950018

EQB

University of Minnesota Steam Service Facilities

Draft Environmental Impact Statement

November 1994

TH
7641
.U55
1994

ENTAL QUALITY BOARD
PLANNING

UNIVERSITY OF MINNESOTA STEAM SERVICE FACILITIES
DRAFT ENVIRONMENTAL IMPACT STATEMENT

NOVEMBER 1994

The Environmental Impact Statement (EIS) on this project is being prepared pursuant to Minnesota Rules Part 4410.2000, Subpart 3B. The Responsible Governmental Unit for the EIS is the Minnesota Environmental Quality Board.

Environmental Quality Board Contact:

John N. Wachtler
Minnesota Environmental Quality Board
658 Cedar Street
St. Paul, Minnesota 55155
612-296-4095

RECEIVED
JAN 19 1995
LEGISLATIVE REFERENCE LIBRARY
STATE OFFICE BUILDING
ST. PAUL, MN 55155

Project Proposer Contact:

Ms. Susan J. Markham
Assistant Vice President Physical Plant
University of Minnesota
250 Shops Building
319 15th Avenue SE
Minneapolis, Minnesota 55455

The University of Minnesota is proposing to add multiple-fuel fired boilers (coal, wood, natural gas, fuel oil) and a 15 megawatt steam turbine to the Southeast Plant on the Minneapolis Campus, and retire the Minneapolis Main Plant. The University also has the option to install an additional 22 megawatt combustion turbine. On the St. Paul Campus, the University is proposing to replace two gas/oil boilers with a new gas/oil boiler. The existing coal boilers at the St. Paul Plant would be retained primarily for backup use.

A public informational meeting at which testimony will be recorded for the EIS record will be held at **7:00 p.m. on December 20, 1994** at:

The Roy Wilkens Room of the Hubert H. Humphrey Public Policy Institute on the West Bank of the University of Minnesota.

The portion this meeting at which testimony will be taken for the record begins at 7:00 p.m. and will continue until 8:30 p.m. or until the last person who wishes to testify has been heard. Between 12:30 and 5:30 on December 20, 1994, EIS information will be available in the Wilkens room, and representatives of the Environmental Quality Board and technical consultants who participated in preparing the EIS will be available to answer questions from the public regarding the contents of the Draft EIS.

The Public Comment Period during which written comments may be submitted for the record begins on Monday, November 28, 1994 and ends at 4:30, Wednesday, January 11, 1995. Written comments should be addressed to Mr. Wachtler at the address provided above.

TABLE OF CONTENTS

UNIVERSITY OF MINNESOTA STEAM FACILITIES ENVIRONMENTAL IMPACT STATEMENT

SUMMARY S-1

CHAPTER 1
INTRODUCTION 1-1

1.1 Existing Facilities: Minneapolis Campus 1-4
1.2 St. Paul Campus 1-7

CHAPTER 2
THE PROPOSED PROJECT 2-1

2.1 Case A 2-2
2.2 Case B 2-6

CHAPTER 3
DESCRIPTION OF ALTERNATIVES 3.1

3.1 Alternative No. 1 Minneapolis Deferred Construction (No Action) 3-3
3.2 Alternative No. 3 Southeast Plant Using Coal with Natural Gas Cogeneration 3-5
3.3 Alternative No. 4 Southeast Plant without Coal with Natural Gas 3-8
3.4 Alternative No. 6 New Plant at Alternate Location with Coal 3-10
3.5 Alternative No. 7 New Plant at Alternate Location without Coal 3-12
3.6 Alternative No. 11 St. Paul Deferred Construction (No Action) 3-14
3.7 Alternative No. 13 St. Paul without Coal 3-16

CHAPTER 4
ALTERNATIVES CONSIDERED BUT NOT ANALYZED IN DETAIL 4-1

4.1 Alternative No. 2 Southeast Plant Natural Gas/Oil 4-2
4.2 Alternative No. 5 Southeast Plant with Large Cogeneration 4-3
4.3 Alternative No. 8 Main Plant Renovation and Expansion 4-4
4.4 Alternative No. 9 Purchase Steam from Third Parties 4-5
4.5 Alternative No. 10 Interconnect Minneapolis/ St. Paul Systems - New Plant 4-7
4.6 Alternative No. 12 St. Paul Plant with Cogeneration 4-8

CHAPTER 5
NATURAL ENVIRONMENT 5-1

CHAPTER 6
AIR QUALITY IMPACTS 6-1

6.1 Major Emission Factor Assumptions 6-5
6.2 Predicted Emission Rates 6-12
6.3 Potential Emissions of Criteria and Air Toxic Pollutants 6-22
6.4 Dispersion Modeling Results 6-25
6.5 Noise 6-37
6.6 Fugitive Dust 6-38
6.7 Applicable Air Quality Regulations 6-41

CHAPTER 7
WATER QUALITY **7-1**

7.1 Wastewater 7-2
7.2 Stormwater 7-4
7.3 Potential Impacts from Fuel Spill 7-8

CHAPTER 8
SOLID AND HAZARDOUS WASTE **8-1**

CHAPTER 9
LAND USE, HISTORIC, VISUAL AND OTHER SOCIOECONOMIC IMPACTS **9-1**

9.1 Existing Land Use 9-2
9.2 Land Use Conflicts 9-6
9.3 Visual Impacts 9-10
9.4 Historic Significance 9-15
9.5 Compatibility with City of Minneapolis Land Use Plans 9-19
9.6 Special State and Federal Programs for the Riverfront 9-29
9.7 St. Paul Campus 9-36

CHAPTER 10
MITIGATION **10-1**

10.1 Demand and Energy Reduction 10-2
10.2 Cogeneration 10-6
10.3 Environmental 10-11
10.4 Foster Wheeler Contract Options 10-13

CHAPTER 11
ECONOMIC FEASIBILITY ANALYSIS **11-1**

11.1 Summary of Screening Analysis 11-2
11.2 Additional Work Completed for Phase 11 Analysis 11-6
11.3 Present Value Cost Comparison 11-8
11.4 Fuel Price Projections 11-18
11.5 Value of Cogenerated Electricity

CHAPTER 12
REQUIRED PERMITS **12-1**

APPENDICES

LIST OF PREPARERS

TABLE OF CONTENTS

LIST OF TABLES

SUMMARY

	Summary Table of Steam Plant Alternatives	S-4

CHAPTER 6

6.1	Table 1 Summary of Major Emission Control Assumptions	6-6
6.2	Table 2 Predicted Emission Rates	6-12
	Table 3 Predicted Annual CO_2 Emissions Minneapolis Campus Alternatives	6-14
	Table 4 Criteria Pollutant Externatility Costs	6-15
	Table 5 Predicted Criteria Emissions at St. Paul	6-15
	Table 6 Predicted Annual Toxic Emissions	6-17
6.3	Table 7 Potential Criteria Emission Rates	6-22
	Table 8 Potential Annual Air Toxic Emission Rates	6-24
6.4	Table 9 Maximum Short Term Ambient Concentrations of Criteria Pollutants	6-27
	Table 10 Maximum Modeled Air Toxic Concentrations at PTE	6-30
	Table 11 Modeled Annual Criteria Pollutant Concentrations at Predicted Emission Rates	6-32
	Table 12 Worst Case Annual Toxic Concentrations Compared to ALC's	6-35
6.6	Table 13 Fugitive Dust Emission Sources	6-38
	Table 14 Southeast Plant Fugitive Dust Concentrations Southeast Heating Plant Modeled Fugitive Dust Concentrations	6-39
	Table 15 St. Paul Plant Fugitive Dust Concentrations St. Paul Heating Plant Modeled Fugitive Dust Concentrations	6-39
6.7	Table 16 Ambient Air Quality Standards	6-41

CHAPTER 10

10.1	Table 1 Present Value Operation and Maintenance Costs	10-3
10.2	Table 2 Plant Efficiency and Combined Efficiency	10-7
	Table 3 Predicted Emissions Adjusted for Cogeneration	10-9

CHAPTER 11

11.1	Table 1 Screening Analysis Present Value Costs	11-3
	Table 2 Present Value Combined Alternatives	11-4
11.3	Table 3 Present Value Costs of University Steam Supply Alternatives	11-9
	Table 4 Present Value of Combined Alternatives	11-10

TABLE OF CONTENTS

LIST OF FIGURES

CHAPTER 5

	Figure 1 Geologic Profile Bottom of Bluff-Riverfront Site	5-1

CHAPTER 6

	Figure 6-1 Comparison of Potential and Predicted Annual s02 Emissions: Case A and 100% Gas/Oil Plant	6-3
6.2	Figure 2 Predicted Annual Emission Rates of SO2 and NOX	6-13
	Figure 6-3 Predicted Annual Arsenic Emission Rates	6-19
	Figure 6-4 Predicted Annual Mercury Emissions	6-20
	Figure 6-5 Predicted Annual Formaldehyde Emissions	6-21

CHAPTER 9

9.1	Figure 9-1 UM Riverfront Site Minneapolis	9-2
	Figure 9-2 Alternative Site UM Minneapolis Campus	9-2
	Figure 9-3 UM St. Paul Campus Site	9-2
	Figure 4 Riverfront Dam Flats Area: Down River View From Near Southeast Plant	9-3
9.2	Figure 5 Existing View of Main Plant Coal Operations from Sanford Hall	9-7
	Figure 6 Computer Image of Main Plant Area Coal Operations and Fuel Oil Tanks Removed	9-7
9.3	Figure 7 Existing View of Southeast Plant from Riverfront	9-11
	Figure 8 Computer Image of Southeast plant: After Proposed Modification	9-11
	Figure 9 Existing Southeast Plant from Stone Arch Bridge (Before Completion of Bridge)	9-11
	Figure 10 Computer Image of Southeast Plant from Stone Arch Bridge After Proposed Modification	9-11
	Figure 11 Existing Alternative Site Near Stadium Village from nearby Parking Lot	9-14
	Figure 12 Computer Image of Alternative Site Coal/Oil/Gas Facility	9-14
	Figure 13 Computer Image of Alternative Site 100% Natural Gas, Fuel Oil Facility	9-14
	Figure 14 Riverfront Trailway Feasibility Analysis	9-23
	Figure 15 Photograph of Main Plant Area from Riverfront	9-25
	Figure 16 Photograph of St. Paul Coal Storage Area from Adjacent Daycare Building	9-36

CHAPTER 10

10.2	Figure 1 Predicted Net Annual Mercury Emissions Including Credit for Cogeneration	10-10

CHAPTER 11

11.3	Figure 1 Present Value Costs of Minneapolis Alternatives and St. Paul Alt. 13, Compared to Case A and Case B	11-11

Summary

The University is Proposing a Major Renovation to its Steam Facilities

The University of Minnesota, Twin Cities, heats its buildings with steam produced at three separate University-owned steam plants. Two of the facilities -- the Southeast Plant and the Main Plant -- serve the Minneapolis campus, and one facility -- the St. Paul Plant -- serves the St. Paul campus. In this report, wherever possible, the situations and impacts at the two campuses will be evaluated separately.

All three plants have been operated since 1992 by the University's steam vendor, Foster Wheeler Twin Cities, Inc.

The University is proposing a major renovation to these steam production facilities. The Minnesota Environmental Quality Board is the Responsible Governmental Unit for the Environmental Impact Statement on this proposed project.

Existing Facilities Described

The Minneapolis campus has one of the largest district heating loads in Minnesota. Steam use currently averages about 270,000 lbs/hr, with winter peak demand of approximately 520,000 lbs/hr. Baseload steam demand is approximately 110,000 lbs/hr, and campus electricity use is about 234,000 mw-hours/yr.

The Southeast Plant, with two old coal-fired boilers in operation, has a total capacity of 230,000 lbs/hr, and the Main Plant, with five old coal-fired boilers and one newer natural gas/fuel oil burner in operation, has a total capacity of 570,000 lbs/hr.

The fuel mix for the Minneapolis campus is 85-90% coal, 5-10% natural gas, and small amounts of distillate fuel oil. Coal is delivered by rail to the Main Plant, where it is stored in an open storage area and delivered by truck as necessary to the Southeast Plant. The Southeast Plant also has a smaller outdoor coal bunker of its own. Coal ash is temporarily stored near the river.

The Main Plant has two above-ground and 14 underground fuel oil storage tanks, and the Southeast Plant has one above-ground storage tank.

The St. Paul Plant, with six old coal-fired boilers and one newer gas/oil-fired boiler, has a total capacity of 330,000 lbs/hr, against 90,000 lbs/hr in average demand and 170,000 lbs/hr in winter peak demand. Electricity use is 71,000 mWh/yr.

The current fuel mix for the St. Paul plant is about 46% coal, 48% natural gas, and 6% fuel oil, which is a higher percentage

of natural gas than would be used at least cost fuel dispatch. Coal is delivered to the St. Paul Plant by truck and is stored in an open area behind the plant. The plant also has one large above ground oil storage tank and two smaller underground storage tanks.

University's Project Defined by its Contract with Foster Wheeler

The University's proposed project is defined by the 1992 construction contract between the University and Foster Wheeler. The contract includes two basic equipment options, labeled "Case A" and "Case B."

Minneapolis Case A Would Cogenerate Electricity and Burn Primarily Coal

Under Case A at the Minneapolis Campus, the Southeast Heating Plant would be modified, and the Main Plant would be retired. Steam would be produced by a new circulating fluidized bed boiler with multiple-fuel capability, new gas/oil-fired boilers, and by existing coal-fired boilers. Electricity would be cogenerated by a 15 mW non-condensing steam turbine. Although a range of fuels could be used at the Southeast Plant, coal would continue to be the primary fuel.

Minneapolis Case B Would Cogenerate More Electricity With Natural Gas, and Burn Coal

Under Case B, the situation at the Minneapolis Campus would be similar to Case A, except that one of the gas/oil-fired boilers would be replaced with a 22 mW gas/oil combustion turbine and a waste-heat boiler, for a total of 37 mW capacity. Assuming least cost fuel dispatch, the percentage of natural gas used would increase, and annual tonnage of coal used would decrease slightly, compared to Case A.

St. Paul Case A and Case B Would Burn Natural Gas and No. 2 Fuel Oil

Under Case A and Case B (which are identical for the St. Paul Campus), the St. Paul Plant would produce steam with a new 250,000 lb/hr natural gas/No 2 fuel oil burner. Existing boilers would be used for peaking and backup. Coal would be used primarily for backup purposes.

Alternatives Considered for Environmental Potential and Economic Feasibility

Thirteen other steam production alternatives were quantitatively analyzed for potential environmental superiority and technical and economic feasibility. Five alternatives were selected for further analysis. All are on-campus cogeneration systems that use primarily natural gas or a mixture of coal, natural gas, fuel oil. The "No Action" alternatives were also carried into the next phase.

Alternative No. 1 Is the Minneapolis "No-Build" Option	Under Alternative No. 1, construction at the Minneapolis Campus would be deferred until 2001, when new coal-fired boiler capacity would be installed in the Southeast Plant. All boilers capable of burning coal would be dispatched first.
Alternative No. 3 Would Cogenerate Electricity and Burn Coal	Under Alternative No. 3, the Southeast Plant would be modified, and the Main Plant would be retired. Electricity would be produced by combustion turbines using natural gas or fuel oil, and steam would be produced first with waste-heat boilers, then by existing coal-fired boilers, followed by new gas/oil fired boilers. Coal operations would remain, but be enclosed.
Alternative No. 4 Would Cogenerate Electricity and Burn Natural Gas and No. 6 Fuel Oil	Under Alternative No. 4, the Southeast Plant would be modified to 100% gas/oil, and the Main Plant would be retired. Electricity would be produced by combustion turbines, and steam would be produced by waste heat and gas/oil fired boilers. All coal boilers would be retired.
Alternative No. 6 Would Cogenerate Electricity and Burn Coal	Under Alternative No. 6, a new plant similar to the University's proposed Case A would be constructed at an off-river site, with entirely enclosed coal handling operations. Both existing Minneapolis plants would be retired. Electricity would be produced by a non-condensing steam turbine, and steam would be produced by a fluidized bed boiler and gas/oil boilers.
Alternative No. 7 Would Cogenerate Electricity and Burn Gas/Oil	Under Alternative No. 7, a new gas/oil cogeneration plant would be constructed at an off-river site, and both existing Minneapolis plants would be retired. Electricity would be produced by combustion turbines, and steam would be produced by waste heat and gas-oil-fired boilers.
Alternative No. 11 Is the St. Paul No-Build Option	Under Alternative No. 11, construction at the St. Paul Campus would be deferred until 2001, when a new gas/oil-fired boiler would be installed. All boilers capable of burning coal would be dispatched first.
Alternative No. 13 Would Burn Natural Gas and No. 2 Fuel Oil	Under Alternative No. 13, the St. Paul Plant would be modified. Coal storage and use would be eliminated. Electricity would not be produced, and steam would be produced by new and existing gas/oil boilers.

Summary Table of Steam Plant Alternatives

	Location	Boilers & Economic Dispatch Order	Electrical Capacity (mW)	Annual Fuel Mix	Elect. Prodtn. (mW-hrs)	Coal Handling
Case A	Southeast Plant	1. CFB 2. Gas/Oil	15 Steam Turbine	81 % Coal 17% Gas 2% Oil	52,000	Existing, With Options
Case B	Southeast Plant	1. CFB 2. Waste-Heat 3. Gas/Oil	15 Steam + 22 mW Combustion Turbine (CT)	50% Coal 46% Gas 4% Oil	197,000	Existing, With Options
Alt. 1	Southeast & Main	Existing Coal	None	97% Coal	0	Existing
Alt. 3	Southeast Plant	1. Waste Heat 2. Existing Coal 3. Gas/Oil	22.5 CT	62% Gas 32% Coal 6% Oil	187,000	Riverfront, But Enclosed
Alt. 4	Southeast Plant	1. Waste Heat 2. Gas/Oil	22.5 CT	92% Gas 8% Oil	187,000	Eliminated
Alt. 6	Off-River Site	1. CFB 2. Gas/Oil	17 Steam	72% Coal 25% Gas 3% Oil	60,000	Off-River Enclosed
Alt. 7	Off-River Site	1. Waste Heat 2. Gas/Oil	22.5 CT	92% Gas 8% Oil	187,000	Eliminated
Case A St. Paul	St. Paul	Gas/Oil	None		0	Existing, But Improved
Alt. 13 St. Paul	St. Paul	Gas/Oil	None		0	Eliminated

Air Quality Impacts Estimated for Both "Predicted" and "Potential" Emissions

Both "predicted" and "potential" emission rates were estimated for criteria and non-criteria air pollutants.

Predicted emissions are those that would result from operating plant equipment to meet the anticipated steam load, using the least-cost fuel first.

Potential emissions are those that would result from operating plant equipment all year long at rated capacity, using the highest emitting fuel. These emissions rates represent a facilities maximum potential to emit -- not actual emissions.

Based on the pending University air quality permit application and preliminary assessment of the other alternatives, emission limits in the eventual air quality permit are likely to be significantly less than "potential" emissions, and closer to the "predicted" emissions.

Emission Rate Calculations Depend on at Least Five Different Variables

Emission rates depend on a number of variables, including boiler technology, fuel, pollution control technology, source of emission factor, and total fuel consumption (more electricity cogeneration consumes more fuel).

Predicted Criteria Pollutant Emissions Lowest for Gas/Oil Alternatives, but All Lower Than Existing

In general, under expected operating conditions, predicted annual emissions of criteria pollutants were similar for most Minneapolis options, with the exception of the "No Action" alternative, which had the highest estimated emissions of SO_2, NO_X, and particulates. There are not large differences between alternatives, in part, because SO_2 and NO_X emissions from coal are effectively controlled in the proposed circulating fluidized bed boiler.

Predicted annual SO_2 emission rates for gas/oil plants, for example, were about 50% less than facilities that use coal. However, both proposal and other options that use coal had predicted SO_2 emissions at least 50% less than the "No Action" alternative, even with the additional fuel needed for electricity cogeneration.

Predicted Criteria Emissions Similar for Proposal and Alternatives in St. Paul

In St. Paul, predicted emission of most criteria pollutants are the same because both alternatives assume the use of natural gas and fuel oil exclusively.

Coal Based Plants have Higher Predicted Emissions of Mercury and Some Other Air Toxics

Predicted annual emissions of non-criteria pollutants are similar for all options with the exception of mercury and a few other air toxics. Emissions of most trace metals are similar for coal and gas/oil facilities because, based on recent research results, coal-boiler particulate controls effectively remove most trace metals.

Mercury, however, is a regional concern because of its tendency to bioaccumulate in fish. Overall, predicted mercury emissions are closely related to coal use. For gas/oil only alternatives, some mercury is emitted from the fuel oil, but 92% of the annual fuel mix is natural gas, which has negligible mercury emissions.

Similarly, chlorine, fluorine, dioxin, and benzene emissions were related to coal use. The "No-Action" alternative—Alternative #1 -- generally would have the highest emission rates for trace metals, including mercury.

Predicted formaldehyde emissions, however, were highest for gas/oil cogeneration plants (high formaldehyde emissions were estimated for the combustion turbines).

Potential Emissions of Criteria Pollutants Are Similar for All Options

Potential emissions of criteria pollutants are similar for all options because 1) oil, which is the worst-case fuel for gas/oil boilers, has uncontrolled emissions which are similar to or higher than emissions from coal boilers, and 2) all alternatives have similar installed maximum capacities.

Potential Emissions of "Air Toxic" Pollutants Similar for all Options

Potential emissions of non-criteria pollutants also do not differ greatly, but are slightly higher for gas/oil alternatives. This occurs because fuel oil is the worst-case fuel for gas/oil boilers, and air toxic emissions from gas/oil boilers are assumed to be mostly uncontrolled. Coal boilers, however, include particulate controls that are assumed to effectively remove many (not all) trace metals.

Toxic Emissions from Fossil Fuel Plants are Currently Subject of Extensive Research

Large-scale research on air toxic emissions from coal plants is ongoing on the federal level by EPA, DOE, EPRI and others. Some of the information in this report is based on preliminary data from this research. Trace metal emissions from fuel oil and natural gas are based on the small amount of data currently available for these fuels. The most recent data available does indicate that emissions of most toxics from natural gas are negligible, including emissions of most products of incomplete combustion.

Worst-Case Modeled Concentrations of Criteria Pollutants Similar for All Alternatives

With boilers running at rated capacity and using the worst fuel, maximum modeled ambient concentrations of criteria pollutants are similar for Cases A and B and all alternatives. The high stacks at the Southeast Plant or the alternative site (200 feet or higher) effectively reduce local impacts by dispersing pollutants over a wide area.

Modeled annual concentrations based on worst-case "potential" emission rates were unlikely to result in standard violations.

Modeled annual SO_2 concentrations based on predicted -- rather than potential -- emissions were lowest for gas/oil alternatives, but all were less than 5% of the applicable standards.

Short-Term Ambient Air Concentrations of Criteria Pollutants Highest for Gas/Oil Alternatives

Short-term ambient air concentrations of criteria pollutants are highest for gas/oil alternatives because, in the worst case, those alternatives use 100% fuel oil at maximum rated capacity (possible on a very cold winter day, when curtailment of natural gas supply is most likely).

At the Minneapolis Campus, Alternatives 3, 4, 6, and 7 have higher modeled short term concentrations than Case A or Case B. High short-term SO_2 concentrations modeled for some alternatives are probably due to the effects of building "downwash" that increased maximum modeled concentrations near the plants. Dispersion for the alternatives could be improved during detailed design.

At the St. Paul Campus, the proposal has slightly higher modeled concentrations than Alternative No. 13.

For Air Toxics, Annual Concentrations Within Regulatory Guidelines, Except For Arsenic

Modeled maximum annual concentrations of air toxics for the proposal and all alternatives varied little. However, worst-case modeled arsenic concentrations for 100% gas/oil only cogeneration alternatives did exceed the current Air Concentration Limit guidelines currently used by the MPCA. Fuel oil limits could be accepted in an eventual permit for these facilities, however. Modeled concentrations at predicted emission rates were 100 times below the Air Concentration limit. All other modeled toxic concentrations were within regulatory guidelines even at the higher potential emission rates.

"Predicted" concentrations of most air toxics were generally lower for gas/oil alternatives than for coal alternatives, partly because the building height increase necessary for the University's proposal would create some downwash effects.

Higher predicted ambient concentrations of mercury and some other metals were modeled for coal-based alternatives. Overall, however, modeled concentrations at predicted emission rates for the proposal and alternatives were within an order of magnitude of each other for most pollutants.. There was no indication that the proposal or any alternative would create, by itself, an unacceptable local health risk as long as emission controls were operated as designed.

Runoff and leachate from Ash and Coal Piles was Within Regulatory Limits

All three plants discharge wastewater into the municipal sewer system. Samples taken from the Southeast and St. Paul plants were all within published disposal limits (although the University does not have a current discharge permit). Quality of wastewater could be improved by installing the University proposed new

demineralization package.

Stormwater from coal storage at Minneapolis mostly discharges into municipal sewer system. Stormwater from ash piles does not appear to directly discharge into the Mississippi, but could be reaching the river through the local groundwater system. Run-off from the coal and ash piles, and samples of coal, ash, and soil were analyzed and were found to be within regulatory limits.

To improve stormwater run-off, Foster Wheeler has proposed a new optional retaining wall at the Southeast Plant and a stormwater collection and storage system at the St. Paul Campus.

No Indication of Major Contamination Found at Riverfront Site

At the Riverfront Site, coal, ash, and fuel storage present contamination concerns. Coal, ash, and soil samples were within regulatory limits, and fuel oil storage tanks on the site currently show no evidence of leaking. The site could also be affected by two nearby leaking storage tanks. No indication of historical contamination of the riverfront site was found, although there are leaking fuel tanks in the surrounding neighborhood, and the fuel oil stored on site always presents a risk.

At the Alternative Site, creosote compounds in the soil requires remediation, and a remediation report is currently being prepared. The site could also be affected by two nearby leaking storage tanks and by low levels of VOCs found in nearby soil.

Land near Riverfront Site is Historically and Recreationally Important

The land around the Riverfront Site is an important historical and recreational resource. The area is also used for industrial, retail, and residential purposes. Hennepin Bluffs Park and the historic Stone Arch Bridge are located just west of the site.

The land around the Alternative Site is primarily University facilities and parking lots, with residential areas about one-half mile away. Daycare centers are located near each of the sites.

Proposal or Alternatives Would Have Little Effect on Existing Land Use

The proposal or alternatives would have little effect on existing land use. Under the proposal, the Main Plant would be retired. Therefore, the primary impact of continuing operations at the Southeast Plant would be an increase in the number of coal trucks operating between the Main Plant coal storage area and Southeast Plant. Land use conflicts due to the coal trucks can be mitigated by installing a coal conveyor (a University contract option) or by eliminating the use of coal at the Southeast Plant. A new power plant at the Alternative Site would not adversely affect surrounding land uses because the site is bordered by parking lots, grain elevators, railroad tracks, a research facility

and a waste management facility.

Visual Landscape Would Affected Under Proposal and Some Alternatives

Existing plants at the Riverfront Site are visible from nearby historical, recreational, and residential areas and create an industrial atmosphere. Proposed modifications would affect views of the Southeast Plant, and some alternatives would affect views of the area near the Main Plant by eliminating or enclosing the coal handling operations.

The general land use near the Alternative Site is mostly industrial, but a new plant requiring a 200 foot stack would affect views from the University facilities, nearby businesses and hotels, and nearby neighborhoods.

Plant Operation would Conflict with Plans for Trails and Parkways

Continued operation of the Southeast and Main Plants, as it exists and under the proposed renovation, interferes with City of Minneapolis land use plans for riverfront trails and parkways.

Without major bridge construction or other modifications, continued operation of the Main Plant and its associated storage facilities would probably preclude the development of an at-grade motorway and of both "upper" and "lower" bikeways. Topography and multiple landowners, however, also interfere with the development of riverfront trailways.

Even with continued coal use on the riverfront, an alternative "lower" bikeway could be developed were the Main Plant to be removed, but would likely be expensive. Steam plant operations would not affect plans for a proposed pedestrian parkway, although substantial investment would be required to overcome topographical obstacles.

Constructing a plant at the off-river Alternative Site would open up the riverfront to a substantially larger number of parkway and recreational options.

Moving the steam facilities off-river, however, would eliminate the opportunity to develop an innovative -- but as yet unidentified -- riverfront design that might successfully integrate the continued industrial use of the Southeast Plant with recreational or other plans.

Proposal Does Not Specifically Encourage Some Parts of Critical Area Plan.

The University's Critical Area Plans for the Riverfront Site envision opportunities for open space and public viewing of the river, with conditions for buffering, landscaping, and revegetating the area.

The proposed project does not contain any specific plans for maximizing open space or opportunities for public viewing of the river. Renovations, however, should have no adverse effect on vegetation, and the project does conform with plans to protect the bluffs and vegetation and to provide a greenway window from a scenic observation area at the north side of the Stone Arch Bridge.

The Minneapolis Critical Area Plan envisions a continuous trail corridor for pedestrians, bicyclists and motorists along both sides of the Mississippi River. To build a continuous parkway, however, the City would have to acquire land or contract with property owners. Also, if the Southeast Plant were to be used for some purpose other than generating power, limited funds are currently available for converting the plant to some other use.

Proposal and Riverfront Alternatives Compatible with MNRRA

The proposal and other riverfront alternatives appear to be consistent with the Mississippi River National River and Recreation Area (MNRRA) Plan.

The proposed plan complies with the applicable MNRRA provisions on historic use and shoreline restrictions because the development 1) will continue historic uses of structures and will rehabilitate one structure of historical importance, 2) is exempt from vegetated shoreline and height restrictions because the site is located in a downtown area, and 3) does not conflict with the policy about distance from the shoreline because the expansion of the Southeast Plant will be upward, not outward.

The proposed project is also appears to be compatible with applicable state shoreland and floodplain ordinances as an existing non-conforming use.

Mitigation Options Categorized

Four main types of mitigation options have been identified.

- Demand and Energy Reduction
- Cogeneration
- Environmental
- Foster Wheeler Contract Options

Implementation of Centralized Chilled Water Plans Would Save Energy

Continuing the University Building Energy Efficiency Project (UBEEP), initiated in 1989 to reduce the University's energy consumption by 30%, would reduce the present value operating and maintenance costs of the project and alternatives.

Full implementation of existing University plans to replace building absorption chillers with new central steam chilled water production units would reduce energy consumption for chilled water auxiliaries and for pumping and cooling tower fans. Central chilled water units would also encourage additional on-site electricity cogeneration by increasing base-load steam use and leveling off seasonal fluctuations.

Implementing central chilled water production and distribution systems would also facilitate conversion of the campus steam distribution system to a more efficient hot water system, since steam distribution to individual buildings would no longer be needed in summer.

Conversion to a Hot Water Distribution System Would Encourage a Metro Cogeneration Network

Converting the existing steam distribution system to a hot water distribution system would not only increase on-site cogenerated electricity production, but would encourage the development of a large metro thermal network because greater efficiency is possible in cogeneration plants that use hot water than in those that steam.

Cogeneration Would Reduce Area-Wide Air Emissions

Cogeneration increases point source air emissions, but would reduce area-wide air emissions because less fuel is needed to produce the same quantities of thermal and electric energy in a cogeneration plant than would separate facilities operating independently. Combined electrical and thermal efficiencies at the Minneapolis campus range from 59% for a thermal only plant (No Action) to 63% for a steam-turbine only plant (Case A, Alt 6), to a maximum of about 71% for the University's proposed Case B (slightly less than 70% for EIS alternatives 3, 4, and 7).

After adjusting for "cogeneration credits," annual predicted emissions of SO_2, NOx, and mercury are lowest for gas/oil only alternatives, and next lowest for EIS alternative 3 and the University's Case B, both of which use coal-fired boilers as auxiliary units.

Technical Options Would Reduce Fugitive dust and NO_X Emissions

Fugitive dust emissions could be mitigated by installing the new coal and ash handling systems included under Alternatives 3 and 6. Under these alternatives, coal would be stored in covered enclosures and transported in covered conveyors. Ash would be hauled directly to a landfill, without first being stored on the ground.

For Alternative 3, the high NO_X emissions from the existing coal boilers at the Southeast Plant could be reduced by installing additional controls (probably SNCR).

Environmental Mitigation Options Available Under Foster Wheeler Contract

Environmental mitigation options are also available under the Foster Wheeler contract options. A NO_X reduction system could reduce the already comparatively low NO_X emissions from the fluidized bed boiler an additional 88 tons a year. The Minneapolis ash screen-wall option, although it would not stop wind-borne dust, would partially hide the pile and could contain some runoff. The Minneapolis coal pile screen-wall option, although it would not stop wind-borne dust, would partially hide the pile. The coal conveyor option would reduce truck traffic and wind-borne dust. The ash pile stormwater collection option would reduce any runoff or groundwater contamination at the St. Paul campus. The St. Paul coal pile screen-wall option would marginally improve dust control, but would partially hide the pile.

EIS Alternatives Had Lower Present Value Costs Than University's Case A or Case B

The costs of EIS alternatives were estimated and compared to the costs of the proposal in order to assess economic feasibility. Construction costs were estimated by a professional cost estimator, and operating costs included fuel (50% to 70% of total costs), labor, maintenance, insurance and other costs. Estimated capital and operating costs for a 25 year period were present valued to 1994 dollars.

All combinations of alternatives were found to have lower costs than the University's Case A or Case B, and sensitivity analysis of the discount rate, price escalation rate, steam load, and the differences between fuel and electricity escalation rates did not affect the rankings of alternatives. The combination of Minneapolis Campus Alternatives 3 and St. Paul Campus alternatives 13 had the lowest projected present value cost of a cogeneration alternative that does not use coal at the St. Paul Campus.

Chapter 1. Introduction

The University of Minnesota is proposing a major renovation of its steam plants

The University of Minnesota heats its Twin City campuses with steam produced at three separate University-owned steam plants. Two of the facilities -- the Southeast Plant and the Main Plant -- serve the Minneapolis campus, and one facility -- the St. Paul Plant -- serves the St. Paul campus.

Most of the equipment in the plants was installed in the 1950's, and by 1988, a consultant's report indicated that the equipment was deteriorating. In 1992, the University Board of Regents selected a steam plant renovation project, the purpose of which was to provide reliable thermal energy to the University for the next 25 years and beyond.

The University Regents had Six Major Objectives

The University of Minnesota Regents, when selecting the proposed renovation, had five major objectives, with a sixth added later:

- Ensuring reliable steam service and supply
- Obtaining the lowest steam cost possible
- Maintaining maximum fuel price protection through fuel flexibility or pricing guarantees.
- Minimizing adverse environmental and health impacts
- Minimizing business risk to the University
- Implementing an economic electricity cogeneration system.

Major EIS Issues Include land use, coal impacts, and maximizing electricity cogeneration.

The Environmental Quality Board (EQB) is the Responsible Governmental Unit (RGU) for the Environmental Impact Statement (EIS) on this steam plant renovation project. A scoping decision outlining the major issues to be addressed in this EIS was adopted by the EQB in August, 1993. The EIS is being completed pursuant to Minnesota Rules Part 4410.2000, Subpart 3b.

Major issues identified during the scoping process include:

- Riverfront land use
- Potential negative environmental impacts of handling and burning coal compared to natural gas
- Long-term energy policy
- Maximizing the use and environmental benefits of electricity cogeneration to meet University steam demand

The Purpose of the EIS is to Disclose Information

The purpose of the EIS is to provide accurate information to governmental units, the project proposer, and the public regarding the impacts of the proposal, the feasibility and impacts of alternatives, and the potential for reducing adverse environmental effects.

EIS Technical Support Documents are Available

This EIS is largely a summary of information contained in a number of detailed reports completed for this project. The following technical support documents are available:

1. *Alternatives to the University of Minnesota's Steam Service Facilities Renovation, Screening Analysis*, March 25, 1994, by Dahlen, Berg & Company

2. *Fuel Price Projections*, March 30, 1994, by Dahlen, Berg & Company

3. *Value of Cogenerated Electricity*, April 1, 1994, by Dahlen, Berg & Company

4. *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, July 29, 1994, by Dahlen, Berg & Co.

5. *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis*, October 27, 1994, by Trinity Consultants, Inc.

6. *Soil and Groundwater Contamination Site Assessment*, October 1994, by B.A. Liesch Associates, Inc.,.

7. *Water Quality Study, University of Minnesota Steam Services*, September 1994, by B.A. Liesch Associates, Inc,

8. *Summary of Land Use Plans, St. Anthony Falls Riverfront, City of Minneapolis*, October 1994, by the Environmental Quality Board

---

The EIS First Describes the Existing Plants, the Proposal, and Thirteen Alternatives.

Chapter 1 describes the existing steam facilities. Chapters 2 describes the University's proposal ("Case A" and "Case B"), and chapters 3 and 4 describe the alternatives developed for the EIS.

The remainder of the chapters describe potential impacts.

- Chapter 5 describes the natural environment at existing and

potential steam plant sites

- Chapter 6 addresses air pollutant emissions and impacts;
- Chapter 7 addresses water quality issues in the Mississippi and elsewhere;
- Chapter 8 addresses solid and hazardous waste;
- Chapter 9 describes land use planning efforts in the affected areas and addresses the impacts of the proposal and alternatives;
- Chapter 10 describes potential mitigation for environmental impacts, including cogeneration benefits;
- Chapter 11 addresses the economic and technical feasibility of the EIS alternatives;

Section 1.1. Existing Facilities: Minneapolis Campus

The University Heats its Buildings with Steam Produced at Three Separate Facilities.

Two of the three existing steam plants serve the Minneapolis Campus, and one serves the St. Paul campus.

1. The Southeast Plant is located between the Mississippi River and the corner of 6th Avenue S.E. and Main Street S.E., Minneapolis, near lower St. Anthony Falls and the east end of the Stone Arch Bridge.
2. The Minneapolis Campus "Main" Heating Plant is located adjacent to the campus at 1180 Main Street S.E., near the Steel Truss Bridge, Minneapolis.
3. The St. Paul Campus Heating Plant is located at 1952 Commonwealth Avenue, Falcon Heights.

Figure 1-1 shows the general location of the three existing facilities on a USGS 7.5 minute, 1:24,000 scale map. See Chapter 9 for a detailed description of each site and its surrounding land uses.

The University Steam Plants are Operated by Foster Wheeler, Inc.

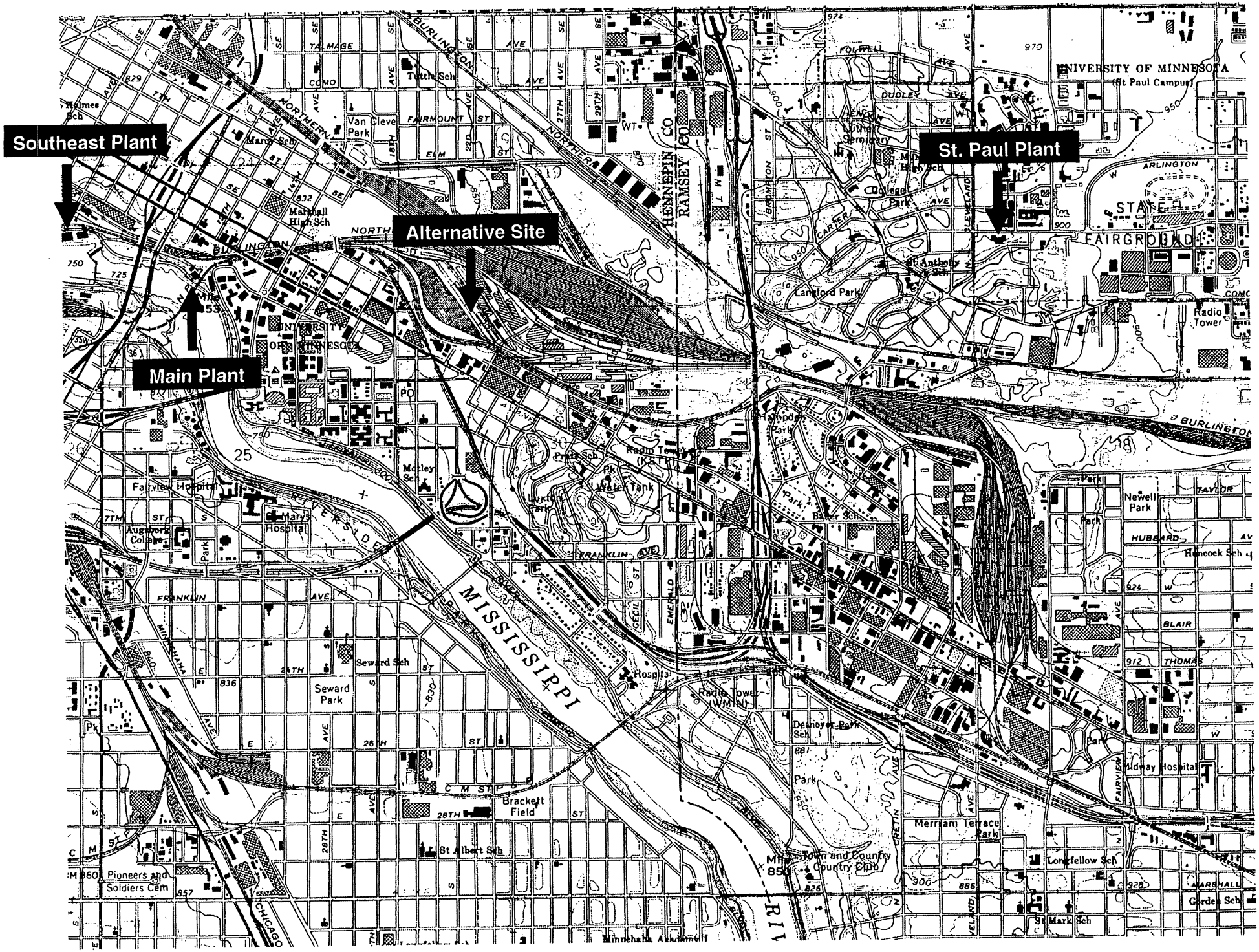
Although owned by the University, the three steam plants have been operated since 1992 by the University's steam vendor, Foster Wheeler Twin Cities, Inc.

