unit 8. The sources of the remaining heat depends on what combinations of Units 1, 2, and 6 are operated. If Unit 6 is operating at full load, Units 1 and 2 can be operated only at partial loads. If Unit 6 is not operating, Units 1 and 2 can be operated at higher loads.

For the study reported herein, only the impacts of retrofitting Units 6 and 8 turbines were analyzed.* The electrical capacities, cogene-

*It is extremely unlikely that Units 1 and 2 turbines would be converted to cogeneration operation since they are relatively old and have small capacity. The feasibility/economic study[1] visualized replacing the retired Unit 7 turbine with a new cogeneration turbine. It is likely that any new unit would have a closed circulating water system, and its impact on the river temperature would be relatively small compared to those from Units 6 and 8 turbines.

ration thermal capacities, waste heat loads, and circulating water flow rates for Units 6 and 8 are listed in Table 5.6. It was assumed that circulating water flow rates for both of these units would be the same with and without cogeneration.

The inside diameter of the circulating water discharge pipe for Unit 6 is 2.12 m (6.96 ft) and that for Unit 8 is 1.98 m (6.50 ft). The centerline elevation at the discharge end of both of these pipes is 236.8 m (776.9 ft) MSL. The discharge end of Unit 8 pipe is located 3.23 m (10.6 ft) upstream and 3.91 m (12.8 ft) further away from the plant than the discharge end of Unit 6 pipe. The included angle between the river centerline and Unit 6 discharge pipe is 54° and that for Unit 8 discharge pipe is 37°.

TABLE 5.6. RIVERSIDE GENERATING PLANT ELECTRICAL CAPACITIES, COGENERATION THERMAL CAPACITIES, WASTE HEAT LOADS, AND AND CIRCULATING WATER FLOW RATES[1,61,63]

	Electrical Capacity MW(e)	Cogeneration Thermal Capacity MW(t)	Waste Heat Load (MW(t)	Circulating Water Flow Rate m^3/s (ft^3/s)	
				Winter	Summer
Unit 6	62	0	117	1.80 (63.5)	2.75 (96.9)
Unit 8	216	0	322	3.52 (124.3)	7.04 (248.6)
Unit 6 Cogeneration	48	110	21	1.80 (63.5)	2.74 (96.9)
Unit 8 Cogeneration	127.5	330	80.5	3.52 (124.3)	7.04 (248.6)

5.3.2 Analysis and Results

The analysis was done for Riverside Units 6 and 8 operating in their present configuration at full load and retrofitted for condensing tail cogenerating operation at full load. The circulating water flow rates, velocities, and excess temperatures for these two configurations are listed in Table 5.7. It can be seen that converting these turbines to cogeneration units would result in relatively large decreases in the discharge water temperatures.

As for High Bridge, the water discharge into the river from the discharge pipes can be considered as buoyant jets, and they will behave as discussed for the High Bridge analysis (Section 5.2.2). Since Riverside Units 6 and 8 circulating water normally discharges 6.8 m (22.3 ft) below the river, the Hirst model for predicting the behavior of submerged buoyant jets[64,65,69,70] was used to model the behavior of each of these discharges. This integral model was used here to predict the discharge water temperature in both the ZFE and ZEF for the units operating in their present configuration and modified for cogeneration operation.

TABLE 5.7. CIRCULATING WATER PARAMETERS AT THE RIVERSIDE GENERATING PLANT UNITS 5 AND 6 DISCHARGES

	Unit 6 Discharge	Unit 8 Discharge
Flow Area, m^2 (ft^2)	3.53 (38.0)	3.08 (33.2)
Flow Rate, m^3/s (ft^3/s)		
Winter	1.80 (63.5)	3.52 (124.3)
Summer	2.74 (96.9)	7.04 (248.6)
Velocity, m/s (ft/s)		
Winter	0.51 (1.67)	1.14 (3.75)
Summer	0.78 (2.55)	2.28 (7.49)
Excess Temperature °C (°F)		
Present		
Winter	15.6 (28.0)	21.9 (39.4)
Summer	10.2 (18.4)	10.9 (19.7)
Cogeneration		
Winter	2.8 (5.1)	5.4 (9.8)
Summer	1.8 (3.3)	2.7 (4.9)

The Hirst model predicted that in the winter scenario the individual jets started to "merge" at about 18 m (60 ft) downstream of the discharge pipes. However, the predicted overlap of the jet boundaries does not become significant (where there is interference equal to one-half of the jet radius) until about 36 m (120 ft) downstream of the discharge pipes. By the time the discharge water reaches this point, it has entrained sufficient river water to have relatively low (less than 2°C for the worst case) excess temperature. In the summer scenario, the jets do not start to "merge" until they are relatively far (greater than 60 m [200 ft]) downstream of the discharge pipes. Therefore, as a first approximation, it was reasonable to assume that the two discharges behave as individual jets.

The volumes of water in the Mississippi River having excess temperature due to the operation of Riverside Units 6 and 8 are shown in Figures 5.7 and 5.8. It can be readily seen that converting these units to cogeneration would reduce the excess temperatures dramatically. The volume of water associated with a given excess temperature would be reduced by at least an order of magnitude after converting these units.

The volume of water within the discharge mixing zones (having greater than 5°C excess temperatures) are small compared to the overall size of the main river channel at the Riverside plant. Here at the present time, at the points where the discharge water therml plumes' centerline temperature is reduced to 5°C, it was predicte that combined widths of the plumes are 10 m (34 ft) in the winter and 8 m (25 ft) in the summer. With retrofit, this values were predicted to be negligible. Compared to the river main channel width of 120 m (400 ft), these values are small. Thus again, there is no problem having an adequate passage zone for the fish in the river.

Potential cold shock problems, when switching from straight condensing mode to cogeneration mode of operation, should be minimal at Riverside. Up to the middle 1970's, the presence of gizzard shad in the river at this plant has not been observed.[61] The fish population at Riverside

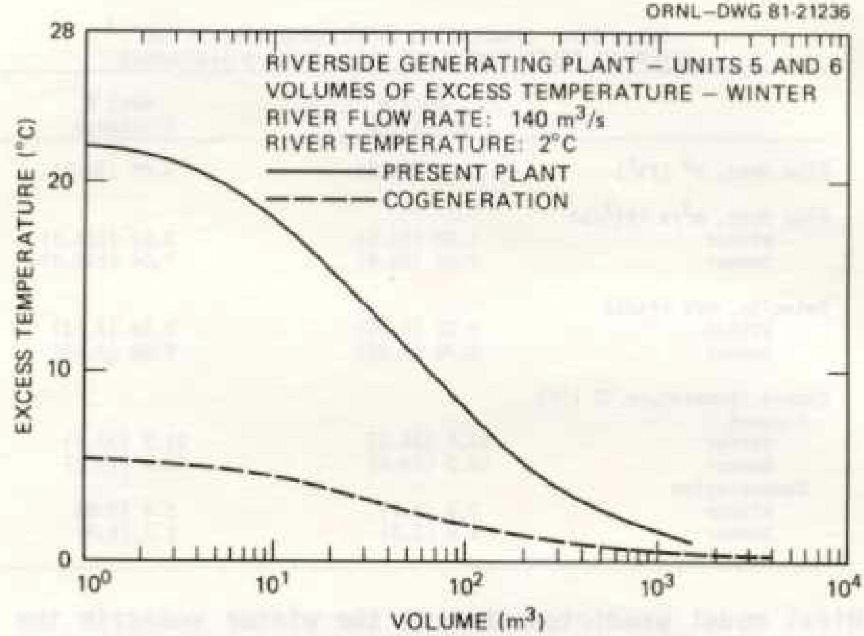

Fig. 5.7. River volumes of excess temperatures at Riverside Generating Plant - winter.

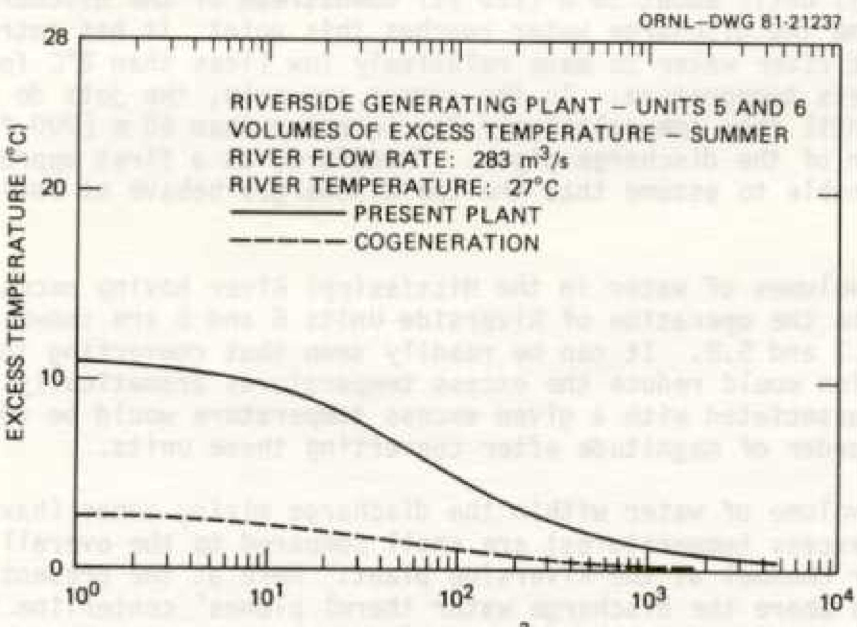

Fig. 5.8. River volumes of excess temperatures at Riverside Generating Plant - summer.

consist predominantly of walleye, northern pike, black crappie, channel catfish, river shiner, smallmouth bass, and carp.[61] These fishes can acclimate to the cold water temperatures during the winter, and they are less susceptible than gizzard shad to adverse effects from cold shock.[67,68]

SECTION 6

ENVIRONMENTAL IMPACTS OF COAL STORAGE AND SOLID WASTE DISPOSAL AT THE NEW 190 MW(e)/335 MW(t) COGENERATION PLANT

6.1 TYPES OF WASTES AND DISPOSAL REGULATIONS

The new 190 MW(e)/335 MW(t) cogeneration plant envisioned for the city-wide heating/cogeneration system would produce a number of liquid and solid wastes which would require environmentally acceptable methods of disposal. Significant liquid waste streams are, generally, the result of runoff from coal, solid waste, and sorbent storage piles. In this study is was assumed that sorbent would be stored in silos, eliminating runoff from sorbent storage. The principal solid wastes produced at the power plant would be fly ash, bottom ash, and flue gas desulfurization (FGD) waste. It was assumed that all fly ash and FGD waste would be collected in the particulate control equipment. This is a reasonable assumption since NSPS allows no more than 0.013 g/MJ (0.03 lb/million Btu) of TSP be released.[20] A relatively small quantity of solid waste material would be generated at the liquid waste treatment facilities. However, it was assumed that the volume of wastes generated at the treatment facilities would be negligible compared to the overall volume.

Regarding the liquid wastes, a zero discharge philosophy was assumed here, that is, all liquid waste streams would be processed and either returned for plant use or evaporated. During upset conditions, or periods of uncommonly heavy rainfall, excess waste could be discharged into the municipal sewer system. Normally, however, the liquid wastes entering the site liquid waste treatment plant would be pretreated with calcium oxide (CaO) or sulfuric acid (H_2SO_4), depending on the pH of the entering liquids, in order to precipitate dissolved chemical species. Filtration would then be employed, which would remove the major portion of the precipitate and any other suspended solids.

Two different types of combustors for the new cogeneration plant are considered here, a pulverized coal combustor, which is the firing method used by most coal fired power plants, and an atmospheric fluidized bed combustor (AFBC). These are the type of units considered in the conceptual design study for this plant.[19] The total quantity of coal ash, both fly and bottom ash, would be about the same for both types of combustors. However, due to the differences in SO_2 control mechanisms, the quantity and composition of the FGD waste from the two types of combustion systems will be different. The quantity of FGD waste is dependent on sulfur capture efficiency. When firing the assumed design coal, which has a sulfur content of 0.9%, an ash content of 10.8%, and a higher heating value of 19.3 MJ/kg (8300 Btu/lb), the sulfur capture efficiency required by the NSPS is 72.3%.[20,21]

It is anticipated that solid waste would be disposed of in a landfill several kilometers from the plant. A landfill of the size required for a 190 MW(e)/335 MW(t) cogeneration facility would require the granting of a permit by the Minnesota Pollution Control Agency. Rather porous rock, such as sandstone bedrock, or sandstone together with dolomite, underlies much of the Minneapolis-St. Paul area.[1] Due to the nature of the underlying rock, it would probably be necessary to line the landfill site, as well as the coal and ash pile sites, with an impervious material such as bentonite, to control ground water contamination by leaching. It is beyond the scope of this study to determine, quantitatively, the expected impacts on ground water in the vicinity of the landfill site.

Federal regulations pertaining to solid waste disposal are in the form of the Resource Conservation and Recovery Act of 1976 (RCRA), which is administered by EPA. In the interim hazardous waste regulations promulgated on May 19, 1980, EPA specifically excluded large volume utility wastes from regulation under the hazardous waste section of RCRA.[71] Similarly, scrubber sludge and ash are not considered hazardous wastes as defined by Minnesota Statute 116.06, Subdivision 13.[5] However, if low volume hazardous wastes, such as metal cleaning wastes, were combined with scrubber sludge and ash, the entire mixture may be classified as hazardous.[69] In this study, it was assumed that low volume hazardous wastes would be disposed of separately and in an environmentally suitable manner.