The description of the existing facilities, the proposal, and the alternatives each contain the following information:

- Steam and electrical production technology
- Boiler capacity
- Fuel mix and usage
- Material handling system

Southeast Plant has two Older Coal-Fired Boilers in Operation.

The Southeast Plant is a five story red-brick, turn-of-the-century industrial building of historical significance (see chapter 9). The Southeast Plant has two coal fired boilers in service: a pulverized coal unit, 53 years old, rated at approximately 110,000 lb/hr steam, and a spreader stoker unit, 45 years old, rated at approximately 120,000 lb/hr steam. Two additional boilers in the plant are retired. The Plant is configured for electrical generation, but it is not operational. Total plant capacity is 230,000 lb/hr.


Southeast Plant
Alternative Site
St. Paul Plant
Main Plant
MISSISSIPPI
UNIVERSITY OF MINNESOTA
(St Paul Campus)
STATE FAIRGROUNDS
HENNEPIN CO
RAMSEY CO
Marshall High Sch
Van Cleve Park
Tuttle Sch
Holmes Sch
Mary's Hospital
Fairview Hospital
Augsburg College
Seward Park
Seward Sch
Bracket Field
St Albert Sch
Pioneers and Soldiers Cem
Radio Tower (KSTP)
Radio Tower (WMIN)
Hospital
Water Tank
Hamline Park
Lexington Park
Lauderdale Park
Merriam Terrace Park
Midway Hospital
Newell Park
Hancock Sch
Longfellow Sch
Gorden Sch
St Mark Sch
Town and Country Country Club
Minnehaha Ave
Franklin Ave
Hubbard
Blair
Thomas
Taylor
Fairview
Chicago
Northern Pacific
Burlington
Milw
St P

Minneapolis Campus ("Main") Plant has Five Older Coal-Fired Boilers and One Newer Gas/Oil Boiler in Operation

Six existing boilers at the Main Plant burn coal, oil and natural gas. There are three coal-fired spreader stoker units, one 45 years old and rated at 60,000 lb/hr of steam, one 42 years old rated at 60,000 lb/hr of steam, and one 41 years old rated at 70,000 lb/hr of steam; two pulverized coal units, one 29 years old rated at 80,000 lb/hr of steam and one 26 years old rated at 120,000 lb/hr of steam. There is one comparatively new 23-year old oil/gas unit rated at 180,000 lb/hr of steam. A seventh boiler (a pulverized coal unit, 57 years old, capacity of approximately 100,000 lb/hr of steam) is in near-operable condition but is not currently permitted. Total plant capacity is 570,000 lb/hr.

Minneapolis Campus Steam Load is one of the Highest in Minnesota

The University's Minneapolis campus has one of the largest district heating loads in Minnesota. Steam use at the Minneapolis campus currently averages about 270,000 lb/hr. The peak winter heating demand reaches approximately 520,000 lb/hr. Summertime steam use is also high because the University cools many of its buildings with steam driven chiller units (see Chapter 10). The minimum or baseload steam demand is approximately 110,000 lb/hr. Electricity use at the Minneapolis campus is about 234,000 mw-hours annually.

Recent Minneapolis Fuel Mix:
85-90% Coal
10% Natural Gas

The current annual fuel mix on the Minneapolis campus is approximately 85-90% coal, 5%-10% natural gas, and small amounts of distillate fuel oil. Total annual coal consumption was about 150,000 tons in FY 92-93.

Coal Unloaded and Stored at Main Heating Plant

Subbituminous western coal is delivered by rail to the Minneapolis campus. The railcars are first unloaded in a shed adjacent to the Main Plant, where the coal is dropped into a small underground storage area, treated with dust suppressant, and transferred via a covered conveyor to an open storage area near the Main Plant.

Coal for the Southeast Plant is trucked from the Main Plant on a private road above the riverfront bluff. A short-term coal supply for the Southeast Plant in stored in an adjacent, uncovered outdoor bunker. See Chapter 9 for additional description of the riverfront coal handling operations.

Coal Ash is Temporarily Stored Under 10th Avenue Bridge, Near Mississippi Shoreline, and then Trucked to Sanitary Landfill In Wisconsin

The ash from the coal boilers at both the Main and Southeast Plants is first cooled and stored in ash silos attached to the steam plant buildings. The ash is then unloaded into trucks that transfer the ash to a bermed temporary storage area located under the 10th Avenue Bridge along the Mississippi riverfront. The ash is removed from the storage site in larger trucks and eventually disposed of in a licensed sanitary landfill in Madison, Wisconsin. More detailed descriptions and location information regarding the temporary ash storage and the ash handling impacts are described in Chapters 7 and 8.

Two Above Ground Fuel Oil Tanks, and Fourteen Underground Tanks at the Minneapolis Campus

An fuel oil unloading station and two above ground storage tanks, 500,000 gallons and 250,000 gallons, are located and utilized at the Main Plant. There are fourteen underground storage tanks for fuel oil at the Main Plant. There is one 10,000 gallon aboveground oil storage tank located at the Southeast Plant containing distillate fuel oil for use in boiler startup only.

Section 1.2. St. Paul Campus

St. Paul Plant has Six Coal-Fired Boilers and One New Gas/Oil Fired Boiler.

The St. Paul Plant has seven boilers, ranging in age from 1 to 54 years: two pulverized coal units, each 38 years old, each rated at approximately 30,000 lb/hr of steam; two oil/gas units, each 54 years old, each rated at approximately 30,000 lb/hr of steam; two coal spreader stoker units, 24 and 16 years old, each producing approximately 60,000 lb/hr of steam; and a newly installed (1991 start-up) oil/gas unit rated at approximately 80,000 lb/hr of steam. The present total capacity at the St. Paul Plant is 330,000 lb/hr of steam.

Average Annual Steam and Demand is About 90,000 lb/hr

Steam demand at the St. Paul campus currently averages about 90,000 lb/hr.. The winter heating peak demand reaches approximately 170,000 lb/hr. Electricity demand averages approximately 71,000 mw-hours annually.

Recent Fuel Mix at St. Paul:
46% Coal
48% Natural Gas
6% Fuel Oil

The annual fuel mix on the St. Paul campus in FY 1992-93, the most recent complete data available, was 46 % coal, 48 % natural gas, and 6% distillate fuel oil. The University has indicated that it keeps annual coal use at about 65% of total energy use. Total annual coal consumption was 16,000 tons coal. This fuel mix uses more natural gas than would a strictly economic fuel dispatch.

Eastern Bituminous Coal is Delivered to St. Paul Plant by Truck and Stored in Open Area in Back.

The St. Paul Plant uses bituminous eastern coal. The coal is delivered directly from coal suppliers' docks and stored in an open coal pile to the rear of the building. The coal storage volume was recently reduced, and coal handling facilities were upgraded to include some partitioning in the coal bunkers.

Ash Stored in a Nearby Concrete Bunker, Surrounded by Berms

The ash handling system includes an ash silo and a recently installed concrete ash bunker, from which ash is trucked to a sanitary landfill. There is a earth berm installed to contain stormwater runoff. A detailed description of the St. Paul facility and the surrounding land uses is contained in Chapter 9. Potential material handling modifications are described in the chapter on mitigation (Chapter 10).

Fuel Oil Storage Consists of A Large Storage Tank and Two Small Tanks

The St. Paul plant has one 400,000 gallon above ground oil storage tank which is currently used for number 2 fuel oil. Also in use are two smaller underground "day tanks" of 35,000 gallons each.

Chapter 2. The Proposed Project

The University's Proposal is Defined by its Contract

The University's proposed project, including options, is defined by the 1992 construction contract between the University and Foster Wheeler. The contract includes specific renovations to the steam plants at both campuses, so the following project description and the financial evaluation includes a discussion of both campuses. Most environmental and other impacts for the two campuses, however, are addressed separately, except when describing the general terms of the University's contract and as otherwise necessary.

The Construction Contract Includes Two Major Equipment Options.

The University's contract includes two basic equipment configurations, designated as "Case A" and "Case B, which are described below. The University has not decided between these options, but it has submitted an air quality permit application to the Minnesota Pollution Control Agency only for Case A.

Contract Includes Tariff Rate for Steam Consumption.

The University's contract includes a tariff rate for steam consumption (with both fixed and variable components) and base rates for monthly operation and maintenance charges. The contract also includes base rates for steam consumption charges.

Under the University's contract, insurance, ash disposal costs, and fuel price changes pass directly through to the University. The quantity of fuel charged to the University is based on minimum efficiency guarantees in the contract. Any fuel efficiency savings above the guaranteed levels are shared by the University and its steam provider.

A copy of the tariff description is included in the *Financial Projections* report, by Dahlen, Berg & Co.

Section 2.1. Case A

Introduction

This section describes the proposed equipment configuration and the plant operation for the Case A option. The Minneapolis Campus is described first, followed by the St. Paul Campus.

Steam Would Be Produced at the Southeast Heating Plant With New Circulating Fluidized Bed Boiler and Two Conventional Gas/Oil Boilers.

Under Case A, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Case A, 650,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from a 200,000 lb/hr circulating fluidized bed boiler, and from conventional boilers (450,000 lb/hr). Existing coal-fired boilers 3 and 4 would be retained primarily for backup. Total steam capacity including existing boilers 3 and 4 would be 830,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr. The fluidized bed boiler has operational and criteria pollutant emission advantages over conventional coal boilers that are briefly described in Chapter 6.

The new combustion equipment would exhaust flue gasses through the two stacks that are not currently used.

15 mW Steam Turbine Would Be Installed at Southeast Heating Plant.

A nominal 15 mW noncondensing steam turbine would be installed at the Southeast Heating Plant and would produce electricity in proportion to the Minneapolis campus steam load. Net electricity production would be approximately 50,000 mW-hours annually depending on steam load.

Southeast Heating Plant Would Be Modified, Roof Section Raised 40 Feet.

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The weight of the new circulating fluidized bed boiler would be roof-hung and supported on new structural steel columns independent of the existing structure.

In order to accommodate the new CFB boiler, 40 feet would be added to the existing turbine hall building height. The footprint of the building would not be changed. (See Chapter 9 for building renovation description.)

Main Plant Would be Decommissioned Following Renovation.

The Main Plant will be operated and maintained to provide steam service for the Minneapolis Campus during design and construction of the new facilities at the Southeast Plant. Following the beginning of commercial operation of the renovated Southeast Plant, the Main Plant would be retired.

Contract Includes Minneapolis and St. Paul Construction Options.

The University's contract includes eight construction options at additional cost for the Minneapolis campus and three construction options for the St. Paul campus. These options are discussed in more detail in Chapter 10. The University has not yet exercised any of these options, which may be described as follows.

Minneapolis Options

1. Install NO_X control equipment (Denox System) on the fluidized bed boiler.
2. Construct a wall partially to enclose the Minneapolis Campus ash pile.
3. Construct a wall partially to enclose the Main Plant coal pile.
4. Install an additional gas boiler.
5. Install an additional fluidized bed boiler.
6. Install a coal conveyor between the Main Plant and the Southeast Plant.
7. Modify the fluidized bed boiler to allow 100% natural gas firing.
8. Modify the fluidized bed boiler to allow up to 30% firing with petroleum coke.

Existing Main Plant Coal Handling Facilities Would Be Used, with Optional Use of Coal Conveyor.

The existing coal unloading and storage facilities at the Main Heating Plant would continue to be used. Coal would continue to be trucked to the Southeast Heating Plant. The contract includes an option to partially screen the coal storage area and to install a coal conveyor from the Main Heating Plant to the Southeast Heating Plant through the existing tunnel, although the University has not exercised this option.

Existing No. 2 Oil Storage Facilities in Minneapolis Would Be Used.

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the packaged natural gas and No. 2 oil conventional boilers. An oil pipeline would be installed between the two plants. Fourteen underground storage tanks are anticipated to be retired at the closure of the Main Plant (see Chapter 8).

Economic dispatch assumes fluidized bed boiler first, followed by new gas/oil boilers and existing coal boilers as needed

The costs and emission levels for the University's proposed Case A project are based on the following least-cost fuel dispatch of steam production equipment:

- circulating fluidized bed boiler first, to meet baseload steam demand
- conventional high pressure natural gas and fuel oil boiler, second
- Southeast coal boilers number 3 and 4 third, and
- conventional medium pressure natural gas boilers last

The University has described the likely dispatch order as using the medium pressure conventional boiler before the existing coal-boilers.

Fuel Mix at Minneapolis:
81% Coal
17% Natural Gas
2% Fuel Oil

After completion of the facilities in FY 1998, the Case A fuel mix in Minneapolis would be approximately 81% coal, 17% natural gas, and 2% fuel oil, based on economic dispatch of the steam production facilities. The total fuel consumed in FY 1998 would be 3,000,414 MMBtu's. The fuel consumed varies with annual steam production, but the fuel mix remains relatively stable throughout the 25-year projections. Economic dispatch could also include up to 7% waste-wood and up to 20% petroleum coke (additional cost option), depending on fuel availability, cost, and transportation difficulties.

Steam Would Be Produced at the Existing St. Paul Heating Plant.

Under Case A, steam would be produced at the St. Paul Heating Plant. Existing primarily-coal fired boilers 1, 2, 5, 6 and 7 would remain in service and two older gas/oil boilers, 3 and 4, would be decommissioned. The total capacity of boilers 1, 2, 5, 6 and 7 is 250,000 lb/hr.

Under Case A, 250,000 lb/hr of steam capacity would be added at the St. Paul Heating Plant. The total steam capacity including existing boilers would be 500,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 250,000 lb/hr.

Case A Includes Options for St. Paul Plant.

St. Paul Options:

1. Construct ash pile storm water collection system.
2. Construct walls to partially enclose the coal pile.
3. Install a combustion turbine.

St. Paul Heating Plant Would Be Expanded for Gas/Oil, but Coal Storage Would be Retained.

The St. Paul Heating Plant would be expanded to provide space for the new production equipment. The new natural gas. fuel oil boiler would be enclosed in a pre-engineered building with metal siding. A dedicated 200-foot steel chimney will also be provided.

The existing coal unloading and storage facilities at the St. Paul Heating Plant would be retained because coal would continue to be used for backup, according to the University.

Existing No. 2 Oil Storage Facilities in St. Paul Would Be Used.

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

Fuel Mix at St. Paul Would Be
92% Natural Gas
8% Fuel Oil

The University has defined the proposal as using negligible quantities of coal at the St. Paul Campus following renovation, although coal permits will be retained. After completion of the facilities in FY 1997, the Case A fuel mix in St. Paul would be approximately 92% natural gas and 8% fuel oil, based on economic boiler dispatch–and assuming no use of coal. The total fuel consumed in FY 1997 would be 932,368 MMBtu's. The fuel consumed varies with steam production, and the fuel mix remains relatively stable throughout the projections.

Section 2.2. Case B

Introduction

Case B is an option to the proposed construction contract between the University and Foster Wheeler. The contract includes the same steam consumption tariff rates and the same construction options as those contained in Case A.

Case B is Case A with 22 mW Combustion Turbine with Waste-Heat Boiler Replacing Conventional Natural Gas, Fuel Oil Boiler

For Case B, as under Case A, nominal 15 mW noncondensing steam turbine would be installed and would produce electricity in proportion to the Minneapolis campus steam load. But for Case B, a 22 mW combustion turbine, powered by natural gas and No. 2 fuel oil, would also be installed and would produce electricity to meet the Minneapolis campus electric load net of the steam turbine production.

Waste heat from the 22mW combustion turbine would be used to produce up to 60,000 lb/hr of steam in the waste heat boiler. Net combined electricity production would be about 197,000 mW-hours annually.

Steam Would Be Produced at Southeast Heating Plant With Waste-Heat Boiler, Fluidized Bed Boiler, and Gas/Oil Boiler.

Under Case B, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Case B, 600,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from a waste heat boiler with supplementary firing (200,000 lb/hr), a 200,000 lb/hr fluidized bed boiler, and from a conventional gas/oil boiler (200,000 lb/hr). Total steam capacity including existing boilers 3 and 4 would be 830,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

The new combustion equipment would exhaust flue gasses through the two stacks that are not currently used.

Southeast Heating Plant Would Be Modified.

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. While the conventional boiler would be installed in a building addition, the combustion turbine, waste heat boiler and fluidized bed boiler all would be installed within the Southeast Plant. An additional 40 foot height addition to the boiler hall

would be required.

Existing Coal Handling Facilities in Minneapolis Would Be Used.

The existing coal unloading and storage facilities at the Main Heating Plant would continue to be used. Coal would be trucked to the Southeast Heating Plant. The contract includes an option partially to enclose the coal storage area and to install a conveyor from the Main Heating Plant to the Southeast Heating Plant through the existing tunnel, although the University has not exercised this option.

Existing No. 2 Oil Storage Facilities in Minneapolis Would Be Used.

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the packaged natural gas and No. 2 oil boilers. An oil pipeline would be installed between the two plants.

Economic Fuel Dispatch, Would be Waste Heat for Part of Baseload, Followed by the Fluidized Bed and Gas/Oil Boilers.

At economic dispatch, the Case B boiler configuration would generally be used to meet steam requirements in the following order

- waste-heat boiler using combustion-turbine exhaust, first
- fluidized bed boiler, second, depending on steam load
- supplemental gas/oil firing of waste heat boiler, third
- conventional gas/oil boiler and existing coal boilers last

Fuel Mix at Economic Dispatch Predicted to Be
50% Coal
46% Natural Gas
4% fuel Oil

After completion of the facilities, the Case B fuel mix in Minneapolis would be 50% coal, 46% natural gas, and 4% fuel oil, based on economic dispatch of the steam production facilities. The total fuel consumed in FY 1998 would be 3,867,420 MMBtu's. The fuel consumed varies with steam production, and the fuel mix remains relatively stable throughout the projections.

St. Paul Proposal for Case B Is the Same as for Case A.

Under Case B, equipment modifications, plant modifications, fuel handling, and fuel mix for the St. Paul facility would be the same as under Case A.

Chapter 3. Description of Alternatives

The Alternatives Chosen for Detailed Analysis Focused on Economically Reasonable, Proven Reliable Technologies.

The thirteen alternatives listed in the EIS scoping document, including off-site steam production, were quantitatively analyzed in an initial environmental and feasibility screening analysis. The results of this screening study, are described in *Alternatives to the University of Minnesota's Steam Service Facilities Renovation*, March 25, 1994, by Dahlen, Berg & Company.

Five alternatives were chosen for detailed analysis, four in Minneapolis and one in St. Paul. All are on-campus cogeneration systems that use primarily either natural gas with fuel-oil backup, or use a mixture of coal, natural gas, fuel oil. The alternatives are located either at riverfront Southeast Plant or at an alternative "23-acre" site located near Marriucci Arena and some Archer Daniel Midlands elevators. The two "No Action" alternatives (one per campus), were also carried into the next phase for comparison purposes.

The alternatives chosen for detailed analysis were based on the following criteria:

- Estimated point source emissions
- Estimated emissions adjusted for cogeneration benefits
- Cost and technical feasibility
- Potential for beneficial land use impacts
- Mix of technology, fuels, and location

Seven Alternatives Described

First, the alternatives analyzed in detail, as listed below, will be described.

Minneapolis Campus

Alt. No. 1	Minneapolis Deferred Construction
Alt. No. 3	Southeast Plant using Coal with Natural Gas Cogeneration
Alt. No. 4	Southeast Plant without Coal with Natural Gas Cogeneration
Alt. No. 6	New Plant at Alternative Location with Coal
Alt. No. 7	New Plant at Alternative Location without Coal

St. Paul Campus

Alt. No. 11	St. Paul Plant Deferred Construction
Alt. No. 13	St. Paul Plant without Coal

Detailed Descriptions of Alternatives Contained in Separate Report

Conceptual engineering design drawings of the alternatives chosen for detailed analysis, and the associated financial cost assumptions and calculations are described in a separate report: *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, July 29, 1994, by Dahlen, Berg & Co.

Six Other Alternatives Described

Alternatives which did not survive the initial Screening Analysis are listed below. These alternatives are described in Chapter 4, along with the reasons why they were not chosen for further consideration.

Minneapolis Campus

Alt. No. 2 Southeast Plant Natural Gas and Oil
Alt. No. 5 Southeast Plant with Large Cogeneration
Alt. No. 8 Main Plant Renovation and Expansion

Combined Campuses

Alt. No. 9 Purchase Steam from Third Parties
Alt. No. 10 Interconnect Minneapolis and St. Paul Systems—New Plant

St. Paul Campus

Alt. No. 12 St. Paul Plant with Cogeneration with coal

Section 3.1. Alternative No. 1 Minneapolis Deferred Construction (No Action)

Under Alternative No. 1, the Southeast Heating Plant and the Main Heating Plant would be operated in their current configurations until 2001. At that time, Southeast boilers 3 and 4 and Main boilers 1 and 2 would be retired. New coal-fired boiler capacity would be installed in the Southeast Plant.

This description of Alternative No. 1 includes the following components.

- Coal Used as the Primary Fuel
- Steam Produced at the Southeast Heating Plant
- Steam Produced at the Main Heating Plant
- Coal Storage and Handling Modified
- Southeast Heating Plant Modified
- Fuel Mix Identified

The purpose of this alternative is to provide an environmental comparison with other renovation alternatives, It represents the minimum effort required to continue to provide steam using the existing system, based on existing information. No conceptual design drawings have been made, and no permitting or other regulatory feasibility analysis has been conducted.

Coal Would Be Used as the Primary Fuel

Under Alternative No. 1, all boilers capable of burning coal would be dispatched first.

Steam Would Be Produced at the Southeast Heating Plant

Under Alternative No. 1, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4, with a total capacity of 230,000 lb/hr, would remain in service until 2001, when 360,000 lb/hr of new coal fired capacity would be installed.

The new boilers would exhaust flue gasses through the two stacks that currently are not used. The building height above the boiler hall would be increased similar to that required for Case A and Case B.

Steam Would Be Produced at the Main Heating Plant	Under Alternative No. 1, the existing boilers at the Main Heating Plant would be used. Boilers 1 and 2 would be retired and their capacity would not be replaced.
Coal Handling Would Be Modified	The coal unloading and storage facilities at the Main Heating Plant would be modified. Coal unloading and storage would be in enclosed areas and would be transported to the Southeast Plant on a new conveyor installed in the existing tunnel.
Southeast Heating Plant Would Be Modified	The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The roof would be removed to demolish existing boilers 3 and 4 and to install the new ones.
Fuel Mix Would Be 97% Coal 3% Natural Gas and Fuel Oil	The fuel mix for Alternative No. 1 in FY 2002, the first year the renovated plant would be operated, is projected to be 97% coal and 3% natural gas and fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be approximately 98% coal. The quantity of fuel consumed varies with the steam produced, but the fuel mix is remains stable throughout the 25-year projections.

Section 3.2. Alternative No. 3 Southeast Plant Using Coal with Natural Gas Cogeneration

Under Alternative No. 3, the Southeast Heating Plant would be modified and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines and steam would be produced by waste heat boilers, by new packaged natural gas and No. 6 fuel oil boilers, and by the two existing coal-fired boilers. This description of Alternative No. 3 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Electricity Distributed to East and West Bank Campuses
- Steam Produced at Southeast Heating Plant
- Coal Storage and Handling Modified
- No. 6 Oil Storage Provided
- Existing No. 2 Oil Storage Used
- Southeast Heating Plant Modified
- Fuel Mix Identified

Steam Produced at Southeast Heating Plant

Under Alternative No. 3, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Alternative No. 3, 525,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (250,000 lb/hr). Total steam capacity including existing boilers 3 and 4 would be 755,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler

	Electricity production would be about 187,245 mW-hour annually.
Electricity Distributed to East and West Bank Campuses	Because electricity produced under Alternative No. 3 would exceed the east bank campus load, electrical feeders to the west bank campus would be installed.
Coal and Ash Handling Would Be Modified	The coal unloading and storage facilities at the Main Heating Plant would be modified. Coal would be stored in the same area near the Main Plant, but in an enclosed structure, coal would be transported to the Southeast Heating Plant on a new conveyor installed in the existing tunnel similar to conveyor option in University contract. The practice of temporarily storing ash on-site would be discontinued. The ash would be cooled in ash silos and then transported by truck directly to a local ash repository.
No. 6 Oil Storage Would Be Provided	350,000 gallons of new No. 6 oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be added on site, either near the existing Main Plant, or near the Southeast Plant. An oil pipeline would be installed between as required.
Existing No. 2 Oil Storage Would Be Used	The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the combustion turbines and heat recovery boilers. An oil pipeline would be installed between the two plants.
Southeast Heating Plant Would Be Modified	The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The combustion turbines, waste heat boilers and conventional boilers would be installed within the Southeast Heating Plant. The exterior of the building would remain unchanged.
At Economic Fuel Dispatch, Base-Load Gas/Oil Cogeneration first, then supplemental gas/oil firing and existing coal boilers	At economic dispatch, the boilers would be used to meet steam requirements in the following order • waste-heat boiler using combustion turbine exhaust, first • supplemental gas/oil firing of waste heat boiler , second • existing coal-fired boilers No. 3 and No. 4, third

- conventional natural gas, fuel oil boiler, last

Fuel Mix Would Be
62% Natural Gas
32% Coal
6% Fuel Oil

The fuel mix for Alternative No. 3 in FY 1999, the first full year the renovated plant would be operated, is projected to be 62% natural gas, 32% coal and 6% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable.

Chapter 3.3. Alternative No. 4 Southeast Plant without Coal with Natural Gas

Under Alternative No. 4, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines, and steam would be produced by waste heat boilers and by new packaged natural gas and No. 6 fuel oil boilers. The existing coal boilers at the Southeast Heating Plant would be retired. This description of Alternative No. 4 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Steam Produced at Southeast Heating Plant
- Coal Storage and Handling Would Stop
- No. 6 Oil Storage and Handling Would Be Provided
- Existing No. 2 Oil Storage and Handling Would Be Used
- Southeast Heating Plant Would Be Modified
- Fuel Mix Identified

Steam Produced at Southeast Heating Plant

Under Alternative No. 4, 815,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (540,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 635,000 lb/hr.

The new combustion equipment would exhaust flue gasses through the existing stacks.

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler. Electricity production would be about 187,245 mW-hours annually.

Coal Storage and Handling Would Stop	The existing coal unloading and storage facilities at both the Southeast Heating Plant and the Main Heating Plant would be decommissioned.
No. 6 Oil Storage Would Be Provided	760,000 gallons of new No. 6 oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be added either in or near the existing Southeast Plant coal bunker, or possibly near the Main Heating Plant. An oil pipeline would be installed as necessary.
Existing No. 2 Oil Storage Would Be Used	The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the combustion turbines and heat recovery boilers. An oil pipeline would be installed between the two plants.
Southeast Heating Plant Would Be Modified	The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The combustion turbines, waste heat boilers and conventional boilers would be installed within the Southeast Heating Plant.
Economic Dispatch is Base-Load Gas/Oil Cogeneration, followed gas/oil firing.	At economic dispatch, the boilers would be used to meet steam requirements in the following order • waste-heat boiler using combustion turbine exhaust, first • supplemental gas/oil firing of waste heat boiler, second • medium pressure conventional gas/oil boilers, last
Fuel Mix Would Be 92% Natural Gas 8% Fuel Oil	The fuel mix for Alternative No. 4 in FY 1999, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable over the 25-year projections.

Section 3.4. Alternative No. 6 New Plant at Alternate Location with Coal

Under Alternative No. 6, a new plant would be constructed with an equipment configuration similar to Case A, but at an off-river site. Both the Southeast Heating Plant and the Main Heating Plant would be retired. Electricity would be produced by a noncondensing steam turbine. Steam would be produced by a circulating fluidized bed boiler and by packaged natural gas and No. 6 fuel oil boilers. This description of Alternative No. 6 includes the following components.

- 17 mW Steam Turbine Installed
- Steam Produced at Southeast Heating Plant
- 12,000 Tons of Coal Storage Would Be Provided
- 890,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed
- New Building Would Be Built

17 mW Steam Turbine Installed

A nominal 17 mW noncondensing steam turbine would be installed to produce electricity. Electricity would be generated in proportion to the Minneapolis campus steam load. Electricity production is predicted to be about 60,000 mW-hours annually, but would increase as steam use increased in the future.

A New Building Would Be Built at Off-River Site

Under Alternative No. 6, 840,000 lb/hr of steam capacity would be installed at a new building at an off-river site.. The capacity would be from a circulating fluidized bed boiler (210,000 lb/hr) and from conventional boilers (630,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

A multi-flue chimney would be constructed.

12,000 Tons of Coal Storage Would Be Provided

Coal would be delivered by rail, and 12,000 tons of coal storage would be provided in an enclosed dome-shaped coal storage and reclaim system. This would provide capacity to accept a unit train delivery plus seven days' capacity at the maximum coal-firing rate.

890,000 Gallons of No. 6 Fuel Oil Storage Would Be Provided

890,000 gallons of No. 6 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be installed for the conventional boilers. The equipment and coal unloading and storage would be entirely enclosed.

Economic Dispatch uses CFB first to meet baseload steam demand–up to 200,000 lb/hr; followed by gas/oil boilers as needed.

At economic dispatch, the new boiler configuration would generally be used to meet steam requirements in the following order:

- circulating fluidized bed, first
- medium pressure gas/oil boilers, second

Fuel Mix Would Be 72% Coal 25% Natural Gas 3% Fuel Oil

The fuel mix for Alternative No. 4 in FY 1999, the first full year the renovated plant would be operated, is projected to be 72% coal, 25% natural gas and 3% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the amount of steam produced, while the fuel mix is projected to remain stable.

Section 3.5. Alternative No. 7 New Plant at Alternate Location without Coal

Under Alternative No. 7, a new plant would be constructed, and both the Southeast Heating Plant and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines and steam would be produced by waste heat boilers and by new packaged natural gas and No. 6 fuel oil boilers. This description of Alternative No. 7 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Steam Produced at New Plant
- 760,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed
- 580,000 Gallons of No. 2 fuel Oil Storage Would Be Installed
- New Building Would Be Built
- Fuel Mix Identified

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler. Electricity production would be about 187, 245 mW-hours annually.

Steam Produced at New Plant

Under Alternative No. 7, 815,000 lb/hr of steam capacity would be installed. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (540,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 635,000 lb/hr.

A new multi-flue chimney would be constructed.

760,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed

760,000 gallons of No. 6 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be installed for the conventional boilers.

580,000 Gallons of No. 2 Fuel Oil Storage Would Be Installed	580,000 gallons of No. 2 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 2 oil-firing rate, would be installed for the combustion turbines and waste heat boilers.
New Building Would Be Built	The equipment would be installed in a new multilevel structure.
Economic Dispatch is Base-Load Gas/Oil Cogeneration, followed gas/oil firing.	At economic dispatch, the boilers would be used to meet steam requirements in the following order • waste-heat boiler using combustion turbine exhaust, first • supplemental gas/oil firing of waste heat boiler, second • medium pressure gas/oil, last
Fuel Mix Would Be 92% Natural Gas 8% fuel Oil	The fuel mix for Alternative No. 7 in FY 1999, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable over the 25-year projection period.

Section 3.6. Alternative No. 11 St. Paul Deferred Construction (No Action)

Under Alternative No. 11, the St. Paul Heating Plant would be operated in its current configuration until 2001. At that time, existing boilers 3 and 4 would be retired, and a new gas/oil fired boiler installed.

This description of Alternative No. 11 includes the following components.

- Coal Used as the Primary Fuel
- Steam Produced at St. Paul Heating Plant
- Coal Storage and Handling Would Remain
- Existing No. 2 Oil Storage Would Be Used
- St. Paul Heating Plant Would Be Expanded
- Fuel Mix Identified

Coal Would Be Used as the Primary Fuel

Under economic fuel dispatch for alternative No. 11, boilers capable of using coal would be dispatched first.

Steam Would Be Produced at the Southeast Heating Plant

Under Alternative No. 11, steam would be produced at the St. Paul Heating Plant. The existing boilers would be operated until 2001. At that time, boilers 3 and 4 (total capacity of 50,000 lb/hr) would be retired, and a new 50,000 lb/hr gas/oil fired boiler would be installed. Existing boilers 1, 2, 5, 6 and 7 (total capacity of 250,000 lb/hr) would remain in service.

The total steam capacity before boiler replacement would be 300,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 220,000 lb/hr. After boiler replacement, the total and firm capacities would remain at 300,000 lb/hr and 220,000 lb/hr respectively.

A new 120 foot steel stack would be provided for the new boiler.

Existing Coal Handling Would Remain

The existing coal unloading and storage facilities at the St. Paul Heating Plant would remain.

Existing No. 2 Oil Storage Would Be Used

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

St. Paul Heating Plant Would Be Expanded

The St. Paul Heating Plant would be expanded to provide space for the new production equipment.

Fuel Mix Would Be 92 % Coal 7 % Natural Gas 1 % Fuel Oil

The fuel mix for Alternative No. 11 in FY 2002, the first year the renovated plant would be operated, is projected to be 92.6% coal, 6.8% natural gas, and 0.6% fuel oil. Prior to renovation, the fuel mix for each of the St. Paul alternatives is projected to be 93% coal. After renovation, the fuel consumed would vary with the amount of steam produced, with increasing use of natural gas.

Section 3.7. Alternative No. 13 St. Paul without Coal

Under Alternative No. 13, the St. Paul Heating Plant would be modified. Coal would no longer be used. Steam would be produced by new and existing boilers. Electricity would not be produced. Alternative No. 13 is similar to the proposed project, except for the total elimination of coal storage and use, and the installation of a smaller new gas/oil conventional boiler. This description of Alternative No. 13 includes the following components.

- Steam Would Be Produced at St. Paul Heating Plant
- Coal Storage and Handling Would Be Eliminated
- Existing No. 2 Oil Storage Would Be Used
- St. Paul Heating Plant Would Be Expanded
- Fuel Mix Identified

Steam Would Be Produced at St. Paul Heating Plant

Under Alternative No. 13, steam would be produced at the St. Paul Heating Plant. Existing boilers 1, 2, 5, 6 and 7 would remain in service, and boilers 3 and 4 would be decommissioned. The total capacity of boilers 1, 2, 5, 6 and 7 is 250,000 lb/hr.

Under Alternative No. 13, 50,000 lb/hr of steam capacity would be added at the St. Paul Heating Plant. The total steam capacity including existing boilers would be 300,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 220,000 lb/hr.

A new 120 foot steel stack would be provided for the boiler.

Coal Storage and Handling Would Be Eliminated

The existing coal unloading and storage facilities at the St. Paul Heating Plant would be decommissioned.

Existing No. 2 Oil Storage Would Be Used

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

St. Paul Heating Plant Would Be Expanded

The St. Paul Heating Plant would be expanded to provide space for the new production equipment.

Fuel Mix Would Be 92% Natural Gas 8% Fuel Oil

The fuel mix for Alternative No. 13 in FY 1998, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the St. Paul alternatives is projected to be 93% coal. After renovation, the fuel consumed would vary with the steam produced, while the fuel mix is projected to remain stable.

Chapter 4. Alternatives Considered but Not Analyzed in Detail

Introduction: Emerging Biomass-Fired Technologies Eliminated Because of Uncertain Reliability

A number of emerging power and steam production technologies were considered as part of the screening analysis, including integrated coal gassification combined cycle (IGCC), fuel cells, and biomass gassifier combined cycle (BGCC), but none were analyzed in detail.

These technologies have potentially significant environmental benefits. For example, IGCC, like the fluidized bed system proposed by the University, produces lower sulfur dioxide and nitrogen oxide emissions than conventional coal boilers, and has potentially better solid waste handling features. And a biomass gassification plant would reduce or eliminate the negative environmental and economic impacts associated with the use of fossil fuels.

These alternatives, however, have not yet had extensive operational field testing, and the reliability and costs of both are unknown. The necessity of providing reliable thermal energy to the University at a reasonably predictable cost eliminated emerging technologies.

Each alternative is described and the reasons for not studying it in detail are provided

The remainder of this chapter describes the alternatives for which the costs and impacts were quantified in a screening analysis, but that were not addressed in detail. Each alternative is described, and the reason for not addressing it further is provided.

Detailed descriptions of each alternative, and detailed information on costs and feasibility are described in detail in a separate report, *Alternatives to the University of Minnesota's Steam Service Facilities Renovation, Screening Analysis*, March 25, 1994, by Dahlen, Berg & Company. A summary of the costs of all alternatives addressed in the screening analysis is also included in Chapter 11.

Section 4.1. Alternative No. 2 Southeast Plant Natural Gas/Oil

Conventional Natural Gas, Fuel Oil Facility at Southeast Plant Without Cogeneration

Under Alternative No. 2, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Steam would be produced by new packaged natural gas and No. 6 fuel oil boilers. No electricity would be cogenerated. All existing coal-fired boilers would be decommissioned. This description of Alternative No. 2 includes the following components.

- Steam Would Be Produced at the Southeast Plant
- Coal Storage and Handling Would Stop
- Existing No. 2 Oil Storage Would Be Converted to No. 6
- Gallons of No. 6 Fuel Oil Storage Would Be Added to the Main Heating Plant
- Southeast Heating Plant Would Be Modified
- Two Fuel Scenarios: 92% Natural Gas/8% Fuel Oil
- 100% Natural Gas
- Alternative Rejected Because No Cogeneration

Existing No. 2 Oil Storage Would Be Converted to No. 6

The existing No. 2 oil storage facilities would be converted to No. 6, which costs less than No. 2 fuel oil. Tanks would be insulated and oil heaters and pumps would be installed. An oil pipeline would be installed between the two plants.

Alternative Rejected Because No Cogeneration and 100% Natural Gas Version Too Expensive

The costs for Alternative No. 2 were similar to the costs for Alternative No. 4, but Alternative No. 2 did not include the potentially significant environmental and energy efficiency benefits of electricity cogeneration.

The 100% natural gas version of this alternative was not considered further because the operating costs were $100 million higher than when an alternative fuel (No. 6 fuel oil) was assumed to be available.

Section 4.2. Alternative No. 5 Southeast Plant with Large Cogeneration

Under Alternative No. 5, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Electricity would be produced by large combustion turbines, and steam would be produced by waste heat boilers and a conventional boiler. The two existing coal-fired boilers would be converted to burn natural gas and No. 6 fuel oil. This description of Alternative No. 5 includes the following components.