6.2 COAL STORAGE LEACHING

The main environmental concern associated with coal piles is liquid runoff which generally is acidic and usually contains suspended solids and dissolved solids, such as sulfates, iron, and various trace elements. The flow of runoff is not constant but is a function of precipitation rate. As water seeps down through the pile, it picks up small solids and water soluble metal salts. The runoff would be collected and sent to a on-site liquid treatment plant where the liquid would be neutralized and filtered to remove suspended solids and precipitate.

The mass of solids collected during the water treatment process would be greater than the total mass of contaminants originally present in the runoff, due to the addition of treatment chemicals. It has been found that approximately four moles of hydroxyl ion, in the form of slaked lime [$Ca(OH)_2$],[72] per mole of iron must be added to the runoff liquid to ensure neutralization.

The particular low sulfur western coal envisioned to be used in the new unit[19] cannot be identified at this time. In lieu of specific information, runoff data for an average of western coals[73] were used to determine concentrations of various runoff constituents. These concentrations are given in Table 6.1. Using those values, calculations yield a value of 4.41×10^3 g/m^3 (0.275 lb/ft^3) of total solids, including treatment chemicals, that would be removed from the runoff.

The average annual precipitation rate in the Minneapolis-St. Paul area is 652.2 mm/y (25.4 in./y),[34] and the conceptual design of the new cogeneration plant indicates that the area of the base of the coal pile would be about 37,740 m^2 (406,200 ft^2).[19] For the purpose of this study, a conservative runoff coefficient, which is the fraction of the precipitation incident on the coal pile which exists as runoff, of 0.8 is assumed. The annual average runoff is calculated to be 1.948×10^4 m^3/y

TABLE 6.1. RUNOFF CONSTITUENT CONCENTRATIONS OF AN AVERAGE WESTERN COAL STORAGE PILE[73]

Constituent	Concentration (g/m^3)
Total Suspended Solids	2.485×10^3
Total Dissolved Solids	1.900×10^3
Sulfates	2.40×10^2
Iron	8.20

(6.879×10^5 ft^3/y). Multiplying the average annual runoff volume by the average weight of solids per unit volume yield 8.59×10^4 kg/y (1.89×10^5 lb/y) of solids that would be collected. The collected solids would consist mainly of coal fines, dirt, and calcium compounds. Assuming that these collected solids are not considered hazardous, they would be disposed of with FGD and ash wastes.

6.3 DISPOSAL OF ASH AND FGD SYSTEM WASTE

The solid waste streams from pulverized coal fired units and AFBCs are different in composition and quantity. It is likely that the differences between the solid effluents could affect the means by which they are stored, handled, and disposed.

6.3.1 Pulverized Coal Unit

A pulverized coal fired unit produces approximately 20% bottom ash and 80% fly ash. Generally, some of the pyrite in the coal is separated out in the pulverizers, and may be added to the bottom ash portion for disposal.

When firing the design coal, the new cogeneration unit would produce a maximum of 1.34×10^8 kg/y (2.94×10^8 lb/y) of total ash.[19] The average total ash production rate, assuming a 65 percent load factor, would be 8.75×10^7 kg/y (1.93×10^8 lb/y). The corresponding bottom ash production rates are 2.59×10^7 kg/y (5.94×10^7 lb/y) maximum and 1.68×10^7 kg/y (3.70×10^7 lb/y) average. Fly ash would be produced at a rate of 1.08×10^8 kg/y (2.37×10^8 lb/y) maximum and 7.00×10^7 kg/y (1.54×10^8 lb/y) average.

Bottom ash consists mainly of silicon and aluminum oxides which are present in the original coal. Also present in bottom ash are oxides of other metals such as iron and the alkali earths. Bottom ash, as compared to coal and fly ash is enriched in some of the less volatile metals. It is likely that bottom ash would be disposed of in the same landfill as fly ash and FGD wastes.

The use of a dry lime FGD system and baghouse has been proposed for the new cogeneration plant.[19] The waste from a dry lime scrubber with a baghouse system is a powdery mixture of fly ash, spent sorbent, and lime inerts. The fly ash consists primarily of silicon, aluminum, iron, and alkali earth oxides. It is somewhat enriched in more volatile elements, especially mercury, lead, and selenium. Spent sorbent consists of calcium sulfate ($CaSO_4$), calcium sulfite ($CaSO_3$), and calcium oxide (CaO). For the dry lime scrubbing system, a stoichiometry of 1.35 moles CaO/mole SO_2 removed and 90% available reagent in the lime were assumed producing a waste having a sulfite to sulfate ratio in the waste is approximately 0.7/0.3.[74]

The quantity of FGD waste produced is dependent on the sulfur capture efficiency employed. Firing the design coal, a 72.3% sulfur capture efficiency is required to NSPS emission factor of 260 ng/J (0.60 lb/million Btu) for SO_2. Using this, together with a 65% load factor, the quantity of solid waste (including fly ash) resulting from flue gas clean-up would be 9.65×10^9 kg/y (2.12×10^8 lb/y). Thus, at this load factor, a total of 1.13×10^8 kg/y (2.5×10^8 lb/y) of solid waste would be produced.

Before final disposal, the combined fly ash and FGD wastes probably would be stored in a small stackout pile with runoff control systems similar to those of the coal storage pile.[19] Runoff from the stackout pile would be directed to the liquid waste treatment facility. It is believed that the additional solids generated by runoff treatment chemicals would not add significantly to the quantity of waste to be disposed.

Table 6.2 presents a summary of solid waste streams, emissions, fuel, and sorbent requirements, at various capacity factors, for the 190 MW(e)/ 335 MW(t) pulverized coal fired unit.

TABLE 6.2. FUEL, SORBENT, AND SOLID WASTE QUANTITIES ASSOCIATED WITH A 190 MW(e)/335 MW(t) PULVERIZED COAL-FIRED COGENERATION FACILITY

Load Factor percent	Fuel kg/y	Lime (72.3% efficiency) kg/y	FGD wastes + fly ash kg/y	Bottom Ash kg/y	Liquid Treatment Waste kg/y
100	1.2×10^9	2.08×10^7	1.48×10^8	2.59×10^7	8.59×10^4
75	9.3×10^8	1.56×10^7	1.11×10^8	1.94×10^7	8.59×10^4
65	8.1×10^8	1.36×10^7	9.65×10^7	1.68×10^7	8.59×10^4
50	6.2×10^8	1.04×10^7	7.42×10^7	1.29×10^7	8.59×10^4

6.3.2 Atmospheric Fluidized Bed Unit

An AFBC operates on a completely different principle than a pulverized coal fired furnace. In an AFBC a mixture of coal and limestone is fed to the combustor and fluidized by combustion air passing through the bed.

The bottom and fly ash percentages are different for an AFBC, as compared to pulverized coal firing. The design proposed for the new cogeneration facility would produce approximately 49.9% fly ash and 50.1% bed letdown solids.[19] Also, the proposed design calls for a calcium to sulfur stoichiometry of 3.91 moles calcium/mole sulfur removed, which is much greater than the stoichiometric ratio 1.35 assumed for the pulverized coal unit with a dry lime scrubbing. As a result of the relatively high calcium to sulfur stoichiometries, the AFBC would produce more solid waste than the pulverized coal combustor with dry lime scrubbing. The higher calcium requirement envisioned for the AFBC is consistent with the present state of technology.[75]

When firing the design coal at maximum rating, with the quantity of limestone required for 72.3% sulfur capture, there would be a total of 2.07×10^8 kg/y (4.58×10^8 lb/y) of waste produced. The average solid waste production rate, assuming a 65% load factor would be 6.74×10^7 kg/y (1.49×10^8 lb/y) of particulate matter and 6.76×10^7 kg/y (1.49×10^8 lb/y) of bed letdown solids.[19] At this load factor, a total of 1.35×10^8 kg/y (3.0×10^8 lb/y) of solid waste would be produced.

Waste from an AFBC consists primarily of coal ash and calcium compounds. It was estimated that at 90% sulfur capture efficiency, the calcium component of the AFBC waste would consist of 58% CaO and 24% $CaSO_4$ in an anhydrous form.[76] It is believed that the wastes from an AFBC are non-toxic and stable.[77] Therefore, it is anticipated that AFBC waste could be safely disposed of in the same manner as waste products from a pulverized coal plant with a dry FGD system, that is, in a prepared landfill.

AFBC wastes probably would be stored in a stackout pile before transportation to a final disposal site. Due to the relatively large proportion of free CaO in AFBC waste, the runoff from the stackout pile is reported to be highly alkaline.[76] Thus runoff from the AFBC waste stackout pile would be directed to the on-site liquid waste treatment plant. In this analysis, it is assumed that sulfuric acid is used to precipitate out the calcium in the runoff as $CaSO_4$ (gypsum). In this approach, an estimated 1.19×10^3 kg/y (4.20×10^3 lb/y) of additional waste would be generated.

Table 6.3 gives a summary of waste streams, emissions, fuel consumption, and sorbent requirements, at various capacity factors, associated with the proposed 190 MW(e)/335 MW(t) AFBC cogeneration facility.

TABLE 6.3. FUEL, SORBENT, AND SOLID WASTE QUANTITIES ASSOCIATED WITH A 190 MW(e)/335 MW(t) ATMOSPHERIC FLUIDIZED BED COMBUSTOR COGENERATION FACILITY

Load Factor percent	Fuel kg/y	Limestone (72.3% efficiency) kg/y	Bed letdown solids kg/y	Particulate matter kg/y	Liquid Treatment Waste kg/y
100	1.2×10^9	1.46×10^8	1.04×10^8	1.03×10^8	8.78×10^4
75	9.3×10^8	1.10×10^8	7.81×10^7	7.78×10^7	8.73×10^4
65	8.1×10^8	9.51×10^7	6.76×10^7	6.74×10^7	8.71×10^4
50	6.2×10^8	7.31×10^7	5.21×10^7	5.19×10^7	8.69×10^4

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APPENDIX A

PROCEDURES FOR CALCULATING SOURCE EMISSIONS

PROCEDURES FOR CALCULATING SOURCE EMISSIONS

The sources of sulfur dioxide (SO_2) and total suspended particulate (TSP) emissions in the Twin Cities study were classified into four categories:

(1) Generating plant sources,
(2) Point sources,
(3) Commercial and industrial area sources,
(4) Residential area sources

These categories were selected primarily on the basis that a different procedure was used to estimate the emission rates for each of them.

This Appendix describes the procedure and assumptions used to calculate the SO_2 and TSP emissions for each of the last three categories. The procedure and assumptions used to calculate the generating plant emission sources are described in Section 4.3.1 of the main report.

For all categories of sources, emission rates were calculated on an annual average basis and for the six selected 24-h episodes listed in Section 4.2 of the main report. The heating degree days associated with each of those episodes are given in Table A.1.

TABLE A.1. HEATING DEGREE DAYS FOR SELECTED 24-h EPISODES

Episode	Celsius Heating Degree Days[a]
1	24.2
2	28.9
3	28.1
4	25.3
5	35.6
6	0.0

[a]Based on 18.3°C.

A.1 POINT EMISSION SOURCE CALCULATION PROCEDURE

A.1.1 Annual Emissions

The point emission source inventories were developed from 1976 Natural Emission Data System (NEDS) data for the region and the gas curtailment plans developed by Northern Natural Gas Company, the supplier for the Twin Cities area. The 1976 annual data in the NEDS file were reviewed and updated by the Minnesota Energy Agency (MEA).[1,2] Totals of the 1976 emission rates for these sources are given in Table A.2.

The 1987 annual emission rates were estimated from the corrected 1976 data and the quantities of alternate fuels that were substituted for curtailed natural gas in 1976 and projected curtailed natural gas in 1987. Totals of the 1987 rates for the point sources are also given in Table A.2.

TABLE A.2. TOTAL EMISSION RATES FROM POINT SOURCES EXCLUDING POWER AND HEATING PLANTS, g/s

		Old Natural Gas Curtailment Plan			New Natural Gas Curtailment Plan		
	1976	1987 Without District Heating/ Cogeneration	1987 With District Heating/ Cogeneration	1987 Change	1987 Without District Heating/ Cogeneration	1987 With District Heating/ Cogeneration	1987 change
			SO_2 Emission Rates				
Annual	1048	1236	1158	-78	1127	1054	-73
Episode 1	2053	2350	2192	-158	1953	1850	-103
Episode 2	2588	2701	2514	-187	2685	2503	-182
Episode 3	2506	2637	2457	-180	2515	2350	-165
Episode 4	2123	2432	2268	-164	2147	2028	-119
Episode 5	3191	3191	2969	-222	3191	2969	-222
Episode 6	465	465	450	-15	471	456	-15
			TSP Emission Rates				
Annual	558.7	583.6	575.8	-7.8	559.9	553.0	-6.0
Episode 1	1075.1	1110.5	1094.0	-16.5	946.1	936.8	-9.3
Episode 2	1265.3	1283.8	1264.6	-19.2	1282.4	1263.7	-18.7
Episode 3	1231.9	1252.9	1234.1	-18.8	1233.6	1217.5	-16.1
Episode 4	1114.4	1151.2	1134.0	-17.2	1117.1	1105.5	-11.6
Episode 5	1527.9	1527.9	1504.4	-23.5	1527.9	1504.4	-23.5
Episode 6	204.1	204.1	202.4	-1.7	204.3	202.9	-1.4

Natural gas users in the Twin Cities area are assigned priority classes according to need; the classification is used to determine the order of curtailment when the supply of natural gas becomes insufficient. The curtailment plan in effect at the time when the previous air quality study[1] was done is presented in Table A.3. This plan has 11 priority classes: Class 1, which includes the residential customers, having the highest priority; and Class 11, the generating plants, having the lowest priority. Subsequent to the previous study, the 1978 Natural Gas Policy Act was passed, and a new curtailment plan was developed.[3] The revised plan is presented in Table A.4, and it reflects that the availability of natural gas for 1987 will be higher than anticipated in the previous plan. The number of priority classes in the revised plan was reduced to eight.

Natural gas curtailment factors, defined as:

$$C_f(76) = \frac{D(76) - S(76)}{S(76)}, \qquad (1)$$

TABLE A.3. PRIORITIES OF SERVICE AS PROPOSED IN NORTHERN NATURAL GAS COMPANY CURTAILMENT PLAN (EFFECTIVE IN 1976)[2]

Priority 1	Residential, small commercial, and industrial requirements (less than 200 Mcf on a peak day).
Priority 2	(a) Customer storage injection requirements, (b) Firm industrial requirements for plant protection, feed-stock, and process needs, or (c) Commercial and industrial requirements 200 to 499 Mcf per day and less than 50,000 Mcf annually. NOTE: If curtailment in Priority 2 is required, the order of curtailment is (c), (b), and (a).
Priority 3	All commercial requirements from 500 Mcf per day through 1499 Mcf per day and all industrial requirements not specified in Priorities 1, 2, 4, 5, 6, 7, 8, 9, or 10.
Priority 4	Firm commercial requirements or firm industrial requirements for boiler fuel use (from 1500 Mcf per day through 2999 Mcf per day), where alternative fuel capabilities can meet such requirements.
Priority 5	Firm commercial requirements or firm industrial requirements for boiler fuel use (3000 Mcf or more per day), where alternative fuel capabilities can meet such requirements.
Priority 6	Industrial requirements of more than 3000 Mcf per day during the summer period (Mar. 27 through Sept. 26) from the data of FERC.
Priority 7	Interruptible industrial requirements not specified in Priority 11 from 500 Mcf per day through 1499 Mcf per day, where alternative fuel capabilities can meet such requirements.
Priority 8	Interruptible industrial requirements not specified in Priority 11 and interruptible commercial requirements from 1500 Mcf per day through 2999 Mcf per day where alternative fuel capabilities can meet such requirements.
Priority 9	Interruptible industrial requirements not specified in Priority 11 and interruptible commercial requirements from 3000 Mcf per day through 9999 Mcf per day where alternative fuel capabilities can meet such requirements.
Priority 10	Interruptible industrial requirements not specified in Priority 11 and interruptible commercial requirements of 10,000 Mcf per day or more where alternative fuel capabilities can meet such requirements
Priority 11	"EG Plant Sales" which shall mean gas used except for plant protection by the gas utility itself in, or resold by the gas utility, to an electrical generation plant on an interruptible basis where the requirements of such electrical generation plant equals or exceeds 200 Mcf per day or equivalent.

$$C_f(87) = \frac{D(87) - S(87)}{S(76)}, \tag{2}$$

where, $C_f(76)$ = curtailment factor in 1976,

$C_f(87)$ = curtailment factor in 1987,

$D(76)$ = natural gas demand in 1976,

$D(87)$ = natural gas demand in 1987,

$S(76)$ = natural gas sales in 1976,

$S(87)$ = natural gas sales in 1987,

TABLE A.4. REVISED PRIORITY CLASS DEFINITIONS - NORTHERN NATURAL GAS COMPANY (EFFECTIVE IN 1979)[3]

Priority 1	(a) Residential, small commercial and irrigation requirements less than 50 Mcf on a peak day. (b) All commercial and irrigation requirements from 50 Mcf per day through 199 Mcf per day and all industrial requirements through 199 Mcf per day. (c) Customer storage injection requirements. (d) Requirements greater than 199 Mcf per day for schools, hospitals, sanitation facilities, correctional institutions, police protection, and fire protection except where the use of a fuel other than natural gas is economically practicable and that fuel is reasonably available. (e) Requirements for essential agricultural uses as certified by the USDA except where the use of boiler fuel other than natural gas is economically practicable and that fuel is reasonably available. If curtailment in priority class 1 is required, the order or curtailment shall be (e), (d), (c), (b), and then (a).
Priority 2	Requirements for essential process and feedstock uses and plant production other than when production operations are shut down, except where the use of a fuel other than natural gas is economically practicable and that fuel is reasonably available.
Priority 3	All commercial and industrial requirements from 200 Mcf per day through 499 Mcf per day, not otherwise classified.
Priority 4	All commercial and industrial requirements for non-boiler use 500 Mcf per day and over, not otherwise classified; all commercial requirements from 500 Mcf per day through 1499 Mcf per day, not otherwise classified.
Priority 5	Industrial requirements for boiler fuel use from 500 Mcf per day through 1499 Mcf per day, not otherwise classified.
Priority 6	Commercial and industrial requirements for boiler fuel use from 1500 Mcf per day through 2999 Mcf per day, not otherwise classified.
Priority 7	Commercial and industrial requirements for boiler fuel use from 3000 Mcf per day through 10,000 Mcf per day, not otherwise classified.
Priority 8	Commercial and industrial requirements for boiler fuel use over 10,000 Mcf per day, not otherwise classified.

were derived from the data presented in the two plans,[2,3] and they are listed in Table A.5. In deriving the factors for the revised plan, the eight priority classes in that plan were recast into the eleven priority classes used in the previous plan. Details of this procedure are given by Cole and Kinnear (Appendix D of this report).[3]

The 1987 natural gas sales then were estimated from the 1976 sales data and these factors assuming that the demands are the same for the two different years.

$$S(87) = [1 + C_f(76) - C_f(87)]S(76) . \qquad (3)$$

The percentage of the 1976 natural gas sales that will be curtailed in 1987 then can be calculated as

$$\%\ \text{curtailed} = \frac{S(76) - S(87)}{S(76)}(100) = [C_f(87) - C_f(76)](100) . \qquad (4)$$

TABLE A.5. NATURAL GAS ANNUAL CURTAILMENT FACTORS AND CURTAILMENT TEMPERATURES[2,3]

Priority Class	Annual Curtailment Factor 1976	1987-old curtailment plan	1987-new curtailment plan	Curtailment Temperature °C 1976	1987-old curtailment plan	1987-new curtailment plan
1	0.196	0.196	0.197	-10.0	8.9	-10.6
2	0.179	0.669	0.263	-10.6	1.7	-10.0
3	0.303	1.059	0.110	-8.3	8.9	-8.3
4	0.643	0.534	0.471	0.0	-3.9	-11.1
5	0.532	1.437	0.445	-2.2	8.9	-6.1
6	0.0	0.143	0.0	-17.8	-10.0	-5.6
7	0.776	1.112	0.652	2.8	8.9	-2.8
8	0.828	0.970	0.518	3.9	8.3	-6.1
9	0.819	1.080	0.551	3.3	8.9	-5.6
10	0.819	1.819	1.424	5.6	8.9	-5.6
11	5.837	6.837	6.837	8.9	8.9	18.3

Data identifying the priority class for each point source natural gas customer and the fuel used to replace the curtailed natural gas for this customer were developed by MEA.[1,2] Using these data, the change in the pollutant emission rate, ΔE, can be calculated by the relation:

$$\Delta E = T_{NG}(76) \quad (\Delta C_f) \quad \left[\frac{H_{NG}}{H_{AF}}\right] \mu_{AF} - \mu_{NG} \quad , \tag{5}$$

where $T_{NG}(76)$ = natural gas use in 1976,

ΔC_f = change in curtailment factor from 1976 to 1987,

H_{NG} = heating value of natural gas,

H_{AF} = heating value of alternate fuel,

μ_{NG} = emission factor of natural gas,

μ_{AF} = emission factor of alternate fuel.

Values of H and μ assumed in calculating the 1987 emission rates were assumed to be those listed in Ref. 4.

With the full development of the city-wide district heating/ cogeneration system, the overall point source emission rates will decrease due to connections to the system. The sources that would connect to the system were identified by the MEA in the previous annual air quality study.[1,2] It was assumed for those sources connecting to the system, the annual average emission rate is reduced equivalent to that portion of the source energy used for space heating. Totals of the 1987 emission rates modified for connections to the district heating system are given in Table A.2.

A.1.2 24-h Episode Emission

For the 24-h episodes, estimates were made by Cole and Kinnear[3] of the temperatures below which natural gas supply to the users would be discontinued. These temperatures are listed in Table A.5. They were determined for the first ten priority classes from Northern Natural Gas Company data of natural gas supplies available for the State of Minnesota and recognizing that the gas is used both for process heat and space heat. It was assumed that Priority Class 11, the power plants, will not use any natural gas at or below 18.3°C. The process heat demands were assumed to be constant throughout the year and the space heat demands were assumed to be proportional to the number of heating degree days.

For each of the ten priority classes, the fraction of annual energy that is used for space heat was assumed to be the value given in Table A.6.

TABLE A.6. ASSUMED ANNUAL VALUES OF FUEL FRACTION USED FOR SPACE HEATING[3]

Priority Class	Fraction Used for Space Heating
1	0.70
2	0.60
3	0.50
4	0.40
5	0.20
6	0.20
7	0.20
8	0.20
9	0.20
10	0.20

The remaining portion of energy in each priority class was assumed to be used for the process heat. It was further assumed here that there are 4533 Celsius heating degrees per year, the value for a typical year in the Twin Cities.[5] The daily energy requirements then can be determined by the relation

$$DE = AE \left[\frac{f}{4533} (HDD) + \frac{1-f}{365} \right] , \qquad (6)$$

where, DE = daily energy requirement,

AE = annual energy requirement,

f = fraction of annual energy used for space heat,

HDD = Celsius heating degree days for the selected day.

Starting with the coldest day of the year, values of DE were determined for each succeeding warmer day and summed with the values of DE for all the days having colder temperatures. When the value of this sum was equal to the energy equivalent to the total annual amount of natural gas that is curtailed for that priority class, the average temperature for that day was assumed to be the curtailment temperature. Further details are given by Cole and Kinnear.[3]

Using these curtailment temperatures, the daily emission rates were predicted from the annual emission rates by Moore and Tevepaugh (Appendix E of this report).[6] Sums of the emission rates from the point sources for the 24-h episodes are presented in Table A.2.

In deriving the daily emission rates, Moore and Tevepaugh first used Equation (6) to estimate the daily energy requirement for each point source.* Values of f in this relation were obtained from the NEDS data file. The mix of fuels used to provide energy for each point source was next determined assuming that highest priority used for natural gas is space heating. This was done by first calculating the annual throughput of natural gas at each source if it had not been curtailed (annual demand for natural gas) by the relation:

$$T_{NGU} = T_{NG}(76)\ [1 + C_f(76)]\ , \qquad (7)$$

where, T_{NGU} = annual uncurtailed natural gas throughput.

If the value of T_{NGU} equaled or exceeded the annual space heating requirement for the source, it was assumed that all space heating needs above the curtailment temperature were met by natural gas and that any remaining gas would be used for process heat. If the value of T_{NGU} was below the annual space heating requirement, it was assumed that at or above the curtailment temperature that all the available natural gas and the necessary portion of the other fuels used at the source would be used to provide the space heating needs.

*Moore and Tevepaugh[6] in their calculation used the 1976 value of 4359 Celsius degree days instead of the typical year value of 4533 degree days. The error introduced by this difference is less than the uncertainty in the point source data.

Below the curtailment temperature, alternate fuels specified by MEA for the point source data base[1,2] were assumed to replace the curtailed gas for both the space and process heating needs. Here the increase in emissions, due to the curtailment of gas was assumed to be

$$\Delta E = -\Delta T_{NG} \left[\frac{H_{NG}}{H_{AF}} \mu_{AF} - \mu_{NG} \right], \tag{8}$$

where T_{NG} = change in natural gas supply rate due to curtailment. As for the calculations for the annual emission rates, values of H and μ were assumed to be those listed in Ref. 4. Further details of the calculation procedure for determining the 24-h point source emission rates are given by Moore and Tevepaugh.[6]

The totals of the point source emission rates for the 24-h episodes during 1976 and 1987 are presented in Table A.2. As for the annual scenario, the 1987 episode point source emission rates will decrease with the full development of the district heating/cogeneration system. Again it was assumed for each source connecting to the system, the reduction of emission rate in equivalent to that portion of fuel required for space heating. Totals of these modified point source emission rates are given in Table A.2.

A.2 COMMERCIAL AND INDUSTRIAL AREA SOURCE CALCULATION PROCEDURES

Emissions from commercial and industrial area sources were estimated by basically a two-step procedure. First, the distillate oil and residual oil being used or will be used by these sources were determined. Knowing these oil use rates, the emissions from these sources were calculated using the appropriate emission factors. This procedure tacitly assumes that the emissions from natural gas combustion at these sources are small compared to those from fuel oils, which is reasonable.

A.2.1 Annual Emissions

To determine the annual rate of fuel oil use by these sources, the total oil used by the stationary sources in each county of the area in 1976 was first estimated. This was done by Cole and Kinnear[3] using data collected by the State of Minnesota and the U.S. Department of Commerce. These rates are presented in Table A.7. For 1987, Cole and Kinnear used MEA's state-wide petroleum use projections based on the predictions of an econometric input model that considers the projected prices of alternate types of fuel and the cross-price elasticities for making changes in the fuel type.[7] Low, intermediate, and high projections of fuel oil use in the state were made. The intermediate values for the counties of interest are presented in Table A.7. The low estimates are 3.9% and 8.3% lower than the intermediate values for distillate oil and residual oil, respectively. The high estimates are 8.1% and 4.0% higher than the intermediate values for these two fuel oils, respectively.