- 80 mW Combustion Turbines Installed
- Cogeneration of Steam and Electricity Would be Maximized
- Steam Would Be Produced at the Southeast Heating Plant
- Coal Storage and Handling Would Stop
- No. 2 Oil Storage Would Be Increased
- Gallons of No. 6 Oil Storage Would Be Added to the Southeast Heating Plant
- Southeast Heating Plant Would Be Modified
- Fuel Mix: 92% Natural Gas, 8% Fuel Oil
- Alternative Rejected Because of Land Use Constraints and Because it is Too Expensive for the Near Future

80 mW Combustion Turbines Installed

Eighty mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 80 mW total capacity would be provided by two nominal 40 mW units. The combustion turbines would provide most of the University's electrical requirements.

Alternative Rejected Because Too Expensive

Alternative No. 5 was rejected because it was too expensive to justify the incremental improvement in energy efficiency ($50 million more than other cogeneration alternatives). The avoided cost paid to the University by the utility for production beyond the University's needs was not enough to compensate for the cost of production. Potentially large space needs would have required major additions to the Southeast Plant or acquisition by the University of a large adjacent property.

Section 4.3. Alternative No. 8 Main Plant Renovation and Expansion

Under Alternative No. 8, the Main Heating Plant would be modified to fire 100% gas/oil. The Southeast Heating Plant would be retired. Steam would be produced by existing boiler 6 and by new packaged boilers. All boilers would use natural gas and No. 6 fuel oil. No electricity would be generated. All existing coal-fired boilers in both plants would be decommissioned. This description of Alternative No. 8 includes the following components.

- Steam Would Be Produced at the Main Plant
- The existing gas/oil in the Main Plant would remain in service. All other boilers in the Main Heating Plant and the Southeast Heating Plant would be decommissioned
- Coal Storage and Handling Would Stop
- No. 6 Oil Storage and Handling Would Be Added
- Main Heating Plant Would Be Modified
- Fuel Mix: 92% Natural Gas, 8% Fuel Oil Alternative Rejected Because of Lack of Space

Main Heating Plant Modified

The interior of the existing Main Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The new boilers would be installed entirely inside the Main Heating Plant.

Alternative Rejected Because of Lack of Space

Alternative No. 8 had the lowest construction cost of any alternative considered in the screening analysis, lower even than the "Deferred Construction" alternative (Alt. 1) at the Southeast Plant because of the higher capital cost of coal boilers. It also had a reasonable 25-year net present value cost, although it is 100% natural gas and fuel oil.

Alternative No. 8, however, was not analyzed in more detail because there was no room for cogeneration equipment and no room for any necessary future expansion.

Section 4.4. Alternative No. 9 Purchase Steam from Third Parties

Under Alternative No. 9, steam would be provided from the University of Minnesota heating plants and from existing third party, off-campus vendors. This description of Alternative No. 9 includes the following components.

- Steam Would Be Transmitted from a Minneapolis Site
- Steam Would Be Transmitted from a St. Paul Site
- Fuel Mix for Generated Steam Identified
- Alternative Rejected Because Too Expensive, with High Emissions

Steam would Be Transmitted from a Minneapolis Site

Under Alternative No. 9, steam would be produced at both Minneapolis heating plants. The existing heating plants would be operated in their current configuration. Minimal capital improvements would be made.

Steam also would be produced at Minneapolis heating plants such as Hennepin County Energy Center or Minneapolis Energy Center. 140,000 lb/hr would be available and would be transmitted to the west bank side of the Minneapolis campus through a 24-inch pipeline. Condensate would be returned through a 10-inch pipeline. Each pipeline would be direct buried and about 6,600 feet long.

The boiler capacity would be dispatched in the following order:

- Steam Line
- Southeast Heating Plant - Using coal fired boilers
- Main Heating Plant - Using coal fired boilers
- Main Heating Plant - Using gas/oil fired boilers

Steam would Be Transmitted from a St. Paul Site

Steam would be produced with the St. Paul Heating Plant operating in its current configuration. Minimal capital improvements would be made.

Steam also would be produced at a St. Paul plant such as NSP's High Bridge generating plant, probably using existing coal boilers that are not equipped for cogeneration currently. 150,000 lb/hr would be available and would be transmitted to the St. Paul system through a 24-inch pipeline. Condensate would be returned through a 10-inch pipeline. Each pipeline would be

direct buried and about 8,000 feet long.

The boiler capacity would be dispatched in the following order:

- Steam Line
- St. Paul Heating Plant - Using coal fired boilers
- St. Paul Heating Plant - Using gas/oil fired boilers

Off Campus Fuel Mix Would be Mostly Coal

The most likely least-cost fuel for such a system would be coal, but the mix could include natural gas, fuel oil, and possibly municipal waste if a variety of steam sources were included in the "network."

Fuel Mix for On-Site Generated Steam Could Be: 100% Coal, 100% Natural Gas or a Combination

The least-cost fuel mix for the steam generated at the remaining campus plants under Alternative No. 9 is 100% coal in FY 1995. Then, natural gas and fuel oil would only be needed as backup for the coal boilers.

The total fuel consumed for on-campus steam production in FY 1995 is estimated to be 1,199,906 MMBtu's. The 100% use of natural gas for on-site production would decrease most air emissions and eliminate the fugitive dust and other problems associated with coal. 100% use of on-site natural gas instead of coal was projected to increase NPV cost by an additional 18 million dollars.

Alternative Rejected Because Too Expensive, with High Emissions

Alternative 9 was not addressed in detail because it was too expensive without necessarily adding any of the environmental benefits of cogeneration. Without cogeneration, this alternative had high emissions.

Implementation of Alternative 9 or a similar off-campus steam supply would reduce or eliminate on-campus impacts from coal dust, ash and associated land use problems. The steam lines could also be an important first step toward a metropolitan wide thermal network that includes the widespread use of cogeneration. Such a network could maximize electrical production "waste heat" to heat the University (see Chapter 10).

The feasible short-term, and likely long-term, version of this alternative, however, simply relocates the air emission source to one or more older, higher emitting facilities that are currently not technically compatible with cogeneration.

Section 4.5. Alternative No. 10 Interconnect Minneapolis/St. Paul Systems - New Plant

Under Alternative No. 10, one new plant would be constructed between the two campuses, and would provide steam for both. The Southeast Heating Plant, Main Heating Plant and St. Paul Heating Plant would be retired. Electricity would be produced by a noncondensing steam turbine. Steam would be produced by a circulating fluidized bed boiler and by packaged natural gas and No. 6 fuel oil boilers. The scenario would include the following components.

- Steam Turbine Installed
- Coal Storage and Handling Would Be Provided
- No. 6 Oil Storage and Handling Would Be Installed
- New Building Would Be Built
- Fuel Mix: 53% Coal, 43% Natural Gas, 4% Fuel Oil
- Alternative Rejected Because Too Expensive, Without Offsetting Environmental Benefits

Alternative Rejected Because Too Expensive

Construction costs for this alternative were the highest of any alternative reviewed in the screening analysis. Total costs for Alternative No. 10 were also approximately the same as for all-gas, oil facilities at both campuses, yet this alternative had higher emissions than natural gas facilities would have had.

Chapter 4.6. Alternative No. 12 St. Paul Plant with Cogeneration

Under Alternative No. 12, the St. Paul Heating Plant would be modified. Electricity would be produced by a new combustion turbine. Steam would be produced by a new waste heat boiler and the existing boilers. This description of Alternative No. 12 includes the following components:

- 4 mW Combustion Turbine Installed
- Steam Would Be Produced
- Existing Coal Boilers and Handling Facilities Would Be Used to Minimize Cost to the University.
- Existing No. 2 Oil Storage Would Be Used
- Plant Would Be Expanded
- Fuel Mix Identified
- Alternative Rejected Because of High Emissions

Alternative Rejected Because of High Emissions

Alternative No. 12, although it did include an economical cogeneration system, was rejected because of the high emissions and fugitive dust problems which resulted from using coal. Using coal also contradicted the University's public commitment to using all gas and oil at St. Paul.

Chapter 5. Natural Environment

This chapter describes the soils, hydrology, and important flora and fauna at the Riverfront, Alternative, and St. Paul Sites. A more detailed description of the geology and hydrology of the Minneapolis sites is available in a separate report, *Soil and Groundwater Contamination Site Assessments*, October 1994.

Soils and Geology of the River Flats Differ from Those atop the Bluff

The surface elevation of the Riverfront Site varies from approximately 725 feet above sea level along the Mississippi River to approximately 825 feet above sea level along the railroad tracks atop the river bluff.

Atop the bluff, varying depths of fill overlie approximately 20 feet of interbedded glacial till and alluvium, which in turn overlie limestone bedrock of the Platteville formation.

Along the river at the base of the bluff, the Platteville Limestone and underlying Glenwood Shale bedrock units have been eroded away by the river. Here, the uppermost bedrock unit, overlain by varying depths of till and weathered limestone, is the St. Peter Sandstone (See Figure 1).

Groundwater Flows toward the Mississippi

In the bluff areas of the Riverfront Site, the water table reportedly occurs in the surficial deposits (glacial drift and alluvium) at an elevation of approximately 800 feet or lower.

At the base of the bluff, the water table occurs in the St. Peter Sandstone bedrock or in the river bank sediments at the elevation of the Mississippi River. River elevation is approximately 750 feet upstream and 725 feet downstream of the lock and dam located at the western end of the site.

Groundwater flow at the site is locally influenced by the proximity of the Mississippi River and of the lock and dam at the site. Generally, groundwater flows southwest and discharges to the Mississippi River.

Two Separate Groundwater Systems Divided by Confining Layer

The groundwater system at the top of the bluff differs from the St. Peter Sandstone bedrock groundwater system below it. The two systems are separated by confining zones of low permeability soil (i.e., clay) or bedrock units (i.e., shale).

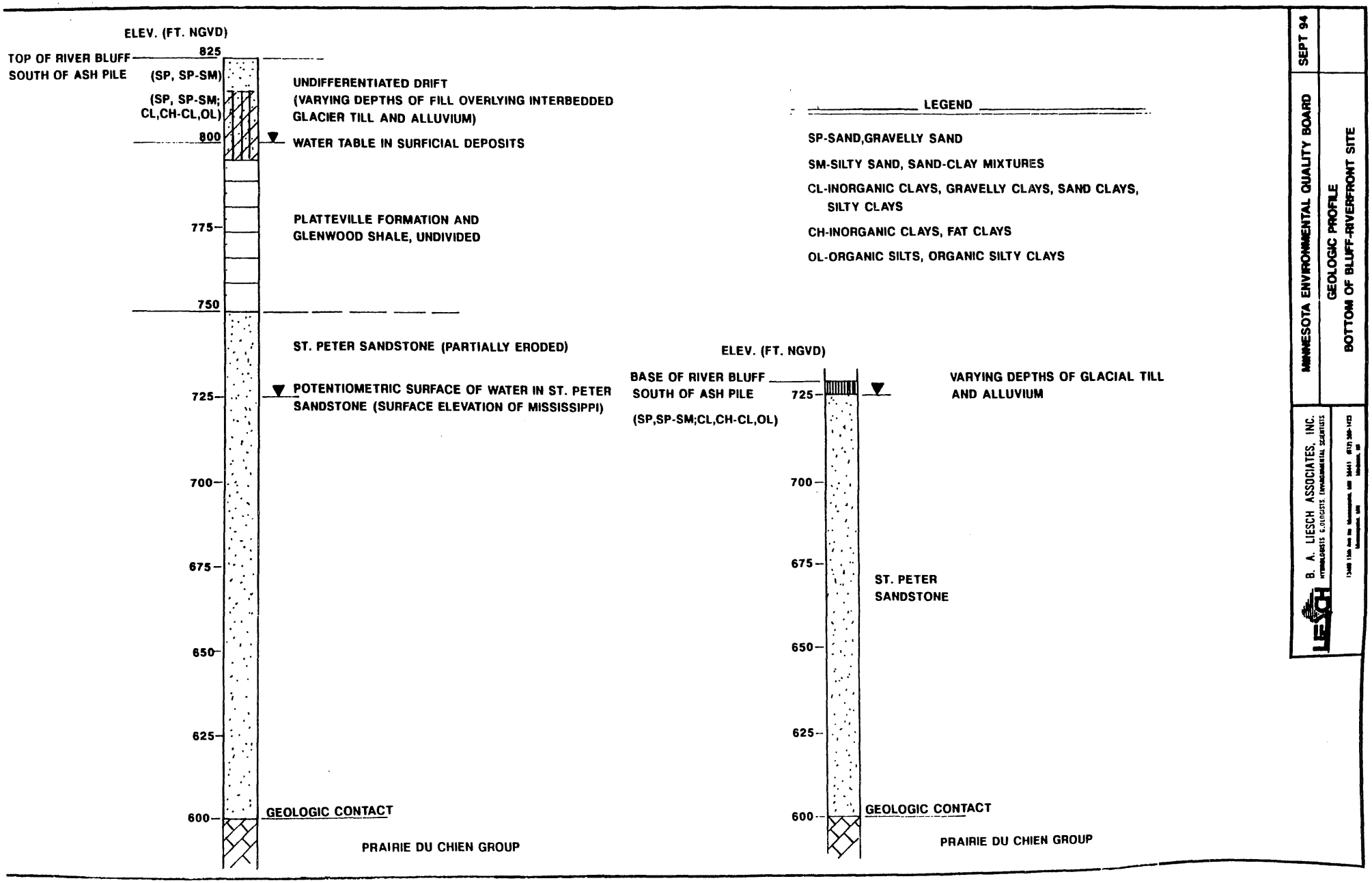

ELEV. (FT. NGVD)
TOP OF RIVER BLUFF SOUTH OF ASH PILE
825
(SP, SP-SM)
(SP, SP-SM; CL,CH-CL,OL)
800
775
750
725
700
675
650
625
600
UNDIFFERENTIATED DRIFT
(VARYING DEPTHS OF FILL OVERLYING INTERBEDDED GLACIER TILL AND ALLUVIUM)
WATER TABLE IN SURFICIAL DEPOSITS
PLATTEVILLE FORMATION AND GLENWOOD SHALE, UNDIVIDED
ST. PETER SANDSTONE (PARTIALLY ERODED)
POTENTIOMETRIC SURFACE OF WATER IN ST. PETER SANDSTONE (SURFACE ELEVATION OF MISSISSIPPI)
GEOLOGIC CONTACT
PRAIRIE DU CHIEN GROUP
LEGEND
SP-SAND,GRAVELLY SAND
SM-SILTY SAND, SAND-CLAY MIXTURES
CL-INORGANIC CLAYS, GRAVELLY CLAYS, SAND CLAYS, SILTY CLAYS
CH-INORGANIC CLAYS, FAT CLAYS
OL-ORGANIC SILTS, ORGANIC SILTY CLAYS
ELEV. (FT. NGVD)
BASE OF RIVER BLUFF SOUTH OF ASH PILE
(SP,SP-SM;CL,CH-CL,OL)
725
700
675
650
625
600
VARYING DEPTHS OF GLACIAL TILL AND ALLUVIUM
ST. PETER SANDSTONE
GEOLOGIC CONTACT
PRAIRIE DU CHIEN GROUP
MINNESOTA ENVIRONMENTAL QUALITY BOARD
SEPT 94
GEOLOGIC PROFILE
BOTTOM OF BLUFF-RIVERFRONT SITE
B. A. LIESCH ASSOCIATES, INC.
HYDROLOGISTS & GEOLOGISTS ENVIRONMENTAL SCIENTISTS
LIESCH

Figure 1

Groundwater in the surficial deposits at the top of the bluff eventually discharges from the bluff at the overburden/bedrock contact point and follows topography to the river as surface runoff. Surface water then either infiltrates into the river bank sediment and enters the bedrock groundwater system, or enters the Mississippi River directly.

Limited vertical recharge through the confining layers may also occur, mixing with the St. Peter water table and ultimately discharging to the Mississippi River. Limited recharge of the bedrock groundwater system by surficial runoff (or by the Mississippi during high water) probably occurs as well. Limited contamination of the bedrock aquifer by a riverfront spill or by contaminated river water is therefore possible.

Peregrine Falcons Nest within a Mile of Riverfront Site

The Department of Natural Resources (DNR) records one endangered, threatened or special concern bird species with a mile of the Riverfront Site (Peregrine falcons, Endangered) and one species of bat (Eastern Pipistrelle Bats, Special Concern). The peregrines nest on the Multifoods Tower in Downtown Minneapolis, and the bats hibernate in the Heinrich Brewery Cave downstream from the Washington Avenue Bridge.

An insect, the American Burying Beetle (Federal Endangered), has also been recorded within a mile of the site, but the records are old. In the University's 1976 Planning Base Inventory, wildlife in and near the area is noted to be song birds, gray squirrels, rabbits, and rodents.

Groundcover and Vegetation Described

The DNR records two plant species within a mile of the site: Dragon's Mouth (Special Concern) and Valerian (Threatened). DNR staff indicated to the University that these plants probably no longer occur in the area.

The general groundcover is described in the Minneapolis Critical Area Plan as natural succession woodland. The vegetation is mostly opportunistic pioneer woody trees and shrubs and herbaceous plants. Boxelder, Cottonwood, Elm, Sumac, Elder, and Riverbank Grapevine and Cocklebur are common.

Minneapolis Alternative Site Characterized

The alternative site, comprising approximately 23.8 acres of land between 17th Avenue SE on the west, 25th Avenue SE on the east, 4th Street SE on the south and the Burlington Northern railroad right of way to the north, is currently undeveloped and

is overgrown with weeds. (For surrounding land use and a map of the area, see Chapter 9)

The ground surface elevation of the alternative site is approximately 840 feet, sloping gradually to the southwest. At the Site, one to five feet of till overlie approximately 40 feet of Mississippi River Terrace Deposits (sand, gravely sand, and silty sand) and glacial till, which in turn overlie the Platteville Formation, the uppermost bedrock unit beneath the site.

Bedrock occurs at an elevation of approximately 800 feet. Past investigations completed at the Alternative Site have encountered the water table at 13 to 19 feet in the Terrace Deposits. Groundwater generally flows southwest toward the Mississippi River.

St. Paul Site Characterized

The ground surface elevation of the St. Paul site is about 900 feet. The site is estimated, consistent with an urban campus site, to be approximately 75% impervious surface. Soil cover consists of up to 15 feet of silty-sand and clayey-sand fill over a layer of clay topsoil. These upper layers cover various depths of sandy and silty gravel alluvium. The water table varies from 16 to 20 feet below the surface.

Chapter 6. Air Quality Impacts

This Chapter Addresses Both Criteria and Non-Criteria Pollutants

This chapter addresses the emission rates and impacts of both criteria and non-criteria pollutants for the University of Minnesota's proposed project and alternatives.

Criteria pollutants are those for which federal ambient air standards have been established and for which a wide variety of regulatory schemes have been in place for over 20 years. Emission rates and control efficiencies for these pollutants are well documented.

Non-criteria hazardous air pollutants—or "air toxics"—are pollutants for which ambient air standards have not yet been established, but which are coming increasingly under regulatory scrutiny because of their potential for adverse effects at relatively low concentrations. Emission rates for air toxics are less well understood than for criteria pollutants, particularly for fossil-fuel fired plants.

Emissions of Five Regulated Pollutants and Twenty Air Toxics Estimated

Emissions were estimated for the following regulated criteria pollutants.

- Sulfur Dioxide (SO_2)
- Carbon Monoxide (CO)
- Particulate Matter Smaller than 10 Microns Diameter (PM_{10})
- Nitrogen Oxides (NO_X)
- Volatile Organic Compounds (VOC)

Emissions were also estimated for twenty air toxics for which reliable information could be found (emission factors for some air toxics could be found only for general categories).

SO_2 and NO_X Are Important Pollution Indicators

Criteria pollutants that do not exceed national air quality standards are classified by regulatory agencies to be "in attainment." Pollutants that exceed allowable standards are "non-attainment."

Seven counties (Hennepin, Ramsey, Washington, Anoka, Carver, Scott, and Dakota) are nonattainment for SO_2. Hennepin, Ramsey, Washington, and Anoka and portions of Carver, Scott, Dakota, and Wright are also nonattainment for CO.

A portion of Ramsey county is a nonattainment area for PM_{10}. The metropolitan area is an attainment area for NO_X and VOC.

SO_2 is currently not only a local non-attainment pollutant, but is also the primary precursor of acid precipitation. NO_X, while currently in attainment, contributes to ozone formation, a pollutant of increasing concern in the Twin Cities, and also contributes to acid precipitation.

"Potential" Emissions and "Predicted" Emissions Both Estimated

Because final permit conditions would be difficult to predict for the proposal and each of the alternatives, two methods were used to estimate annual air pollutant emission rates.

The two methods are referred to in this report as "predicted" and "potential" emissions.

Predicted emissions are those that would result from operating plant equipment to meet projected steam load, using the least-cost fuel first (economic boiler dispatch). These emissions are a best-estimate of the actual emissions that would result from facility operation.

Potential emissions are the maximum that would result from operating plant equipment all year long at rated capacity, using the highest emitting fuel. This scenario represents a "worst case"—the equipment's maximum potential to emit—not actual emissions.

Modeling of Short-term Ambient Concentrations Based on Potential Emission Rates Only

Annual average fuel estimates cannot be used to model maximum short term ambient air concentrations (24-hour, 3-hour, and 1-hour) because the short-term fuel mix varies greatly throughout the year.

Natural gas based alternatives, for example, use natural gas exclusively -- except during natural gas curtailment -- which occurs only on the coldest winter days. When natural gas is unavailable, 100% fuel oil firing at close to maximum capacity could occur. (One very cold week can account for most of the 8% annual fuel oil fraction). Therefore, only "potential" emissions were used to model maximum short term ambient concentrations.

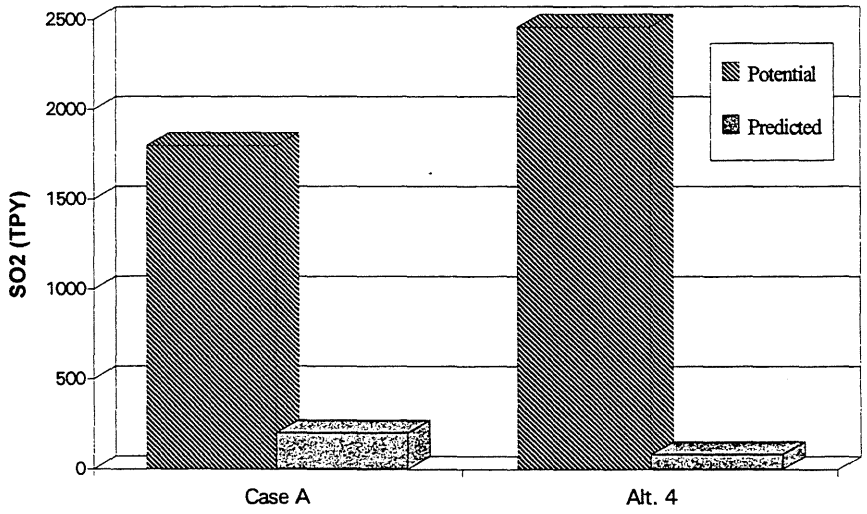
Eventual Permit Limits Likely to Be Closer to Predicted Emissions Than Potential Emissions

Potential emissions for all alternatives are substantially higher than predicted emissions, but the difference is particularly large for gas/oil alternatives. For example, potential SO_2 emissions from gas/oil boilers are calculated by assuming 100% fuel oil firing, while predicted emissions are based on a 92% natural gas, 8% fuel oil mixture. Potential emissions, therefore, are high from gas/oil

facilities not only because actual steam use is usually much less than total boiler capacity, but because fuel oil has a much higher emission factor than natural gas for most pollutants.

Based on the pending University air quality permit application and preliminary assessment of the other alternatives, the legally enforceable emission and fuel use limits in the eventual air quality permit are likely to be closer to the "predicted" emissions than "potential" emissions (see Figure 6-1 below.). For example, the University's permit application requests a limit of about 600 TPY SO_2.

Figure 6-1. Comparison of Potential and Predicted Annual SO2 Emissions: Case A and 100% Gas/Oil Plant (Tons per Year)



Predicted Emissions of Selected Pollutants Adjusted for Cogeneration In Chapter 10

Finally, cogeneration of electricity and steam increases point source air emissions, but the electricity produced reduces base-load electricity demand at utility plants, resulting in offsetting emission reductions. Improved fuel efficiencies and lower emissions from cogenerations plants could result in overall regional reductions of air emissions. In Chapter 10 (mitigation options), annual air emissions are adjusted for "cogeneration credits" for SO_2, CO_2 and Mercury.

Remainder of This Chapter in Six Sections

The remainder of the discussion in this chapter is divided into the following sections.

- 6.1 Major Emission Factor Assumptions
- 6.2 Predicted Emission Rates
- 6.3 Potential Emission Rates
- 6.4 Ambient Air Quality Modeling Results
- 6.5 Noise
- 6.6 Fugitive Dust Impact
- 6.7 Air Quality Regulations

Section 6.1 Major Emission Factor Assumptions

Emission Rates Depend on More Than Five Different Variables

Emission rates are calculated by multiplying the emission factors (with applicable removal efficiency) by the MMBtu heat input. So emission rates depend on a number of variables, including boiler technology, fuel use assumptions, pollution control technology, emission factor, and total fuel consumption (cogeneration requires additional fuel).

The predicted emissions assume that cogeneration of electricity would be maximized (within the constraints of equipment configuration and campus load) and that lowest variable cost equipment would be operated first.

The exception is the University's proposed project (Case A) at St. Paul where the estimates assume that no coal would be burned. The University stated that the intended mix of fuels would be about 90% natural gas and 10% fuel oil.

The technological and fuel use assumptions are described in Chapters 2 through 4. Pollution control and emission factor assumptions are described below.

Criteria Pollutant Assumptions

The technologies and control efficiencies of each type of boiler for criteria pollutants are provided in 1 below. Natural gas, fuel oil boilers and turbine emissions are uncontrolled unless otherwise indicated. Specific removal efficiencies are indicated where applicable.

Table 1. Summary of Major Emission Control Assumptions

	Particulates	SO_2	NOx	Non-Volatile Metals	Mercury
Case A	99.25% for baghouses on CFB and Coal None for Gas/Oil	92% Limestone Injection in CFB 70% for Existing Southeast Plant Scrubbers	CFB Low Temp; Low NOx burners for gas/oil boilers	Same as Particulate Control: For All Alternatives	Uncontrolled, .06 ppm Hg in Coal
Case B	Same as Case A	Same as Case A	Same as Case A, with Steam Injection for Combustion Turbine		Uncontrolled, .06 ppm Hg in Coal
Alt. 1	99.25% for baghouses		None		Uncontrolled
Alt. 3	99.25% for Baghouses None on Gas/Oil	70% for Existing Coal Scrubbers at Southeast; New Scrubbers for #6 Fuel Oil	Low NOx burners with flue gas recirculation for gas/oil boilers Water Injection for Turbines		Uncontrolled .06 ppm Coal
Alt. 4	Uncontrolled	Scrubbers for #6 Fuel Oil Use Primarily Natural Gas	Same as Alt. 3		Uncontrolled
Alt. 6	99.25% for baghouse on CFB	92% Limestone Injection in CFB Scrubbers for #6 Fuel Oil	Same as Case A		Uncontrolled .06 ppm Hg in Coal
Alt. 7	Uncontrolled	Same as Alt. 4	Same as Alt. 3		Uncontrolled
Case A St. Paul	Baghouse as needed	None	Low NOx burners for gas/oil boilers		Uncontrolled
Alt. 13 St. Paul	Uncontrolledl	None	Low NOx burners with FGR for gas/oil boilers		Uncontrolled

Emission Rates from Circulating Fluidized Bed Boiler Discussed

The circulating fluidized bed boiler (CFB) is designed to fire a variety of fuels in addition to coal—up to 50% natural gas, and up to about 15% wood chips. (Optional modifications allowing coke, or additional natural gas and wood firing are not included for

alternative 6 and are an additional cost option in Cases A and B.) SO_2 emissions from a CFB can generally be reduced by 92% or better using limestone injection.

The SO_2 emission factor used for this study is 0.137 lb/MMBtu. The CFB emission rate using coal alone would be less than this using low-sulfur coal (.110 lb/MMBtu in the University permit application), but a 0.137 lb/MMBtu emission factor is guaranteed in the University's contract, and was used here to account conservatively for the possible use of petroleum coke, a high sulfur fuel.

Particulate emissions are assumed controlled at 99.25% efficiency with a baghouse.

NOx emissions in CFBs are inherently lower than conventional coal boilers due to the lower operating temperature. No additional control was assumed, although selectively non-catalytic reduction systems could be added to reduce emissions further (see Chapter 10).

SO_2 Emissions from Existing Boilers at Southeast Plant Controlled with Dry Scrubbers.

Existing coal-fired boilers Number 3 and Number 4 at the Southeast Plant remain in service under the proposal options Case A and Case B, and for Alternative 3. SO_2 emissions for these boilers are controlled by a dry scrubber system. Foster Wheeler, through recent improvements, has been able to achieve 90% SO_2 removal with the existing scrubbers, but a more conservative 70% removal efficiency was assumed for this report. Particulate controls consist of baghouses, assumed to operate at 99.25% control efficiency.

Emission Controls for Natural Gas, Fuel Oil Boilers Described

The package boilers, combustion turbine generator, and heat recovery steam generators in the proposed Case A and Case B are designed to fire both natural gas and Number 2 fuel oil. Sulfur control for these boilers consists of using primarily natural gas, which contains only negligible amounts of sulfur. SO_2 emissions are otherwise uncontrolled. SO_2 emissions from package boilers using Number 6 fuel oil (alternatives only) are assumed to be controlled to .5 lb/MMBtu using wet scrubbers.

NOx emissions for Case A and Case B package boilers are controlled by low-NOx burners. NOx emissions for the alternatives are assumed to have further controls, low-NOx burners with flue-gas recirculation. The combustion turbines for the proposal and the alternatives are assumed to have steam or water injection for NOx control.

Particulates from package boilers and turbines are uncontrolled for criteria emissions. (Air toxic calculations assume that wet scrubbers on boilers using number 6 fuel oil control toxics associated with particulates to some extent, discussed below.)

Detailed Information on Criteria Emission Rates in Appendix A

Criteria Pollutant emission estimates may vary depending on the emission factor used. Dahlen, Berg & Company developed criteria pollutant emission factors from the following sources.

- *Design and Construction Agreement by and Between the Regents of the University of Minnesota and Foster Wheeler Twin Cities, Inc.* (Foster Wheeler).
- *AIRS Facility Subsystem Source Classification Codes and Emission Factor Listing for Criteria Pollutants*, United States Environmental Protection Agency (AIRS).
- Environmental permits for the existing boilers.
- Direct communication from Nebraska Boiler.

Specific criteria emission factors used for each pollutant and technology are provided in EIS Appendix A.

Air Toxic Emission Assumptions

Four Main Factors Control Air Toxic Emission Rates

Four main factors largely control differences in air toxic emissions:

- Chemical nature of pollutant
- Primary fuel (natural gas or coal)
- Assumed pollution control efficiencies
- Total annual fuel consumption (cogeneration alternatives require additional fuel)

Large-Scale Cooperative Research on Air Toxics is Ongoing

The accuracy of many air toxics emission factors listed for fossil fuel plants in standard EPA sources have come into question as analytical measurement techniques improve. Consequently, the Clean Air Act Amendments of 1992 mandated a comprehensive study of the air toxic emission rates and health risks associated with fossil fuel fired power plants.

Because the issue is complex, with large amounts of money at stake, the Environmental Protection Agency, the U.S. Department of Energy

(as part of the Clean Coal Technology Program), and the Electric Power Research Institute (EPRI) are currently conducting large-scale cooperative research efforts, particularly on the efficiency of existing particulate and sulfur pollution controls. This research is costly, complicated, and time consuming, in part because toxic emissions are often at or near current analytical detection limits.

Until more of this research is completed and the results published, toxic emission rates for this study are based on the assumptions outlined below.

Results described for four categories of air toxics

Air toxic emission estimates and assumptions are described for each of four general categories of air toxics: (1) non-volatile metals, (2) volatile metals (mercury), (3) the acid gases chlorine (HCl) and fluorine (HFl), and (4) "products of incomplete combustion."

Non-Volatile Metal Emissions Determined by Particulate Controls

Emission rates of generally non-volatile metals assume that the fuel content is 100% converted to flue gases. However, trace metal concentrations in coal and fuel oil can vary significantly. The emission rates used in this report are based on laboratory data provided by Foster Wheeler, Inc , from recent University fuel samples.

Researchers are currently developing empirical relationships between trace metal emission rates and coal ash fraction, metal content, and particulate removal in coal fired power plants. These empirical relationships are being developed for individual toxics because each behave somewhat differently, depending on volatility and other factors. However, the coefficients for these empirical relationships have not yet been published.

In the interim, the non-volatile trace metal emission rates presented in this report are based on the assumption that 100% of trace metals partition to particulates, and that the metals are assumed controlled at the same efficiency as particulates (99.25% in this case). Consequently, non-volatile metals from coal-fired boilers equipped with baghouses are assumed controlled at 99.25%. This assumption is based on consistent results from the ongoing research described above, as well as MPCA data on NSP facilities, which use similar coal to that of the University.

Trace Metal Emissions From Fuel Oil are Mostly Uncontrolled

Trace metal emissions are assumed uncontrolled for Number 2 fuel oil, with 100% of fuel content released in the stack.

Number 6 fuel oil emissions assume that the wet scrubbers would

reduce particulate emissions somewhat, and therefore also reduce metal emissions to roughly the level of emissions from Number 2 fuel oil. A trace metal analysis of Number 6 fuel oil was not available.

Toxic Emissions From Natural Gas Assumed Negligible, Except Formaldehyde

Natural gas emissions of non-volatile metals, based on currently available information, are assumed to be negligible (although actual data is surprisingly difficult to find). The only air toxics emissions estimated for natural gas are formaldehyde and mercury. There are published reports of some extremely high mercury concentrations in natural gas reserves throughout the world, although the studies are old.

North American mercury concentrations are reported as much lower, and emission rates were estimated from these low numbers. Recent preliminary data from EPRI supports this low mercury concentration assumption for natural gas. Given these assumptions, annual metal emissions from 100% gas/oil facilities come almost entirely from the 8% annual Btu fuel oil fraction.

Petroleum Coke Has High Concentrations of Nickel and Vanadium

No information on the trace metal concentrations in petroleum coke, which can be efficiently burned in a CFB, could be found. It is known that petroleum coke does contain elevated levels of at least two metals: nickel and vanadium. One source listed a typical vanadium concentration as about 400 ppm, which is significantly higher than coal. However, concentrations of other metals could not be estimated for petroleum coke, so emissions for facilities with a CFB were not adjusted for this possibility.

Mercury Emissions Proportional to Fuel Content

Mercury is a volatile metal which apparently does not condense or adsorb onto particulates at baghouse temperatures as do other trace metals (or at least not in any currently predictable way). Nor is there enough data as yet to justify mercury control due to flue gas scrubbers. Emission estimates therefore assume that the mercury in the fuel is 100% converted to flue gas, but that zero percent of the emissions are removed by control equipment. Mercury stack emissions, then, are in direct proportion to the amount of mercury in the fuel. For this analysis, the following mercury concentrations in fuel-stock were assumed.

Coal	0.06 ppm	MPCA Technical Work Paper on Mercury Emissions, 1992, and preliminary data provided by the U.S. Department of Energy.
No. 2 and No. 6 Fuel Oil	0.068 ppm	MPCA Technical Work Paper on Mercury Emissions, 1992; results similar to AP42 Emission Factors
Natural Gas	0.1 µg/m3	Phannenstiel et al. 1975, reported as maximum concentration found in midwest North America gas streams.

The mercury estimates for oil and natural gas used in this study are three to five times higher than indicated by recent preliminary data from EPRI researchers. The more conservative estimate was used for this report.

Emission of Acid Gases and Products of Incomplete Combustion Based On a Variety of Sources

Other emission factor assumptions, including those for acid gases and products of incomplete combustion, are taken from a variety of sources, listed below with the emission rate results. These sources include the EPA FIRE data base, Foster Wheeler data, and other sources. Specific emission factors used for air toxics are provided in spreadsheet form in Appendix A.

Section 6.2 Predicted Emission Rates

Predicted Criteria Emissions

Minneapolis Campus Predicted and Potential Emissions Are Estimated

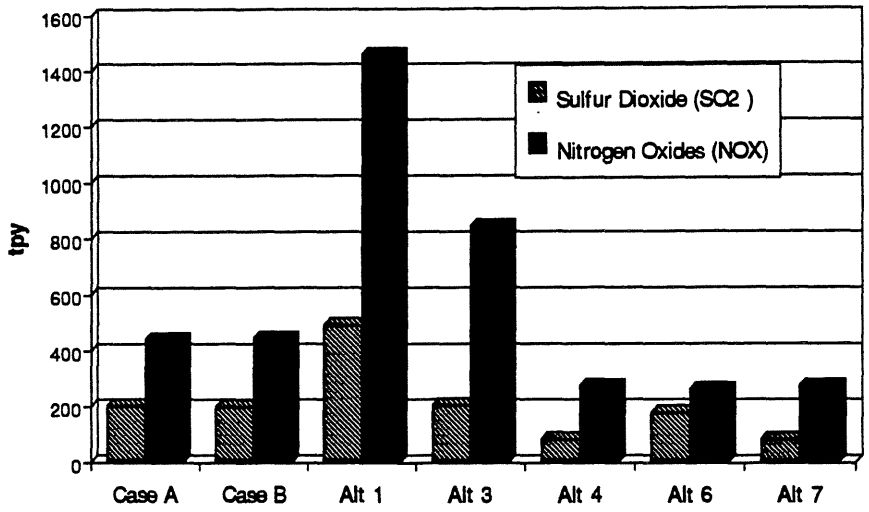
Predicted emissions assume that plant equipment will operate to meet the estimated campus load, using the least cost fuel first. Table 2 below lists predicted annual criteria emissions in tons per year. The highest emitting alternative is indicated in bold for each pollutant.

Detailed emissions calculations are presented in Appendix A.

Table 2. Predicted Emission Rates (Tons Per Year)

	Case A	Case B	Alt 1	Alt 3	Alt 4	Alt 6	Alt 7
Sulfur Dioxide (SO_2)	203	198	**491**	205	84	178	84
Carbon Monoxide (CO)	202	271	212	**310**	189	181	189
Particulate (PM_{10})	44	36	**143**	75	8	30	0
Nitrogen Oxides (NO_X)	439	444	**1459**	843	272	261	272
Volatile Organic Compounds (VOC)	18	**26**	6	19	17	18	17

Figure 2. Predicted Annual Emission Rates of SO2 and NOx (Tons per Year)



Deferred Construction Alternative 1 has Highest Emissions of Most Criteria Pollutants

The "No Action" alternative (number 1) has the highest estimated emissions of SO_2, NOx, and particulates, although all renovation options are predicted to emit more VOCs.

Case A, Case B, and alternative 6 have lower sulfur emissions because of the effective limestone injection system used in fluidized bed boilers.

The lowest predicted SO_2 emissions, however, occur under the natural gas, fuel oil only alternatives. Based on the assumptions outlined above, SO_2 emissions from alternatives 4 and 7 would be about half those of that use coal. SO_2 emissions for Alternative 3 are also relatively low because that alternative uses natural gas, fuel oil turbines for the baseload steam demand, and emissions from the existing Southeast Plant coal boilers are effectively controlled with the already in place dry scrubbers.

Predicted annual NOx emissions are highest under alternative 3 because that alternative uses existing coal boilers instead of a lower-emission circulating fluidized bed boiler. As with the fluidized bed boilers, however, additional NOx controls could be retrofit on these boilers at additional cost (see Chapter 10).

Carbon Dioxide Emissions About 25% Less For Gas/Oil Alternatives

Global warming impacts can be compared by estimating carbon dioxide emissions. CO_2 emissions from 100% gas/oil alternatives are about 25 % less than for coal alternatives (see Table 3 below). On an equal Btu basis, coal produces roughly 70% more carbon dioxide than natural gas, but the gas/oil cogeneration alternatives use extra fuel for electricity production. However, cogeneration emissions would be offset by reductions from regional electrical utilities. (See section 11-3).