TABLE A.7. ESTIMATED TOTAL ANNUAL DISTILLATE AND RESIDUAL OIL USE IN THE TWIN CITIES AREA, m^3

	Distillate Oil				Residual Oil			
County	Total[3]	Total in Billing Districts[3]	Point Source Total	Commercial and Industrial Area Source Total	Total[3]	Total Billing Districts[3]	Point Source Total	Commercial and Industrial Area Source Total
				1976				
Anoka	30,794	4,709	0	4,709	65,719	10,046	0	10,046
Dakota	58,220	30,321	0	30,321	65,056	33,883	1,976	31,907
Hennepin	248,270	170,050	5,163	164,887	268,850	184,141	87,027	97,114
Ramsey	85,164	85,164	5,247	79,917	175,250	175,250	98,830	76,420
Scott	48,116	47,174	0	47,174	80,895	79,399	0	79,399
Washington	4,811	4,811	0	4,811	1,991	1,991	0	1,991
				1987 Without District Heating/Cogeneration				
Anoka	28,069	4,293	0	4,293	94,851	14,498	0	14,498
Dakota	53,068	27,641	0	27,641	93,856	48,885	3,937	44,948
Hennepin	226,310	155,010	23,939	131,071	387,868	265,660	84,347	181,313
Ramsey	77,631	77,631	36,722	40,909	252,835	252,835	129,628	123,207
Scott	43,858	42,998	0	42,998	116,840	114,550	0	114,550
Washington	4,387	4,387	0	4,387	2,873	2,873	0	2,873

It should be noted that the values in Table A.7 are higher than these used in the previous air quality study.[1] This is because the fuel oil use data to derive the data reported herein became available subsequent to the time when the previous study was done. Further details regarding the derivation of these values are given in the previous study[1,2] and by Cole and Kinnear.[3]

The distribution of the use of fuel oil by the commercial and industrial area sources in the study area was assumed to be proportional to the distribution of the amount of natural gas that was curtailed throughout the area.[2,3] The first step in this process was to determine for each county the oil use in that portion of the county within the study area. This was done by noting that Minnegasco and NSP are the primary natural gas utilities serving the study area, and that other natural gas utilities serve the counties primarily outside the study area. The total amounts of distillate and residual oil use in the Minnegasco and NSP natural gas billing districts in each county were estimated by multiplying the county oil use totals by the ratio of the sum of Minnegasco and NSP curtailed gas in each county to the sum of all the curtailed gas in each county. Values of these estimates are listed in Table A.7.

To obtain the area source oil use in each county, the total point source oil use was subtracted from the total billing district oil use. The total point source oil use in each county for 1976 was determined by first identifying the sources using oil from the Source Classification Code (SCC) numbers included in the point source data.[4] The oil throughputs for each of these identified sources were then summed to obtain the total point source oil use. For 1987, without district heating/cogeneration, the increase in oil throughput T_{AF} for the point sources using oil to replace the increased curtailment of natural gas was determined by the relationship:

$$T_{AF} = T_{NG}(76)(\Delta C_f)\,\frac{H_{NG}}{H_{AF}} \quad . \tag{9}$$

The sum of these increased oil throughputs was then added to the 1976 point source oil use to give the 1987 point source oil use. (It was assumed that the revised natural gas curtailment plan [Table A.4] would be used in 1987.) The sums of the annual point source oil use are listed in Table A.7.

In order to be consistent with the county billing district totals, the point source fuel oil totals do not include any oil used at the following sources:

Black Dog Generating Plant

Riverside Generating Plant

High Bridge Generating Plant

Inver Hills Generating Plant

University of Minnesota, Minneapolis Campus

Hoerner-Waldorf Company

Koch Refinery

Ashland Refinery

Armour and Company

Swift Process Meat Company

St. Paul Ammonia.

The total commercial and industrial area source oil used rates in each county were then calculated by subtracting the adjusted point source oil use totals from the billing district oil use totals. These totals and differences are shown in Table A.7.

The area oil use totals were converted to SO_2 emissions by assuming that the distillate oil has a sulfur content of 0.5% and residual oil, 1.9%. Residual oil sulfur content ranges from 0.8 to 1.9%; the 1.9% sulfur oil is that used in smaller combustion units that are more likely to be used by the area source users.[1,2] Similarly for TSP, it was assumed on the basis of the information in Ref. 4 that the emission rate from distillate oil is 240 g/m^3 (2 lb/1000 gal) and from the residual oil is 2.54 kg/m^3 (22 lb/1000 gal). Values of the total SO_2 and TSP emissions for the commercial and industrial sources are given in Table A.8.

TABLE A.8. TOTAL EMISSION RATES FROM COMMERCIAL AND INDUSTRIAL AREA SOURCES (NEW NATURAL GAS CURTAILMENT PLAN), g/s

	1976	1987 Without District Heating/Cogeneration	1987 With District Heating/Cogeneration	1987 Change
		SO_2 Emission Rates		
Annual	429	617	573	-44
Episode 1	450	983	889	-94
Episode 2	1,188	1,510	1,338	-172
Episode 3	800	1,013	917	-96
Episode 4	446	984	899	-85
Episode 5	1,288	1,812	1,581	-231
Episode 6	171	353	353	0
		TSP Emission Rates		
Annual	27.4	42.1	39.1	-3.0
Episode 1	28.4	65.0	58.7	-6.3
Episode 2	70.4	91.9	81.6	-10.3
Episode 3	47.6	64.9	58.7	-6.2
Episode 4	28.6	64.2	58.4	-5.8
Episode 5	75.8	109.2	95.7	-13.5
Episode 6	12.6	25.9	25.9	0

The total area source SO_2 and TSP emissions for each county were then proportioned into the individual natural gas billing districts according to the amount of natural gas that is or would be curtailed in each of the billing districts. The gas billing district area sources were then reapportioned into the Computer Assisted Area Source Emissions (CAASE) grid.[8] This is a square-grid system that uses the Universal Transverse Mercator (UTM) coordinates[9] used in the dispersion model calculations.

A typical plot of the commercial and industrial area SO_2 source strengths is shown in Figure A.1. The grid size associated with this figure varies with location. The smallest grids are near the downtown area, where grid squares of 1 to 4 km^2 are appropriate. In the outer areas, the grid size is larger (primarily because the gas billing districts in the outer regions are larger).

For 1987, with district heating/cogeneration, it was assumed that the district heating system would replace all the area sources used for space heating in the district heating zones. The boundaries of these zones are outlined in Figure A.1.[1,2] This implies that about 37% of the oil used by the commercial and industrial area sources in the district heating zones would be eliminated and the total area source emissions would be reduced by the amounts shown in Tables A.8 and A.9. The quantities of oil saved by these sources connecting to the district heating system are given in Table A.9.

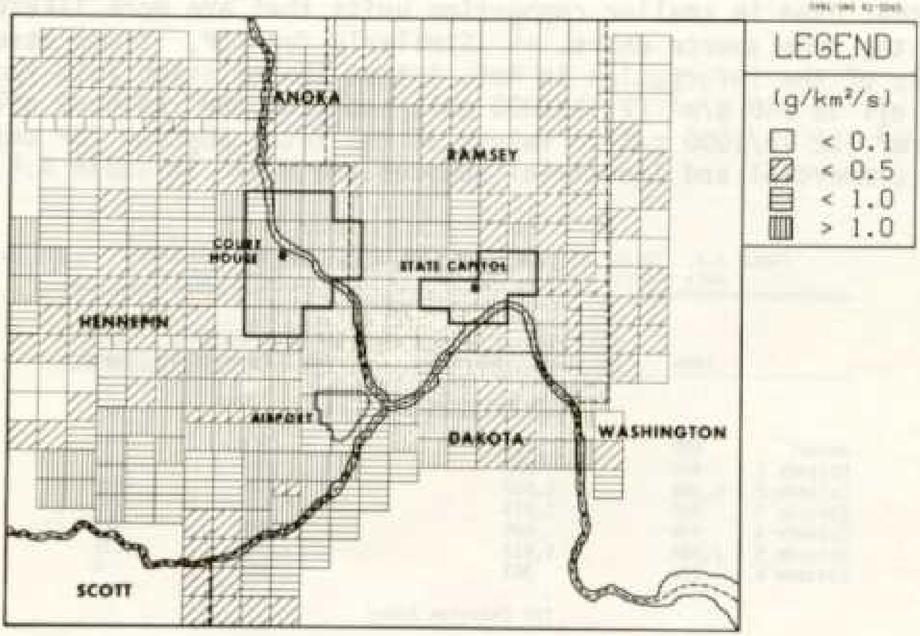

Fig. A.1. Estimated annual averaged commercial and industrial area source SO_2 emissions for 1987 without district heating/cogeneration ($g/km^2/s$). (Heavy outlines are the district heating zone boundaries).

TABLE A.9. REDUCTION OF COMMERCIAL AND INDUSTRIAL AREA SOURCE FUEL OIL BY DISTRICT HEATING/COGENERATION IN 1987

	Fraction of Oil Used for Space Heating		Oil Displaced by District Heating System, m^3			Emission Reduction by District Heating System, g/sec	
	Distillate Oil	Residual Oil	Distillate Oil	Residual Oil	Total Oil	SO_2	TSP
Annual	0.45	0.35	25,552	33,160	58,710	44	3.0
Episode 1	0.33	0.51	117	197	314	94	6.3
Episode 2	0.56	0.59	511	290	801	172	10.3
Episode 3	0.44	0.56	192	185	377	96	6.2
Episode 4	0.29	0.50	109	179	288	85	5.8
Episode 5	0.65	0.65	745	375	1,120	231	13.5
Episode 6	0.0	0.0	0	0	0	0	0.0

A.2.2 24-h Episode Emissions

For the quantities of distillate and residual oil used by the commercial and industrial area sources during each 24-h episode, the methodologies used to estimate these from the annual oil use rates were somewhat different for each of these two fuels.[3] The fraction of the total distillate oil used in the metropolitan area on a given day was assumed to be proportional to the fraction of the annual curtailed natural gas that would be curtailed for Minnesota on that day by Northern Natural Gas Company. For the residual oil being used in the metropolitan area, only 16% of its use can be attributed to the curtailment of natural gas. The remaining portion of the residual oil was assumed to be used at a constant rate throughout the year.

To obtain the fraction of annual curtailed natural gas that would be curtailed on a given day, the priority classes that would not be supplied with gas on that day were identified from the curtailment temperatures listed in Table A.5. For the priority classes having curtailment temperatures below the average temperature on that day, the fractions of the annual demands of natural gas that would be used for space heating were assumed to be the values given in Table A.6. The amount of Minnesota's annual natural gas demand in each priority class that would be used for space heating was then divided by the number of degree days for an average year, 4533 Celsius heating degree days. These quotients were then multiplied by the degree days for the selected day to yield the amounts of curtailed gas that would have been used for space heating on that day. The remaining portions of the annual curtailed gas demands were assumed to be used for process heat, and were divided by 365 to obtain the daily demands. The estimated daily quantities of the curtailed natural gas for each priority class were added and divided by the annual amount of natural gas curtailed in the state to yield the fraction of the curtailed natural gas on a given day. Values of these fractions are listed in Table A.10. Further details of the procedures used to derive values are given in Cole and Kinnear's report.[3]

TABLE A.10. FRACTIONS OF ANNUAL CURTAILED NATURAL GAS CURTAILED FOR EACH 24-h EPISODE[3]

	1976		1987	
	Process Heat	Total	Process Heat	Total
Episode 1	0.003	0.004	0.004	0.006
Episode 2	0.005	0.013	0.007	0.016
Episode 3	0.004	0.009	0.005	0.009
Episode 4	0.003	0.004	0.005	0.007
Episode 5	0.005	0.015	0.007	0.020
Episode 6	0.000	0.000	0.000	0.000

The sum of the daily use of distillate oil in the Minnesgasco and NSP billing districts in each county were determined from the annual totals given in Table A.7 multiplied by the fractions listed in Table A.10. These total daily values are tabulated in Cole and Kinnear's report.[3]

To obtain the sum of the daily use of residual oil in these billing districts in each county, the portions of the residual oil used to replace the curtailed natural gas were determined from the annual values of these portions given in Table A.7 multiplied by 0.16 and by the fractions listed in Table A.10. The remaining portions of the residual oil used for space heating were determined by assuming that 35% of annual values of the remainder of the residual oil are used for space heating. Using a procedure analogous to that for determining the fractions listed in Table A.10, these portions of residual oil used for space heating were divided by 4533 Celsius heating degrees and then multiplied by the heating degree days for the selected days. The annual amount of the portions of residual oil used for process heat were divided by 365 to obtain the daily use rates. All these portions of the residual oil use rates for each day were added to obtain the total daily use rates for the Minnegasco and NSP billing districts in each county. Values of these oil use rates and further details regarding the methodology used to derive these values are presented in Cole and Kinnear's report.[3]

To obtain the daily oil use rates for the commercial and industrial area sources from these daily total billing district oil use rates, the sums of the point source daily distillate and residual oil use rates were first determined from the daily point source data. This was done using the same methodology developed for predicting the annual oil use rate described in Section A.2.1. These point source totals were then subtracted from the billing district totals in each county to yield the area source totals in each county.

The daily commercial and industrial area source oil use rate totals are listed in Tables A.11 and A.12 for 1976 and 1987, respectively. It can be seen that there is an increase in fuel oil consumption by the area sources in 1987 due to the anticipated increased curtailment of natural gas. Of course there are significant increases in the rates of oil use on the colder days due to the increased need for energy for space heat and the greater use of distillate and residual oil to replace the curtailed natural gas.

TABLE A.11. ESTIMATED DAILY DISTILLATE AND RESIDUAL OIL USE BY STATIONARY COMMERCIAL AND INDUSTRIAL AREA SOURCES IN MINNEGASCO AND NSF BILLING DISTRICTS FOR 1976, m^3

County	Episode 1	Episode 2	Episode 3	Episode 4	Episode 5	Episode 6
			Distillate Oil			
Anoka	18.9	61.2	42.4	18.9	70.6	0.0
Dakota	121.3	394.2	272.9	121.3	454.8	0.0
Hennepin	431.5	1,736.2	1,092.0	423.5	1,892.9	0.0
Ramsey	250.7	798.6	554.3	248.5	903.2	0.0
Scott	188.7	613.2	424.6	188.7	707.6	0.0
Washington	19.2	62.5	43.3	19.2	72.2	0.0
			Residual Oil			
Anoka	38.0	72.2	57.7	38.6	82.9	10.8
Dakota	120.8	212.8	187.8	123.0	244.2	25.6
Hennepin	202.6	707.9	457.1	194.5	737.7	158.3
Ramsey	161.8	388.3	161.8	152.3	364.2	131.0
Scott	306.3	577.8	463.0	311.4	663.2	84.8
Washington	8.2	15.1	12.2	8.4	17.4	2.1

TABLE A.12. ESTIMATED DAILY DISTILLATE AND RESIDUAL OIL USE BY STATIONARY COMMERCIAL AND INDUSTRIAL AREA SOURCES IN MINNEGASCO AND NSF BILLING DISTRICTS FOR 1987 WITHOUT DISTRICT HEATING/COGENERATION, m^3

County	Episode 1	Episode 2	Episode 3	Episode 4	Episode 5	Episode 6
			Distillate Oil			
Anoka	25.7	68.7	38.6	30.1	85.9	0.0
Dakota	165.8	442.2	248.8	193.5	552.8	0.0
Hennepin	793.0	1,945.4	956.6	828.4	2,442.3	0.0
Ramsey	299.2	927.1	399.4	371.4	1,178.3	0.0
Scott	258.0	688.0	387.0	301.0	860.0	0.0
Washington	26.3	70.2	39.5	30.7	87.7	0.0
			Residual Oil			
Anoka	60.3	60.3	71.5	63.8	105.2	20.0
Dakota	154.1	278.8	227.5	202.9	312.1	56.9
Hennepin	684.9	949.6	685.8	611.1	1,115.8	323.5
Ramsey	565.9	631.6	378.4	553.3	722.9	287.2
Scott	474.0	697.5	562.1	501.8	827.6	158.2
Washington	11.7	17.2	13.9	12.4	20.4	4.0

The daily commercial and industrial area source oil use rate totals listed in Tables A.11 and A.12 were converted into emission rates using the same conversion and distribution factors assumed for the annual case discussed in Section A.2.1. Total daily emission rates from these sources in the study area are presented in Table A.8.

As for the annual case, it was assumed for the daily episodes in 1987 with district heating/cogeneration that the district heating system would supply all the space heating needs in the district heating zones. The fractions of commercial and industrial area source distillate and residual oil used for space heating in these zones, estimated by Cole and Kinnear,[3] are listed in Table A.9. The quantities of oil and emissions corresponding to these fractions are presented in Table A.9. The total emissions from these area sources for this situation are listed in Table A.8.

A.3 RESIDENTIAL AREA SOURCES

In 1970, natural gas was used to heat 84.2% of the residences in the Twin Cities and oil was used to heat 9.7% of the residences.[10] Table A.13 lists the number and type of residences in the Twin Cities as well as their annual space heating requirements.

From MEA data[7] for the number of new residences built in the state of Minnesota between 1970 and 1976, estimates were made of the number of new units built in the Twin Cities region during this time. These estimates are given in Table A.13. The same data indicate that 94% of these new residences use natural gas and the remaining 6% use other energy

TABLE A.13. NUMBER OF HOUSING UNITS AND THEIR SPACE HEATING REQUIREMENTS IN THE TWIN CITIES AREA[7,10]

Structure Type	Number in 1970	Estimate of Number Built in 1970-1976	Number Predicted to be Built 1976-1987	Annual Space Heating Requirements, kJ	
				Unit Built Before 1976	Unit Built After 1976
Single Family	220,894	16,430	36,760	155	113
Multiple Family	164,997	42,670	65,330	69	51
Mobile Home	1,355	1,780	2,330	106	75

sources, such as oil, propane, and electricity, for space heating. It was assumed here that the new units using oil replaced retired older units using oil. This implies that there was no net change in the number of residential units using oil between 1970 and 1976.

For all units built in and before 1976, the average annual space heating requirements are the values shown in Table A.13. Single family dwellings have the highest requirements 155 kJ, and multi-family dwellings have the lowest requirement, 69 kJ. For computational purposes, the number of different types of housing units were converted to the number of single family units using an equivalent amount of energy during 1976 (1976 ESFU). Table A.14 presents the number of 1976 ESFU in the Twin Cities using natural gas and oil for space heat.

TABLE A.14. NUMBER OF HOUSING UNITS HAVING SPACE HEATING REQUIREMENTS EQUIVALENT TO 1976 SINGLE FAMILY UNITS (1976 ESFU) IN THE TWIN CITIES AREA

Fuel	1976	1987	In District Heating Zones 1987
Natural Gas	282,640	331,430	90,400
Oil	28,680	27,140	7,200

For 1976 to 1987, estimates were made from the MEA state-side projections[7] of the number of new residential units that would be built in the Twin Cities area. It was assumed that 94% of these new residences would use natural gas for space heat and that the remaining 6% would use other energy sources. Moreover, it was again assumed that any new residences using oil would replace existing residences using oil. In addition, it was anticipated that the units built subsequent to 1976 will have lower energy requirements, and the space heating requirements for the new units would be the values listed in the right column of Table A.13. Because of the increasing cost of fuel oil, MEA estimated that 11% of the existing residences using oil in Minnesota will convert from oil to natural gas between 1979 through 1987. The numbers of 1976 ESFU's using oil and natural gas in 1987 were calculated from these data using these assumptions, and these values are presented in Table A.14. It can be seen that there is a significant increase in the number of equivalent units using natural gas in 1987 and a small decrease in the number of equivalent units using oil in 1987.

To determine the SO_2 and TSP emission rates from the residences, use of fuels for purposes other than space heating were ignored. It was assumed that the units burning oil use 0.5% sulfur distillate oil. It was further assumed that TSP emission factor for the oil use in these units is 300 g/m^3 (2.5 lb/1000 gal) and that for the natural gas is 0.16 g/m^3 (10 $lb/10^6$ ft^3).[4] Using these assumptions, the total annual emissions rates were calculated to be those presented in Table A.15.

For the dispersion calculations, it was assumed that the 1976 ESFU, and thus the emissions, are distributed in the study area in proportion to population density in the area as reported in the 1970 census data.[10] For 1987 using this assumption, the number of 1976 ESFU located in the district heating zones were predicted to be those shown in Table A.14. With the development of the district heating/cogeneration system, it was assumed that all these units would connect to the system and their emission rates would be reduced to zero. The predicted magnitudes of the reduction of the emission rates and the total residential emission rates in the area are given in Table A.15.

For the 24-h episodes, the emission rates were assumed to be proportional to the number of heating degree days, assuming that there are 4533 Celsius heating degrees per year. The emission rates thus determined are listed in Table A.15.

TABLE A.15. TOTAL EMISSION RATES FROM RESIDENTIAL AREA SOURCES, g/s

	1976	1987 Without District Heating/Cogeneration	1987 With District Heating/Cogeneration	1987 Change
		SO_2 Emission Rates		
Annual	31	30	22	-8
Episode 1	61	58	43	-15
Episode 2	73	69	51	-18
Episode 3	71	67	49	-18
Episode 4	64	60	44	-16
Episode 5	90	85	62	-23
Episode 6	0	0	0	0
		TSP Emission Rates		
Annual	6.8	7.7	5.6	-2.1
Episode 1	13.2	15.0	10.9	-4.1
Episode 2	15.8	17.9	13.0	-4.9
Episode 3	15.3	17.4	12.7	-4.7
Episode 4	13.8	15.7	11.4	-4.3
Episode 5	19.5	22.1	16.1	-6.0
Episode 6	0	0	0	0

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APPENDIX B

METEOROLOGICAL DATA FOR THE SIX SELECTED 24-H EPISODES

METEOROLOGICAL DATA FOR THE SIX SELECTED 24-H EPISODES

Hourly meteorological data for the six selected 24-h episodes (Section 4.2 of the main report) are presented in Table B.1. The mixing height data in this table were determined by interpolating the mixing height measurements made every 12 h. Most of these data were obtained from the records of hourly measurements at the Minneapolis-St Paul Airport.[1] The mixing height data were obtained at St. Cloud, Minnesota.[1] The five winter episodes had cold temperatures and relatively poor dispersion characteristics while the summer episode was a warm day when space heating demand was at a minimum. These five winter days can be place in two markedly different meteorological categories. The first four episodes are similar because during each day the winds were light to moderate in strength, generally blowing from between east and south, the atmosphere was usually neutral to stable, the mixing heights were quite low, and the temperatures were well below freezing. Episode 5 contrasts with the first four days by having strong northwesterly winds, neutral atmospheric stability, comparatively high mixing heights, and cold temperatures dropping throughout the day to very low readings. By comparison, Episode 6, a late summer episode, had moderate to moderately strong west to northwesterly winds, generally neutral stability, very high mixing heights, and mild temperatures.

TABLE B.1. HOURLY METEOROLOGICAL DATA FOR THE SIX SELECTED EPISODES

Wind Speed Classes

Class Index	Speed (m/s)	Speed Class Interval (Kt)
1	1.5	0 - 3
2	2.46	4 - 6
3	4.47	7 - 10
4	6.93	11 - 16
5	9.61	17 - 21
6	12.52	over 21

Stability Classes

Class Index	Stability
A	Very unstable
B	Moderately unstable
C	Slightly unstable
DD	Neutral (day)
DN	Neutral (night)
E	Slightly stable
F	Stable

(continued)

TABLE 8.1. (continued)

Episode 1 January 7, 1975

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	DD	3	180	-5.6	22U
2	DN	2	160	-6.1	248
3	DN	2	170	-6.7	276
4	DN	2	170	-6.7	304
5	DN	2	150	-7.2	332
6	E	1	0	-7.2	359
7	E	1	180	-6.7	387
8	DN	2	140	-6.7	383
9	DD	3	140	-6.7	378
10	DD	3	140	-6.7	374
11	DD	3	160	-6.7	370
12	DD	3	140	-6.7	365
13	DD	3	40	-6.1	361
14	DD	3	120	-6.1	357
15	DD	3	90	-6.1	352
16	DD	3	120	-6.1	348
17	DD	3	100	-6.1	344
18	DD	3	70	-6.1	339
19	DD	3	50	-5.6	335
20	DN	2	60	-5.0	345
21	DN	2	40	-4.4	350
22	DD	3	60	-4.4	355
23	DN	2	50	-4.4	360
24	DN	2	10	-4.4	364

Episode 2 December 21, 1975

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	E	2	250	-13.9	377
2	F	1	0	-13.3	337
3	F	1	180	-15.6	297
4	F	1	150	-15.6	257
5	F	1	0	-15.0	217
6	F	1	130	-16.1	177
7	F	1	0	-15.6	137
8	E	2	120	-15.6	162
9	F	1	120	-16.7	187
10	C	1	0	-14.4	212
11	C	2	140	-11.1	237
12	C	3	140	-8.9	262
13	C	3	160	-7.8	287
14	C	3	190	-5.0	312
15	DD	3	170	-5.0	337
16	DD	4	180	-4.4	362
17	DN	3	180	-5.0	387
18	DN	3	180	-6.1	412
19	E	2	150	-7.2	437
20	E	2	180	-6.7	464
21	DN	3	180	-6.7	478
22	DN	3	190	-5.0	492
23	DN	3	190	-4.4	505
24	DN	3	200	-4.4	519

TABLE 8.1 (continued)

Episode 3 January 4, 1975

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	F	1	200	-12.2	468
2	F	1	230	-13.9	408
3	E	1	130	-14.4	349
4	DN	2	110	-11.7	289
5	E	2	150	-13.3	230
6	E	2	120	-14.4	170
7	E	2	120	-15.0	111
8	E	2	120	-15.0	121
9	F	1	0	-14.4	131
10	DD	2	120	-14.4	141
11	B	1	0	-11.7	151
12	C	3	260	-8.9	161
13	DD	2	230	-7.8	171
14	DD	3	230	-7.2	181
15	C	3	240	-5.6	191
16	DD	3	260	-4.4	201
17	DN	3	250	-4.4	211
18	DN	3	240	-6.1	221
19	F	1	250	-6.7	231
20	E	2	220	-10.0	341
21	F	1	0	-9.4	396
22	F	1	230	-10.6	451
23	F	1	0	-10.0	506
24	F	1	0	-9.4	561