Table 3. Predicted Annual CO_2 Emissions
Minneapolis Campus Alternatives

Alternative	Carbon Dioxide (TPY)
Case A	3.2E+5
Case B	3.5E+5
Alt 1	3.0E+5
Alt 3	3.2E+5
Alt 4	2.5E+5
Alt 6	3.1E+5
Alt 7	2.5E+5

Nitrous Oxide is also a greenhouse gas

N_2O is also a greenhouse gas produced by fossil fuel plants that has a global warming impact per molecule 270 times that of CO2. Furthermore, coal boilers and CFB boilers in particular have been reported to convert fuel-bound nitrogen into N_20 at higher rates than natural gas boilers (due to low operating temperatures). However, more recent studies indicate that these initial results were due to a sampling problem, and that there is no significant difference in N_2O emissions from coal and natural gas fired boilers. Differences in N_2O emissions have not been estimated.

80% to 90% of Externality Costs From CO_2

Based on the interim PUC externality ranges on criteria pollutant emissions, predicted emission from the proposal and alternatives are provided below in Table 4. For the proposal and all alternatives, CO2 emissions accounted for 85% to 95% of calculated externatility costs. Although the dollar per ton range for CO2 is comparatively low, total emissions are high compared to the other pollutants.

Differences between alternatives is almost entirely accounted for by differences in CO2 emissions, which are higher for coal

facilities (No Action), and for the larger cogeneration facilities, which require more fuel (Case B).

The Interim Externality Values Have Wide Ranges

Interim MN PUC Externality Value Range
(dollars per ton)

SO2	$0	to	$300
NOx	$69	to	$1,640
VOC	$1,180	to	$1,200
PM-10	$167	to	$2,380
CO2	$6	to	$14

Table 4. Criteria Pollutant Externatility Costs ($ Millions per Year)

Alternative	From	To
Case A	1.9	5.2
Case B	2.2	5.7
Alt 1	1.9	7.0
Alt 3	2.0	5.9
Alt 4 & 7	1.5	3.9
Alt 6	1.9	4.8

Case A, St. Paul Would Have Lower Local Emissions

In St. Paul, predicted emissions of most pollutants are the same because both alternatives are assumed to use natural gas and fuel oil exclusively (Table 5) NOx emissions are slightly higher for Case A (St. Paul option Case B is the same as under Case A), because additional controls are assumed for the new boiler under alternative 13 that were not assumed for Case A. The additional control (flue gas recirculation) could also be added to the Case A package boiler at additional cost.

Table 5. Predicted Criteria Emissions at St. Paul

	Case A	Alt 13
Sulfur Dioxide (SO_2)	21	21
Carbon Monoxide	20	20
Particulate (PM_{10})	2	2
Nitrogen Oxides (NO_X)	**72**	57
Volatile Organic Compounds (VOC)	1	1

Predicted Air Toxics Emissions

Predicted Actual Toxics Emission Rates Estimate Likely Impacts

Like SO_2, air toxic emissions not only affect local air quality, but can also affect the regional and global environment through long-range transport and deposition, and in some cases, bioaccumulation. Table 6 on the next page summarizes the predicted annual emission rates, in pounds per year, for air toxics for which reliable fossil fuel emission factors could be found or estimated.

	Case A	Case B	Alt 1	Alt 3	Alt 6	Alt 4	Alt 7	Case A St. Paul	Alt 13 St. Paul
Arsenic (1)	8	12	6	14	9	***17***	***17***	4	4
Beryllium	7	13	5	16	9	***22***	***22***	5	5
Cadmium	2	3	2	3	3	3	3	1	1
Chromium-VI	2	3	2	3	2	3	3	1	1
Chromium-tot	23	***30***	21	***30***	24	***30***	***30***	7	8
Copper	49	43	***55***	29	45	3	3	1	1
Iron	11296	9600	***12693***	6217	10115	3	3	1	1
Lead	12	16	11	16	13	***17***	***17***	4	4
Manganese	150	128	**168**	83	134	2	2	0	0
Mercury (2)	17	15	**19**	10	16	1	1	0	0
Nickel	26	25	**28**	19	24	8	8	2	2
Selenium	***10***	***10***	***10***	9	***10***	6	6	2	2
Vanadium	50	48	**54**	37	47	17	17	4	4
Zinc	59	53	**65**	38	54	8	8	2	2
Chlorine (3)	4422	4533	**4599**	3761	4166	2307	2307	567	575
Fluorine (3)	2385	2184	**2605**	1582	2177	468	468	115	117
Benzene (4)	418	373	**461**	261	379	53	53	13	13
Dioxin/Furan (5)	.0004	.0003	**.0004**	.0002	.0003	5E-5	5e-5	1E-5	1E-5
Formaldehyde (6)	749	2284	652	**2958**	578	2893	2893	234	161
POM (PAH & Phenols) (7)	8	***9***	7	8	7	7	7	2	2
Total (TPY) (8)	10	10	11	8	9	3	3	0	0

Table 6. Predicted Annual Toxic Emissions (lb/yr)

Table 6. Air Toxics Emission Factor Sources

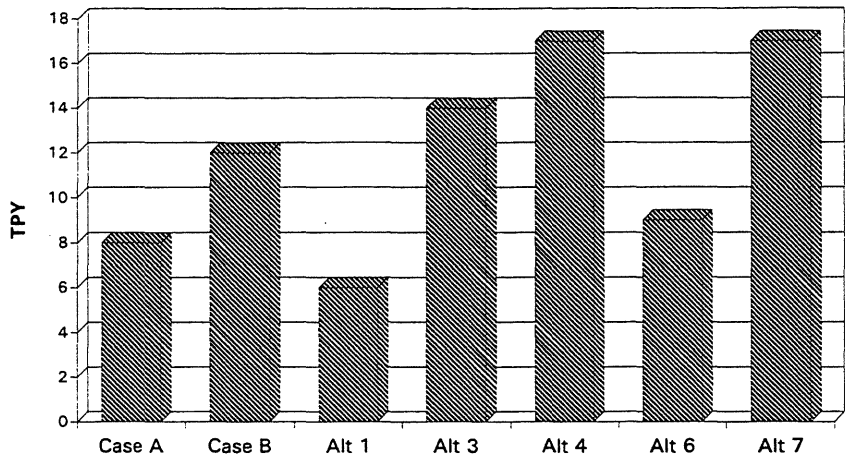
(1) Non-volatile trace metals assume 100% conversion from fuel to flue gas for all fuels; controlled at same efficiency as particulates (99.25% for baghouse).
(2) Mercury assumed to be volatile; 100% conversion from fuel to flue gas, no control due to any air emission control equipment.
(3) Chlorine and Fluorine emissions based on boiler test data submitted by Foster Wheeler
(4) Benzene emission factors based on 4% of VOC (from Foster Wheeler permit application), verified as similar to AP-42 emission factors and preliminary data from EPRI and DOE.
(5) AP-42 Emission data unavailable except for wood. Emission factor of 1.4E-10 lb/MMBtu for total dioxin/furan emissions from DOE Clean Coal study site at Clay Boswell Power Plant that uses subbituminous Powder River coal. Same factor used for fuel oil. No emission controls.
(6) Separate AP-42 Emission Factors from FIRE database for coal boilers, gas/oil turbine with water injection, gas/oil boilers with flue-gas recirculation (alternatives), gas/oil boilers with low-NOx burner only (proposal).
(7) Coal emission factors based on maximum value in Table 1.1-13 of AP-42 (independent of boiler type). Fuel oil factors based on AP-42.
(8) Total includes iron emissions, which is not on the current EPA list of Hazardous Air Pollutants

---

Alternatives 4 and 7 Have Highest Emissions of Arsenic, Beryllium, and Lead

The gas/oil alternatives (#4 and #7) have the highest predicted emissions of arsenic, beryllium, and lead. These elements are present in similar quantities in recent coal and fuel oil data provided by the University. Predicted emissions of these toxics are high for gas/oil facilities because emissions from coal are assumed to be controlled at an efficiency of 99.25%. The uncontrolled emissions from fuel oil results in higher annual emissions, even though oil constitutes only 8% of the fuel used annually. Arsenic emissions are shown in Figure 6-3 as an example of this category of air toxic.

Figure 6-3. Predicted Annual Arsenic Emission Rates (lb/yr)



Alternative #3 and Case B Have Highest Emissions of Chromium and Selenium

Estimated emissions of chromium and selenium are similar for all alternatives, but the highest emissions occur under Alternative #3 and Case B, which are cogeneration alternatives with the highest total fuel requirements. (Alternative #3 uses some older, less efficient boilers, and Case B produces the most cogenerated electricity.)

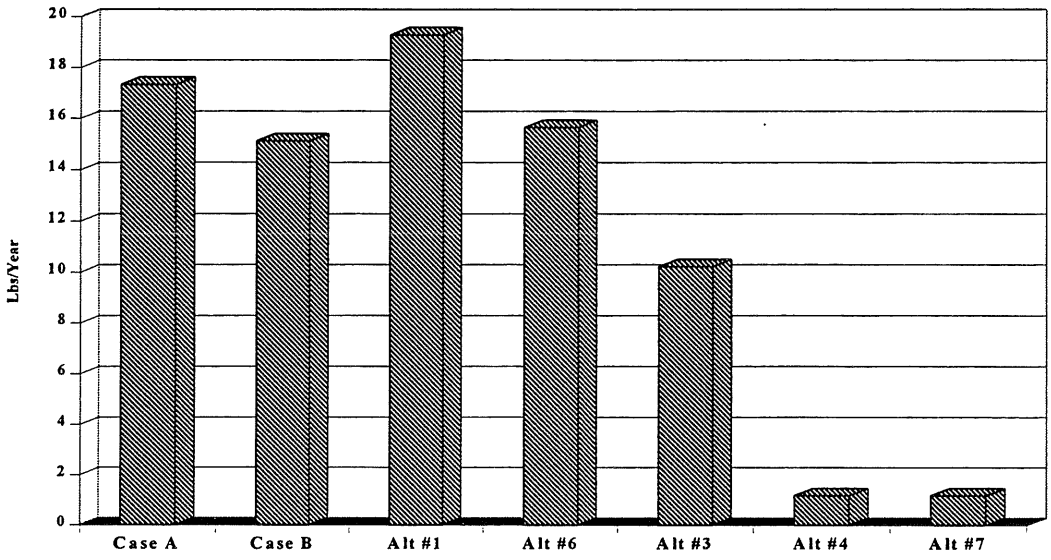
Alternative #1 and Case A Have Highest Emission Rates of Other Non-Volatile Metals

The "No Build" alternative (#1) and Case A have the highest predicted emission rates for copper, iron, manganese, nickel, vanadium, and zinc. Emissions of these metals are closely related to the projected use of subbituminous coal. Even though air toxics control efficiencies of 99.25% were assumed for coal combustion emissions, these metals are present in much higher concentrations in subbituminous coal than in fuel oil.

Coal Alternatives Have Higher Mercury Emissions

The No Build alternative (#1) has the highest predicted mercury emissions—approximately 19 pounds per year. Case A, Case B, and alternative #6 are projected to have only slightly lower mercury emissions because, although they use significant amounts of natural gas, their overall fuel use would increase because they would need additional fuel to cogenerate electricity. (See Figure)

Figure 6-4. Predicted Annual Mercury Emissions (lb/yr)



Although fuel oil is estimated to contain nearly half the amount of mercury per Btu as coal, the gas/fuel oil alternatives are projected to emit only minimal amounts of mercury because of the low concentrations of mercury in natural gas, which accounts for 92% of total fuel use for gas/oil alternatives. Predicted mercury emissions from Alternative #3, which uses a base-loaded combustion turbine and existing coal boilers, falls between.

Chlorine and Fluorine Emissions Also Related to Coal Use

Emissions of chlorine and fluorine are most strongly related to the predicted amount of coal use. Fuel oil fired boilers emit HCl and HFl, but natural gas does not, resulting in lower overall emissions compared to coal alternatives. While not considered to be particularly hazardous, these pollutants account for most of the total air toxics (excluding iron) emitted from primarily coal fired facilities.

Coal Facilities Have Highest Emissions of Dioxin and Benzene

No EPA emission factors for most boiler types could be found for dioxin/furans or for benzene. The primarily coal facilities (Alternatives #1 and #6 and Case A) are assumed to have ten times higher emissions of dioxin and benzene—products of incomplete combustion—than do the gas/oil only alternatives.

Coal emission factors for total dioxin/furans are taken from DOE Clean Coal research data from a site that uses western

subbituminous coal. Fuel oil emissions, for lack of an alternative, were assumed to be the same as coal. Natural gas emissions, since there are no published emission factors, were assumed to be negligible.

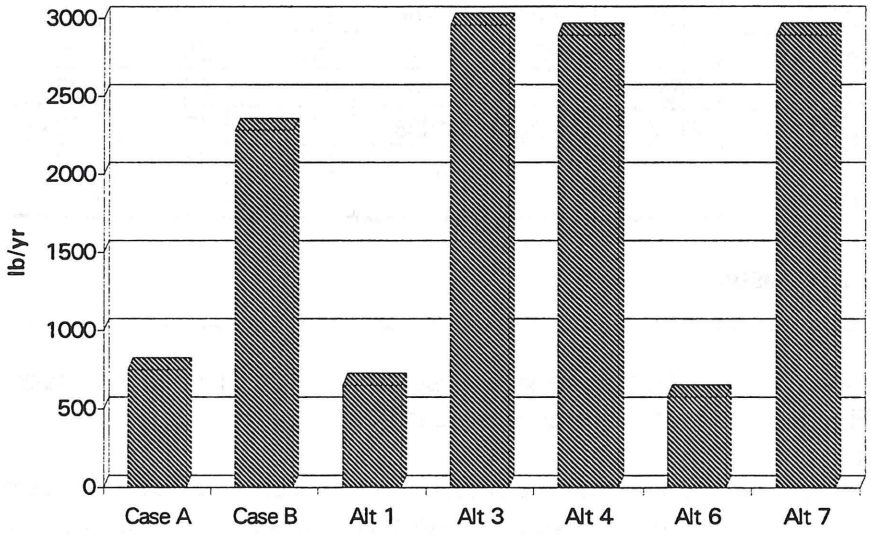
Formaldehyde Emissions Highest For Gas/Oil Alternatives

Formaldehyde is the only air toxic, according to currently available EPA emission factors, to which natural gas use significantly contributes, illustrated in Figure 6-5 below.

Formaldehyde emission factors currently listed in EPA's FIRE database for combustion turbines are about ten times higher per Btu than those from gas, oil, or coal boiler emissions. As a result, base-load natural gas cogeneration alternatives have the highest predicted formaldehyde emissions. The EPA reliability rating for this turbine emission factor was low; however, implying that it is not based on extensive research.

POM emissions are similar for all alternatives.

Figure 6-5. Predicted Annual Formaldehyde Emissions (lb/yr)



Section 6.3 Potential Emissions of Criteria and Air Toxic Pollutants

Potential Criteria Emissions

Potential Emissions at Rated Capacity are Similar for All Alternatives

Potential emissions—emissions from operating plant equipment all year long at rated capacity, using the highest emitting fuel—are shown in Table 7 below. Potential emissions are a function of boiler type, fuel type, assumed control technology, and total installed steam capacity.

Potential emissions for most pollutants are similar for all alternatives for two primary reasons. First, the worst-case fuel for the natural gas, fuel oil boilers is fuel oil, and uncontrolled fuel oil emissions are similar to or worse than emissions from the coal boilers (depending on pollutant). Second, all the alternatives are designed to meet the University's steam demand, so all have similar installed maximum capacities.

Table 7. Potential Criteria Emission Rates (TPY)

	Case A	Case B	Alt 1	Alt 3	Alt 4	Alt 6	Alt 7
Sulfur Dioxide (SO_2)	1798	2170	1966	2005	***2462***	1855	***2462***
Carbon Monoxide (CO)	524	***882***	647	743	552	293	552
Particulate (PM_{10})	220	223	***489***	269	227	273	227
Nitrogen Oxides (NO_X)	2158	2282	***4085***	2319	1245	1245	1245
Volatile Organic Compounds (VOC)	28	***45***	20	28	24	22	26

Potential Air Toxic Emissions

Potential Air Toxics Emissions Are Highest for Gas/Fuel Oil Facilities, but Not by Much

Table 8 below shows calculated potential air toxics emissions rates. Highs are noted in bold italic print.

Potential annual emissions are a function of total boiler capacity and worst-case fuel. Therefore, air toxic emissions for most metals are highest for gas/fuel oil boilers because fuel oil is the worst-case fuel and emissions are uncontrolled. In contrast, emissions of non-volatile metals from coal boilers are assumed to be controlled at the same efficiency as particulates.

Natural gas/fuel oil alternatives #4 and #7, therefore, have the highest emissions. Overall, however, worst-case air toxics emissions do not differ greatly between alternatives.

Potential "Worst-Case" Emissions of Some Air Toxics are Highest For Coal Boilers

Compared to fuel oil, coal contains large amounts of copper, iron, and zinc See. Therefore, Case B, which uses the largest quantity of coal and has the highest rated capacity, generates the highest potential emissions of these pollutants. Fluorine, benzene, and dioxin emissions are also highest under Case B primarily because Case B has the largest total rated capacity of all the alternatives.

Table 8. Potential Annual Air Toxic Emission Rates (lb/yr)

Constituents	Case A	Case B	Alt. 1	Alt. No. 3	Alt. No. 4	Alt. No. 6	Alt. No. 7	St. Paul Case A	Alt. No. 13
Arsenic	278	354	121	362	***533***	385	***533***	291	187
Beryllium	341	436	143	448	***663***	478	***663***	363	233
Cadmium	56	71	26	72	***104***	76	***104***	57	37
Chromium-VI	51	65	24	65	***94***	69	***94***	51	33
Chromium-tot	511	645	242	651	***940***	688	***940***	514	330
Copper	157	172	***168***	130	104	118	104	57	37
Iron	24310	24325	***34074***	13909	104	10026	104	57	37
Lead	282	356	131	360	522	382	***522***	286	183
Manganese	348	355	***462***	218	52	169	52	29	18
Mercury	55	***60***	59	45	36	40	36	19	12
Nickel	183	221	126	205	***261***	208	***261***	143	92
Selenium	118	147	66	143	***198***	150	***198***	109	70
Vanadium	364	439	247	407	***522***	415	***522***	286	183
Zinc	256	293	227	246	***261***	238	***261***	143	92
Chlorine	44673	54948	26478	51165	***67939***	50463	***67939***	39228	25145
Fluorine	12259	14344	9857	12204	***13785***	11550	***13785***	7959	5102
Benzene	2746	***2984***	1564	1573	1575	2435	1575	910	583
Dioxins/Furans	***2.9E-02***	1.7E-03	1.4E-03	1.4E-03	1.4E-03	1.3E-03	1.4E-03	6.7E-02	5.1E-04
Formaldehyde	3330	5564	2547	5169	***5750***	3252	***5750***	2303	1476
POM (PAH & Phenols)	128	161	65	155	***217***	155	***217***	125	80
Total	90444	105940	76627	87527	***93661***	81298	***93661***	52930	33927

Section 6.4. Dispersion Modeling Results

Ambient Air Concentrations of SO_2, NOx, PM_{10}, and Twenty Air Toxics Modeled at Potential and Predicted Emission Rates.

Ambient concentrations of SO_2, NOx, PM_{10}, and twenty air toxics were modeled for Case A, Case B, and alternatives 3, 4, 6, 7, and 13. Stack emissions of PM_{10}, and carbon monoxide, were not modeled in this analysis, although PM_{10} emissions from fugitive dust sources were modeled.

In this section, modeled annual and short-term concentrations of air toxics (based on "potential" emissions) are described first, followed by modeled annual concentrations based on the much lower (though more realistic) "predicted" emissions.

For each emission estimate, criteria modeling results are presented first, followed by air toxics modeling results.

Detailed assumptions, methodology, and results are described in a separate report, *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis*, dated October 27, 1994, by Trinity Consultants.

Modeling Methodology

Ambient Air Concentrations Depend on Emissions and Dispersion

Modeled ambient air concentrations depend both on the amount of pollutant emitted and on how the pollutant is dispersed. Pollutant dispersion, in turn, depends on a number of variables, including local topography, stack height, plume rise (affected by flue gas temperature and velocity), and the effects of building "downwash," which occurs when a stack's effluent is caught in the turbulent wake of a nearby building or other structure and is pulled close to ground level, thereby increasing local ground level pollutant concentrations.

Modeling Done With EPA's ISCT2 Dispersion Model, and Five Years of Meteorological Data

Version 93109 of the ISCST2 model was used to calculate ground-level concentrations in simple terrain, since prior modeling demonstrated that ISCST2 was the dominant (conservative) dispersion model for all pollutants and all averaging periods.

Direction specific downwash parameters were calculated using U.S. EPA's BPIP downwash algorithm. Five years of surface meteorology and upper atmosphere data, from 1973 to 1977, were used to model maximum concentrations.

Averaging Periods Modeled Vary by Pollutant

The following criteria pollutants and averaging periods were modeled:

SO_2	1-hour, 3-hour, 24-hour, annual
NO_x	Annual
PM_{10}	24-hour, annual

Air Toxics Modeled by Scaling to SO_2 Emission Rate

Air toxics modeling was completed by using modeled SO_2 concentrations and "scaling" the toxic emission rate to the SO_2 emission rate. This process assumes that the dispersion characteristics of air toxics are similar to those of SO_2. This assumption is reasonable for facilities with particulate and acid gas controls such as those proposed. Air toxic concentrations could be modeled, therefore, by adjusting (or scaling) the modeled SO_2 ambient concentration by the ratio of the air toxic emission rate to that of SO_2 for each individual stack. A summary of air toxics modeling methods is provided in the separate *Proposed Alternatives Air Quality* report by Trinity Consultants, Inc.

All modeled concentrations shown represent the high modeled annual concentration and the high-second-high modeled short-term concentrations from the five-years of meteorological data used in the analysis.

Details on Methodology and Results In Separate Consultant's Report

The detailed air quality study, *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis*, dated October 27, 1994, by Trinity Consultants includes details on criteria modeling assumption, a detailed explanation of air toxic modeling assumptions, and all results.

"Worst-Case Criteria Concentrations

Worst-Case Annual SO_2 Concentrations are Similar for Proposal and all Alternatives.

Modeled annual average concentrations of criteria pollutants at "potential" emission rates were nearly the same for the proposal and all alternatives because potential criteria emissions are similar for all alternatives. Overall, the tall stacks at the Southeast Plant and alternatives would effectively disperse emissions, reducing local impacts. Slight differences do occur because of different dispersion characteristics.

Worst-Case modeled annual SO_2 concentrations, for example, ranged from 15 to 20 $\mu g/M^3$ for the proposal and all alternatives (The No Action alternative was not modeled).

Short-term Concentration Comparisons Significantly Different Than Annual

Short term modeling results vary between alternatives somewhat more than "worst-case" annual results because dispersion differences show up more over short-term averaging periods.

More importantly, however, short-term concentrations at potential emission rates approximate conditions that could occur during short averaging periods. Predicted annual concentrations are based on annual fuel average fuel mix. So short term maximums can be substantially different for a particular alternative, especially for 100% gas/oil facilities, for which the highest short term impacts occur during natural gas curtailment in the winter and 100% fuel oil firing. But predicted annual concentrations are calculated at the 92%/8% predicted fuel dispatch.

Table 9. Maximum Short Term Ambient Concentrations of Criteria Pollutants (μg/M3)

Pollutant	Avr. Period	Case A Mpls	Case B Mpls	Alt. #3	Alt. 4	Alt. #6	Alt. #7
PM_{10} (lb/hr)		(50)	(50)	(61)	(52)	(62)	(51)
	24-hour	22.39	20.91	21.59	24.28	18.72	24.29
SO_2 (lb/hr)		(410)	(495)	(418)	(562)	(423)	(562)
	24-hour	140.89	145	187.20	238.04	127.44	192.01
	3-hour	200.14	213	335.99	421.08	274.83	448.80
	1-hour	236.02	249	423.87	599.71	561.45	761.04

Natural Gas, Fuel Oil Alternatives Have Highest Short-Term Concentrations

100% natural gas, fuel oil alternatives have the highest short-term modeled ambient air concentrations of criteria pollutants (see Table 9). The highest short-term concentrations occur for alternatives 4 and 7 for a number of reasons, including higher emissions and building downwash effects. Modeled one- and three-hour SO_2 concentrations are near enough to ambient air quality standards to be of concern.

Alternatives Have Higher Short-Term Concentrations than Case A or Case B

In addition, all the EIS alternatives (3, 4, 6 and 7) have higher modeled short-term concentrations of SO_2 than Case A or Case B. This is most likely because the conventional boilers for these alternatives use Number 6 fuel oil, and are equipped with wet scrubbers for sulfur control. (Case A and Case B use low-sulfur

Number 2 fuel oil, and no scrubbers.) The wet scrubbers reduce flue gas temperatures and, as a result, reduce plume rise.

Lowered Flue Gas Exit Temperatures Apparently Increase Short-Term Concentrations

Lowered flue gas exit temperatures probably increase short-term concentrations. This problem could be eliminated by reheating the flue gas after it is scrubbed in order to get proper plume rise and dispersion. Modeled short-term concentrations for all pollutants would improve for alternatives 3, 4, and 7 if this change were made.

The Highest Short-Term Concentrations Shift between Alternative 4 and 7 for Several Possible Reasons

Alternatives 4 and 7 have the highest short-term modeled concentrations. However, these alternatives as designed are exactly the same, with identical emission rates. Only the locations are different. Yet the high modeled short-term concentration shift between the two depending on averaging period. Reasons include the following.

- The polar grid modeling coordinates submitted by Foster Wheeler and used as a basis for this modeling have a higher density receptor-grid near the Southeast Plant than near the off-river Alternative 7. This increases the likelihood that a high concentration spot would be modeled for Alternative 4 in some circumstances.

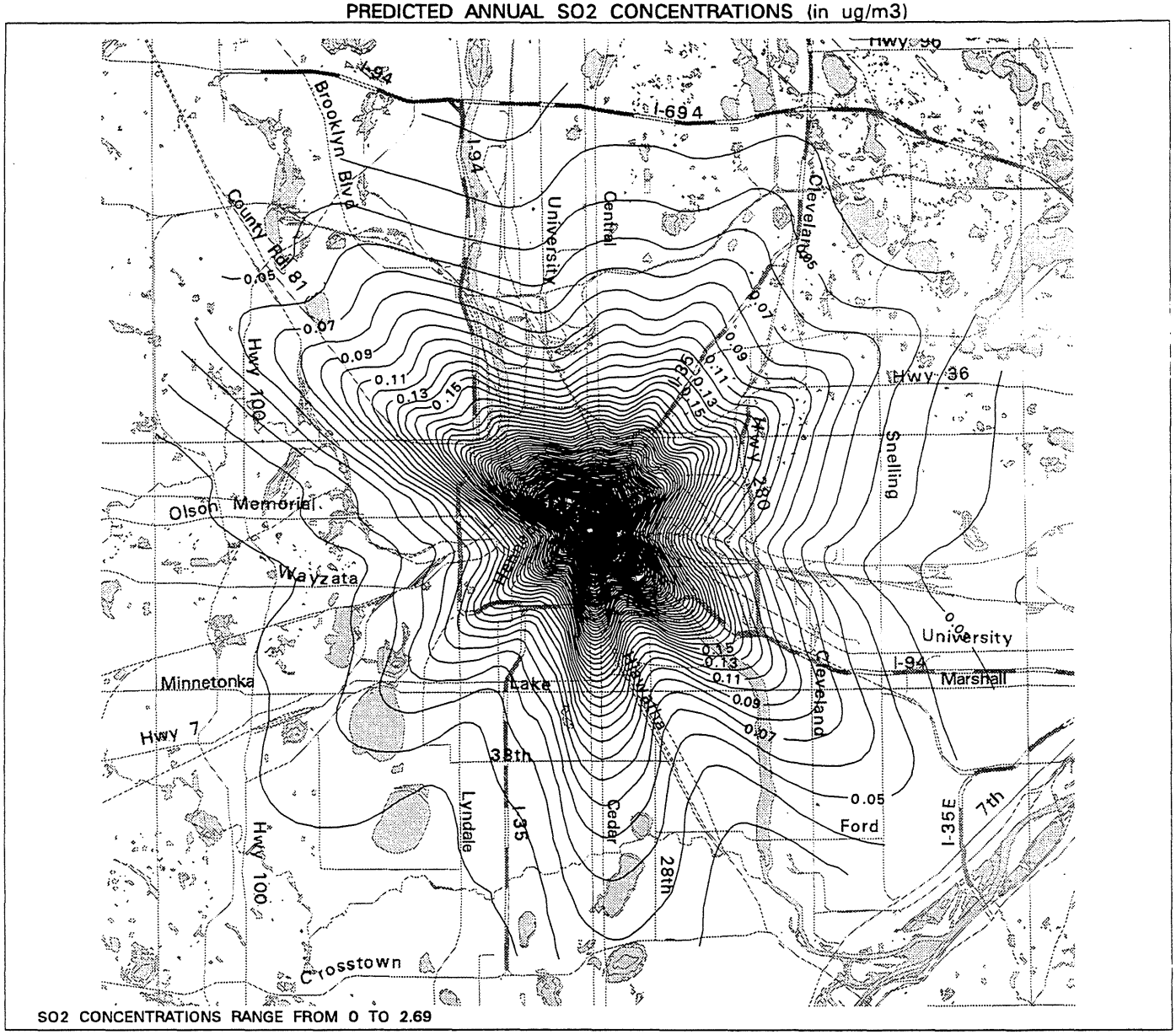
- Short-term meteorological effects also increase the chance for higher modeled concentrations near the Southeast Plant because the higher receptor grid increases the chance that one receptor is affected by short-term meteorological anomalies.

- Under some circumstances, the location and height of alternative 7 at the off-river site make the plumes susceptible to building downwash, even though the stack height was increased to 200 feet from the 150 feet originally designed. Alternative 4 pollutant plumes are not downwashed.

At St. Paul Campus, Proposal Has Higher Short-Term Concentrations

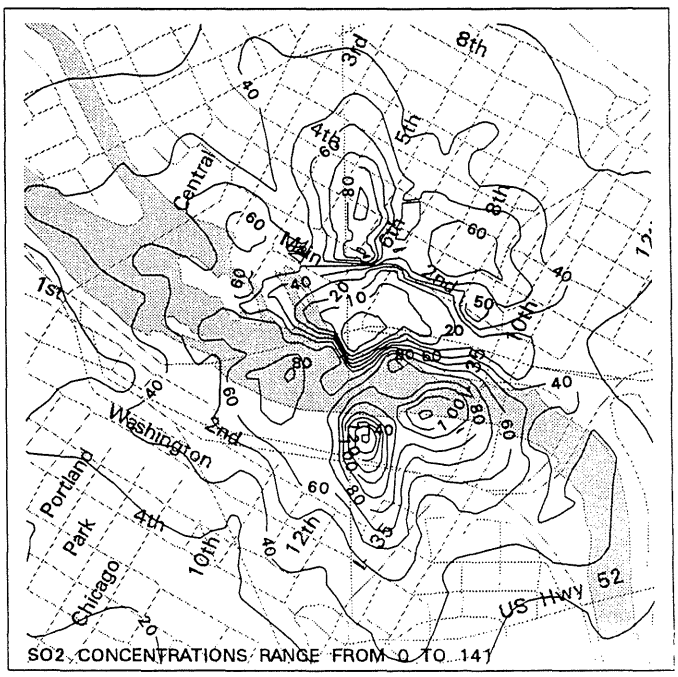
At the St. Paul campus, modeled short-term concentrations are somewhat higher for the proposal than for Alternative 13 because the proposed new natural gas, fuel oil package boiler has significantly more capacity, and therefore more potential emissions, than the new boiler included in alternative 13.

PREDICTED ANNUAL SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 2.69

POTENTIAL 24 HOUR SO2 CONCENTRATIONS (in ug/m3)



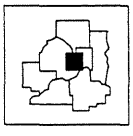
SO2 CONCENTRATIONS RANGE FROM 0 TO 141

SOUTHEAST PLANT - CASE A

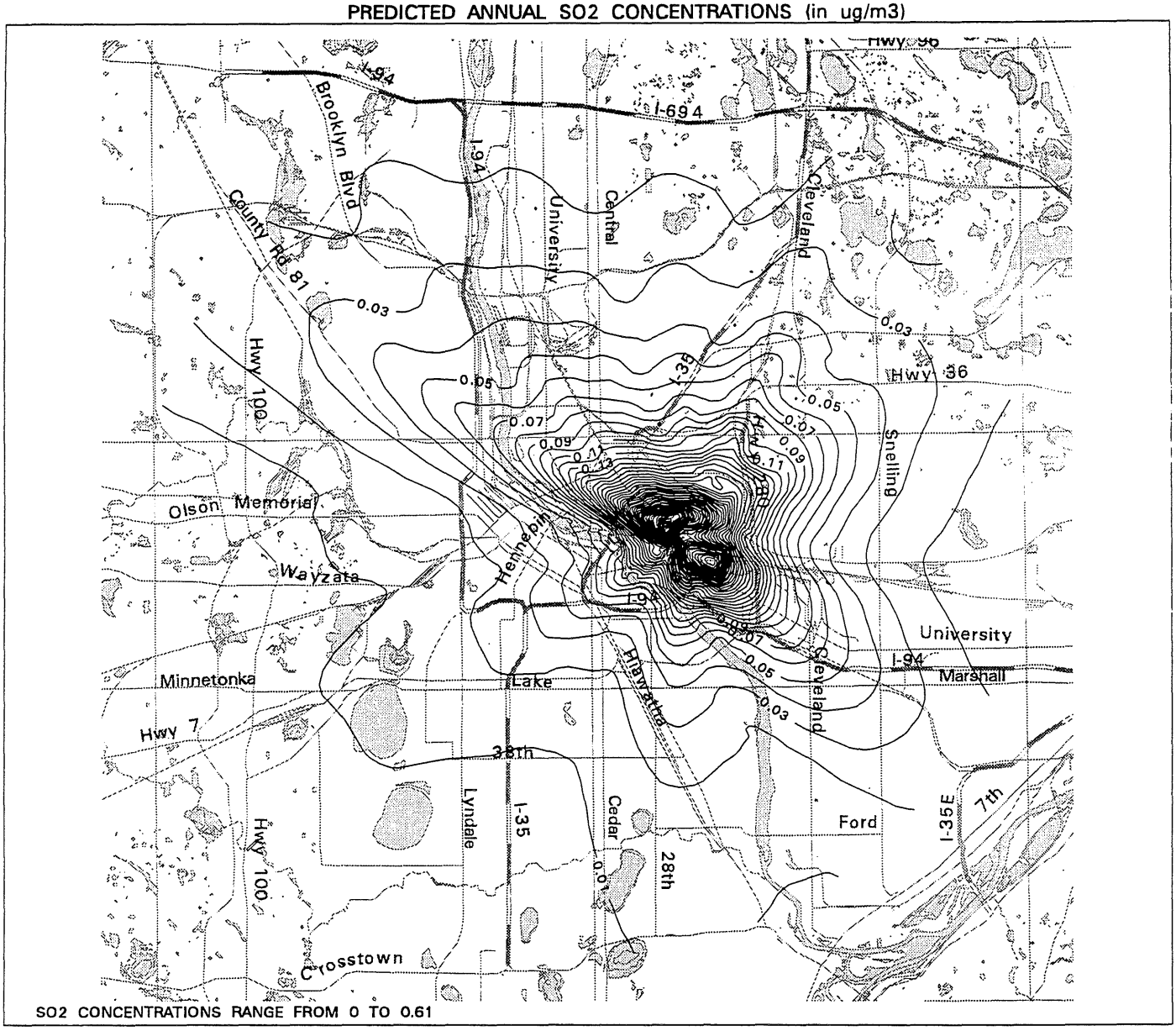
24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1984.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory,USFWS.

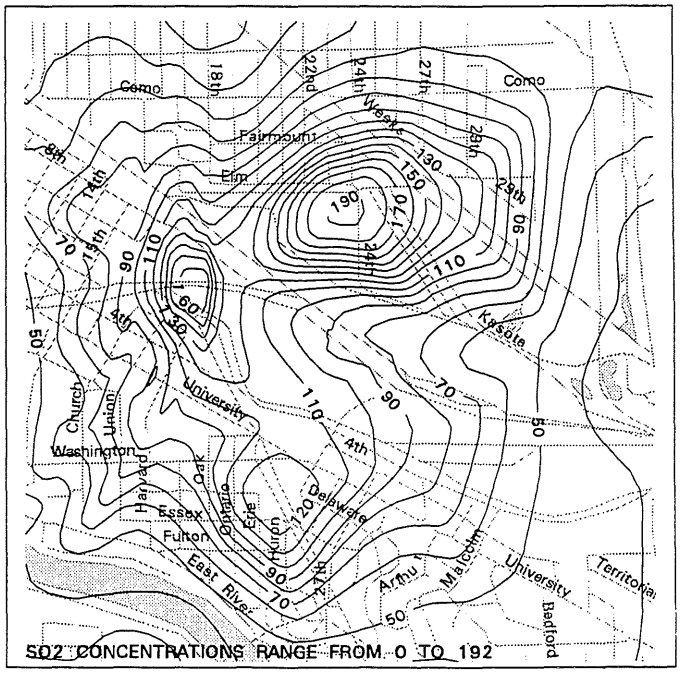


PREDICTED ANNUAL SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 0.61

POTENTIAL 24 HOUR SO2 CONCENTRATIONS (in ug/m3)



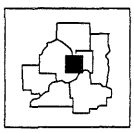
SO2 CONCENTRATIONS RANGE FROM 0 TO 192

OFF-RIVER SITE - ALTERNATIVE 7

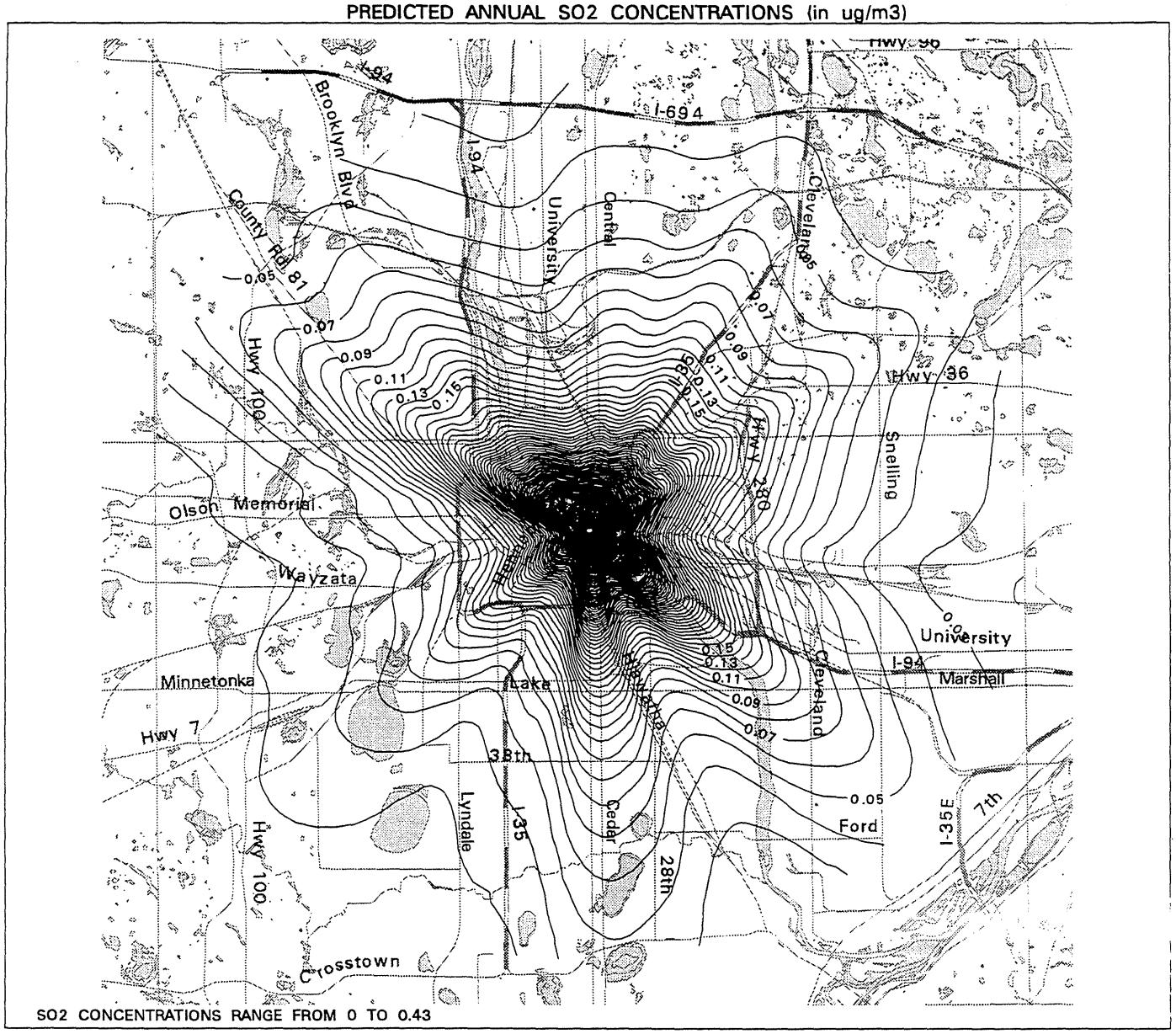
24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1994.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory,USFWS.

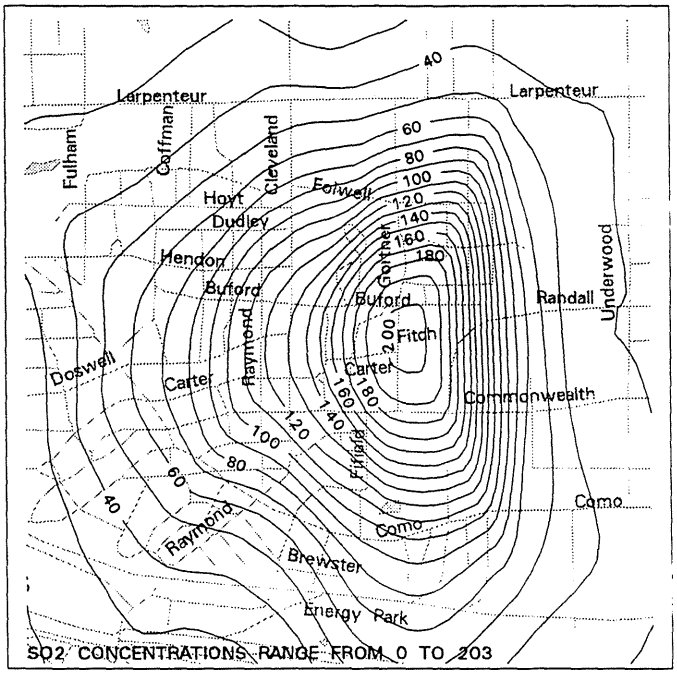


PREDICTED ANNUAL SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 0.43

POTENTIAL 24 HOUR SO2 CONCENTRATIONS (in ug/m3)



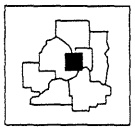
SO2 CONCENTRATIONS RANGE FROM 0 TO 203

ST. PAUL PLANT

24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1994.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory,USFWS.



Annual and 24-Hour SO2 Dispersion Modeling Pattern Mapped.

Illustrative air emission dispersion patterns are shown in the dispersion isopleth maps provided, showing annual and 24-hour concentration isopleths for Case A at the Southeast Plant and for Alternative 7 at the off-river site. Predicted concentrations are shown in the larger figure, 24-hour in the smaller. The figure demonstrates graphically how modeled concentrations drop off quickly from the high spot, which in this case occurs near the stacks, probably due to downwash effects.

Worst Case Modeled Air Toxic Concentrations

Worst-Case Air Toxics Concentrations Similar for All Alternatives

At worst-case potential emission rates, there is little difference in modeled ambient concentrations between the proposal or any alternatives (Table 10 below). The worst-case fuel for coal boilers was assumed to be coal, and worst-case fuel for package boilers and turbines was fuel oil. For most pollutants, uncontrolled air toxic emission rates from fuel oil are similar to or only higher than emission rates from coal boilers equipped with a baghouse. Modeled concentrations for the different alternatives are within a range of plus or minus 50%, a low variability given the amount of uncertainty involved.

Case B does have slightly higher modeled concentrations for some pollutants because it has one of the highest total installed capacities, in part because of the cogeneration combustion turbine. Differences in dispersion characteristics are the same as that for criteria pollutants, described above.

Table 10. Maximum Modeled Air Toxic Concentrations at PTE (μg/m3)

Constituents	Case A	Case B	Alt. No. 3.	Alt. No. 4.	Alt. No. 6	Alt. No. 7	Case A St. Paul	Alt. No. 13
Arsenic	1.06E-03	1.05E-03	1.99E-03	**2.84E-03**	1.59E-03	2.40E-03	2.50E-03	1.47E-03
Beryllium	1.29E-03	1.28E-03	2.46E-03	**3.54E-03**	1.97E-03	2.98E-03	3.11E-03	1.83E-03
Cadmium	2.19E-04	2.17E-04	3.95E-04	**5.57E-04**	3.13E-04	4.70E-04	4.90E-04	2.87E-04
Chromium-VI	1.99E-04	1.97E-04	3.56E-04	**5.02E-04**	2.82E-04	4.23E-04	4.41E-04	2.59E-04
Chromium-tot	1.99E-03	1.97E-03	3.56E-03	**5.02E-03**	2.82E-03	4.23E-03	4.41E-03	2.59E-03
Copper	**8.09E-04**	8.07E-04	6.42E-04	5.57E-04	4.01E-04	4.70E-04	4.90E-04	2.87E-04
Iron	**1.42E-01**	1.42E-01	5.98E-02	5.57E-04	2.14E-02	4.70E-04	4.90E-04	2.87E-04
Lead	1.09E-03	1.09E-03	1.97E-03	**2.79E-03**	1.56E-03	2.35E-03	2.45E-03	1.44E-03
Manganese	**1.98E-03**	1.98E-03	9.80E-04	2.79E-04	4.35E-04	2.35E-04	2.45E-04	1.44E-04
Mercury	**2.82E-04**	2.81E-04	2.21E-04	1.90E-04	1.37E-04	1.60E-04	1.67E-04	9.77E-05
Nickel	7.96E-04	7.92E-04	1.09E-03	**1.39E-03**	8.20E-04	1.17E-03	1.23E-03	7.19E-04
Selenium	4.82E-04	4.79E-04	7.78E-04	**1.06E-03**	6.05E-04	8.92E-04	9.32E-04	5.46E-04
Vanadium	1.58E-03	1.57E-03	2.18E-03	**2.79E-03**	1.64E-03	2.35E-03	2.45E-03	1.44E-03
Zinc	1.22E-03	1.21E-03	1.27E-03	**1.39E-03**	8.82E-04	1.17E-03	1.23E-03	7.19E-04
Chlorine	1.85E-01	1.84E-01	2.75E-01	**3.62E-01**	2.02E-01	3.03E-01	3.37E-01	1.97E-01
Fluorine	5.62E-02	5.60E-02	6.36E-02	**7.34E-02**	4.38E-02	6.15E-02	6.83E-02	4.00E-02
Benzene (1)	**1.38E-02**	1.38E-02	8.03E-03	8.39E-03	7.37E-03	7.03E-03	7.81E-03	4.58E-03
Dioxins/Furans (2)	**1.54E-07**	7.20E-09	7.03E-09	7.34E-09	4.61E-09	6.15E-09	6.83E-09	4.00E-09
Formaldehyde (3)	1.50E-02	1.97E-02	2.67E-02	**3.01E-02**	1.25E-02	2.39E-02	1.98E-02	1.16E-02
POM (PAH & Phenols) (4)	5.08E-04	5.05E-04	8.42E-04	**1.15E-03**	6.32E-04	9.67E-04	1.07E-03	6.29E-04

Worst-Case Air Toxics Concentrations Exceed Air Concentration Limit for Arsenic

The results indicate that with boilers running at rated capacity and using the worst fuel, alternatives 3, 4, and 7 have modeled annual concentrations that are near or exceed the MPCA Air Concentration Limit for arsenic. Other steam plant options, including the proposal, however, are at least about one-half the Air Concentration Limit.

Arsenic emissions for all options could by limiting annual fuel oil consumption. (Modeled concentrations based on the much lower "predicted" emissions are 100 times less than these worse-case results.) In addition, with improved dispersion using flue gas reheat for the gas/oil alternatives, there would probably be little difference between 100 % gas/oil alternatives and other alternatives.

Modeled Concentrations at Predicted Emission Rates

Criteria Pollutants

Predicted Annual Ambient Air Concentrations of Criteria Pollutants Summarized

Annual average air concentrations of criteria pollutants for predicted emission rates generally correspond with the amount of pollutant emitted. Facilities that use coal, for instance, generally have higher modeled SO_2 concentrations. (See Table 11 below)

The proposed Case A configuration had the highest predicted concentrations of SO_2. Alternative 3 had the highest predicted NOx concentrations.

Modeled concentrations for Case A and Case B, however, are slightly higher than Alternative 6 because the forty-foot building height increase at the Southeast Plant creates downwash effects not present for other alternatives.

Modeled annual concentrations for all alternatives, however, are well below annual ambient air quality standards.

Table 11. Modeled Annual Criteria Pollutant Concentrations at Predicted Emission Rates (µg/m3)

Pollutant	Avr. Period	Alt. 3	Alt. 4	Alt. 6	Alt. 7	ase A	Case B
PM_{10} (lb/hr)	Emission	(17.1)	(1.8)	(6.8)	(1.8)	(9.95)	(8.26)
	Annual	0.66	0.07	0.16	0.05	0.61	0.49
NO_X (lb/hr)	Emission	(192.5)	(61.2)	(59.5)	(62.2)	(100.24)	(102.34)
	Annual	7.51	2.65	1.39	2.00	5.50	4.44
SO_2 (lb/hr)	Emission	(46.7)	(19.2)	(40.7)	(19.2)	(46.40)	(45.27)
	Annual	1.80	0.80	0.97	0.61	2.69	2.31

At St. Paul Campus, Predicted Annual Concentrations Affected by Stack Height

At the St. Paul campus, modeled annual concentrations at predicted operating conditions (not shown) are nearly identical for the proposal and for alternative 13, because both assume 92% natural gas, 8% fuel oil consumption. Slightly higher concentrations were modeled for the proposal (Case A and Case B are the same for the St. Paul plant) are attributable to the use of stacks with different heights.

Emissions from boiler No. 7 are routed to a 90 foot stack that is susceptible to downwash effects because it is only 40 feet above nearby buildings. Alternative 13 uses boiler No. 7 more than would be required under the proposal. Under Case A, a larger portion of the steam demand would be met with the new high capacity package boiler, which uses a new 200 foot high stack.

Predicted Air Toxic Concentrations

Predicted Annual Air Toxic Concentrations provided in Appendix

Air toxic concentrations were also modeled at predicted emission rates, and the detailed results are provided in Appendix B. The maximum concentrations at predicted emission rates are in many cases 100 or more times less than the concentrations modeled for the "worst-case" maximum at potential emission rates, and all are fifty to 100 times below Air Concentration Limits, as described below in this chapter.

Although modeled concentrations are low, there are some

differences between alternatives, summarized below.

Modeled Toxic Ambient Concentrations Determined Mostly by Emission Rates

Differences in emission rates largely determine predicted average annual concentrations of air toxics. As a result, the facilities that use coal have somewhat higher predicted ambient air concentrations for some non-volatile metals, for mercury, and for three of the four products of incomplete combustion for which emissions could be estimated. For these air toxics, Case A concentrations are slightly higher than those of Case B or of alternatives 3 or 6. Alternatives that use mostly natural gas have the lowest predicted concentrations.

Alternatives 4 and 7 Have Highest Predicted Concentrations of Some Non-Volatile Metals and Formaldehyde.

The natural gas, fuel oil alternatives 4 and 7, however, have the highest modeled concentrations at predicted emissions rates for arsenic, beryllium, cadmium, chromium, lead, and formaldehyde. Emissions of these pollutants are attributed to fuel oil use, with the exception of formaldehyde, which is also produced during natural gas firing.

Alternative 4 has identical air toxic emissions to alternative 7 but has slightly higher modeled ambient air concentrations, possibly due to downwash effects as discussed above.

Predicted Annual Air Toxic Concentrations Lower at St. Paul than at Minneapolis

At the St. Paul campus, predicted air toxic concentrations are significantly lower that near the Minneapolis facilities because of the lower fuel use. The proposed St. Paul Case A has slightly different modeled concentrations than does alternative 13.

Predicted Actual Ambient Concentrations are Within Current MPCA Air Concentration Limits

Annual air-toxic concentrations modeled are lower for alternatives 4 and 7 because, at predicted fuel dispatch, these facilities use 92% natural gas, which is assumed to have negligible emissions of most toxics.

Predicted ambient concentrations for all alternatives, however, are below MPCA Air Concentration Limits (shown below). In addition, the concentrations modeled for Case A, Case B, and all alternatives are within an order of magnitude of each other for most air toxics. The exceptions are manganese, mercury, and iron, for which maximum modeled annual concentrations for alternatives 4 and 7 are about 1% of those for Case A or Case B, or Alternative 6.

Compatibility of Steam Technologies with Use of Biomass

CFB Options More Likely to Use More Biomass In Short Term

Biomass fuels are net zero emission greenhouse gas emitters. In the short-term, it is likely that the facilities that include a circulating fluidized bed boiler (CFB), like Case A, Case B, would use more biomass than 100% gas/oil facilities. CFBs are efficient at firing wood, and the base University proposal will be able to use about 7% total Btu with waste wood. or other solid biomass fuels. Modifications for additional biomass firing are also possible.

Promising long-term liquid and gas biomass fuels, such as that produced by alfalfa gassification (or other crops), could probably be filtered adequately to use in the standard combustion turbines described here. However, the gassification or other fuel conversion for such facilities usually takes place on-site with the electrical production equipment because long distance fuel distribution systems for these fuels do not exist. Siting a large scale biomass gasification plant on the University campus would present difficulties.

A gas or liquid biomass distribution system with enough capacity to supply a facility such as the University's steam plants is not likely in the short term, but a large-scale biomass gassification cogeneration heating system is possible for the long term.

Health Risk Assessment

Worst-Case Modeled Toxic Concentrations Below ACL's, Except Arsenic

In order to assess the inhalation pathway cancer risk from steam plant emissions, Table 12 below compares the modeled maximim annual concentration for each air toxic to the current MPCA regulatory guidelines or Air Concentration Limits (ACL). For toxics without ACL's, the workplace Threshold Limit Value (TLV) divided by 1000 are also compared to the modeled maximum. The maximum concentrations in Table 12, again, assume unrestricted potential emission rates.

The far right-hand column in Table 12 is the ratio of worst-case modeled concentration to guideline criteria. The ACL's represent the annual average concentration at which the excess life-time inhalation cancer risk is estimated to be 1 in 100,000. A ratio over 1.0, therefore, represents a modeled excess inhalation cancer risk over 1 in 100,000.

Modeled air toxic concentrations are below the guidelines for all listed air toxics, but arsenic. The highest modeled arsenic concentration was from the 100% gas/ oil alternatives (Alt. 4 and Alt. 7). Since these concentrations assume 100% fuel oil use at maximum rated

accepting fuel oil limits during permitting as necessary. Modeled arsenic concentrations using 92% natural gas and predicted steam demands are 100 times less than these worst-case values.

Table 12. Worst-Case Annual Toxic Concentrations Compared to ACL's

	Max Concentration (ug/m3)	ACL	TLV/1000	MAX/ACL or MAX/TLV
Arsenic	2.84E-03	2.00E-03		**1.42E+00**
Beryllium	3.54E-03	4.00E-03		8.85E-01
Cadmium	5.57E-04	6.00E-03		9.29E-02
Chromium-VI	5.02E-04	8.00E-04		6.27E-01
Chromium-tot	5.02E-03		1.00E-02	5.02E-01
Copper	8.09E-04		5.00E-01	1.62E-03
Iron	1.42E-01		2.00E-01	7.10E-01
Lead	2.79E-03	1.00E-01		2.79E-02
Manganese	1.98E-03	5.00E-02		3.95E-02
Mercury	2.82E-04	3.00E-01		9.39E-04
Nickel	1.39E-03	2.00E-02		6.97E-02
Selenium	1.06E-03		5.00E-02	2.12E-02
Vanadium	2.79E-03		2.00E-01	1.39E-02
Zinc	1.39E-03		5.00E-02	2.79E-02
Chlorine	3.62E-01	7.00E+00		5.17E-02
Fluorine	7.34E-02		1.50E+00	4.90E-02
Benzene	1.38E-02	1.00E+00		1.38E-02
Dioxins/Furans	1.54E-07	8.00E-06		1.92E-02
Formaldehyde	3.01E-02	8.00E-01		3.76E-02
POM (PAH & Phenols)	1.15E-03		3.70E-01	3.12E-03

Case A has the Highest Modeled Worst-Case Mercury Concentrations

Mercury and some other air toxics, however, are a concern not only because of their direct inhallation health effects, but because they bioaccumate in the food chain. Small quantities of mercury contamination in lakes have resulted in elevated mercury concentrations in fish throughout the region. Most of this mercury is from air emission sources.

The University's proposed Case A has higher mercury emissions than other alternatives (see above), and downwash effects increase localized high concentration spots. As a result, the highest worst case mercury concentrations at the Minneapolis Campus were modeled for Case A: 2.8E-4 $\mu g/m^3$.

2.8E-4 $\mu g/m^3$ equals 0.28 nanograms per cubic meter. For reference, background mercury concentrations monitored at remote northern Minnesota sites are 1.0 to 2.0 nanograms per cubic meter.

Nearby Mercury Deposition Rate From Steam Plant Estimated

Mercury deposition onto nearby lakes can be estimated by multiplying the modeled air concentration by a deposition velocity, which is a measure of the rate at which the mercury in the air falls to the ground. The deposition velocity used for this calculation is .002 meters per second, a reasonable value for a facility with particulate and acid gas controls (MPCA personal communication).

Assuming that the modeled worst-case 2.8E-4 $\mu g/m^3$ mercury concentration occurred over nearby lakes all year long, and applying a conservative deposition velocity of .002 meters per second, the calculated mercury deposition rate from Case A is about 17.8 µg/m2/yr.

Worst-case modeled concentrations over nearby water bodies or wetlands are at least ten time less than the high spot, which is near the Southeast Plant. (Although the modeled high is very near the Mississippi River.) At a air concentration of 2.8E-5 $\mu g/m^3$, the annual mercury deposition rate would is calculated to be 1.8 µg/m2/yr.

Published current mercury deposition rates onto remote lakes are approximately 12.5 µg/m2/yr. Using these assumptions, worst-case modeled mercury deposition from Case A, therefore, is about equal to that occurring from ambient background. In addition, the University's current permit application requests fuel and emission limits that would reduce worst case-emissions below the unrestricted emissions assumed here.

Hydrocarbon Vapor Emissions

Hydrocarbon vapor emissions from the fuel oil tanks for the Case A have been estimated to be 0.16 tons per year by the University in their permit application using standard EPA approved formulas and assumptions. Several EIS alternatives would require additional fuel storage, including new tanks for number 6 fuel oil (alternatives 3, 4, and 7). Vapor emissions would be up to twice as high for these alternatives, but with standard emission controls, are not expected to create a localized health risk or other environmental problem. Total emissions of volatile organic carbon from the fuel oil storage tanks are insignificant compared to stack emissions (20 to 30 TPY).

Section 6.5 Noise

Periodic Loud Noise From Steam Plant is Due to Steam Venting at Boiler Start-up

The state daytime L_{10} state standard is 65 decibels (The L_{10} noise level is that exceeded 10% of a given monitoring period.) Background L_{10} levels monitored in the park near the Southeast Plant are about 63 decibels. Of that background, the Southeast Plant is not the dominant noise source. The background hum of the Southeast Plant can typically be heard in the nearby park, but the louder noise in the area is from nearby grain elevators and nearby traffic. On the Dam Flats, the noise from St. Anthony Falls is louder than that from the Southeast Plant as well.

Periodically (about 10 times a year) the Southeast Plant boilers, during start-up and shut-down, produce a much louder than background noise for about 15 to 30 minutes. This loud noise is due to superheated steam that must be vented to avoid damaging plant boiler tubes.

Monitored Noise Levels High, but Not A Regulatory Concern Due to Infrequent Occurrence

L_{10} noise levels were monitored near the Southeast Plant during this startup procedure, but because of planes and construction noise, the monitoring could not be certified as an official reading. Nevertheless, the monitored L_{10} noise levels did reach 81.7 decibels, dominating the noise level in the surrounding area for about fifteen minutes.

The MPCA has indicated, however, that because of the infrequent nature, short duration, and location, the impact of the noise is minimal.

Noise Impact Considered Minimal, and Could Be Mitigated With New Equipment

This start-up noise would continue following plant renovation, but it can be minimized with the installation of mufflers and other equipment on the vent piping. This mitigation could best be done during plant renovation.

Similar noise mitigation could be installed at an alternative at the off-river site to minimize the impact of start-up noise on the surrounding area and motel. Due to this potential mitigation and the traffic noise already occurring at the alternative site, the noise impact from a new steam plant is expected to be insignificant.

Section 6.6 Fugitive Dust

Fugitive Dust is Created by Coal and Ash Piles

A separate fugitive dust modeling analysis was performed by Foster Wheeler and reviewed by Trinity Consultants, Inc. in order to assess the environmental impacts resulting from Case A fugitive dust emissions. Case A would produce the most fugitive dust of any renovation option. For the purposes of this analysis, fugitive dust emissions include area and point source PM_{10} emissions from all material handling and material storage operations. Table 12 summarizes the fugitive emission sources included in the analysis.

Table 13. Fugitive Dust Emission Sources

Emission Source	Plant
Coal Stockpile	Main
Coal Bunker	Southeast
Coal Bunker	Southeast
Coal Stockpile	St. Paul
Ash Pile	Southeast
Ash Pile	St. Paul
Railcar Unloading	Main
Existing Ash Silo	Southeast
New Ash Silo	Southeast
Existing Lime Silo	Southeast
New Limestone Silo	Southeast
Existing Coal Handling	Southeast
New Coal Handling	Southeast
Ash Silo	St. Paul

Modeled Particulate Concentrations From the Coal and Ash Piles Presented

The annual and 24-hour ambient ground-level PM_{10} concentrations resulting from the Southeast Heating Plant fugitive emissions are shown in Tables 13. The annual and 24-hour ambient ground-level PM_{10} concentrations resulting from the St. Paul Heating Plant fugitive dust emissions are shown in Table 14.

Table 14. Southeast Plant Fugitive Dust Concentrations Southeast Heating Plant modeled fugitive dust concentrations.

Averaging Period	Modeled Concentration ($\mu g/m^3$)	UTM Location	
		East (km)	North (km)
Annual	0.53	483.300	4980.700
24-hour	20.76	483.300	4980.700

Table 15. St. Paul Plant Fugitive Dust Concentrations St. Paul Heating Plant modeled fugitive dust concentrations.

Averaging Period	Modeled Concentration ($\mu g/m^3$)	UTM Location	
		East (km)	North (km)
Annual	0.003	485.640	4980.358
24-hour	0.10	485.640	4980.358

Fugitive Dust Emissions Within Regulatory Limits, But Still Create Periodic Annoyance

Results show that the annual and 24-hour fugitive dust from Southeast Plant sources are considerably higher than the concentrations that from St. Paul Plant sources: coal and ash handling quantities are lower at St. Paul, and the bituminous coal used at St. Paul is less fine-grained and dusty than the subituminous coal would be used for the Southeast Plant. In addition, the coal pile at the St. Paul Campus can be packed down tightly and remain inactive for most of the year, since the University will be using coal "primarily" for backup purposes.

Modeled particulate concentrations at both campuses are below the applicable PM_{10} standard; however, the proposed coal handling system (which is the same as existing) does appear to create aesthetic problems in the area of the Main Plant. Coal dust can be seen for some distance around the site in the winter, and some nearby residents are periodically annoyed.

Any problems at St. Paul should be eliminated by the infrequent coal handling. Without frequent use and disturbance of the coal pile, the coal dust problems would be minimal.

Construction Related Impacts Would Be Minimal

Construction at the Southeast Plant would disrupt the area near the Stone Arch Bridge for the one to two year construction period. Additional truck and other traffic would increase. Soil removal would be required for new equipment. A construction stormwater permit would likely be required, and assuming compliance with permit requirements, the impact of runoff on the Mississippi would be negligible.

Construction impacts at the alternative site are also expected to not be significant as long as the required runoff containment and other standard procedures are implemented properly. Traffic in the area of the existing parking lots could be disrupted during the construction period as well.

Section 6.7 Applicable Air Quality Regulations

Applicable air Quality Regulations

Federal and Minnesota Primary and Secondary Ambient Air Quality Standards. Minnesota and the federal government have established Ambient Air Quality Standards (AAQS) for six criteria pollutants: CO, NO_2, Ozone, TSP (Minnesota only), PM_{10} (federal only), and SO_2. Two classes of AAQS have been established: primary and secondary. The primary standards define the level of air quality necessary to protect public health. Secondary standards define levels for protecting the general welfare (soils, vegetation, and wildlife). The Minnesota and federal AAQS are summarized in Table 16.

Table 16. Ambient Air Quality Standards ($\mu g/m^3$)

		National		State	
Pollutant	Time	Primary	Secondary	Primary	Secondary
CO	8-hour 1-hour	10,000 40,000	10,000 40,000	10,000 35,000	10,000 35,000
NO_2	Annual	100	100	100	100
Ozone	1-hour	235	235	235	235
TSP	Annual 24-hour	- -	- -	75 260	60 150
PM_{10}	Annual 24-hour	50 150	50 150	- -	- -
SO_2	Annual 24-hour 3-hour 1-hour	80 365 - -	- - 1,300 -	80 365 1,300 1,300	60 365 1,300 -

The Federal and State Regulations and Standards Listed

- Federal Prevention of Significant Deterioration (PSD) Regulations.
- The proposed project is subject to (PSD) review for TSP and PM_{10}. The proposed project is not subject to PSD review for SO_2, CO, NO_x, VOC, and lead. A PSD applicability review was not completed for each selected alternative.
- New Source Performance Standards (NSPS). NSPS are federal rules that establish requirements for emissions testing, monitoring, and reporting for specific emission units. The emission rates in the proposal must be less than the NSPS requirements. Compliance with NSPS will be demonstrated through CEMs, stack testing, fuel testing, and fuel flow monitoring.

  - Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators for which Construction is Commenced after August 17, 1971- Subpart Db - Standards of Performance for Industrial/Commercial/Institutional Steam Generating Units
  - Subpart GG - Standards of Performance for Stationary Gas Turbines
- National Emission Standards for Hazardous Air Pollutants (NESHAPS).
- Minnesota Air Pollution Control Regulations and Minnesota Standards of Performance.
- Minnesota Acid Deposition Rule. The Minnesota acid deposition rule applies "only in sensitive areas" and only to an electric utility whose generating facilities located in Minnesota have a total combined generating capacity greater than 1,000 megawatts.
- Acid Rain - Title IV. Title IV of the Clean Air Act applies when a plant cogenerates more than 25 megawatts of electric output. In addition, a cogeneration unit that does not supply more than one-third of its potential electrical output capacity and more than 25 megawatts of electrical output to a utility power distribution system for sale is not subject to the allowance requirements of Title IV.
- Great Lake States Air Permitting Agreement. The Great Lake States Air Permitting Agreement requires, consistent with present federal and state regulatory schemes, that BACT be installed wherever possible on all new and existing sources of

- persistent HAPs that impact the Great Lakes. Currently, no rules or regulations have been adopted under the agreement.
- Titles I and III of the federal Clean Air Act.

Modeled High Concentrations for Combined Campuses Important for Permitting

Modeled high concentrations for the combined campuses are important for permitting because the EPA has determined that although the Minneapolis and St. Paul campuses are located several miles apart, the facilities should be issued a joint air quality permit. (The permit must include all other University sources as well.) Combined modeling results for the Minneapolis and St. Paul facilities are provided in the detailed *Air Quality* report.

Pollution Dispersion from the Two Campuses Does Not Overlap Much

The EIS modeling results indicate that pollutant dispersion from the two campuses does not overlap much. At predicted emission rates, the annual average high is usually located near the Southeast Plant because emissions there are generally higher. The same is true for modeled maximum potential emissions, except with Cases A and B, for which the maximum potential emissions produced modeled highs at the St. Paul campus, probably due to downwash effects.

As described previously, some of the higher short-term modeled concentrations for alternatives at the Minneapolis campus are probably due to reduced flue gas exit temperatures from scrubbers used when firing fuel oil. The short-term modeled highs would not be reduced through annual fuel or emission permit limits

---

Chapter 7. Water Quality

Sampling Completed of Wastewater, Stormwater, Coal and Ash

This chapter addresses the impacts of wastewater and stormwater discharges from the existing steam facilities and summarizes the results of sampling for trace metals in coal, ash and soil at the facilities' storage areas. Changes to the existing wastewater and stormwater system due to the proposal and alternatives are described and their potential impacts assessed. Potential mitigation measures to reduce any water quality impacts are described in Section 6.2 below. This chapter briefly summarizes this water quality report.

Detailed Results Appear in Separate Report

Details of sampling methodology, parameters, and results, along with a full discussion of water quality issues, can be found in a separate report: *Water Quality Study, University of Minnesota Steam Services*, September 1994, by B.A. Liesch Associates.

Chapter 7.1. Wastewater

Wastewater Comes from Various Sources

Sources of wastewater at steam productions facilities include 1) used boiler make-up water (condensate), which must be treated to remove metals and other corrosion-causing minerals from both the boilers and the steam distribution system. boiler make-up water release or "blowdown", 3) normal domestic sewage, 4) water from floor drains, and 5) coal pile runoff.

Wastewater Discharged into Municipal Sewer System

All three steam plants discharge wastewater into the municipal sewer system, and samples from the Southeast and St. Paul steam plants were analyzed for pH, total suspended solids, chemical oxygen demand, boron and RCRA metals.

All Samples are within Published Disposal Limits

All parameters sampled were within published limits for disposal into the Metropolitan Council Wastewater Services (MCWS) treatment system. Additionally, most of the metals not included in the published limits were either below or only slightly above method detection limits.

Proposal Would Improve the Quality of Boiler Make-up Water and of Wastewater

Installing a new demineralization package—consisting of carbon filters, cation and anion exchangers, regeneration systems, a condensate polishing system, a neutralization tank and associated instrumentation—would improve both boiler make-up water treatment and the quality of wastewater.

This system would improve the pH of the wastewater, reduce spikes of suspended solids, and eliminate the current use of lime in the process. The neutralization effluent from the Southeast Plant would combine with the rest of the process wastewater at the Southeast Plant prior to being discharged into the municipal sewer. The existing treatment system would no longer be used.

All alternatives except "No Action" assumed a similar improvement to the current water treatment system.

Permit for Entire Campus Denied

The University of Minnesota submitted a discharge application MCWS for the entire campus. MCWS staff, however, have indicated that the application was not accepted as yet because of the diverse nature of discharges from the Universities various activities, and there are apparently no applications pending.

Permit and Semiannual Reporting May Be Required

The University anticipates that the Southeast Plant will discharge approximately 18.5 million gallons of process wastewater per year into the municipal sewers and that the St. Paul Plant will discharge approximately 9.5 million gallons.

Although neither Foster Wheeler Twin Cities, Inc. nor the University of Minnesota have an application currently pending, a wastewater discharge permit from MCWS may be required. Discharge amounts, wastewater testing, and discharge flow monitoring may have to be reported semiannually, depending on MCWS requirements.

Section 7.2. Stormwater

Coal and Ash Piles the Main Sources of Stormwater Runoff

The coal and ash piles at the Main, Southeast, and St. Paul plants are the main sources of potentially contaminated stormwater runoff.

The quantity and quality of stormwater runoff will not change from present levels under the proposal or any alternatives because the footprints of the plants or of the coal and ash storage areas will not change.

Runoff from the Main Plant Coal Storage Area Discharges into Main Plant and apparently into Municipal Sewer System

Runoff from the Main Plant coal pile runs below and in back of the pile into the plant—where it mixes with other process effluent—and out through a pipe in the ash unloading area on the riverfront side of the plant. From this point the effluent discharges into the municipal sewers, although detailed flow routes are not known.

Water from a pipe discharging into the river directly downhill from the pipe containing runoff was tested because it appeared to be related to the coal pile effluent, but it appears to be runoff from some source. (The flow increases during rain storms.)

Coal, Ash, and Soil Samples Taken to Determine Impacts

Coal, ash and soil samples were collected to determine potential impacts on soil and groundwater of the earthen berms containing runoff in the storage areas. Ponded stormwater samples were collected to determine impacts on the receiving waters were the earthen berms around the ash storage areas to fail.

Coal and ash samples from the three plants were analyzed for total and TCLP extractable heavy metals and boron.

Stormwater Samples also Taken

Stormwater samples were taken at the Southeast and St. Paul Plants' ash storage areas. Because the stormwater did not breach the containment structures, samples of the ponded water were collected to assess possible impacts on receiving waters should the containment structures fail. However, because suspended solids settle in stationary water, ponded water samples do not fully identify the level of pollutants in the run-off water.

Although no water was observed breaching the earthen berms at the Minneapolis ash storage area, water was being retained in a culvert behind the fill material in the northwest corner of the storage area.

Since, according to Foster Wheeler Twin Cities, Inc., the fill is not always there, its absence would result in additional discharge, which would increase the likelihood that the berms would fail. In addition, it is likely that the collecting runoff enters the shallow groundwater system.

Samples were also taken 1) at the Main Plant near the base of the coal storage bunker and 2) from the PVC pipe below the Main Plant discharging directly to the Mississippi River. Mr. George Delarche of Foster Wheeler Twin Cities, Inc. indicated that the Main Plant coal bunker discharged into the MCWS sewer lines.

The stormwater and discharge water samples were analyzed for heavy metals, strontium, boron, total suspended solids, pH and chemical oxygen demand.

Stormwater Samples also Within Regulatory Limits

Stormwater samples tested were within regulatory criteria for Class 2B waters. The only two exceptions were that the runoff from the Minneapolis ash site had a pH of 9.7 standard units (compared to a standard of 9.0 s.u.) and that the runoff from the St. Paul ash site exceeded the chronic standard for arsenic of 53 ug/l. There is, however, no readily apparent leakage into the receiving waters at the St. Paul ash storage site. Runoff from the Main Plant and samples from the discharge pipe were within regulatory discharge limits and drinking water standards.

Although the samples collected were generally within regulatory criteria, the samples collected in the ash storage areas are not representative of potential runoff. Were the current earthen berms to fail, the resulting discharge could carry ash with a concentration of suspended solids high enough possibly to exceed regulatory criteria.

Coal, Ash and Soil Samples Are Within Regulatory Limits

The toxicity characteristic leach procedure (TCLP) analysis indicated that neither coal nor ash is a hazardous waste at the University of Minnesota's storage facilities. The coal and ash samples analyzed did not approach regulatory action levels for TCLP metals—in other words, they did not have concentration levels high enough to require that regulatory agencies be notified or that the site be remediated.

Similarly, the soil sample collected at the Minneapolis Steam facility ash storage area was also well below the TCLP regulatory action levels, with only barium above the method detection limit. The low TCLP values of the soil sample suggest that the storm run-off water may not be affecting the ground water beneath the

ash storage site.

The soil sample did have higher concentrations of total metals than did the ash and coal samples. This may be from the metals in the ash leaching out and concentrating in the soil. The information collected to date, however, does not permit an estimate of how long it would take for the concentrations in the soil to reach regulatory limits.

NPDES Permits May Be Required

The National Pollution Discharge Elimination System (NPDES) permit program, designed to control the quality of stormwater runoff entering the receiving waters from industrial sites, cities, and construction projects, is administered in Minnesota by the MPCA. That agency does not currently have on file an NPDES permit or a completed application for the University of Minnesota's steam generating plants.

Foster Wheeler Twin Cities, Inc. did file an application. Because the project, however, did not fall under a Standard Industrial Classification (SIC) code identified by the U.S. Environmental Protection Agency, Foster Wheeler Twin Cities, Inc. did not believe that an NPDES permit was necessary, so they did not send the required application fee. MPCA staff reviewed the application and indicated that no stormwater operating permit will be required. There is still uncertainty regarding whether a permit should be required, however, and the MPCA has not identified whether the University of Minnesota needs an NPDES permit following the proposed renovation or an alternative.

Total project size would probably require an NPDES construction permit. Were each plant reviewed individually, however, a permit might not be necessary. Finally, were the steam generating plants modified to produce electricity, a permit would be required.

Foster Wheeler Proposes Measures to Mitigate Ash Runoff

Although the Minneapolis ash storage area is bordered on the north by a bluff, on the south (riverside) by a concrete retaining wall, and on the east and west by earthen benns, Foster Wheeler Twin Cities, Inc. has proposed, as part of the improvements to the Southeast Plant, an optional concrete retaining wall further to reduce the potential for stormwater runoff.

Similarly, Foster Wheeler Twin Cities, Inc. has proposed a stormwater collection and storage system to improve runoff at the St. Paul ash storage bunker. This system would not only contain runoff, but it would allow suspended solids to settle and be removed. (The University has also indicated that it will use

only insignificant amounts of coal at St. Paul following renovation.)

The proposed containment facilities should adequately prevent environmental impacts. The ash samples analyzed indicate that the ash is not hazardous for metals or suspended solids.

Consequently, these efforts to contain the runoff from discharging directly into receiving waters should protect the environment from the metals and suspended solids in the ash.

Chapter 7.3. Potential Impacts from Fuel Spill

A 10,000 gallon aboveground storage tank (AST) will continue to be used at the Southeast Plant to store No. 2 fuel oil, and additional fuel oil storage would be required for riverfront alternatives 3 and 4. This AST has and will have secondary containment, but should that containment fail, and fuel oil be released, there would be several potential impacts.

A fuel oil spill would flow down the access road onto a relatively level area adjacent to the river. Depending on the quantity of the fuel oil, a portion would infiltrate into the soil, and a portion could flow into the river.

With Quick Response, Impact on Soil and Groundwater Should Be Minimal

Were the soils immediately excavated, the long-term impact on the environment would not be significant. Because bedrock lies within ten feet of the surface, excavation of the soils would be limited. Because the river—into which shallow groundwater is presumably discharged—is nearby, the impact on groundwater should be minimal.

Effects on River Life Would Vary with Severity of the Spill

Fuel oil released into the river would float on the river's surface until disturbed by the water passing through the downstream lock and dam. Effects on the biologic populations of the Mississippi River would depend on the amount of fuel oil released and on the timeliness of the emergency response. According to information furnished by MPCA, fuel oil toxicity is second only to that of crude oil.

An environmentally severe fuel spill would kill fish and benthic invertebra in the vicinity of the release. River life downstream would also be affected, until concentrations became sufficiently diluted to be broken down by naturally occurring bacteria.

Release at Alternative Site Could Affect Soil, Groundwater, and the River

Were a new steam facility constructed on the alternative site, that site would also have ASTs for fuel oil. A fuel oil release at this site would potentially affect the soils and, if undetected, the groundwater in the vicinity of the AST. If drainage at the site allowed a release to reach the storm sewer system, diluted fuel oil would eventually reach the Mississippi River.

Chapter 8. Solid and Hazardous Waste

Phase One Site Assessments Completed for the Two Minneapolis Sites.

Phase-one site assessments were completed for the Minneapolis Riverfront and Alternative Sites. The purpose of the assessments was to assess the potential for soil and groundwater contamination from current or historical use or storage of coal, ash, fuel oil, or other potentially hazardous substances. A detailed description of these assessments is provided in a separate technical supporting document, *Soil and Groundwater Contamination Site Assessments*, by B.A.Liesch Associates.

At Riverfront Site, Concern over Four Storage Areas

At the Riverfront Site, the four areas of primary environmental concern are 1) the aboveground storage of fuel oil at the Main and Southeast Plants, 2) the underground storage of fuel at the Main Plant, 3) the storage of coal at the Main and Southeast Plants, and 4) the temporary storage of ash from the steam plant boilers within a bermed area along the river beneath the 35W and 10th Avenue bridges.

There is no indication of site contamination or other ecological stress at Riverfront Site

Three aboveground storage tanks (ASTs) for fuel oil are currently installed on the Riverfront Site: two ASTs totaling 750,000 gallons at the Main Plant and one 10,000-gallon AST near the Southeast facility. The ASTs are registered with the MPCA Tanks and Spills Section. Although the ASTs are provided with secondary containment and there was no evidence of contaminated soil or stressed vegetation near the ASTs during Liesch's walkover of the Riverfront Site, storage of large volumes of fuel oil does represent an environmental risk.