Episode 4 March 8, 1976

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	DN	2	260	-9.4	618
2	F	1	0	-8.9	539
3	F	1	0	-10.6	459
4	F	1	0	-11.1	379
5	F	1	0	-11.1	299
6	F	1	0	-12.8	220
7	F	1	0	-12.8	140
8	DN	2	110	-11.1	194
9	DN	2	110	-9.4	249
10	C	1	150	-8.3	303
11	DD	2	160	-6.1	357
12	C	3	180	-4.4	412
13	C	3	170	-3.3	466
14	C	3	170	-2.2	520
15	DD	3	180	-1.7	575
16	DD	3	170	-1.1	629
17	DD	4	170	-1.7	683
18	DN	2	180	-1.7	738
19	DD	3	150	-1.7	792
20	DD	3	170	-2.2	823
21	DD	3	160	-2.2	839
22	DN	2	150	-2.2	855
23	DN	2	140	-2.2	870
24	DN	2	150	-2.2	886

TABLE 8.1. (continued)

Episode 5 January 19, 1975

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	DD	4	320	-10.6	565
2	DD	4	340	-11.1	603
3	DD	3	330	-11.1	640
4	DD	4	340	-11.1	677
5	DD	4	340	-11.7	714
6	DD	4	350	-13.3	752
7	DD	4	350	-14.4	789
8	DD	4	350	-15.6	755
9	DD	4	350	-16.7	720
10	DD	4	340	-16.7	686
11	DD	4	340	-16.7	652
12	DD	4	330	-16.7	617
13	DD	3	350	-16.1	583
14	C	3	320	-16.7	549
15	C	3	330	-16.1	514
16	DD	3	310	-16.1	480
17	DN	3	310	-16.7	446
18	E	2	300	-18.3	411
19	E	2	300	-20.0	377
20	F	1	280	-18.9	446
21	E	2	240	-21.1	480
22	E	2	220	-22.8	514
23	E	2	180	-23.3	549
24	E	2	200	-23.9	583

Episode 6 September 3, 1975

Hour	Stability Class	Wind Speed Class	Wind Direction (Deg)	Temperature (°C)	Mixing Height (m)
1	DN	2	260	23.3	929
2	DD	3	290	22.2	920
3	DN	3	280	20.6	911
4	DN	3	290	18.9	902
5	DN	3	270	17.8	894
6	E	2	240	15.6	885
7	E	2	260	15.0	876
8	DN	3	270	17.8	928
9	DN	3	290	20.0	980
10	DD	4	290	20.6	1032
11	DD	4	320	21.7	1084
12	DD	4	300	21.7	1136
13	DD	4	300	21.1	1187
14	DD	4	310	21.7	1239
15	DD	4	320	22.2	1291
16	DD	4	310	22.2	1343
17	DD	4	280	22.2	1395
18	DD	4	310	21.7	1447
19	DD	4	310	20.6	1499
20	DN	3	310	17.8	1266
21	DN	3	320	16.1	1149
22	E	2	320	15.6	1033
23	F	1	330	13.9	916
24	F	1	230	14.4	800

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APPENDIX C

RAM COMPARISON STUDIES

RAM COMPARISON STUDIES

In Section 4.4.4 of the main report, the Texas Episodes Model (TEM)[1] was used to predict the 24-h average pollutant concentrations. It was selected over the EPA developed Multiple-Source Air Quality Algorithm (RAM)[2,3] because, in the form used in this study, it could be dimensioned relatively easy to accept a large number of sources and receptors. There are differences in the algothrims and dispersion coefficients used in the two programs, as discussed in Section 4.4.1 of the main report. Furthermore, using TEM in this study, the area sources were approximated as point sources or a 1-km square grid.

In order to check the assumptions using TEM in this study to predict changes in the SO_2 concentrations and the component sources causing these changes, RAM was used to predict the SO_2 concentrations for a limited number of cases. The study area for the RAM calculations is smaller than that for the TEM calculations, as shown in Figure C.1. This was done to keep the number of RAM computations within reasonable limits. As for the TEM calculations, the receptors were assumed to be located on 1 km square grid. Using these predicted values, computer generated isopleths were produced.

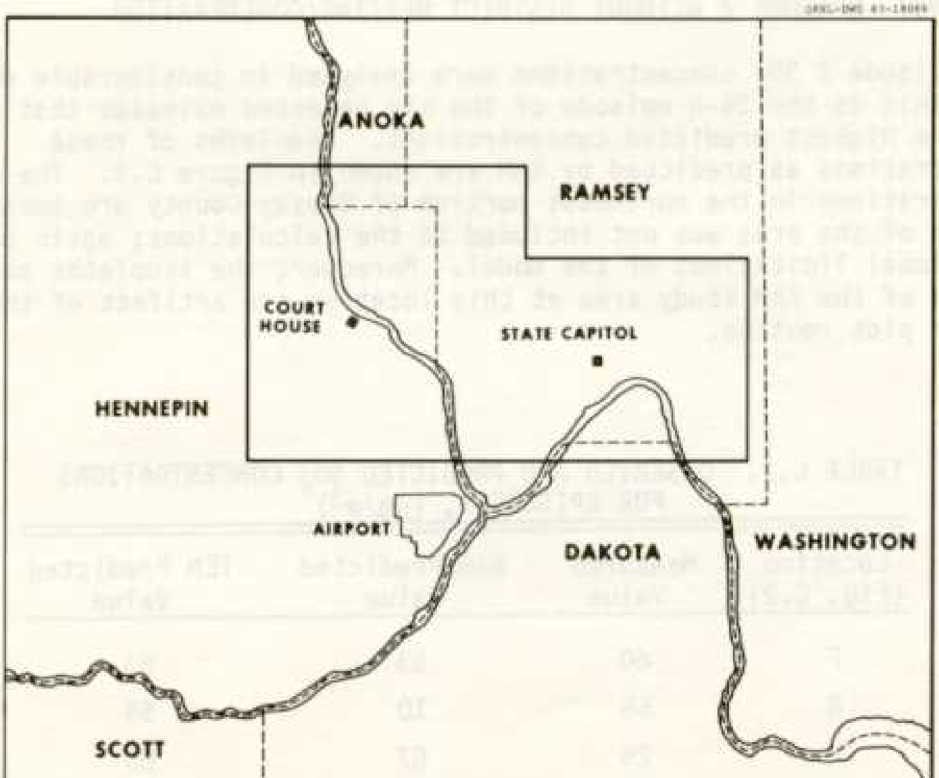

Fig. C.1. 16 x 27-km study area used for RAM calculations.

The 24-h episodes selected for the RAM analysis were Episode 1, having 24.2 degree days for the base year 1976 and Episode 2, having 28.9 degree days for the future year 1987. The latter episode was analyzed with and without district heating, and the contributions of the different source categories were investigated.

It will be seen that the changes in pollutant concentrations predicted by RAM and TEM are generally in good agreement. This in itself does not, of course, imply that the results are accurate. Only comparison with measured data can do this.

C.1 1976--EPISODE 1

The RAM predicted SO_2 concentrations, together with the TEM predicted and the measured values are presented in Table C.1. The locations of these concentrations are the monitoring station F through I shown in Figure C.2. It can be seen that both the measured and the RAM predicted concentrations are generally lower than the TEM predicted values. For the two locations having the very low predicted RAM predicted concentrations, examination of the source and wind data showed that they are downwind of relatively significant area sources that are located outside the RAM study area, but within the TEM study area. It was beyond the scope of this study to examine this in detail, but it is believed that this is at least part of the reason for the low predicted RAM concentrations at these points.

C.2 1987--EPISODE 2 WITHOUT DISTRICT HEATING/COGENERATION

Episode 2 SO_2 concentrations were analyzed in considerable detail since this is the 24-h episode of the six selected episodes that generally have the highest predicted concentrations. Isopleths of these concentrations as predicted by RAM are shown in Figure C.3. The lowest concentrations in the northeast portion of Ramsey County are because this portion of the area was not included in the calculations; again because the dimensional limitations of the model. Moreover, the isopleths shown outside of the RAM study area at this location are artifact of the computer contour plot routine.

TABLE C.1. OBSERVED AND PREDICTED SO_2 CONCENTRATIONS FOR EPISODE 1, ($\mu g/m^3$)

Location (Fig. C.2)	Measured Value	RAM Predicted Value	TEM Predicted Value
F	60	53	83
G	55	10	59
H	26	67	85
I	60	15	63

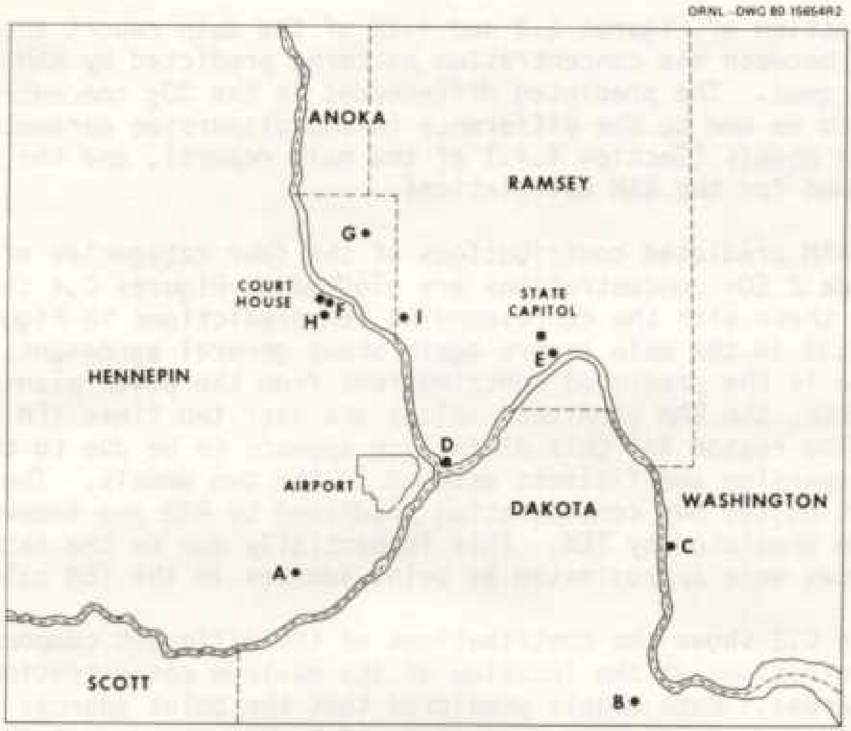

Fig. C.2. Locations of SO_2 sample stations.

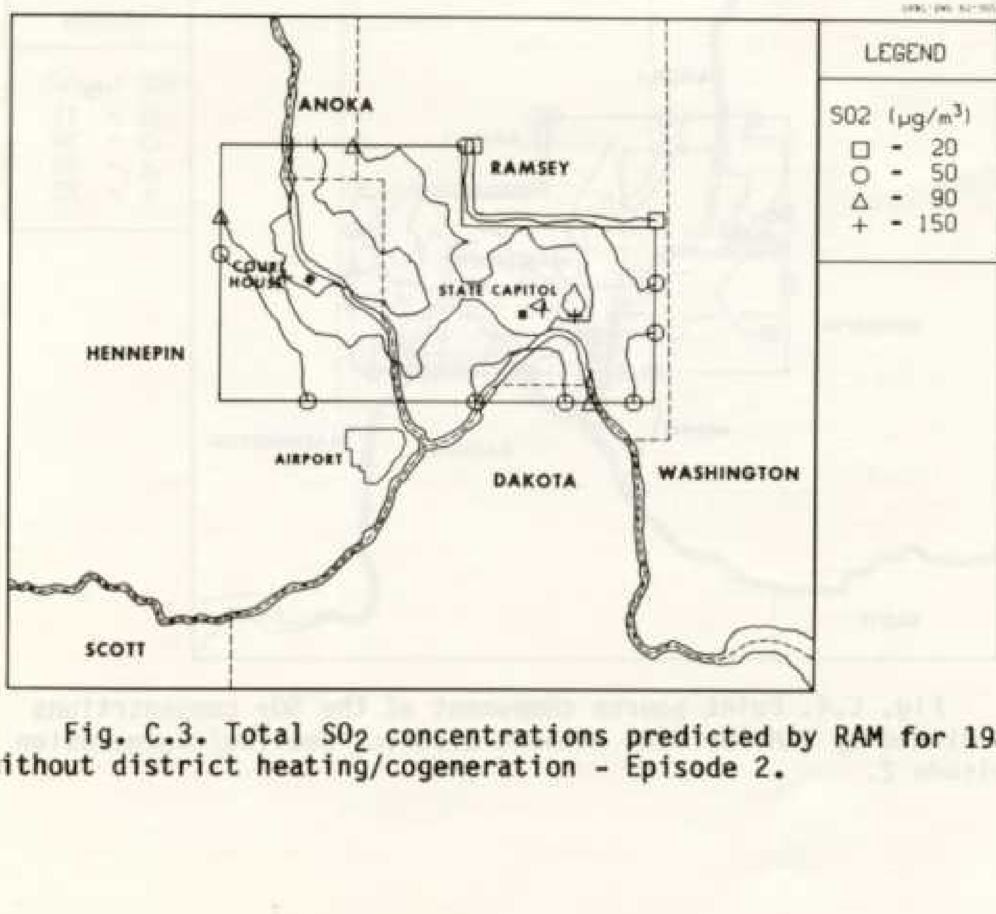

Fig. C.3. Total SO_2 concentrations predicted by RAM for 1987 without district heating/cogeneration - Episode 2.