No Evidence of Leakage from Soon-to-be-Abandoned Underground Storage Tanks

MPCA records indicate that a leaking underground storage tank was reported at the Main facility. However, a site closure letter has been issued for the site, indicating that the site has been remediated to the satisfaction of the MPCA. The University is currently in the process of tightness testing the 14 underground storage tanks at the Main Plant, prior, reportedly, to abandoning them. There is currently no evidence of leakage from these installations.

Concentrations of Metals in Coal Pile Run-off Are Within Regulatory Limits

Coal for both the Main and Southeast plants is brought by rail to the Main plant, where it is stored on the ground. Run-off from the Southeast Plant coal bunker is reportedly discharged directly to the sanitary sewer. Run-off from the coal stockpiles at the Main plant may discharge to the Mississippi River via surface run-off or

infiltration to the ground water. However, laboratory analysis of seepage samples from the Main Plant coal pile indicated that concentrations of metals were within regulatory limits for drinking water.

Concentrations of Metals in Ash and Soil Are Within Regulatory Limits

Samples of ash and soil from the ash storage area were also within regulatory action limits for TCLP metals, and metals in leachate do not pose a significant risk to Mississippi River water quality.

Nearby Leaking Fuel Storage Tanks Probably Affects the Riverfront Site

Five leaking underground storage tanks have been identified immediately above or level with the Riverfront Site. Three of these sites have been closed by the MPCA. The two remaining sites are an Amoco Service Station at the intersection of University Avenue and 10th Avenue SE and the Chateau Community Housing Association at 425 13th Avenue SE.

The Amoco site should directly affect the Riverfront Site. Groundwater monitoring continues at this site, and the source of impacts has apparently not been identified. Were the fuel to continue to leak at the Chateau site, that site also would affect the Riverfront Site. The MPCA recently notified the owners of the Chateau property that the site would have to be inspected and remediated to address impacts at the site.

No Indication of Past Industrial or Other Hazardous Waste Contamination at Riverfront Site

In 1912 the Riverfront Site contained the Twin City Rapid Transit Company steam power facility (west end), the St. Anthony Falls Water Power Company and some residential units (central portion), and the University of Minnesota's New Heating Plant and Power Station (east end). At the northern border, located on the river bluff, were Chicago Great Western Railroad tracks. North of the Riverfront Site were various manufacturing and lumber companies (west end), residential units (central portion), and University of Minnesota facilities (east end).

By 1951, additional residential units had been constructed north of the site and the University of Minnesota's linear accelerator building had been constructed in the central portion of the site. Additional University buildings had been built adjacent to the east end of the site, and additional industrial development had sprung up adjacent to the west end of the site.

By 1952, the University had added a research laboratory at the site and had continued to develop the area adjacent to the east end of the site.

Ash Quantities Estimated for Proposal and Alternatives

The quantities of ash generated by the different steam plant alternatives are directly related to the amount of coal used. The 100% gas/oil plants would produce negligible amounts of solid waste. The CFB alternatives produce more ash per Btu than conventional boilers because of the limestone injected for sulfur control. The quantities of ash generated by each alternative are listed below.

Alternative	Ash Produced (TPY)	10-Ton Trucks / year
Case A	10,450	1050
Case B	8,300	830
Alternative 1	8150	820
Alternative 3	5400	540

Ash production per MMBtu of coal burned in CFB is estimated as lb/MMBtu

Ash in Coal	6.25
Reagent (limestone)	2.06
Sulfur Removal	0.30
Total residue	8.61

Some Solvents Stored on Site

The steam facilities are currently not listed as a hazardous waste generator with Hennepin County. The small amount of solvents and treatment chemical residue is stored in barrels and disposed of.

At Alternative Site, Concern Over Creosote Compounds

At the alternative site, the primary environmental concern is the appearance of creosote compounds in the soils and groundwater, at concentrations which may require remediation. These compounds are from the Republic Creosoting Company, which operated on a portion of the site in the early 1900s.

Remediation Alternative Report Currently Being Prepared

According to Dahl & Associates, Inc., a proposed remediation alternative report is currently being prepared for this site. Approximately 2,000 cubic yards of soil requiring cleanup have been identified. Groundwater will apparently not be remediated during this phase of proposed work.

Several remedial alternatives were considered for the site, and the chosen action will be presented in this report. The MPCA-

VIC program is overseeing work conducted at the site. Pending MPCA review and approval of proposed remedial actions, remediation of the site could begin in fall or winter, 1994. Dahl predicts that site soils remediation will take six weeks to complete.

Nearby Fuel Storage Tanks Could Affect Alternative Site

Five leaking underground storage tanks have been identified immediately above or level with the Alternative Site. Three of the sites have been closed by the MPCA. The two remaining sites are the Chicago & Northwestern Transportation Company (CNTC) site, and a University of Minnesota spill site.

The CNTC site is currently being remediated, but the affect on lower sites is unclear, and it could eventually affect the southern end of the Alternative Site. The location of spillage from refueling at the University of Minnesota site is unknown, although approximately 620 tons of affected soil have been removed. Because groundwater flow conditions in this area fluctuate, the University of Minnesota site could affect groundwater at the Alternative Site.

VOCs in Nearby Soils Could Affect Alternative Site

A soil sample taken from the University of Minnesota's Integrated Waste Management Facility site in 1990 was found to contain low levels of volatile and semi-volatile organic compounds. The Waste Management Facility is operates as a waste transfer site for the University.

Also in 1990, VOCs were identified in soil at the nearby Soo Line Century Mill site. Mandated remediation work was not performed, and the site was subsequently referred to the MPCA Superfund Program for further investigation. Due to lack of information regarding site conditions, potential impacts from the site cannot now be adequately evaluated.

Since 1912, Limited Development at the Alternative Site

In 1912, the Alternative Site was occupied by the Chicago Great Western Rail Yard and the Republic Creosoting Company. Various grain elevators and a linseed oil mill—reportedly built in the late 1800s and early 1900s—were located near the site. Surrounding areas to the north and west contained additional rail yards, grain elevators, and a mill, and surrounding areas to the south, southwest and west contained a bulk oil facility, grain elevators, and residential and University buildings.

By at least 1937, the Republic Creosoting Company was gone, and development since 1912 has consisted mainly of grain elevators.

Chapter 9. Land Use, Historic, Visual, and Other Socioeconomic Impacts

Chapter Contains Seven Sections

This chapter describes impacts of the proposed steam plant renovation project and its alternatives on land use and other impacts that that are neither environmental nor economic. The sections in this chapter are the following:

9.1 Existing Land Use

9.2 Land Use Conflicts

9.3 Visual Impacts

9.4 Historic Significance

9.5 Compatibility with City of Minneapolis Land Use Plans

9.6 Special State and Federal Programs for the Riverfront

9.7 Land Use Impacts at the St. Paul Campus

This Chapter Describes Surrounding Land use and Assesses Impacts

This chapter first describes the Minneapolis riverfront area, then describes the most likely alternative Minneapolis off-river site, and finally, provides a brief description of the St. Paul campus site. The focus, however, is on the Mississippi riverfront site because of the larger public interest in that area.

Section 9.1 Existing Land Use

The land uses surrounding the riverfront site and the alternative site are illustrated on Figures 1 & 2

The riverfront site covers about 0.5 miles of the east bank of the Mississippi River between 6th Avenue SE and 12th Avenue SE. The Main Plant occupies the east end of the site and the Southeast Plant occupies the west. The area is bounded by a railroad corridor on the north, the river on the south, the Southeast Plant and its coal bunker on the west, and the Main Plant and its associated facilities on the east.

The alternative site is a narrow, 23-acre crescent-shaped property north of University Avenue and east of Oak Street.

Figure 1 and Figure 2 are maps depicting the nearby land uses in each area.

Figure 3 is a map of the area surrounding the St. Paul Plant

Riverfront Area Includes Industrial, Recreational, Retail, and Residential land Uses

The area is bounded by a railroad corridor on the north, the river on the south, the Southeast Plant and its coal bunker on the west, and the Main Plant and its associated facilities on the east. Located near the project area are a wide variety of land uses including industry, day care facilities, parks, retail and entertainment, University facilities, and housing (Figure 1).

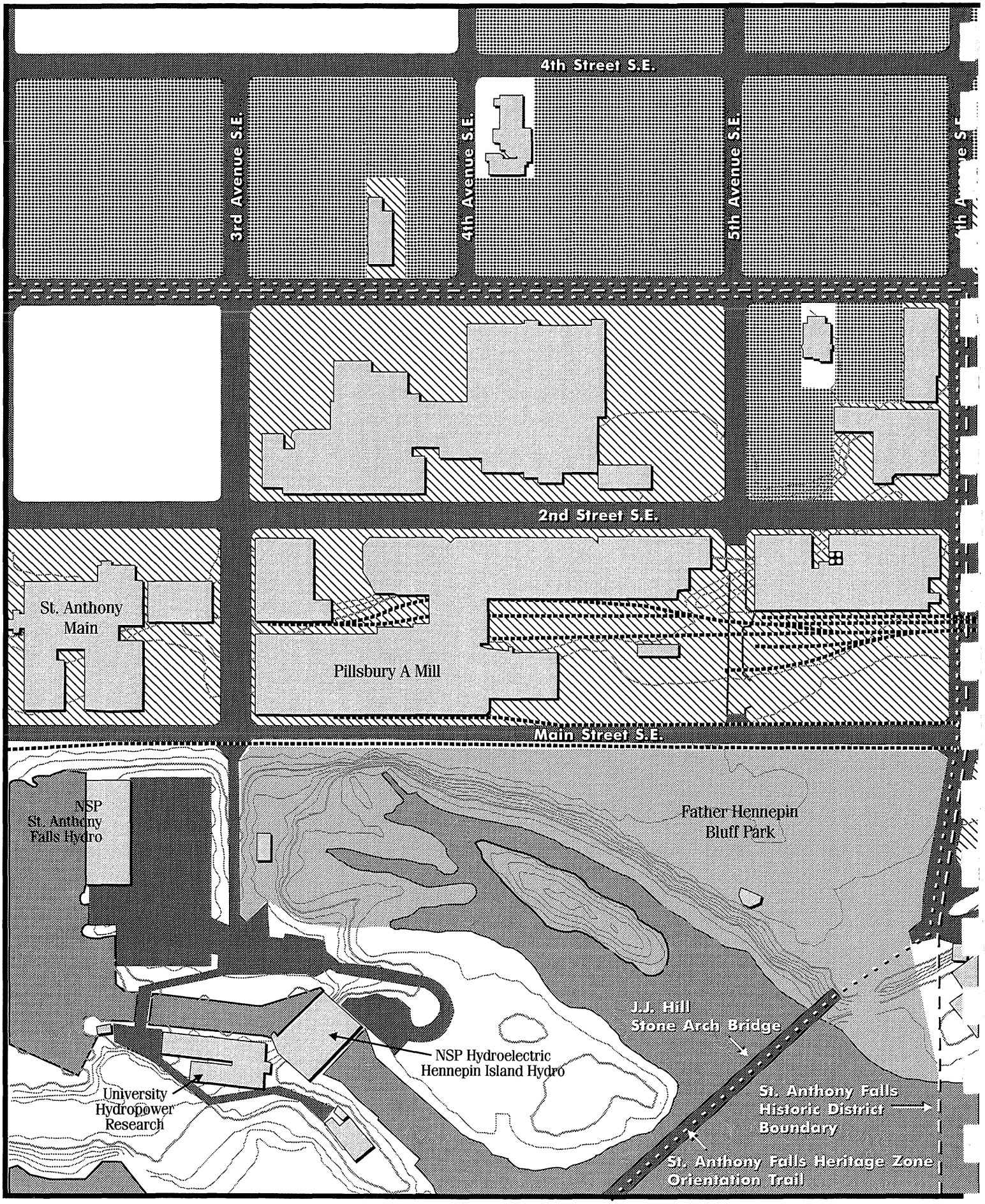
Dam Flats are Located Between the Southeast Plant and Main Plant

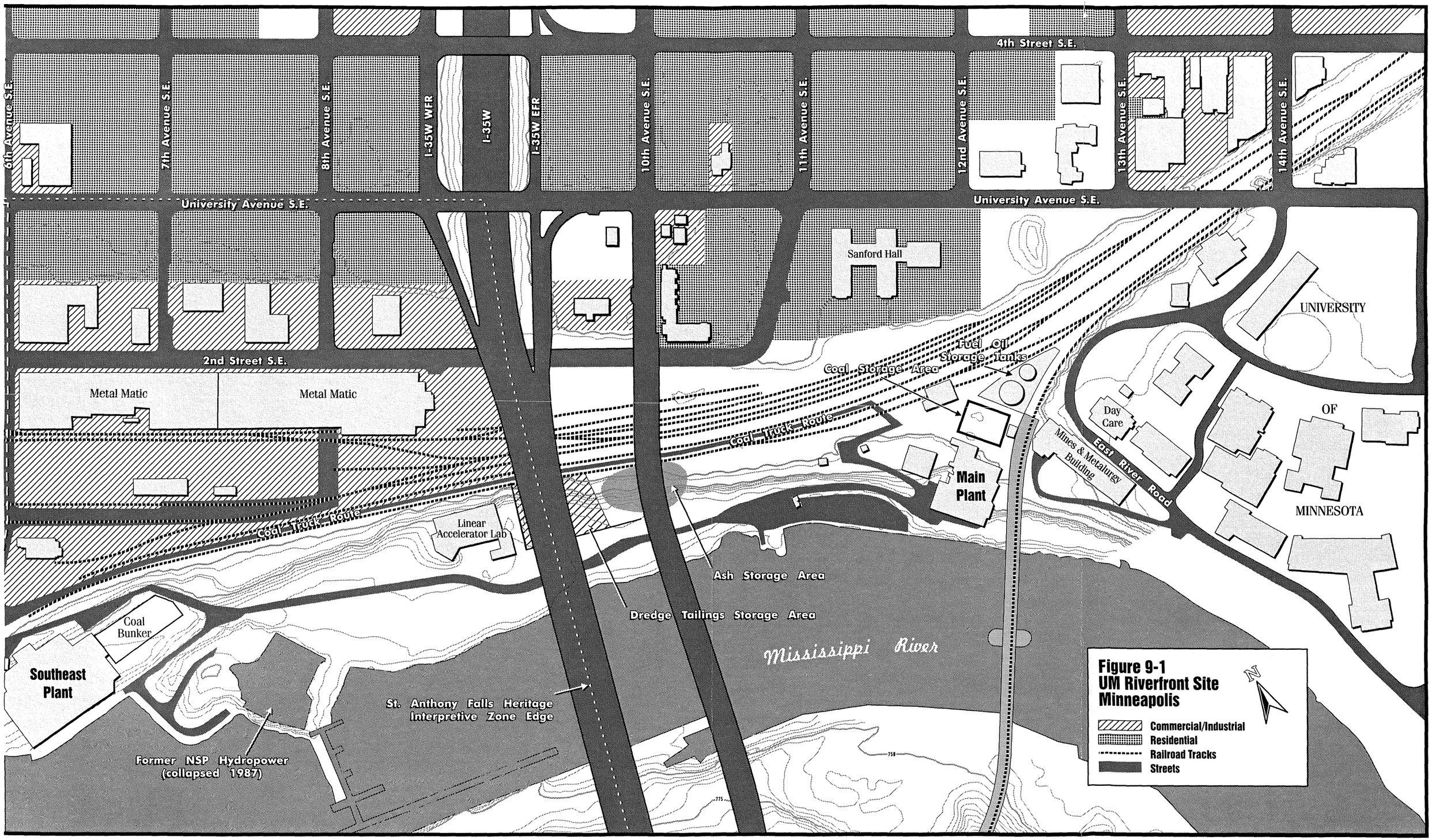
The Dam Flats is a level area between the river and the bluffs that extend between the Southeast Plant and the Main Plant (See Figure 4). Located within this area are the site of the former Northern States Power (NSP) hydropower facility and the access road connecting the two power plants.

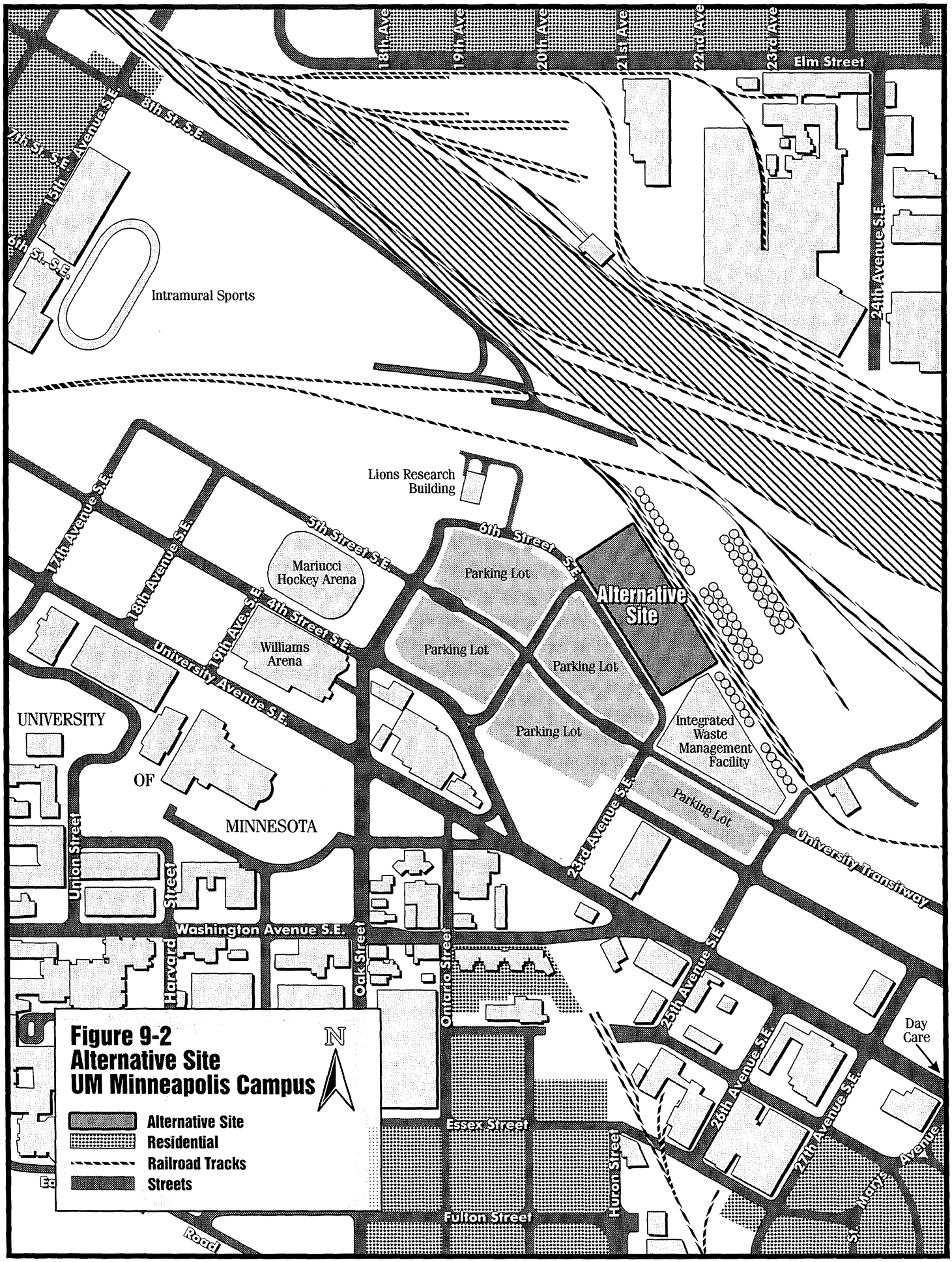
The I-35W and 10th Avenue Bridges cross the Mississippi in the middle of the Flats area. Storage sites for dredged river sediment, the ash storage area, and the University's Tandem Van de Graaf Linear Accelerator Laboratory are located under the bridges, to the north of the flats and across the access road from the river.

Collapsed NSP Hydropower Facility Next To SE Plant

The hydropower facility in the Dam Flats area collapsed in 1987. NSP has no immediate plans for rebuilding this facility but is planning to make a final decision about rebuilding within the next year.


4th Street S.E.
3rd Avenue S.E.
4th Avenue S.E.
5th Avenue S.E.
2nd Street S.E.
St. Anthony Main
Pillsbury A Mill
Main Street S.E.
NSP St. Anthony Falls Hydro
Father Hennepin Bluff Park
J.J. Hill Stone Arch Bridge
NSP Hydroelectric Hennepin Island Hydro
University Hydropower Research
St. Anthony Falls Historic District Boundary
St. Anthony Falls Heritage Zone Orientation Trail


6th Avenue S.E.
7th Avenue S.E.
8th Avenue S.E.
I-35W WFR
I-35W
I-35W EFR
10th Avenue S.E.
11th Avenue S.E.
12nd Avenue S.E.
13th Avenue S.E.
14th Avenue S.E.
4th Street S.E.
University Avenue S.E.
University Avenue S.E.
2nd Street S.E.
Sanford Hall
UNIVERSITY
OF
MINNESOTA
Metal Matic
Metal Matic
Coal Storage Area
Fuel Oil Storage Tanks
Day Care
Mines & Metalurgy Building
East River Road
Coal Truck Route
Coal Truck Route
Main Plant
Linear Accelerator Lab
Ash Storage Area
Dredge Tailings Storage Area
Mississippi River
Coal Bunker
Southeast Plant
St. Anthony Falls Heritage Interpretive Zone Edge
Former NSP Hydropower (collapsed 1987)
758
775
Figure 9-1
UM Riverfront Site
Minneapolis
N
Commercial/Industrial
Residential
Railroad Tracks
Streets


18th Ave
19th Ave
20th Ave
21st Ave
22nd Ave
23rd Ave
Elm Street
24th Avenue S.E.
17th Avenue S.E.
15th Avenue S.E.
St. S.E.
Intramural Sports
Lions Research Building
5th Street S.E.
6th Street S.E.
17th Avenue S.E.
18th Avenue S.E.
19th Ave S.E.
4th Street S.E.
Mariucci Hockey Arena
Williams Arena
Parking Lot
Alternative Site
Parking Lot
Parking Lot
Parking Lot
Integrated Waste Management Facility
Parking Lot
University Avenue S.E.
UNIVERSITY
OF
MINNESOTA
Union Street
Harvard Street
Washington Avenue S.E.
Oak Street
Ontario Street
23rd Avenue S.E.
University Transitway
25th Avenue S.E.
26th Avenue S.E.
Day Care
Essex Street
Huron Street
Fulton Street
St. Mary's Avenue
Road
Figure 9-2
Alternative Site
UM Minneapolis Campus
N
Alternative Site
Residential
Railroad Tracks
Streets

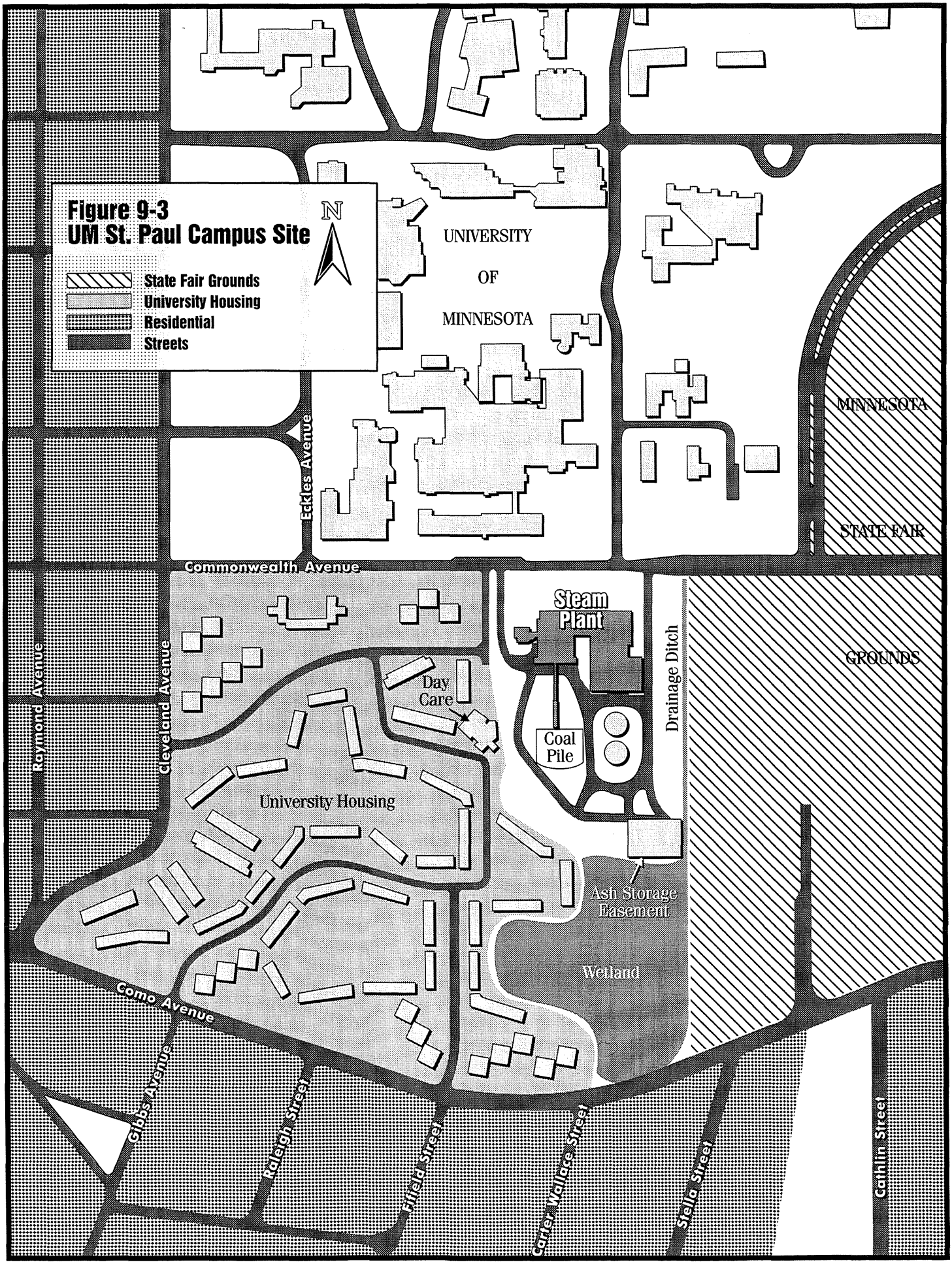

Figure 9-3
UM St. Paul Campus Site
N
State Fair Grounds
University Housing
Residential
Streets
UNIVERSITY
OF
MINNESOTA
MINNESOTA
STATE FAIR
GROUNDS
Eckles Avenue
Commonwealth Avenue
Steam Plant
Drainage Ditch
Day Care
Coal Pile
University Housing
Ash Storage Easement
Wetland
Raymond Avenue
Cleveland Avenue
Como Avenue
Gibbs Avenue
Raleigh Street
Carter Wallace Street
Stella Street
Cahlin Street

Figure 4

Riverfront Dam Flats Area:
Down River View From Near Southeast Plant



Dredged Material and Ash is Stored on Dam Flats

Under the 10th Avenue Bridge, east if the accelerator building, is an open cement bunker owned by the City of Minneapolis, into which material dredged from the river is deposited.

Ash from the steam plants is also temporarily stored under the 10th Avenue Bridge. When the ash is cooled, it is removed by truck to its final landfill destination. (See Chapter 11 for ash handling and Chapter 8 for ash disposal details). A barge slip and several small service buildings are also located on the Dam Flats.

Coal trucks deliver coal to Southeast Plant on a route above the bluff.

Above the riverfront bluff, coal is transported from the Main Plant coal receiving area to the Southeast Plant coal bunker in 10-ton trucks over an easement between the railroad tracks and the bluff face. Approximately 7500 coal trucks currently use that route each year, or an average of about 20 per day (more in winter, less in spring and fall).

Hennepin Bluffs Park Stone Arch Bridge Located Next to SE Plant

Just west along the river from the Southeast Plant is Father Hennepin Bluffs Park, which includes the site of the former hydropower tailrace outlets and a small urban park.

At the Park's eastern edge, closest to the Southeast Plant, the Stone Arch Bridge was recently renovated and reopened to pedestrian and bicycle use, thereby completing the central riverfront trail loop.

West of Father Hennepin Bluffs Park, along the river and extending onto Hennepin Island, are NSP's Hennepin Island hydroelectric facilities and the University's hydropower research facilities. Directly across Main Street, away from the River, sits the Pillsbury A Mill. The railroad corridor terminates at the Pillsbury complex.

The Area to the Immediate North is Primarily Industrial

The land north of the rail corridor from I-35W to as far west as 3rd Avenue SE is primarily industrial. Included here are Metal Matic, a large steel manufacturing facility that dominates the area, and a number of smaller manufacturing and industrial supply firms.

Two daycare facilities are located nearby.

There are two daycare facilities located near the riverfront steam plants. One daycare is located at 2nd Street and 8th Avenue SE. The second daycare is located across East River Road near the Main Plant. The daycare is operated by the University's Education Department.

Area Surrounding Primary Off-River Site is Mostly Industrial

The alternative site encompasses 23.8 acres between 17th Avenue SE on the west, 25th Avenue SE on the east, 4th Street SE on the south and the Burlington Northern railroad on the north. The site is currently undeveloped and overgrown with weeds.

The University Transitway forms the boundary of the site, separating it from a parking complex on the south. The new University of Minnesota Integrated Waste Management facility is located immediately east of the Alternative Site and the Modular Genetic Research facility immediately west of the site. The Williams and Mariucii Arenas are nearby. Intramural sports facilities lie just north of the Lions Research Facility (Figure 2).

Residential

There is residential development approximately 1/2 mile from the site, and a public housing project at St. Mary's Avenue and Williams Avenue. Other housing extends south from the Huron/Essex and Erie/Delaware areas.

Daycare

The Children's World Montessori school is located across University Avenue from the project area at St. Mary's Avenue.

Section 9.2 Land Use Conflicts

Southeast Steam Plant pre-dates many surrounding land uses.

Continued operation of the Southeast Steam Plant as described in the proposal would have no new effect on existing land use, although a number of existing land use conflicts would continue, and some would be increased. The Plant has operated nearly continuously since 1903; its operation predates many of the land uses around it; and those other operations were aware of the Plant's presence when they located in the area.

Land Use Conflicts Due to Use of Coal Most Significant

The most significant land use conflicts caused by the proposed steam plant renovation are due to coal storage, handling, transport and ash. The major impacts are the following:

- Aesthetic impacts on nearby residential areas;
- Land use conflicts between coal and ash trucks and bicyclists and pedestrians;
- Fugitive dust

Residential Buildings Overlook Main Plant Coal Facility

Across the rail corridor from the Main Plant are a dormitory (Sanford Hall) and a row of historic brownstone apartments (Florence Court). Both residences have a clear view of the coal during the winter, when the leaves are gone from the trees along the railroad tracks. Figures 5 and 6 simulate before and after view of the Main Plant area with the coal and fuel oil storage removed, as could be accomplished under Alternatives 6 and 7. Alternative 4 (gas and fuel oil) would allow for the removal of the coal storage but not the fuel oil tanks. Alternative 3 would retain the coal and oil storage, but would enclose the coal pile in some type of structure. There is an option in the University proposal to partially screen the coal pile but the screen would not block the view of the coal pile from across the railroad tracks.

Figure 5

Existing View of Main Plant Coal Operations From Sanford Hall

Figure 6

Computer Image of Main Plant Area Coal Operations And Fuel Oil Tanks Removed





Coal Transport on Riverfront Would Increase under Proposed Project, but Decrease under Alternatives

One impact on existing land use under the proposal would be an increase in the number of coal trucks. Under the proposed project, total coal use would decrease slightly, but all the coal would be used at the Southeast Plant. The coal would continue to be received and stored at the Main Plant site, although the Main Plant itself would be retired.

Assuming economic fuel dispatch, coal use at the Southeast Plant are estimated to increase from about 7500 tons per year currently to about 135,000 tons under Case A and about 110,000 tons per year under Case B. This would increase the number of trucks using the railroad easement from about 7500 10-ton trucks per year currently (an average of about 20 per day, more in winter, less in spring and fall) to about 13,000 per year under Case A. Alternatives 3, and the coal conveyor option in Case A and Case B, would eliminate coal truck traffic.

Coal Transport by Truck Conflicts with Bicyclists and Pedestrians.

Both the existing and the proposed facility conflicts with bicyclists using the area, particularly the easement road used by the coal trucks. The road is not a designated bicycle route, and bicyclists and pedestrians are currently discouraged from using it. However, this route is apparently often used as the most direct route between the University area and the historic, residential and retail areas. Conflicts with this use and the coal trucks would continue under the proposal without the optional conveyor systems. Moreover, as detailed in section 9.5, continued use of coal in the future constrains the planned development of new bikeways (and a planned motorway).

Coal Conveyer or Off-Site Alternative Eliminates Coal Truck Traffic

The University's contract with Foster Wheeler includes an option to install a coal conveyor in the existing tunnel between the two plants that would eliminate the use of coal trucks (except when the conveyor required maintenance). This option is detailed in Chapter 10 on mitigation.

The conveyor system is also included in the design and cost of alternative 3. Alternatives 4, 6 and 7 would eliminate the use of coal on the riverfront altogether

---

Ash Truck Traffic Would Increase under Proposal, Cease Along Riverfront under Some Alternatives

The number of ash trucks using the access road to and from the ash storage area would also increase, from about 800 trucks per year (from both plants), to about 1000 (Southeast Plant only). Alternatives 3, 4, 6 and 7 would eliminate ash truck traffic along the riverfront (although ash trucks would travel from the facility to a landfill under alternatives 3 and 6).

Fugitive Coal Dust Could Be Mitigated or Eliminated

Although the air quality analysis in chapter 5 indicates that fugitive coal dust levels are within regulatory limits, visual observation at the Main Plant site and anecdotal information from neighbors indicates annoyance levels of dust from the coal handling operations. Potential changes in coal use, storage, and handling would reduce these levels to varying degrees. Alternative 3 encloses all coal handling within a covered structure, and such a system could be implemented with either proposal option as well.

Trails and Parkway Conflicts Addressed in Separate Section

Other impacts of the proposal or alternatives at the riverfront site that could be classified as land use conflicts, such as conflicts with planned trails or parkways, but for the EIS are discussed under different sections of this chapter.

Alternative Site Impacts Include Large Use of Space

The coal-based alternative 6 would require a larger "footprint" than a 100% gas/oil plant because of the enclosed dome-shaped coal unloading and reclaim facility and other associated space requirements, leaving little if any space for additional future University development. Visual impacts at this site are addressed below.

Section 9.3 Visual Impacts

Visual Impacts Illustrated Graphically in Figures

Visual impacts at the Southeast Plant, existing, continued, and new, are illustrated in Figures 7 through 11.

Existing Plants Are Visible and Create an Industrial Atmosphere

The Main and Southeast plants are located along the river bank, and can be viewed by river travelers and local roadway traffic from downtown Minneapolis, local parks, the St. Anthony Falls Historic District and Interpretive Trail, and to a lesser extent, from areas on the Minneapolis campus (e.g. Sanford Hall) and from nearby residential areas.

The skyline near the existing plants is dominated by the steam plant stacks which are black and do not blend well with the surrounding area and by other large industrial facilities. From the nearby Hennepin Bluffs Park and other areas to the immediate north of the plant, pollution control equipment and the existing ash silo are also visible, thereby further creating an industrial atmosphere in the immediate area.

In addition, the dust and appearance of the open coal storage areas generally reduce the aesthetic quality of the area. For example, compare the views of the Main Plant area in Figure 4 with the simulated view of the same area in Figure 5 without the coal and fuel oil storage.

Figure 7

Existing View of Southeast Plant From Riverfront

Figure 8

Computer Image of Southeast Plant: After Proposed Modification

---

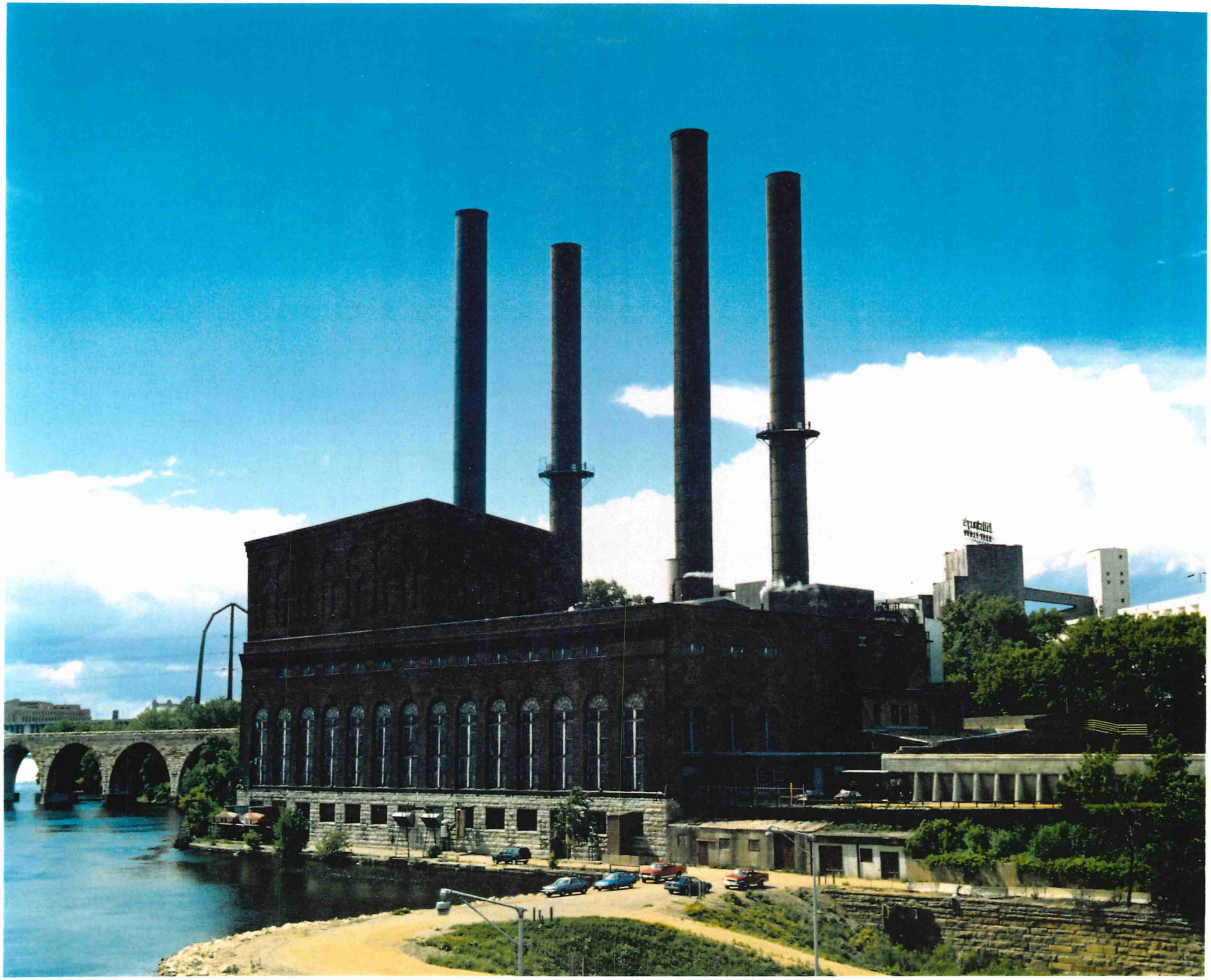
Figure 9

Existing Southeast Plant From Stone Arch Bridge (Before Completion of Bridge)

Figure 10

Computer Image Of Southeast Plant From Stone Arch Bridge After Proposed Modification









View of Southeast Plant Affected by Proposed Project and Alternative 1

The proposed building-height modifications and structural improvements to the Southeast Plant will affect both the riverside view and the view from the Stone Arch Bridge. These impacts are illustrated by two computer enhanced photographs simulating the proposed height increase (Figures 8 and 10). Alternative No. 1-the "No-Action" alternative-would have a visual impact on the Southeast Plant similar to that of the proposed project, but not until the year 2001, when existing boilers would likely be replaced by two new coal-fired boilers that would require a increased roof height.

Smaller, new equipment-including an air cooler and another ash silo-would be visible from the north side of the building. Projected impacts on other parts of the riverfront area are minimal. The "back" of the Southeast Plant could be screened from view somewhat as well.

Other Alternatives would change appearance of Area Near the Main Plant.

Alternatives No. 3 and 4-the two other riverfront alternatives would not much affect views of the Southeast Plant, but would affect views of the Main Plant area. Alternative 3 includes an entirely covered coal unloading and storage structure. (A covered coal handling system could also be implemented as part of the proposed project at additional cost but is not presently proposed). A domed structure similar to that shown below for alternative 6 would not fit near the Main Plant, but an alternative coal silo or tent-shaped structure could be designed.

Alternative 4, which eliminates the use of coal, would allow the coal handling and storage area near the Main Plant to be decommissioned, but the existing fuel oil tanks would remain, and additional tanks in the area would probably be required.

Alternatives 6 and 7 would allow the decommissioning of coal and oil storage at both riverfront plants. In addition, the appearance of the landward side of the Southeast Plant could potentially be enhanced by the removal of ash handling and pollution control equipment if the facility was no longer used for steam generation.

Visual impacts at Off-River Site Involve 200-Foot Stack

The area near the 23 Acre alternative site is generally industrial and of less aesthetic value than the riverfront site, so any visual impacts should be less important. The area can be seen from nearby University office buildings and research facilities, the recently completed Waste Management facility, Williams Arena, Marriucci Arena, local University offices and a hotel.

A photorealistic image of a possible version of coal and natural-gas alternatives for this site are shown in Figure 11 (existing), Figure 12 (coal, gas, fuel oil), and Figure 13 (100% gas/oil).

Air quality modeling indicates that a 200 foot high stack is likely to be required for proper air emission dispersion (see Chapter 6). The stacks of a new facility would not be higher than the nearby existing tower, but the nearby view of the existing grain elevators would be screened from the south, and the view of the Archer Daniels Midlands grain elevators, which can be seen from as far away as I-94 to the south, would be affected.

Figure 11

Existing Alternative Site Near Stadium Village From Nearby Parking Lot

---

Figure 12

Computer Image of Alternative Site Coal/Oil/Gas Facility

Figure 13

Computer Image of Alternative Site 100% Natural Gas, Fuel Oil Facility


20





Section 9.4 Historic Significance

Southeast Steam Plant is Historically Significant

The Southeast Steam Plant has been proposed for inclusion on the National Register of Historic Places, and may be included on the Register by January 1995. The Southeast Steam Plant was built between 1902 and 1903 by the Twin Cities Rapid Transit Company to help meet the increased demand for electricity for its streetcars and to compensate for unpredictable interruptions in hydroelectric power. A detailed history of the Southeast Plant is available in the Minnesota Historical Society's application for the Register.

The Steam Plant incorporated a number of innovations in illumination and coal-handling, including the addition of sky lights over the engine room and light shafts over the coal bunkers. The coal bunker arrangement was described at the time as a radical change from the usual design of overhead bunkers. None of these innovative features survive today.

The Main Plant is Probably of Minor Historical Significance

The Main Plant was built in 1912-1913 and sits on a parcel of land granted to the University in the 1850's as part of the University's original land grant. Throughout the years there have been several additions to the building, all related to the operation of the Plant.

The Main Plant is not on the National Register. The State Historic Preservation Officer (SHPO) has given some minor consideration to the historic significance of the Main Plant. At this point it is not considered a historic building although the SHPO advises that a second look at the building's significance may be needed.

Main Plant Would Be Retired under Proposed Project

Under the proposed project, the Main Plant would be retired, but the site would continue to be used to receive and store coal for use at the Southeast Plant.

The University has no immediate plans for the Plant if it is retired, although they have considered demolishing it or converting it to an office building. In 1992 demolishing the plant was estimated to cost at least $1.1 million, and converting it into an office building was estimated to cost $8.5 million.

Renovation of SE Plant Should Conform With National Historic Renovation Standards.

If a planned renovation of a building on the National Register is federally funded, or if a project requires federal permits or state permits with federally delegated authority, the SHPO has authority to review proposed project for conformance with the Secretary of Interior's Standards for Rehabilitation. Federal funding is not currently being proposed for this project and it is unclear whether the federally delegated air emission permits from MPCA would trigger SHPO review.

If a renovation project is carried out by a state agency on a building on the National Register, the SHPO has authority to review such a project under state law. State law is ambiguous as to whether the University qualifies as a state agency in these situations.

Despite ambiguities in the SHPO's authority to review the proposed renovation plans, the University has voluntarily consulted and plans to comply with that agency's guidance.

Standards for Rehabilitation May Apply to Roof Height Increase

The Secretary of Interior's Standards for Rehabilitation contain guidelines for repair, maintenance and change of historic buildings. The guideline most applicable to this project involves roofs.

The Standards for Rehabilitation indicate that additions to roof should be designed so that they: (1) are inconspicuous from the public right of way; (2) do not damage or obscure character-defining features; 3) should be set back from the wall plane and as inconspicuous as possible when viewed from the street; (4) be designed to make it clear what is historic and what is new.

The proposed project will involve raising the roof 40 feet over the southeast quarter of the building, changing its appearance. The University intends to architecturally coordinate the roof addition with the red brick and arched windows of the existing facade of the building. The likely appearance of the roof height increase from two different viewpoints is simulated in Figures 6 through 9.

Alternative #1, the "no-build" option would eventually have a similar impact on the roofline of the Southeast Plant. In this alternative, new boilers would be installed in approximately 2001 and this installation would require an also required an increase in building height. The other alternatives would not alter the appearance of the building.

The St. Anthony Falls Interpretive Plan Envisions Trails and Interpretive Sites

In 1971, the St. Anthony Falls Historic District was established to help maintain the historic character of the district. In 1980, the Minneapolis Heritage Preservation Commission established regulations for the District. The Southeast Steam Plant is located on the edge of this district but is not within it.

In 1988, the St. Anthony Falls Heritage Interpretive Zone was created, and the St. Anthony Falls Heritage Board was given responsibility for developing a plan for interpreting significant historical components in the Zone. The Southeast Plant is located within the Interpretive Zone.

The St. Anthony Falls Interpretative Plan lists the Southeast Steam Plant as one of 33 major historic assets in the area, which have the potential to be integrated into the interpretive plan. Although it is identified as a major historic asset, there are no specific plans or uses mentioned for the plant.

The Interpretive Plan envisions a heritage trail system that includes an orientation trail through the Heritage Zone and five smaller trails for interpreting the area using defined themes. The orientation trail crosses the Stone Arch Bridge near the Steam Plant but then heads to Hennepin Bluff Park and northward to the Main Street area. Neither the orientation trail nor any of the smaller theme trails include the Southeast Steam Plant. The Main Plant is not within the St. Anthony Falls Historic District or the Heritage Zone.

One Interpretive Use for Southeast Plant Precluded by Case A, Case B, and Probably No Action Alternative

Interest has been shown in renovating a currently unused upper-level control room in the Southeast Plant as an interpretive viewing area. The idea is that visitors would be able to view the operation of the steam plant from this room as well as examine the historic controls once used to operate the plant. The control room could become a stop on the historic interpretive trail network in the St. Anthony Falls Heritage Interpretive Zone.

In the proposed steam plant renovation, however, the control room is likely to be demolished for installation the new fluidized bed boiler. Even if this control room remained, the view of the plant floor would be blocked. The same result would occur under the Alternative 1, although not until 2001. Alternatives 3 and 4 would probably not conflict with this interpretive use. The off-river alternatives (6 and 7) would obviously not physically preclude the renovation of the control room as an interpretive site, however, if the Southeast Plant is retired as an active steam

plant it is problematic whether the building could be kept open for interpretive use unless a viable use is found for the building as a whole.

Alternative Site Borders Archer Daniels Midland Grain Elevator

A turn-of-century Archer Daniel Midlands grain elevator is located adjacent to the 23-Acre industrial site, but no other buildings have not been identified for any particular historic significance. (See section 9.3 for visual impacts of alternatives at this site). It is possible that these grain elevators along the railroad corridor near the alternative site may be of historic significance. The SHPO has not evaluated the elevators. The elevators are located across railroad tracks or otherwise separated from the alternative site and it is unlikely that development of the alternative site would significantly affect the historic value, if there is any.

Section 9. 5 Compatibility with City of Minneapolis Land Use Plans

Riverfront Area Has Been Subject of Many City Plans

The riverfront area in Minneapolis, which includes the Southeast Steam Plant and the Main Plant, holds special interest due primarily to the area's history and location, its recreational and scenic values, and its role in the preservation and restoration of the Mississippi River corridor. This special interest has led the City of Minneapolis, the University of Minnesota, the State of Minnesota, the federal government, and others to develop these numerous plans or programs for the area.

Many of the official riverfront plans and regulations published during the last twenty-five years were examined as part of the EIS study and are summarized in a separate report, *Summary of Land Use Plans, St. Anthony Falls Riverfront Area*, dated October, 1994.

Common Themes of Plans Include Open Space, Access, Preservation, Some Industry

The following City of Minneapolis plans were examined to develop the include the following list of "common themes" described below, upon which the evaluation in this section is based.

- Mississippi/Minneapolis (1972)
- The Mississippi River in Minneapolis (1975).Report of the Long Range Regional River Development and Acquisition Committee to the Minneapolis Park and Recreation Board (1976)
- Southeast Minneapolis Riverfront Plan (1976)
- Central Riverfront Open Space Master Plan (1977)
- Central Riverfront Development (1977)
- Central Riverfront Regional Park: Recreation Areas, Specifics of Development, Capacities, Estimated Costs
- Central Riverfront Urban Design Guidelines (1981)
- Metro 2000 Plan (1988)

Common Themes of City Plans for Riverfront Listed

The following themes for the riverfront emerge from the plans developed by the City of Minneapolis:

1. The City originated at the river but has since "turned its back" on it. Redevelopment of the riverfront will allow a valuable natural and historic resource to be more fully used.
2. An open space/greenway corridor, including pedestrian and bicycle paths, should follow both sides of the river. Public access to the river (often called "windows to the river") and activity nodes along the river are to be developed.

3. Preferred land uses are open space and residential. Any land uses, including industry, that do not need river access should be phased out. Industry that requires access to the river can be a desirable and compatible use. Such industry can offer interest to the riverfront.
4. Railroad tracks in the area that don't serve river terminals should be phased out.
5. Historic buildings should be preserved.

The following sections of the EIS discuss the compatibility of the proposed project and the alternatives with each of these themes.

University Has Unique Legal Status

The University of Minnesota was established in 1851 by an act of the Territory of Minnesota. The State of Minnesota was created about seven years later. Under the State constitution, the University is a constitutional arm of the state government and occupies a unique position. Its governing body, the Board of Regents, is generally free of legislative, executive, or judicial interference as long as it properly executes its duties.

Due to this status, it is not clear whether the plans, zoning and ordinances of Minneapolis and other entities are legally applicable to University land. However, regardless of its legal status, the proposal's compatibility with ordinances and land use plans for the surrounding community need to be examined to determine its potential impact on proposed land use.

Theme 1: Redevelopment of the Riverfront as a Natural and Historic Resource

---

Private and Public Funds have Been Expended Redeveloping the Nearby Riverfront Area.

Not only has much planning been done about recapturing the natural and historic values of the riverfront for public use, but also a substantial amount of public and funds have been spent in redeveloping the central riverfront area. The Minneapolis Community Development Agency (MCDA) reports that over 61 million dollars net have been spent by the City of Minneapolis and the MCDA on 13 projects in the central riverfront area. Another nearly 500 million dollars of money has been invested in these projects. The Minneapolis Park Board has invested 40 million dollars in development of the Central Riverfront Park.

Limited Funding Options Currently Available for the Conversion of the Southeast Steam Plant

If the Southeast Steam Plant were to be used for some use other than power generation, there would not be any currently budgeted source of funds for its purchase or conversion. The 1994-98 proposed capital improvement program of the Minneapolis Park Board does not include any capital expenditures in this portion of the riverfront. If this property did become available for purchase, the Minneapolis Park Board could seek funds from a variety of sources, including reprioritizing their own budget, special funds from the State Legislature, or potential grants through MNRRA.

The Southeast Steam Plant is currently proposed for inclusion on the National Register of Historic Places. Inclusion of the plant on the National Register will not make it eligible for any special funding for renovation. Investment tax credits are available for some historic rehabilitation but tax credits would be no advantage to the University.

Off-River Plant Opens Riverfront, but Eliminates Possible Innovative Coexistence Design

Moving the steam plant off-river would require construction of a new plant on property that the University currently plans to use for other purposes. In addition, it is possible that a creative riverfront design could successfully and creatively resolve these conflicts and integrate riverfront redevelopment plans with the continued industrial use of the Southeast Plant.

Several Plans Specifically Mention Southeast Plant

In 1972, the Mississippi/Minneapolis plan predicted that the Southeast Plant, which was then owned by NSP and used as a reserve power source, would cease operation and suggested that it could be used as an ecology center, museum or community facility.

In 1976, the Southeast Minneapolis Riverfront Plan suggested that the Southeast Plant building, which was not then in use, could be a river aquarium, a greenhouse, or headquarters for the Park and Recreation Board.

Also in 1976, the Central Riverfront Open Space Master Plan hoped to include the Southeast Plant in a historical interpretive network to portray the generation of power and steam from coal.

Theme 2: Riverfront Open Space, Greenways, Trails and Parkways

All Plans Envision a Park or Greenway along the River

All the plans reviewed envision a park or greenway along the riverfront. Most plans call for continuous parkway in the Minneapolis central riverfront and St. Anthony Falls area, linking points of interest and connecting into other parkway systems.

The Minneapolis Critical Area Plan calls for a continuous trail corridor for motorists, bicyclists, and pedestrians along both sides of the river.

The Mississippi National River and Recreation Area Plan envisions a pedestrian/bicycle route along the entire 72 miles of river in the metropolitan area. This federal plan is discussed in Section 9.6.

City Must Acquire Land or Contract with Owners

To build a continuous parkway, the City must either acquire land along the riverfront or reach a cooperative agreement with the property owners. Riverfront property between the Southeast Plant and the Main Plant is owned primarily by the University of Minnesota and by Northern States Power.

University Is Predisposed to Cooperate With Trail Plans

The University's Critical Area Plan shows most of the Dam Flats area as recreation area or open space. The plan also states that the University encourages the establishment of a system of regional trails and notes a willingness to allow pedestrian access to the riverfront, except when it interferes with specific University needs or operations.

Operation of Southeast Plant Itself Does not Present Land Use Conflicts

Since the Southeast Plant operation in the building itself would not increase the land used for the plant, it is not in direct conflict with the goal of developing greenway, except to the extent that it would continue an existing industrial use.

The most notable conflict with greenway development is that the existing plants and coal handling operations constrain the improvement of access to and through the area as outlined in the following section. Plans for the area for the area do not require removal of the Southeast Plant, or that it cease to function as a steam production facility, provided that the operation could be made consistent with a greenspace concept. As an historic building, the Southeast Plant is considered an asset to the area.

Feasibility of Proposed Trails

Proposed Motorway, Bikeways, and Pedestrian Pathways Evaluated; Constraints Identified

This section will discuss the compatibility of the project and alternatives with plans for motorway, bikeway, and pedestrian trail alignments shown in the various plans for the area. Several of the City of Minneapolis plans generally suggest the need for trails through the area, while others recommend specific alignments.

A feasibility analysis of the proposed trail alignments was completed by a registered landscape architect, Mr. James Robin as part of the EIS studies. The results are shown in Figure 14 (Riverfront Trailway Feasibility Analysis) and are available as a separate report. The following discussion relies on the accompanying Figure 14.

The Mississippi River below St. Anthony Falls is a gorge from fifty to one-hundred feet deep. The cliffs and bluffs bar access to the water, even though the bluffs have been substantially altered over the last century.

The trailway and access analysis, therefore, addresses the feasibility of proposed trail alignments based not only on the operation and location of the steam facilities, but also on other constraints, most notably the topography of the area, but also property ownership, current land use, and public health and safety considerations.

Without Major Construction, Main Plant Coal Operations Preclude Motorway Development

Plans propose an extension of East River Road to Main Street. These plans call for an at-grade roadway crossing through the area occupied by the existing coal and fuel oil storage area near the Main Plant. Barring the following changes, the continued operation of the Main Plant and the existing coal handling would preclude development of the proposed at-grade roadway.

Steam Facilities Modifications:

- Relocating existing Main Plant Coal operations
- Realigning or abandoning coal haul road

UNIVERSITY of MINNESOTA
STEAM FACILITIES E.I.S.

Minnesota Environmental Quality Board
658 Cedar Street, Saint Paul, Minnesota 55155

PROPOSED BIKEWAY

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Minneapolis Mississippi River Corridor Critical Area Plan, July, 1989
- Central Riverfront Open Space Master Plan, 1977

Feasibility:
An at grade **Bikeway** as shown in the sudies above is not feasible unless the following conditions are resolved or a different alignment is proposed which avoids the main steam plant and avoids the ramp adjacent to the Southeast Plant

- **2a.** Resolve the direct conflict ith the coal unloading structures, equipment and open storage adjacent to the Main Steam Plant
- **2b.** Resolve the at grade intersection with the rail spurs
- **2c.** Resolve safety problems on steep switchback ramp
- **2d.** Resolve conflicts with existing and future coal handling at the Southeast Steam Plant
- **2e.** Resolve the lack of visibility and conflict with cars at the blind corner adjacent to the coal bunker.
- **2f.** Consider an alternate alignment with a raised parkway bridge.
- **2g.** Consider an alternatge ramp structure
- **2h.** Remove the Main Steam Plant building only which would allow ramp access from the upper level to the river edge.

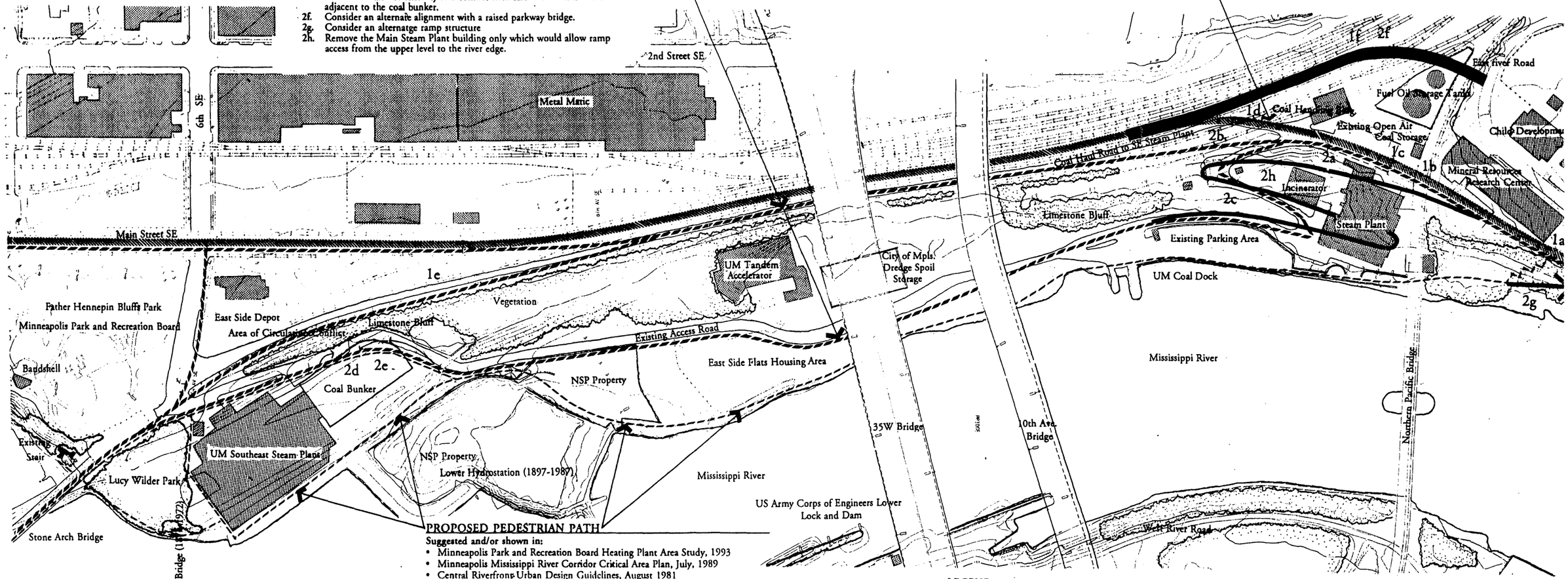
PROPOSED MOTORWAY

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Central Riverfront Open Space Master Plan, 1977

Feasibility:
An at grade Park Motorway as shown in the studies above and consistent with Minneapolis Parkway Reconstructions is not feasible unless the following conditions are resolved or an alternate route to avoid between East River Road on the University Campus and SE Main Street is proposed:

- **1a.** Resolve lack of space at corner of the Mineral Resources Research Bldg.
- **1b.** Resolve at grade intersection with rail corridor
- **1c.** Resolve direct conflicts with coal handling and storage
- **1d.** Resolve at grade intersections with rail spurs
- **1e.** Resolve conflict with coal haul road
- **1f.** Consider an alternative route around and over the conflict area.



PROPOSED PEDESTRIAN PATH

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Minneapolis Mississippi River Corridor Critical Area Plan, July, 1989
- Central Riverfront Urban Design Guidelines, August 1981
- University of Minnesota Mississippi River Corridor Critical Area, Sept. 1979
- Central Riverfront Open Space Master Plan, 1977
- Southeast Minneapolis Riverfront Plan, May 1976
- Mississippi/Minneapolis - A Plan for Riverfront Development, 1972

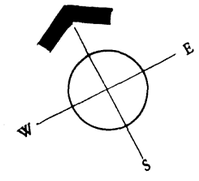
Feasibility:
The development of a pedestrian path as shown in the studies above is feasible and would not require any alteration of the existing steam production facilities.

The development of a pedestrian path would require the following action:

- a significant stairway would need to be constructed to connect the path vertically from below the Mineral Resources Research Building to East River Road.
- a walk along the river side and stair connection along West side of the Southeast Plant
- the path would not be entirely ADA accessible with stairs

LEGEND

- Proposed Motorway
- Proposed Bikeway
- Proposed Pedestrian Path
- Alternate Raised Parkway
- Alternate Bicycle Ramp



Scale: 0 100'

James Robin
Landscape Architect
23420 Park Street
Excelsior, Minnesota
55331
612 / 474-3946

I hereby certify that this plan, specification or report was prepared by me or under my direct supervision and that I am a duly Registered Landscape Architect under the laws of the State of Minnesota.

Name:

Registration No. 1220 Date: 30 AUGUST

TRAIL and MOTORWAY FEASIBILITY ASSESSMENT

26 August, 1994

Other Modifications

- Widening the access road below the Mineral Resources Research Building, which could involve razing the building.
- Negotiating easements with the railroads and reconfiguring track alignments
- Reconciling the at-grade intersection with a future potential use of the Northern Pacific Bridge.

Alternatives 4, 6, and 7 Allow at-grade Motorway

These modifications would only be possible under Alternatives 4, 6, and 7. Alternative 3, although enclosing the coal operations, does not allow room for an at-grade motorway or trailway.

Other Solutions Are Possible, Including Bridge or Underground Space

Alternatively, a bridged parkway route over the coal/fuel facility may be feasible, but such an alternative would require civil and transportation engineering feasibility studies prior to implementation -- and a multi-million dollar capital investment-- if the concept proved feasible.

A third possible solution involves using "cut and cover" construction to develop underground space for coal delivery, storage, and transport (coal transport from the Main Plant area to the Southeast Plant would be in the existing tunnel). This approach would allow the proposed at-grade motorway, and would also provide riverfront access for residents of nearby Sanford Hall and Dinkytown. The use of underground space, while technically feasible, would probably require such a gradual slope to accommodate the heavy coal-trains that the cut section would have to begin 2,500 feet or more back to the east. There are also numerous underground pipelines, tunnels, and lines in the area that would create difficult conflicts to resolve.

If feasible technically and financially, both the bridge and the trench concepts for crossing the coal/oil storage area would be possible under any of the alternatives or the proposed project.

Barring Changes, Main Steam Plant Coal Storage Operation Precludes Most Bikeway Development

The plans propose two bikeways along the riverfront between the two steam plants. An upper bikeway would follow the existing coal hauling road along the top of the bluff. A lower bikeway would follow the alignment of the existing access road through the Dam Flats area.

Barring changes, the continued operation of the Main Steam

Plant and of the existing coal storage and handling facilities would preclude development of both "upper" and "lower" bikeways.

Major Modifications Required for "Lower" Bikeway Route Under Any Alternative

Both bikeways would be possible if a connection to the University via East River Road were located along the lower access road alignment of the Mineral Resources Research Building. The proposed upper bikeway alignment, however, goes directly through the current coal handling and storage areas and would not be feasible if the coal handling and storage facilities were to remain in the current location. Bikes could then use existing road alignments as shown in Figure 14. And, as described below, expensive modifications would likely be required near both the Main Plant and Southeast Plant in order to make the "lower" route safe for bicycle traffic -- whether the coal handling remained in its existing location or not.

Modifications necessary to make the bikeways possible include:

Steam Facility Modifications

- Relocating or eliminating Main Plant coal unloading and storage area;
- For "lower" bike trail, expensively modifying or demolishing Southeast Plant coal bunker to provide safe line-of-sight on the trail alignment, given that continued vehicle access to the Tandem Accelerator Facility (and, if necessary, to the ash storage area) would be required;
- Redesigning or eliminating coal truck operations so as not to conflict with safe bikeway alignment.

Other Modifications

- Acquiring easements from the University and the railroad
- Resolving conflict with future potential use of the Northern Pacific Railroad Bridge.

Even with coal handling removed, the existing road from the Main Plant to the riverfront is too steep to be safe for bicycle use. Significant modifications of the lower alignment along the bluff would be required to improve safety. (See Figure 15, a photograph of the existing Main Plant access ramp to the riverfront.)



Alternatives 4, 6 & 7 Eliminate Coal and Allow Proposed Bikeway

The listed modifications would only be possible under Alternatives 4, 6, and 7. (See Figure 5 above for computer image of Main Plant area with coal handling gone and bikeway added.)

Alternative 3 includes the use of coal, but uses a totally enclosed above-ground coal unloading, storage, and delivery system. Although this design would minimize the "footprint" necessary for coal storage, the analysis completed for this report indicates that space limitations would still preclude an at-grade motorway or bikeway through the existing coal handling area. Therefore, while enclosed coal handling facilities would eliminate fugitive dust problems, they would still preclude the "upper" access routes because of lack of space.

Alternative 4 would require the fuel oil tanks to remain in their existing location. No other sites for the tanks were found during the concept level assessment completed for this report. (Additional tanks for number 6 fuel oil would also be required. These tanks could be located near or within the Southeast Plant coal bunker.) Leaving the existing fuel tanks, but removing the coal handling, would provide room for bikeways and pedestrian paths, but the fuel tanks could still diminish the overall aesthetics of the trailway.

An alternative Lower Bikeway is Possible if Main Plant Removed.

Demolishing and removing the Main Plant and incinerator facilities (which is possible under both proposal options and all alternatives) could allow construction of the alternate "lower" route bike ramp shown, but that would require significant funding. On the other end of the riverfront, the impact of the continued use of the Southeast Steam Plant itself on a lower bikeway is primarily confined to the line-of-sight conflict at the coal bunker.

Steam Plant Operations Do Not Affect Proposed Pedestrian Pathway

The proposed pedestrian pathway could be developed without altering existing steam plant operations and is therefore compatible with all options, but a significant investment would be required to overcome the topographical obstacles posed by the bluffs.

A steep stairway would be required to connect the path vertically from below the Mineral Resources Research Building to East River Road and a walkway along the river side and stair connection along west side of Southeast Plant would have to be constructed. The path would not be entirely ADA accessible. Easements from the University and NSP would be needed.

Theme 3: Preferred Land Uses Discourage Industry

Plans Agree that Industry not Dependent on River Location Should Move

The plans generally agree that industry that may be harmful to the river or is not dependent upon a river location should be phased out of the area. The *Mississippi River in Minneapolis* report, for example, stated that any facilities which did not require a location near the river should not be permitted to occupy valuable river frontage.

The *Mississippi/Minneapolis Plan* (1972) noted that industry should be phased out except for hydropower and "high employment" industry that offered a large number of jobs to nearby residents.

The *Minneapolis Critical Area Plan* (1989) recommended that the City establish a special riverfront-related land use category that would include industries providing strong tax revenues and requiring a riverfront location.

Steam Plants Not Dependent on River Location

Since their coal supply no longer arrives by barge but comes exclusively by rail, neither the Southeast Plant nor the Main Plant is dependent on a river location. Nor does either plant provide large numbers of jobs to area residents or high tax revenues. By these criteria, the continued use of the steam plants is not compatible with City of Minneapolis plans for the riverfront area. However, some specific plan provisions contradict this general conclusion.

Metro 2000 Plan Excepts Power Plants

For example, while the Metro 2000 plan lists open space as the priority for the riverfront, with residential second and nonresidential uses subordinate. it states that exceptions to this are the "powerhouses" (presumably NSP, the Southeast Plant, and perhaps the Main Plant), the Post Office, Mill Place, Riverplace, and St. Anthony Main.)

It is possible that the continued operation of the Southeast Plant could enhance the character and experience of the riverfront if conflicts can be resolved through creative solutions. Despite the many plans for the riverfront, there have been few feasible proposals for the joint use of the Southeast Plant facility, except the control room interpretive site concept described earlier.

Theme 4: Remove Railroad Tracks Where Possible

Plans Anticipate Removal of Railroad Tracks

The plans also anticipate that railroad tracks in the area would eventually be removed. The Mississippi/Minneapolis plan notes that all railroad tracks are expected to be removed from the area as industrial activity is reduced, except for the tracks leading to the Stone Arch Bridge and the Burlington Northern railroad bridge south of 10th Ave. The City's Critical Area Plan states that railroad spurs that don't serve river terminals should be eliminated and landscaped.

At this point, Burlington Northern does not plan to discontinue service on the rail corridor behind the project site as long as businesses in the area need rail service. The rail line serves Pillsbury and the University power plants. The rail line terminates at the Pillsbury mill.

Section 9.6 Special State and Federal Programs for the Riverfront

Compatability with Critical Area Plans

State Critical Areas Act Program Enacted To Protect Areas of State-Wide Value

In 1973 the Minnesota Legislature passed the Critical Areas Act to protect areas possessing greater than local significance from being damaged by development.

If the governor, acting on the recommendation of the Environmental Quality Board (EQB), designates a critical area, local governments with jurisdiction in that area must make their own plans and official controls consistent with regional objectives and with the provisions of the designation order.

The Mississippi River corridor from Ramsey to south of Hastings is one of only two designated Critical Areas.

Since both the University of Minnesota and the City of Minneapolis are governmental units under the Act, each has adopted Critical Area Plans.

University Plan States Plants Planned for Continued Power Use

The University's Critical Area Plan designates the Southeast Steam Plant and Main Plant sites for power/heat generation. Most of the Dam Flats area is shown as recreation/open space (excluding the physics lab).

University Critical Area Requires Additional Review of Developments

The University's Critical Area Plan establishes special site plan requirements which include: (1) site plans should maximize opportunities for open space and public viewing of the river; (2) site plans should contain conditions for buffering, landscaping, and revegetation; and (3) locations of improvements should be sensitive to riverland and bluff disruption and interference with views.

Project Will Meet Some of Critical Area Site Plan Requirements

Comparing the steam plant renovation project to these three requirements, it can be concluded that while the proposal is not specifically in conflict with any of them, it does little to further their goals. There are no specific plans in the proposed project to maximize opportunities for open space and public viewing of the river. The plans are considering some buffering but generally little of the vegetation and landscaping around the plants will change from current conditions.

The plans include no additional bluff disruption and the proposed addition to the Southeast Plant's roof will have little interference on river views. Regarding the first requirement especially, some of the alternatives would create more opportunities for public viewing of the river and for riverfront recreation, as discussed in previous sections of this chapter.

Project Does Not Encourage Use of Identified Scenic Viewing Spot

The transportation policy in the plan states that "access will be made available where appropriate for the construction of scenic overlooks and/or to encourage public access to riverfront lands." The Open Space and Recreation Plan section identifies scenic viewing spots and proposed and existing trailways. Good distance views are identified from the southwest corner of the Southeast Plant building and from the Dam Flats area between the former NSP plant and the I-35W bridge. The plan states that such views should be preserved and their utilization encouraged. While the current proposed project does not destroy these view sites, it also does not meet the goal of encouraging the use of these sites.

The Open Space and Recreation map in the plan shows a trail extending from Main Street across the railroad tracks under I-35W and 10th Avenue bridges and down to the river's edge at the Main Plant. The feasibility of this trail is discussed above in section 9.5.

Project Conforms with Minneapolis Critical Area Plan for Bluff Protect and Greenway Window

The City of Minneapolis Critical Area Plan identifies St. Anthony Falls as the focus of the City's efforts to rediscover and redevelop the riverfront.

The Plan includes policies to maintain water flow at the falls and to protect the bluffs and vegetation. Since the proposed renovation to the Southeast Plant would not change the footprint of the building, the renovation should have no new effect on the bluffs or vegetation. Any changes to access routes or storage facilities would have to be designed to conform to these policies.

The plan also provides that, wherever feasible, lateral access routes or greenway windows to the river should be provided. This would include a greenway window along 6th Avenue SE to a scenic observation area on the north side of the Stone Arch Bridge. The operation of the Southeast Plant would not interfere with the development of this window, although the presence of the Southeast Plant directly at the foot of 6th Avenue SE detracts from the view of the river along the approach to the viewing area.

The Minneapolis Critical Area Plan, which includes a larger planning area than the Central Riverfront or St. Anthony Falls Plans, calls for a continuous trail corridor for motorists, pedestrians and bicyclists along both sides of the Mississippi River. These aspects of the Minneapolis Critical Area Plan is discussed in section 9.5.

Industry in Riverfront Must Need River Location

The plan recommends that the City should establish a special "Riverfront Related" land use category. Among the activities that would be appropriate within this category is industry that provides a large amount of tax dollars, enhances the riverfront amenities, and requires river water for its industrial activities. As discussed earlier, the Southeast Steam Plant and Main Plant use coal delivered by rail exclusively and do not require the river for their industrial activities.

Compatibility with Mississippi National River Recreation Area Plan (MNRRA)

MNRRA Goal to Preserve and Enhance Significant Resources

In 1988, Congress created the Mississippi National River and Recreation Area (MNRRA) for the 72 miles of Mississippi River and four miles of Minnesota River in five Minnesota counties from Ramsey to Hastings. as a unit of the national park system. MNRRA identified a national interest in protecting and enhancing the historical, recreational, scenic, cultural, natural, economic, and scientific resources of the Mississippi River corridor in the Twin Cities.

The MNRRA plan establishes conceptual policies concentrating on corridor-wide issues. With the exception of National Park Service development, the plan does not address site specific issues.

MNRRA Offers Monetary Incentives

The MNRRA legislation does not provide regulatory authority. The MNRRA legislation authorizes matching grants of up to 50% of the cost for development of lands by others in the corridor if the development is consistent with the MNRRA plan. Within one year after approval of the plan, a framework for the grants program will be developed.

Several Policies Apply to Renovation of Southeast Plant

The MNRRA plan concentrates on new development in the corridor. Existing development is not expected to be substantially changed by this plan, and the plan would not discourage existing land uses in the corridor from expanding existing facilities if the expansion were consistent with resource protection policies and site development policies.

Policies that might apply to the renovation of the Southeast Plant include:

Provide uninterrupted vegetated shorelines where practical except for downtown areas and existing commercial and industrial areas.

Since the Southeast Plant is in a downtown location, the requirement for uninterrupted shoreline would not necessarily apply. In addition, the proposed project would not expand industrial use along the shoreline beyond what is already existing.

When expanding existing uses located in the shoreline and 40 feet back from the river, expansions should be located as far

back from the shoreline as practical and consistent with existing uses.

The expansion to the Southeast Plant will be upward and does not violate this policy.

To reduce visual impacts and protect views of the river, buildings within 200 feet of the river should be no higher than 30 feet. However building heights are set in local critical area plans and they would be higher in downtown areas.

The proposed renovation of the roofline of the Southeast Plant exceeds this height guideline. However, due to its location in a downtown area, the guideline may not be applicable.

Continue the historic use of historic properties, particularly where interpretation of history themes is planned, in preference to changing the use, even though the change might be compatible with the historic character of the resource.

The proposed renovation of the Southeast Plant is compatible with this.

Rehabilitate historic structures and landscapes for contemporary uses if they cannot adequately serve in the current condition, and if rehabilitation would not alter integrity or character.

The project proposes to renovate an historic structure. The University has already begun discussions with the State Historic Preservation Office to develop a design that will minimize alterations to the integrity of the existing building. Some of the alternatives (3,4,6, and 7), however, would avoid the need to alter the historical building.

Compatibility with Further Policies Discussed Elsewhere

Further policies include providing bicycle and pedestrian trails to connect the river with downtown, encouraging compliance with air quality standards, and reducing runoff. These issues are discussed in section 9.5.

Compatibility with Shoreland and Floodplain Ordinances

University's Critical Area Plan Requires Consistency with Floodplain Policies

Due to the University's unique status within the state (see discussion above), it is not clear whether the shoreland and floodplain ordinances applicable to the surrounding area affect properties owned by the University. The University reports that in the past it has not sought state or local shoreland and floodplain permits for University projects.

However, the University's Critical Area Plan states that for floodplain areas the University's development policies will be consistent with city and state floodplain management policies and that all city, state, and federal standards in force for construction in floodplains and floodways will be observed.

Proposed Project Complies with Some of Floodplain Guidelines

Alterations or additions to existing buildings or structures may be permitted if such will:

- Decrease the flood damage potential of the structure
- Not increase the obstruction to flood flows
- Provide for adequate protection to flood protection elevations (one foot above the regional flood)
- Not endanger human life

A portion of the Southeast Plant is in the 100 year floodplain. The project does not alter the footprint of the building and will not increase the obstruction to flood flows.

The proposal does not include any specific measures to decrease the flood damage potential of the structure.

Actions taken previously may provide for adequate protection to flood protection elevations. The Southeast Plant is located between two sets of dams and locks which are part of the St. Anthony Falls Upper Harbor Project. The pool between these two sets of dams and locks is maintained at a near constant level by the U.S. Army Corps of Engineers. Even at the peak of the 1993 flood, the pool remained within its usual limits. High river flows alone do not present a problem.

Steam Plants a Conditional Use by Shoreland Standards

The Southeast Plant is also within the Shoreland Zoning District. The Shoreland Management law and regulations establish standards for land use in the shorelands of public waters of the state. Local governments are required to adopt shoreland management controls that include the state standards.

Applicable standards include:

- Prevention of erosion or other pollution during and after construction

During construction of the proposed project, a number of existing river intake and discharge conduits, which are no longer in use, will be permanently sealed off. A discussion of runoff from the plant and air quality is included in Chapters 6 and 7.

- Limiting visibility of structures from the water

The Southeast Plant is already fully visible from the river, although the increased roof height of the proposed project (and Alternative 1) would create an even larger structure visible from the river.

- Adequacy of water supply and on-site sewage treatment

Since the Southeast Plant is an established operation in an urbanized area, on-site sewage treatment and water supply are not issues.

Section 9.7 ST. PAUL CAMPUS

Existing Land Use Includes Daycare, Student Housing, University Campus

Current land use around the St. Paul Plant includes student housing to the west and southwest of the plant and a daycare center adjacent to the southwest corner of the steam plant property. The University Physical Plant Building is immediately to the east of the steam plant, and the Minnesota State Fairgrounds lie east of that. On the north across Commonwealth Avenue are various University buildings such as the Veterinarian Diagnostic Laboratory and Veterinarian Services Building. (See Figure 3).

Daycare and Housing Most Likely To Be Impacted

The land use impact of the proposal and alternatives on the St. Paul campus is minimal. No superior alternative sites have been identified, and the only alternative that might eliminate the requirement of any on-campus steam plant is the purchase of steam from an off-campus facility. This alternative was not studied in detail because of cost and potential environmental problems.