Inspection of Figures C.3 and 4.28 of the main report show that the agreement between the concentration patterns predicted by RAM and TEM is generally good. The predicted differences in the SO_2 concentrations are believed to be due to the difference in the dispersion parameters assumed in the two models (Section 4.4.1 of the main report), and the smaller study area assumed for the RAM calculations.

The RAM predicted contributions of the four categories of sources to the Episode 2 SO_2 concentrations are plotted on Figures C.4 through C.7. Comparing these with the corresponding TEM predictions in Figures 4.35 through 4.38 in the main report again shows general agreement. The primary difference is the predicted contributions from the power plants. For the power plants, the RAM predicted values are over two times TEM predicted values. The reason for this difference appears to be due to the difference in the dispersion coefficients assumed in the two models. The area source components of the SO_2 concentration predicted by RAM are somewhat lower than those predicted by TEM. This is partially due to the fact that the area sources were approximated as point sources in the TEM calculations.

Table C.2 shows the contributions of the different components to the SO_2 concentrations at the location of the maximum concentrations in the downtown areas. Both models predicted that the point sources and the commercial and industrial area sources would be the major contributors. The power plants would not be a major contributor at these locations, but RAM

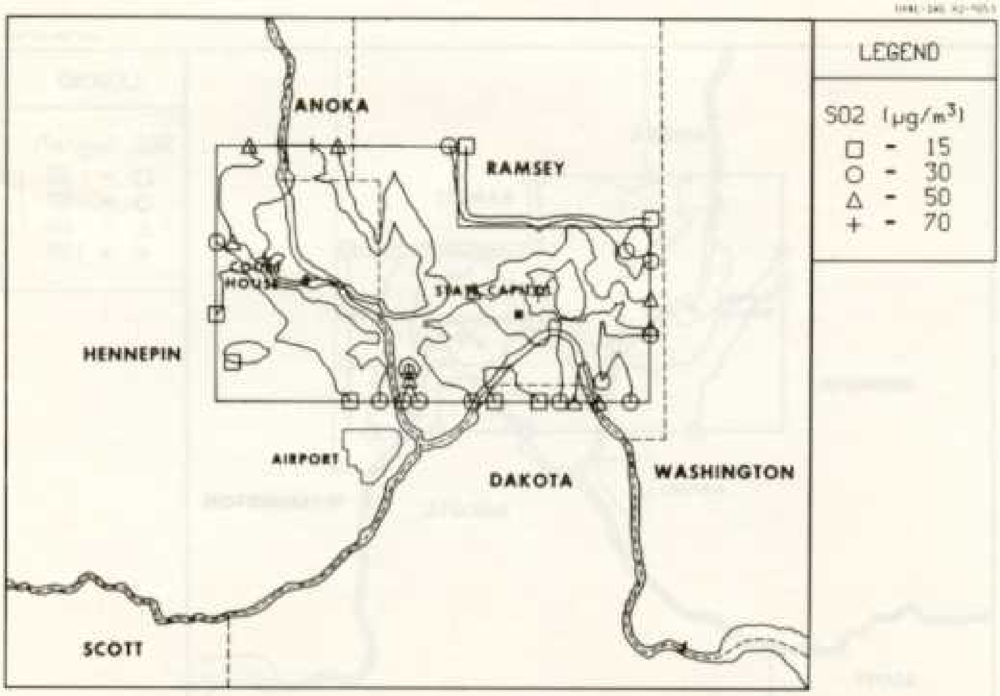

Fig. C.4. Point source component of the SO_2 concentrtions predicted by RAM for 1987 without district heating/cogeneration - Episode 2.

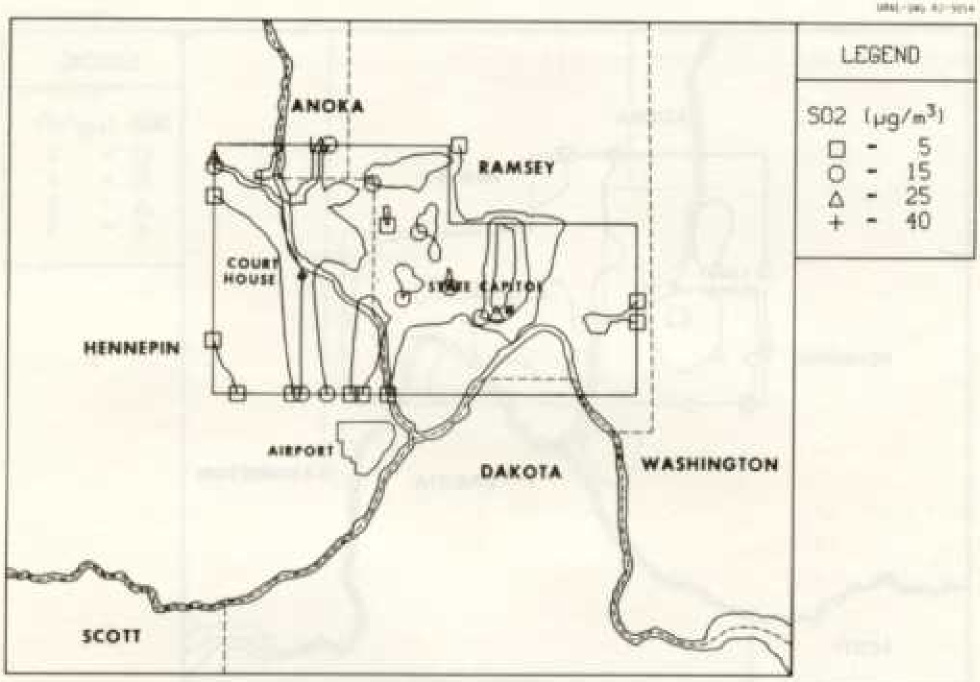

Fig. C.5. Power plant source component of the SO_2 concentrations predicted by RAM for 1987 without district heating/cogeneration - Episode 2.

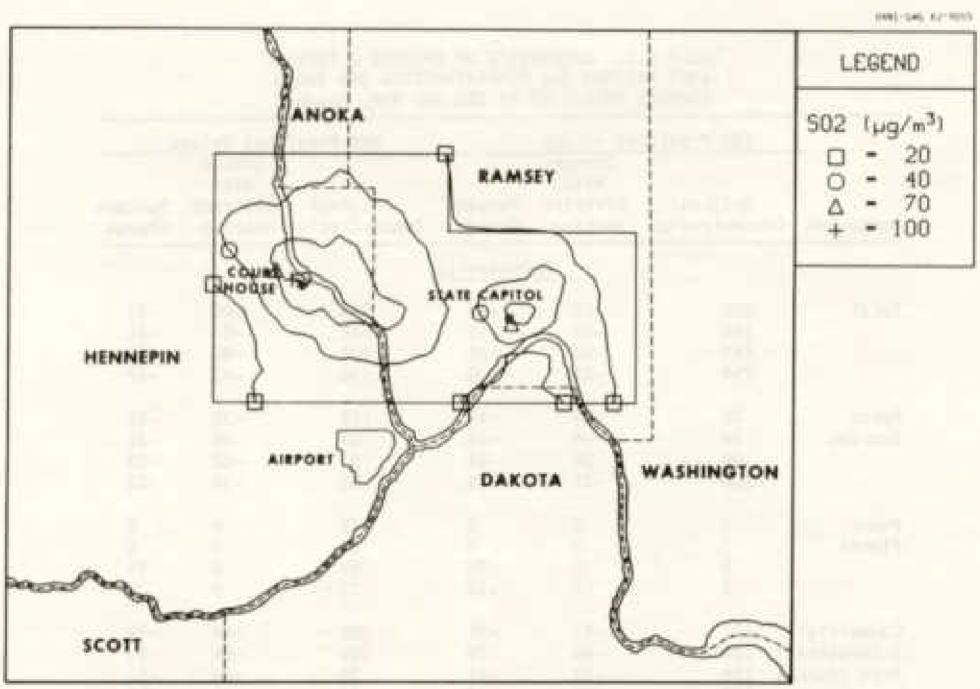

Fig. C.6. Commercial and industrial area source component of the SO_2 concentrations predicted by RAM for 1987 without district heating/cogeneration - Episode 2.

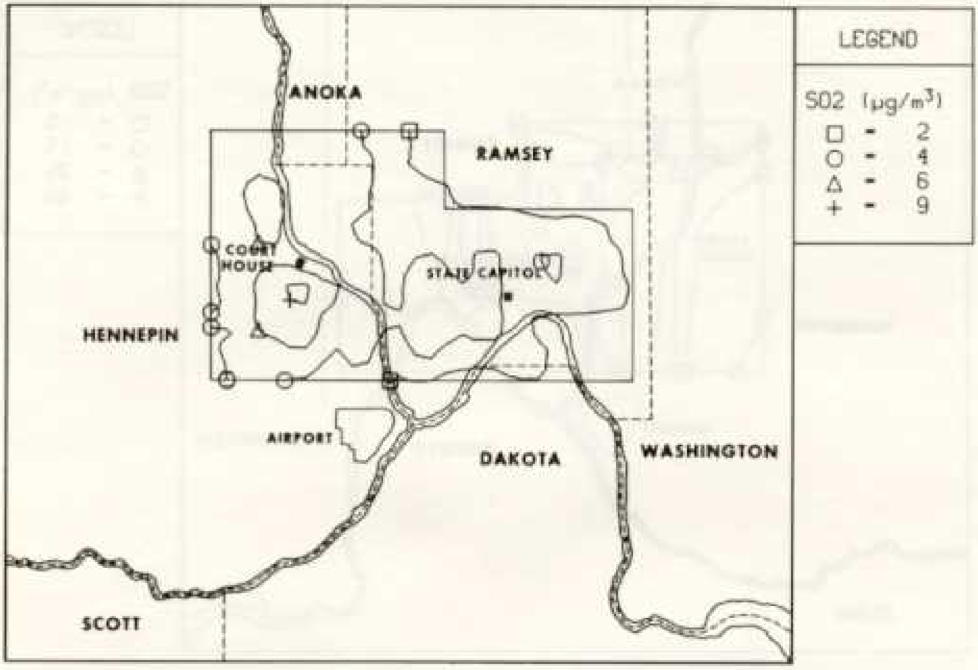

Fig. C.7. Residential area source component of the SO_2 concentrations predicted by RAM for 1987 without district heating/ cogeneration - Episode 2.

TABLE C.2. COMPONENTS OF EPISODE 2 TYPICAL 1987 MAXIMUM SO_2 CONCENTRATIONS AND THEIR CHANGES PREDICTED BY TEM AND RAM, ($\mu g/m^3$)

	TEM Predicted Values			RAM Predicted Values		
Component	Original Concentration	Change With District Heating	Percent Change	Original Concentration	Change With District Heating	Percent Change
			Minneapolis			
Total	202	-57	-28	233	-86	-37
	194	-60	-31	212	-83	-41
	243	-82	-34	204	-60	-29
	254	-83	-33	158	-43	-27
Point Sources	72	-10	-14	114	-36	-32
	58	-9	-16	84	-26	-31
	99	-24	-24	97	-22	-23
	100	-21	-19	82	-15	-18
Power Plants	3	0	0	12	0	0
	3	0	0	17	0	0
	5	-1	-20	24	5	21
	7	-1	-14	23	0	0
Commercial & Industrial Area Sources	117	-43	-37	102	-49	-48
	124	-48	-39	106	-54	-51
	129	-53	-41	78	-40	-51
	127	-55	-43	49	-25	-51
Residential Area Sources	9	-4	-44	5	-4	-80
	8	-3	-38	5	-4	-80
	9	-5	-55	5	-4	-80
	9	-6	-67	5	-4	-80

TABLE C.2. (continued)

Component	TEM Predicted Values: Original Concentration	TEM: Change With District Heating	TEM: Percent Change	RAM Predicted Values: Original Concentration	RAM: Change With District Heating	RAM: Percent Change
			St. Paul			
Total	152	-70	-46	157	-85	-54
	159	-55	-35	135	-40	-30
	122	-54	-44	123	-68	-55
Point Sources	74	-40	-54	57	-29	-51
	70	-19	-27	77	-15	-19
	54	-27	-50	63	-37	-59
Power Plants	6	1	17	14	-9	-64
	6	2	33	15	-3	-20
	3	1	33	0	0	--
Commercial & Industrial Area Sources	69	-29	-42	83	-44	-53
	77	-35	-45	40	-20	-50
	62	-20	-40	56	-28	-53
Residential Area Sources	4	-2	-50	3	-2	-67
	5	-3	-60	3	-4	-67
	3	-1	-33	4	-3	-75

predicted that they would play a more significant role than was predicted by TEM. It is beyond the scope of this study to determine which of the two predictions is the most valid.

C.2 1987--EPISODE 2 WITH DISTRICT HEATING/COGENERATION

As expected, RAM, like TEM, predicted decreases in SO_2 concentrations with the development of the city-wide district heating/cogeneration system. Isopleths of the ratios (normalization) of the RAM predicted SO_2 concentrations with and without district heating/cogeneration are presented in Figure C.8. Figures C.9 through C.12 are similar plots for the following components of the emission sources: (1) point source, (2) power plants, (3) commercial and industrial area sources, and (4) residential area sources. Comparing these plots with the equivalent TEM generated plots, Figures 4.49, 4.54 through 4.57 of the main report, show that these two models predict generally the same impacts by the district heating/cogeneration system. It should be remembered again that study area used for the RAM calculations was much smaller than for the TEM calculations and that RAM and TEM use different dispersion coefficients.

In the downtown areas at the locations of maximum SO_2 concentrations without district heating/cogeneration, Table C.2 shows that the two models predict about the same amount of reduction. However, RAM predicted a slightly greater impact by the area sources than did TEM. Figures C.11 and C.12 show that the area source components of the predicted SO_2 concentrations would be reduced by the district heating system by 50% over much of the urban area. This compares with TEM predicted values of 35 to 40%, shown in Figures 4.56 and 4.57 of the main report. The RAM calculations do further support the conclusion that the displacement of the commercial and

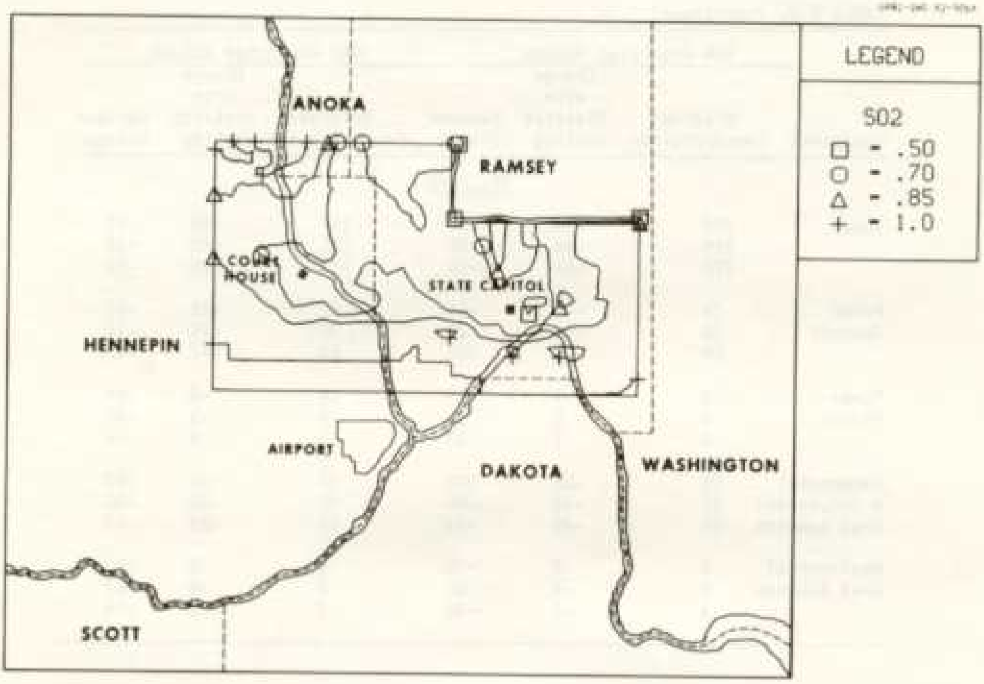

Fig. C.8. Ratio (normalization) of RAM predicted SO_2 concentrations in 1987 with and without district heating/cogeneration - Episode 2.

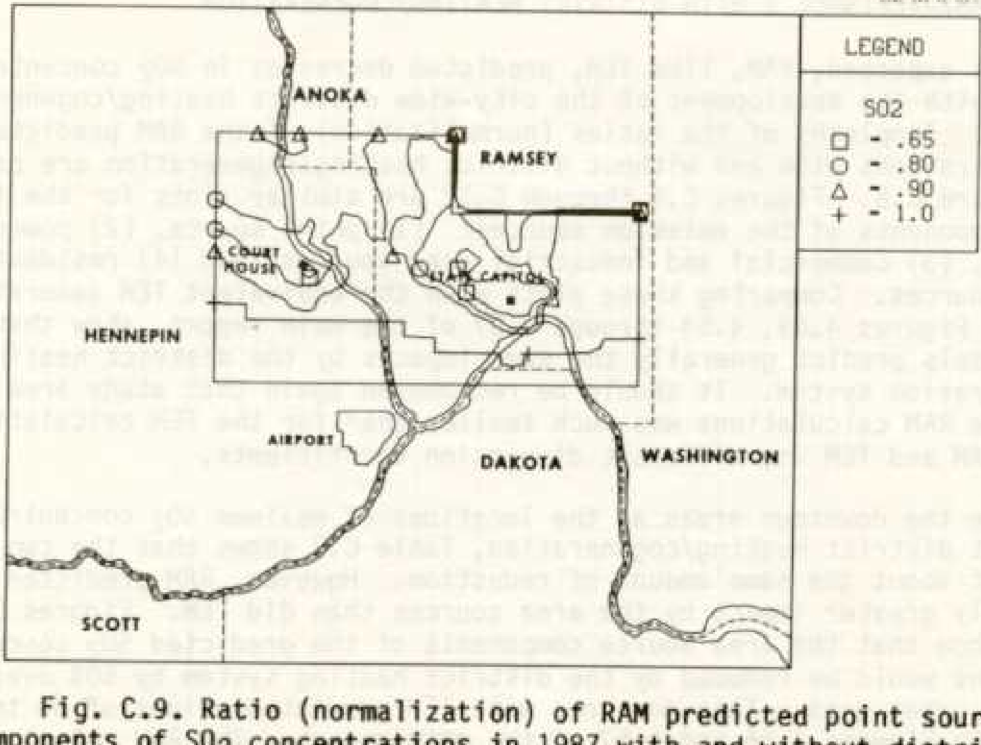

Fig. C.9. Ratio (normalization) of RAM predicted point source components of SO_2 concentrations in 1987 with and without district heating/cogeneration - Episode 2.

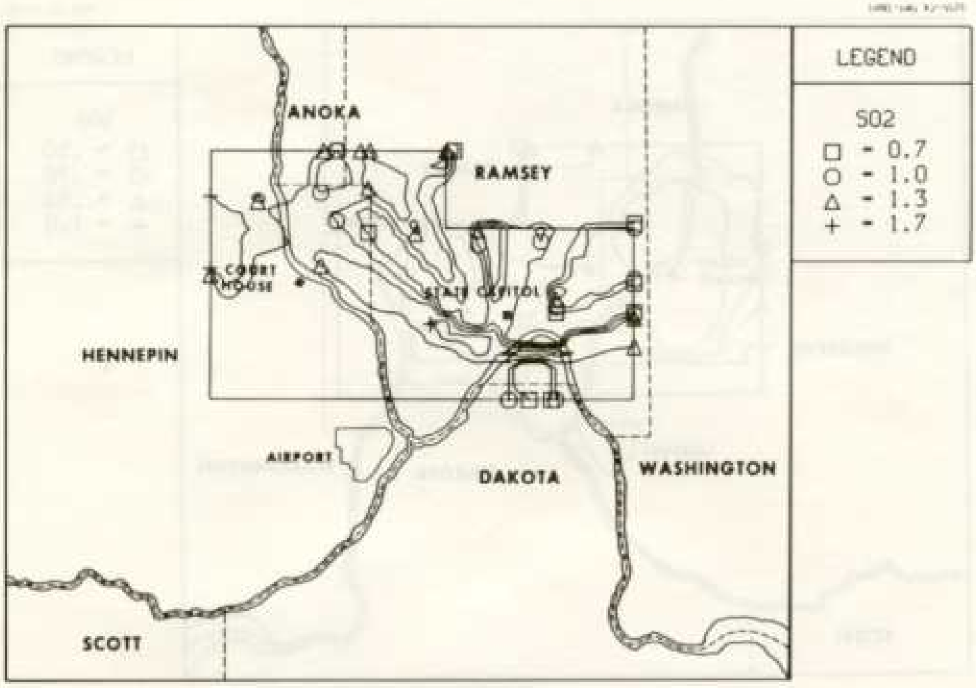

Fig. C.10. Ratio (normalization) of RAM predicted power plant source components of SO_2 concentrtions in 1987 with and without district heating/cogeneration - Episode 2.

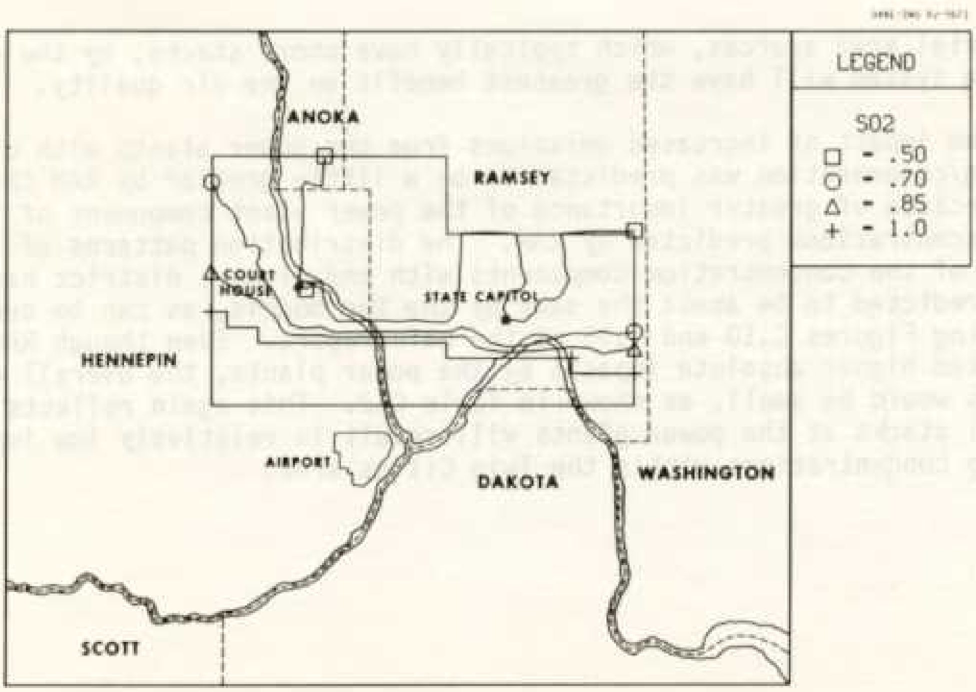

Fig. C.11. Ratio (normalization) of RAM predicted commercial and industrial area source components of SO_2 concentrations in 1987 with and without district heating/cogeneration - Episode 2.

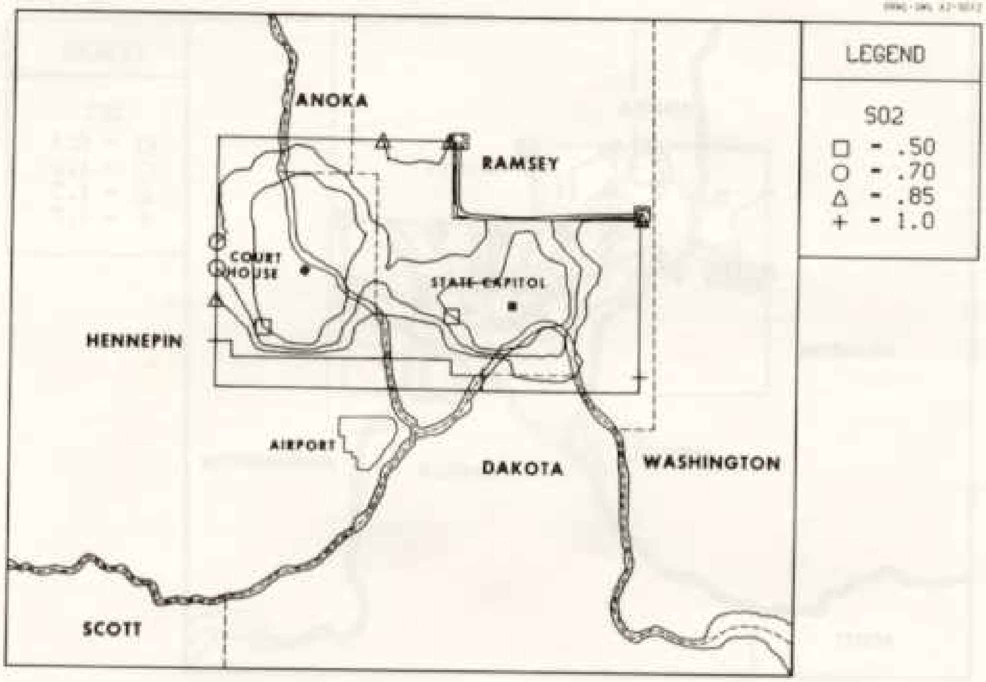

Fig. C.12. Ratio (normalization) of RAM predicted residential area source components of SO_2 concentrations in 1987 with and without district heating/cogeneration - Episode 2.

industrial area sources, which typically have short stacks, by the district heating system will have the greatest benefit on the air quality.

The impact of increased emissions from the power plants with district heating/cogeneration was predicted to be a little greater by RAM than by TEM, because of greater importance of the power plant component of the SO_2 concentrations predicted by RAM. The distribution patterns of the ratios of the concentration components with and without district heating were predicted to be about the same by the two models, as can be seen by comparing Figures C.10 and 4.55 of the main report. Even though RAM predicted higher absolute impacts by the power plants, the overall effect of this would be small, as shown in Table C.2. This again reflects the use of tall stacks at the power plants will result in relatively low impact on the SO_2 concentrations within the Twin Cities area.

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3. Turner, D. B., and J. H. Novak, User's Guide for RAM, Volume 1, Algorithm Description and Use, EPA-600/8-78-016a, 1978.

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ENVIRONMENTAL ASPECTS OF DISTRICT HEATING/COGENERATION IN THE TWIN CITIES

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