Therefore, the only major impacts at the St. Paul facility are environmental. The main impact from the plant in this area is from fugitive coal dust on the nearby daycare (see Figure 16. Photograph of St. Paul Coal Storage Area From Adjacent Daycare Building). Other potential impacts include degradation of water quality in the nearby drainage ditch and wetland from ash runoff or grounwater contamination.

Although the coal pile was reduced recently and dust levels are apparently within regulatory limits, residents of the adjacent housing and daycare employees did complain about recent annoying coal dust problems.

However, as proposed, the University would primarily use existing coal boilers for backup use only, and it is therefore expected that coal use, coal dust, and ash related impacts at this plant would be substantially reduced compared to current conditions. Since the coal pile would not require frequent working , the amount of coal dust generated could probably be controlled adequately by compaction and spraying.

Another possible resolution to the conflict between the day care location and the steam plant would be to relocate the day care somewhere else within the student housing complex.

Alternative 13, which eliminates even the storage of coal on-site,



would eliminate all impacts associated with coal dust, coal handling, and any impacts due to runoff.

Another potential impact to surrounding land uses is noise from the plant's operation. Electrical cogeneration is not proposed currently for this campus, and high pressure at startup was found to be the largest source of noise during recent monitoring at the Southeast Plant (See Chapter 6).

Falcon Heights Has No Regulatory Authority Over University

The St. Paul Plant is located within the City of Falcon Heights. Approximately two-thirds of the total area of Falcon Heights is comprised of University of Minnesota lands and the Minnesota State Fairgrounds. Falcon Heights' Comprehensive Plan states that "Though it is within the City's limits, the University is autonomous." The city has no regulatory authority over the University's land so long as the land is used for its intended public purposes.

While the city has no direct authority over the University, its plan indicates a wish to influence future institutional policy directions of the University to reflect the city's best interests. The city's land use plan shows the power plant site and the University area surrounding it as "Institutional" usage. The plan sets a policy to work with the University to keep informed of any significant changes to long range development plans and encourage the University to expand its physical plant south of Larpenteur rather than in open land.

University's Plan Shows Plant Remaining

The University of Minnesota's Long Range Development Plan for the St. Paul Campus was adopted in December 1971 and revised in June 1972. This plan shows the heating plant and physical plant management buildings remaining in their current location. The area around these two uses is identified as suitable for academic, housing or commercial uses (to the south, east and west) and housing academic, commercial or transportation to the north. The plan also identifies a narrow band of natural area and wildlife habitat to the east of the site (east of the physical plant) connecting to wetlands south of the site.

The University's plan suggests "zoning" the area for plant services. The plan also states that consolidating plant services at this location should be considered as permanent (suggested zoning for some other land uses are considered more flexible). The ten-year framework plan shows what appears to be some buffering to be built around the existing plant.

Chapter 10. Mitigation

Introduction

Three categories of mitigation and control measures that may lessen environmental, land use, or socioeconomic impacts of the proposed project or its reasonable alternatives are described and analyzed in the following sections.

- Section 1. Demand and energy reduction
- Section 2. Cogeneration
- Section 3. Environmental
- Section 4. Foster Wheeler contract options

Section 10.1. Demand and Energy Reduction

In 1989 the University Building Energy Efficiency Project (UBEEP) was initiated by the Minnesota Building Research Center. The objective of this program was to lower current and future energy use by managing and coordinating campus-wide energy conservation efforts. The Board of Regents approved the initial 5 year plan and startup funding. The goal of the UBEEP was to initiate programs that would result in a savings of 30% in energy consumption. It is anticipated that savings of 30% in energy consumption would translate to approximately a 15% savings in energy demand. Reduced energy consumption lowers fuel costs and other variable operation and maintenance costs. Reduced peak demand delays the need capital required for new capacity.

The following are energy conservation projects initiated by UBEEP to date:

- Steam trap and radiator valve repair/replacement
- Fluorescent lamp replacement
- Fan operation strategies in multi-use buildings

The University estimates that they have reached approximately one-half of the 30% energy savings goal.

Resultant University of Minnesota Energy Use Consistent With Other Institutions

As a result of the UBEEP effort steam consumption has been significantly reduced from an estimated 142 pounds per square foot in FY 1990. Steam consumption is now more consistent with other institutions.

The steam consumption for the Minneapolis campus was calculated at 108 pounds of steam per square foot and 146.9 pounds per square foot for the St. Paul campus by OSM for the University of Minnesota in their December 6, 1993 *Energy Benchmark Study*. The study included the University, and the following unidentified institutions; one medical complex, two industrial facilities, and three post secondary educational institutions. The thermal energy benchmark (average of steam consumption from the benchmark institutions) was calculated to be 106.8 pounds of steam per square foot. Thus, OSM claims that the average steam consumption for heating the Minneapolis campus (at 108 pounds per square foot) is about 2% above the thermal energy benchmark and the steam consumption for heating the St. Paul campus (146.9 pounds per square foot) is about 38% above the thermal benchmark of the study. OSM

suggests that steam consumption for greenhouses located on the St. Paul campus partially explains the significant difference between the St. Paul campus and the Minneapolis campus. As an institution, the University's steam consumption is 115.2 pounds per square foot or approximately 8% higher than the study thermal energy benchmark according to the OSM study.

Projected University Conservation Would Reduce PV Operation and Maintenance Cost of Project and Alternatives

The University is projecting additional conservation results from continuing UBEEP and other efforts. The University projects their steam load to decrease during FY95 by 6.06% and during FY 96 by 6.54% as a result of their conservation efforts. However the University has not quantified the investment required to accomplish the projected reductions.

If these conservation efforts are unsuccessful, the present value operations and maintenance costs (25 years, 6% discount rate) for the proposed project and alternatives would be higher than under the University load projection. Table 1 below identifies the present value operations and maintenance costs for the project and each combination of alternatives for the planned conservation and no conservation scenarios. The costs shown include fuel and are net of cogenerated electric value. The supporting documentation for this table is contained in the Dahlen, Berg & Co. July 29, 1994 report *Financial Projections for the University of Minnesota's Steam Supply Alternatives*. The present value difference in operation and maintenance costs between the University projected load and a no conservation projected load is highest for Case A because Case A has the highest marginal cost for steam.

Table 1. Present Value Operation and Maintenance Costs ($ in Millions)

	Conservation	No Conservation	Difference
Alt. Nos. 1 &11	265.6	276.4	10.8
Alt. Nos. 3 &13	294.7	315.4	20.7
Alt. Nos. 4 &13	321.4	345.1	23.7
Alt. Nos. 6 &13	271.3	295.3	24.0
Alt. Nos. 7 &13	321.4	345.1	23.7
Case A	325.5	353.1	27.6
Case B	314.6	340.6	26.0

Replacement of Existing Building Absorption Chillers with New Central Steam Chilled Water Production Units Has Benefits

Adsorption Chillers were installed in many buildings constructed in the early 1960's. Many of these are nearing their effective life and are inefficient, use CFC-11 or CFC-12, and may soon need to be replaced. It is likely that the older chillers will be replaced by more efficient energy centralized units. However, the continued use of steam rather than electricity for chilled water production is necessary to reduce electricity use. Use of steam chilled water production has a direct relationship to the amount of cogenerated electricity. Combining more efficient steam chilled water production units with a district cooling system also has several benefits. A February 22, 1993 study by Ellerbe Becket, Inc *Recommendations for the East Bank Chilled Water System Planning Process* recommended that interconnecting piping with the addition of capacity via a central or satellite plants would appear to be the best means of minimizing capital, maintenance, and energy costs.

The University is planning to interconnect buildings with absorption chillers in a chilled water piping loop although no current construction has been authorized. This allows the equipment to be used more effectively since peak cooling needs for buildings may not occur at the same time. Energy consumption for chilled water auxiliaries, pumping and cooling tower fans, would be reduced.

Conversion to a Hot Water Distribution System Would Conserve Energy and Could Facilitate a Large Metro Thermal Network

Implementing central chilled water production and distribution systems would facilitate converting the campus steam distribution system to hot water since steam would no longer be required at each building.

Further environmental and socioeconomic benefits may result from converting the campus piping system that distributes steam to the various buildings for heating from steam to hot water

Most buildings constructed in the United States after the 1960's utilize hot water rather than steam to distribute heat within a building. Hot water building systems can be more precisely controlled than steam systems and thus save energy. Converting a building from steam to hot water involves improvements to the entire heating system. Experience in Minnesota has demonstrated 20-40 percent savings resulting from converting building heating systems from steam to hot water. The University of Minnesota has minimized the number of buildings that still use building steam heating systems. There are approximately 225 buildings in the University Campus that are heated and maintained for human occupancy. Only a few of these still use steam heating systems. The next logical step

would be to convert the existing steam distribution system which delivers energy to each building to a hot water distribution system.

Hot water distribution systems are generally a more efficient delivery system than steam distribution systems. The International District Energy Association September 1994 *Member Profile Study* indicates that for large district heating systems with a total output of 1,500,000 MMBTU or more hot water systems average 98.3% return compared to 52.9% return for steam systems. District Energy St. Paul, Inc is a successful hot water distribution system which serves downtown St. Paul.

A hot water distribution system would also have the socioeconomic advantage of the facilitation of a large metro hot water thermal network. Hot water energy can be transported over much greater distances for less cost than steam. Further, greater electricity production is possible from cogeneration plants producing hot water than cogeneration plants producing steam. Producing hot water from cogeneration plant would have a significant environmental benefit as discussed in Section 2. This large metro thermal network could ultimately provide the heat sink for distributed cogeneration plants burning a variety of fuels. It could also incorporate existing production facilities such as the University's. This large hot water thermal network was originally proposed in *Feasibility of a Large Scale Cogeneration/Hot Water District Heating System in the Twin Cities*, a 1979 study funded by the Oak Ridge National Laboratory. Conversion of the University's distribution system to hot water would be an important step to accomplishing a large scale hot water thermal network.

Section 10.2. Cogeneration

As discussed in Section 2., the University can have an important role in the further development of cogeneration in the Twin Cities. Cogeneration would reduce area-wide air pollution emissions because it would use less fuel to produce the same quantities of thermal and electric energy than would separate facilities operating independently. In cogeneration, thermal energy and electrical energy are sequentially produced from a single fuel source. Energy rejected from one process is used as an energy input to a subsequent process.

The ratio of useful energy output—power plus thermal energy minus in-plant use—to total fuel input is called efficiency.

Cogeneration Plants Would Be Less Efficient Than Thermal-Only Plants But More Efficient Than Electric-Only Plants

The cogeneration plants considered for the University would be less efficient than the thermal-only plants because under cogeneration some energy is consumed when electricity is produced. The generation of electricity is an inefficient energy conversion process. Less than 40% of the total energy input into an electric generation plant is converted to usable electricity energy.

The University's cogeneration plants would, however, be more efficient than NSP electric-only plants because the cogeneration plants would still use most of the waste heat from generating electricity to generate thermal energy. Unlike an electric-only plant, it would not simply reject this extra heat energy into the atmosphere through the use of cooling towers.

The cogeneration plants would have efficiencies ranging from 69% to 75%, and the thermal-only plants would have efficiencies ranging from 77% to 80%. In contrast, NSP's coal-fired electric generation plants have efficiencies ranging from 29% to 36%.

Combined Efficiency of a Cogeneration Plant and an NSP Plant Would Be Greater than the Combined Efficiency of a Thermal-Only Plant and an NSP Plant

The combined efficiency of a University cogeneration plant and an NSP plant used together to meet the University's total energy requirements—both thermal and electric—would be greater than the combined efficiency of a thermal-only plant and an NSP plant.

Table 2 below lists for each campus the plant, NSP and combined efficiency for Case A, Case B, and each alternative. The combined efficiency is the efficiency that would result if the total campus energy requirements were provided by combining the

plant and NSP output for each alternative. (For Minneapolis Case B, the combined efficiency would be the same as the individual plant efficiency because Case B would produce all of the Minneapolis campus energy requirements).

Table 2. Plant Efficiency and Combined Efficiency

	Type of Plant	Plant Efficiency (1)	NSP Efficiency (2)	Combined Efficiency (3)
Minneapolis Campus				
Alternative 1	Thermal	77.4	36	59.4
Alternative 3	Cogeneration	68.7	36	66.5
Alternative 4	Cogeneration	70.9	36	68.5
Alternative 6	Cogeneration	74.6	36	62.4
Alternative 7	Cogeneration	70.9	36	68.5
Case A	Cogeneration	75.4	36	62.9
Case B	Cogeneration	71.5	36	71.5
St. Paul Campus (4)				
Alternative 11	Thermal	77.7		
Alternative 13	Thermal	78.6		
Case A	Thermal	80.2		

(1) Plant performance data is based on fiscal year 1999 as presented in Financial Projections for the University of Minnesota's Steam Supply Alternatives, dated July 29, 1994.

(2) NSP plant performance is based on the Allen S. King plant, one of NSP's more efficient non-nuclear plants.

(3) Combined efficiency is the efficiency that would result if the total Minneapolis campus energy requirements were provided by combining the output from an alternative with the output from an NSP plant

(4) Combined efficiencies are not presented for the St. Paul campus alternatives because none of the alternatives would produce electricity.

Case B Has the Highest Combined Efficiency

As shown in the above table, Case B has the highest combined efficiency. This occurs because Case B has the most cogenerated electricity, providing all of the Minneapolis campus energy requirements. Alternative 1 has the lowest combined efficiency

because it has no cogenerated electricity. Increased fuel efficiency means reduced fuel burned and less air pollution emissions.

Cogeneration at the University Would Result in Decreased Emissions Elsewhere

Cogenerated electricity produced and used by the University would lower regional base-load electricity demand. In response, NSP would most likely lower production at its older coal-fired plants, which are currently its most expensive facilities.

It is, therefore, reasonable to estimate net emissions from cogeneration facilities by subtracting a "cogeneration credit" from predicted point source emissions. This credit is an estimate of the emissions that would have otherwise been produced by the utility plants. The adjustments are not only due to the efficiency benefits of cogeneration, but also due to the lower emissions of new proposed equipment at the University.

The credit given an individual alternative is determined by the amount of projected electricity production and the emission rate assumed for NSP facilities, a number that in turn depends on which NSP plants are assumed to reduce production first. If estimated NSP emissions are reduced, the "credit" given a cogeneration facility would also be reduced.

While estimated emissions can be adjusted for cogeneration, it in not possible to model the effect on ambient air concentrations. Furthermore, there are not any existing mechanisms for enforcing such cogeneration "offsets."

Cogeneration Credits Estimated for SO_2, CO_2, and Hg

Table 3 below shows "predicted" emissions (see Chapter 6) of SO_2, CO_2, and mercury adjusted for NSP generation displaced by cogeneration. NSP generation considered in this analysis included power plants in the seven county metropolitan area and Sherburne County. Results are in tons per year for SO_2, thousands of tons per year for CO_2, and in pounds per year for mercury.

The credit was estimated based on pollutant emissions and electric generation associated with area-wide NSP power plants. The calculation of the cogeneration credit is presented in Appendix A.

Table 3. Predicted Emissions Adjusted For Cogeneration

	Case A	Case B	Alt 1	Alt 3	Alt 4	Alt 6	Alt 7
Sulfur Dioxide (TPY)	-55	-517	491	-375	-496	-75	-496
Carbon Dioxide (1000s TPY)	235	109	303	112	46	226	46
Mercury (lb/YR)	12	-1	19	-3	-12	11	-12

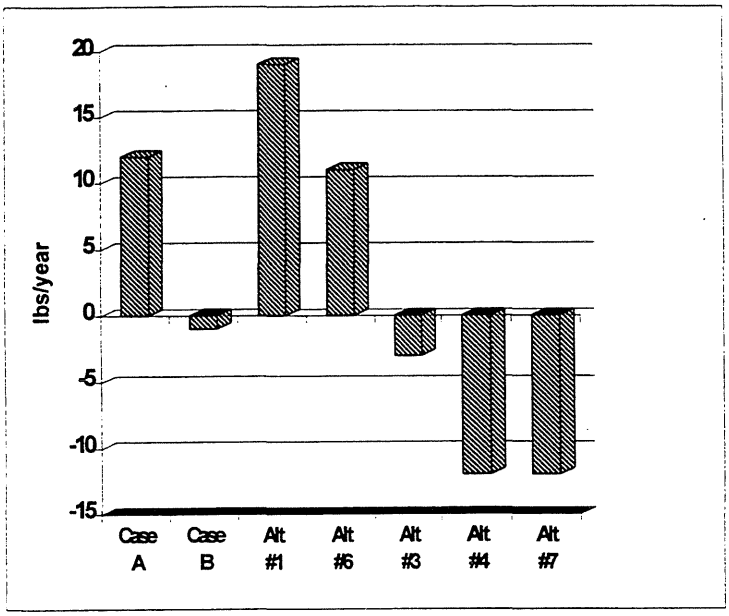
Mercury Emissions Used as Example of Cogeneration Credit Emission Adjustment

Mercury is a pollutant of particular concern because of its ability to bioaccumulate in the food chain. A number of recent studies have indicated that long-range atmospheric transport and deposition of mercury is largely responsible for the elevated concentrations in fish throughout the upper midwest. Therefore, mercury is used here as a "cogeneration credit" example. Cogeneration credits for other air toxics would be a function of the amount of electricity cogenerated and the emission rate estimated for turned-down NSP plants; however, the resulting net emission estimates would vary significantly depending on each alternative's point-source emissions.

Predicted mercury emissions adjusted for cogeneration for 1994/1995 are shown below in Figure 1.

The adjusted mercury emissions shown were calculated using a mercury emission factor of 7.0E-5 lb-Hg/megawatt-hour, based on the following assumptions:

- .06 ppm mercury concentration in utility coal
- 10,440 Btu per kwh
- (Assuming .593 tons coal used per mwh, from 1994-2005 NSP Resource Plan filed with PUC as quoted in *University of Minnesota Evaluation of Steam Service Agreements, 1992*, and 8800 btu/lb low sulfur western coal)



	Emission	Cogen Credit	Net Emission
Case A	17	5	12
Case B	15	16	-1
Alt #1	19	0	19
Alt #6	16	5	11
Alt #3	10	13	-3
Alt #4	1	13	-12
Alt #7	1	13	-12

Figure 1. Predicted Net Annual Mercury Emissions Including Credit for Cogeneration (lb./yr.)

100% Gas/Oil Cogeneration Facilities Have Lowest Net Mercury Emissions

Case B has the largest cogeneration credit applied to it because it is projected to produce the most electricity. This electricity production reduces its direct mercury emissions by 15 pounds, to a net of about minus one pound per year.

Alternatives No. 3, No. 4, and No. 7, which are base-load natural gas facilities, are given credits of approximately 13 lb per year. As a result, mercury emissions from alternative No. 3, which uses existing coal boilers for auxiliary units, are reduced to about negative three pounds per year. The gas/oil only facilities, which have negligible point-source emissions, have net emissions of minus 12 to 13 pounds per year.

Cogeneration credits for the lower electricity production of Case A and alternative No. 6 offset predicted emissions by about 5 pounds.

Results Mostly a Function of Assumed Mercury Concentration in Coal

Note that the same mercury concentration was assumed for utility plants and University coal boilers. Therefore the higher the mercury concentration assumed in coal, the higher the emissions from coal alternatives, the larger the cogeneration credit, and the larger the difference between the coal and natural/gas primary facilities. And conversely, the lower the mercury emissions assumed from coal boilers, the smaller the cogeneration credit.

Section 10.3. Environmental

In this section, we discuss how fugitive dust emissions would be controlled under Alternatives 3 and 6 and how Alternative 3's NO_X emissions could be reduced further, if additional reductions were needed.

Alternatives 3 and 6 Include Coal And Ash Handling Systems Which Would Mitigate Fugitive Dust Emissions

The conceptual designs of the coal burning Alternatives 3 and 6 include $7,000,000 for coal and ash handling systems. Included in the $7,000,000 are three methods that would reduce fugitive dust emissions.

Store coal in enclosures
Transport coal in covered conveyors
Haul ash directly to the landfill instead of storing it on the ground

Store coal in enclosures
Under Alternatives 3 and 6, coal would be stored inside totally covered enclosures instead of in open piles on the ground. By enclosing and covering the coal pile, dust generated during handling would be contained and not released to the environment.

Transport coal in covered conveyors
Coal would be transported in covered conveyors under both Alternative 3 and Alternative 6. Under Alternative 3, which would use some of the existing coal handling equipment, coal would be transported to the Southeast Heating Plant on a new belt conveyor installed in the existing tunnel between the Main Heating Plant and the Southeast Heating Plant. (This would be similar to the $2,400,000 Foster Wheeler contract option which we discuss in Section 5..)

By transporting coal in covered conveyors, the current practice of trucking coal from the Main Heating Plant to the Southeast Heating Plant could almost be eliminated. (Some coal might have to be trucked to the Southeast Heating Plant during extended conveyor outages). Dust generated during conveying by truck would be collected and not released to the environment.

Haul ash directly to the landfill instead of storing it on the ground
Under Alternatives 3 and 6, ash would be loaded once into trucks and transported directly to a landfill. By hauling the ash directly to the landfill instead of the current practice of dumping it on the ground prior to landfill disposal, the ash would be handled less and reduce dust.

Alternative 3's NO_X Emissions Could be Reduced With Additional Controls

Alternative 3's NO_X emissions could be reduced by installing additional controls on the existing coal fired boilers at the Southeast Heating Plant. SO_2 emissions from the existing boilers would be effectively controlled by the existing scrubbers.

We focus our discussion on Alternative 3 because Alternative 3's local NO_X emissions were estimated to be greater than any of the other alternatives and Case A. Alternative 3's NO_X emissions could be reduced over 400 tons per year, by installing selective non-catalytic reduction (SNCR) control systems on each of the two existing Southeast Heating Plant boilers. The installation would cost about $1 million to install and about $191,000 per year to supply the necessary chemicals. Existing burners could be replaced with low NO_X burners to reduce NO_X, however the reduction would not be a effective as with the SNCR control system.

Section 10.4. Foster Wheeler Contract Options

The Foster-Wheeler contract includes six mitigation options:

- Install NO_X control equipment (Denox System on the fluidized bed boiler).
- Construct a wall to partially enclose the Minneapolis Campus ash pile.
- Construct a wall to partially enclose the Main Heating Plant coal pile.
- Install a coal conveyor between the Main Heating Plant and the Southeast Heating Plant.
- Construct ash pile storm water collection system at St. Paul.
- Construct walls to partially enclose the coal pile at St. Paul.

Each option is further described and analyzed below.

The NO_X Reduction System Option Could Reduce NO_X Emissions by 88 Tons per Year

With the NO_X reduction system, Foster Wheeler would inject chemicals into the boiler furnace to react with nitrogen oxides (NO_X) to form nitrogen (N_2), carbon dioxide (CO_2), and water vapor (H_2O).

By exercising the NO_X reduction system option, the University could reduce the fluidized bed boiler NO_X emissions. With an uncontrolled emission rate of 220 tons per year, 88 fewer tons of NO_X would be emitted based on 40% NO_X removal efficiency.

The total owning and operating costs would include not only the $1,170,000 equipment price listed in the *Design and Construction Agreement* (escalated according to the agreement's terms), but also the cost of chemicals and maintenance.

The Minneapolis Ash Screen-Wall Option Would Partially Hide the Pile, and Could Contain Some Runoff, But Would Not Stop Wind-borne Dust

With the Minneapolis ash screen-wall option, Foster Wheeler would construct three walls each 9 feet tall which would partially enclose an area 110 feet long by 110 feet wide. Foster Wheeler would use the adjacent ground embankment for one wall and construct two walls each 110 feet long. The forth wall would be 30 feet long. The 80-foot length without a wall would allow personnel access to load and unload the ash.

The screen wall would partially hide the ash pile from view and could contain some of the stormwater runoff more efficiently than the existing earth berms; however, the walls would not stop wind-borne dust because the proposed ash handling method—

transporting ash in trucks, dumping the ash on the ground to cool, reloading the ash into trucks, and trucking the ash away—would require that the ash be handled too many times.

The primary cost associated with the ash screen-wall would be the construction price listed as $226,000 in the *Design and Construction Agreement*. Of course, the listed price would be subject to escalation according to the agreement's terms.

The Minneapolis Coal Pile Screen-wall Option Would Partially Hide the Pile But Would Not Stop Wind-borne Dust

With the Minneapolis coal pile screen wall, Foster Wheeler would provide two 60-foot tall walls that would form a right angle. One wall would be 90 feet long and the other wall would be 110 feet long.

Although the screen wall would partially hide the pile from view, the walls would not stop coal dust from being blown from the site because dust would still be generated outside of the partial enclosure when coal was transferred between conveyors.

The primary cost associated with the coal screen-wall would be the $624,000 construction price listed in the *Design and Construction Agreement*. Like the other options, the listed price would be subject to escalation according to the agreement's terms.

The Coal Conveyor Option Would Reduce Truck Traffic and Wind-borne Dust

With the coal conveyor option, Foster Wheeler would construct a conveyor in the existing tunnel between the Main Heating Plant and the Southeast Heating Plant.

The coal conveyor option would reduce both truck traffic and wind-borne dust. With the conveyor in place, the current practice of trucking coal from the Main Heating Plant to the Southeast Heating Plant could almost be eliminated. (Some coal might have to be trucked to the Southeast Heating Plant during extended conveyor outages). Not only would this option reduce truck traffic, but this option would also reduce the dusting associated with loading and emptying the trucks. Presumably, dust control measures would be provided with the conveyor to control dusting during conveying operations.

The construction price, subject to escalation, is listed in the *Design and Construction Agreement* as $2,400,000. The total owning and operating costs would include not only the construction price but also the cost of maintaining the conveyor. However, the current labor and maintenance costs associated

with operating and maintaining the coal trucks would be avoided in the future if the coal conveyor option were exercised.

The Ash Pile Storm Water Collection Option Would Reduce Water Pollution at the St. Paul Campus

With the ash pile storm water collection option, Foster Wheeler would provide a system to direct ash pile runoff to a 2,550 gallon fiberglass underground storage tank.

The collection system option would allow solids to settle out and thus would reduce surface water pollution.

The construction price, subject to escalation, is listed in the *Design and Construction Agreement* as $135,000.

The St. Paul Coal Pile Screen-wall Option Would Not Improve Dust Control but Would Partially Hide the Pile

With the St. Paul coal pile screen wall, Foster Wheeler would provide two walls, one 150 feet long and the other 60 feet long. Both walls would slope from 20 feet tall to 10 feet tall. A 60-foot opening would be provided between the two walls to gain access to the coal pile. A cable supported tarpaulin would be provided to cover the opening.

Although the screen-wall would not provide a significant benefit in controlling coal dust, the wall would at least partially hide the pile. At the St. Paul plant, the University intends to burn coal only during emergencies and thus coal would not be handled very often. Because the coal handling system would be effectively shut down, there would be less opportunity for coal dust to be picked up by the wind.

Chapter 11. Economic Feasibility Analysis

The purpose of this chapter is to assess the feasibility of selected EIS alternatives.

The results of an economic feasibility analysis of alternatives to the University's proposed project are described in this chapter. All the technologies used in these alternatives are technically feasible.

The first step in the feasibility analysis was a screening level economic assessment completed on thirteen conceptual level designs (see Chapter 3 for detailed descriptions). On the basis of the screening work, five alternatives were selected for further study. The screening level No Action alternative was also carried into the next phase for comparison purposes.

Details of Economic Analysis Available in four Separate Reports

The detailed economic analysis of the selected alternatives is contained in the report, *Financial Projections for the University of Minnesota's Steam Supply Alternatives, Screening Analysis,* March 25, 1994, by Dahlen, Berg & Co. Other detailed assumptions are contained in the following three reports prepared by Dahlen, Berg & Co. for this EIS:

Fuel Price Projections, dated March 30, 1994

Value of Cogenerated Electricity, dated April 1, 1994

Alternatives to the University of Minnesota's Proposed Steam Service Facilities Renovation, Screening Analysis, dated March 25, 1994.

Economic Feasibility of Cogeneration Controversial.

The University's proposal and all EIS alternatives (except the "No Action" alternative) include some form of electricity cogeneration. The economics of electricity cogeneration at the Minneapolis campus was controversial during the EIS scoping process as well during the University's internal selection process. Therefore, electricity cogeneration is an important part of this economic analysis.

Economic Analysis Presented into Four Sections

This chapter is divided into the following sections.

- Section 1 Summary of Screening Analysis
- Section 2 Additional Work Completed for Phase II Analysis
- Section 3 Present Value Cost Comparison
- Section 4 Fuel Price Projections
- Section 5 Value of Cogenerated Electricity

Section 11.1. Summary of Screening Analysis

Thirteen Alternatives Evaluated in an Initial Screening Analysis

The following thirteen steam production alternatives to the University's proposed project were identified, defined, and evaluated in the *Screening Analysis*.

Minneapolis Campus

Alt. 1a Minneapolis Deferred Construction, Coal Primary
Alt 1b Minneapolis Deferred Construction, Gas and Oil Only
Alt 2b Southeast Plant Natural Gas and Oil
Alt. 2c Southeast Plant 100% Natural Gas
Alt 3 Southeast Plant using Coal with Natural Gas Cogeneration
Alt 4 Southeast Plant without Coal with Nat. Gas Cogenereation
Alt 5 Southeast Plant with Large Cogeneration
Alt 6 New Plant at Alternative Location with Coal
Alt 7 New Plant at Alternative Location without Coal
Alt 8 Main Plant Renovation and Expansion

Combined Campus

Alt 9 Purchase Steam from Third Parties
Alt 10 Interconnect Minneapolis & St. Paul Systems - New Plant

St. Paul Campus

Alt 11 St. Paul Plant Deferred Construction
Alt 12 St. Paul Plant with Cogeneration with Coal
Alt 13 St. Paul Plant without Coal

These alternatives are described in EIS Chapters 3 and 4, and detailed descriptions, including construction cost estimates and operating cost projections, are contained in the appendices to the *Screening Analysis* report. In addition, although it was not considered as a steam production alternative in the *Screening Analysis*, hydroelectric power was discussed as a power production alternative.

25-Year Construction and Operating Costs were Estimated for Thirteen Alternatives

Construction costs, based on the descriptions of alternatives in the *Screening Analysis,* were estimated by John R. Brady and Associates, a professional construction cost estimator. The construction cost estimates are expressed in 1994 dollars. Terminal values were not estimated. However, alternatives with larger construction costs are likely to have higher terminal values than alternatives with smaller construction plans

Operating costs (including fuel) were estimated for each alternative. Operating costs include:

- Fuel
- Labor
- Maintenance
- Insurance
- Water and sewer

Construction Costs High for Coal Plants, Operating Costs High for Natural Gas Plants

The table below shows a comparison of the costs of the alternatives as determined in the screening analysis. The present value costs include construction and operating costs over the period July 1, 1994 through June 30, 2019 discounted at 6% to January 1, 1994.

Alternatives No. 1, 2, and 11 include different fuel scenarios. The "a" designation indicates coal as a primary fuel. The "b" designation indicates natural gas as a primary fuel. The "c" designation indicates all natural gas.

TABLE 1. SCREENING ANALYSIS PRESENT VALUE COSTS

	Construction Costs ($ in Millions)	Net Operating Costs ($ in Millions)	Present Value Costs ($ in Millions)
Minneapolis Campus			
Alt. No. 1a	35.1	182.8	217.9
Alt. No. 1b	35.1	278.8	313.9
Alt. No. 2b	37.3	236.7	274.0
Alt. No. 2c	37.3	366.4	403.7
Alt. No. 3	42.0	193.8	235.8
Alt. No. 4	53.9	221.3	275.2
Alt. No. 5	85.5	237.7	323.2
Alt. No. 6	82.1	162.3	244.4
Alt. No. 7	63.9	219.5	283.4
Alt. No. 8	29.9	237.1	267.0
Combined Campus			
Alt. No. 9	-	505.2	505.2
Alt. No. 10	126.7	246.6	373.3
St. Paul Campus			
Alt. No. 11a	2.1	76.2	78.3
Alt. No. 11b	2.1	110.9	113.0
Alt. No. 12	6.5	81.5	88.0
Alt. No. 13	2.5	103.3	105.8

Minneapolis and St. Paul Costs Must Be Added to Compare to Combined Alternatives

Because some combined alternatives include costs for the both campuses, the costs of the Minneapolis alternatives must be added to those of the St. Paul alternatives, as presented in the following table.

TABLE 2. PRESENT VALUE COMBINED ALTERNATIVES
($ in Millions)

	w/ Alt. No. 11a	w/Alt. No. 11b	w/ Alt. No. 12	w/ Alt. No. 13
Alt. No. 1a	296.2	330.9	305.9	323.7
Alt. No. 1b	392.2	426.9	401.9	419.7
Alt. No. 2a	352.3	387.0	362.0	379.8
Alt. No. 2b	482.0	516.7	491.7	509.5
Alt. No. 3	314.1	348.8	323.8	341.6
Alt. No. 4	353.5	388.2	363.2	381.0
Alt. No. 5	401.5	436.2	411.2	429.0
Alt. No. 6	322.7	357.4	332.4	350.2
Alt. No. 7	361.7	396.4	371.4	389.2
Alt. No. 8	345.3	380.0	355.0	372.8
Combined Campuses				
Alt. No. 9	505.2	505.2	505.2	505.2
Alt. No. 10	373.3	373.3	373.3	373.3

Construction Costs for Alternative 9 Part of Cost of Steam

The $56 million estimated construction cost for connecting the Minneapolis and St. Paul campuses with third party suppliers was assumed to be included in the price of the purchases steam. Although a construction cost estimate was prepared for the screening analysis, the operating cost projection for alternative 9 assumes a market rate for and no capital expenditures.

This cost estimate assumes that peak steam demand would be still be met by an on-campus coal-fired steam plant. The use of natural gas instead as a primary fuel would be significantly more expensive.

Cogeneration Increases Fuel Costs, But Decreases Electricity Costs

Cogeneration of steam and electricity increases the quantity of fuel required and, therefore, the present value cost of fuel. Electrical cogeneration, however, results in an offsetting benefit of decreasing electricity purchases from the local utility. As a result, the *Screening Analysis* estimated that the 25-year total cost of a natural gas, fuel oil cogeneration system that would meet baseload steam demand with turbine "waste heat" (alternative 4)

is about equal to a gas, fuel oil plant without cogeneration capability (alternative 2).

Natural Gas without a Backup Fuel is Costly

If a plant were to use only natural gas, the local natural gas distribution company (LDC) would have to reserve capacity on its distribution system and the interstate pipeline (firm transportation) for the plant's total natural gas requirements. Minnegasco's current firm transportation rate is more than five times as much as its interruptible rate. Reliable steam supply can be accomplished using interruptible transportation, if an alternative fuel can be used when interruptions occur.

Screening Economic Analysis Summarized

The following other general observations can be made based on the results of the screening analysis:

- New plants had the highest estimated construction costs
- Fuel costs had the largest effects on operating cost projections. For alternatives with cogeneration, the value of electricity is the second largest factor
- Alternative 3, a baseload gas/oil cogeneration alternative that uses existing coal boilers as secondary units, had the lowest present value cost of any EIS alternative besides the "No Action"
- The St. Paul campus alternatives that use coal are less expensive than those without coal
- The combined campus alternatives cost more than the separate campus alternatives

Minneapolis Alternatives 1, 3, 4, 6, and 7, and St. Paul Alternatives 11 and 13 Studied in Detail in Phase II.

The three lowest cost alternatives (besides the "No Action" alternative) were alternative 3, 6, and 8. Alternative 8, however, was replaced with Alternatives 4 and 7, which, because they include cogeneration, were projected to be environmentally superior to Alternative 8. The Deferred Construction, or "No Action" Alternative Nos. 1 and 11, were also both included in the Phase II analysis.

Section 11.2. Additional Work Completed for Phase II Analysis

For the Phase II financial projections, the consultants analyzed the University's costs to make them more current than those in previous studies. This section describes the additional work performed for the Phase II analysis.

- More Detailed Construction Costs Prepared
- Operating Cost Projections Reflect Construction Schedule
- Fuel Prices Projected
- Electric Prices Projected
- Operating Cost Categories Expanded
- Sensitivity Analyses Performed

More Detailed Construction Costs Prepared

More detailed construction cost estimates were prepared for each alternative. The estimates were based on detailed conceptual level designs and equipment lists, and on conceptual plant layout and construction drawings which were also prepared for each Phase II alternative. The construction cost estimates also include the University's structuring costs and other contingencies identified by the University.

Operating Cost Projections Reflect Construction Schedule

In Phase II, the operating cost projections reflect the construction schedule for new facilities in each alternative. In Phase I, operating cost projections were based on new facilities for the entire projection period.

Fuel Prices Projected

Fuel prices and escalation rates were projected in a separate EQB report, *Fuel Price Projections*, dated March 30, 1994. Fuel projections were prepared so costs for each alternative would reflect the latest information. Accurate fuel costs are important because fuel costs and escalation rates determine 50% to 70% of the total present value cost of each alternative.

Electric Prices Projected

Electric prices and values were also projected in a separate EQB report, *Value of Cogenerated Electricity*, dated April 1, 1994. That projection was prepared because five of the seven alternatives and Cases A and B include cogeneration.

Operating Cost Categories Expanded

A review of historical University operating costs resulted in two additional operating cost categories: Administrative & General and Supplies. These costs were added to the operating costs of

each of the seven University alternatives.

Sensitivity Analyses Performed

Seven different present value cost scenarios were developed to test the sensitivity of the cost projections to changes in key assumptions (see section 4, below).

Section 11.3. Present Value Cost Comparison

Costs to University for Cases A and B Are Based on University Contracts

In this section, the present value costs of the conceptual level alternative designs developed for the EIS are compared to the University contract options, Cases A and B.

The present value costs to the University for Cases A and B are based on the University's contract for steam supply, which contains detailed designs The University's contract contains technology-specific construction costs and operating and maintenance rates that were designed and negotiated specifically for the construction and operations contemplated under Cases A and B.

Costs for EIS Alternatives Base on the University Constructing and Operating the Plants

The present value cost projections for the EIS alternatives are based on the University constructing and operating the plants. The University's contract was not applied to the EIS alternatives because the contract is technology-specific to Cases A and B.

All of the present value costs, for the University's alternatives, and for Cases A and B, are based on the same steam loads, fuel prices, escalation rates, and scenarios of changes in key assumptions.

Present value analyses show the total costs of alternatives at a common point in time, even while capital investments, operating costs, and operating savings may occur at different times under different alternatives. In this analysis, the present value costs are shown as of January, 1994.

Detailed engineering drawings, construction costs, and financial assumptions are contained in *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, dated July 29, by Dahlen, Berg & Co.

This report contains the following conclusions:

- All University alternatives have lower present value costs than Case A
- All University alternatives have lower present value costs than Case A under each scenario
- Variability of results under the scenarios is larger for some alternatives than it is for others

Costs Projected for Minneapolis Alternatives, St. Paul Alternatives, and Cases A and B

Construction costs and twenty-five years' operating costs were projected for each alternative, including Cases A and B. The alternatives can be grouped in three categories: Minneapolis campus alternatives, St. Paul campus alternatives, and combined Minneapolis and St. Paul campus alternatives. Table 3 shows the projected present value of operating and construction costs for each of the alternatives.

TABLE 3. PRESENT VALUE COSTS OF UNIVERSITY STEAM SUPPLY ALTERNATIVES
($ in Millions)

	Fuel Costs	Non-Fuel Operating	Construction Costs	Value of Electricity	Total Costs
Minneapolis Campus					
Alt. No. 1	95.8	95.0	49.0	0.0	239.8
Alt. No. 3	215.8	92.5	54.1	-110.0	252.4
Alt. No. 4	247.8	87.2	57.1	-110.0	282.1
Alt. No. 6	134.2	80.5	87.9	-39.7	262.9
Alt. No. 7	247.8	87.2	63.6	-110.0	288.6
St. Paul Campus					
Alt. No. 11	36.4	38.3	4.1	0.0	78.8
Alt. No. 13	62.9	33.5	4.4	0.0	100.8
Combined Campuses					
Case A	183.6	175.5	87.8	-33.7	413.2
Case B	253.6	185.2	109.8	-124.1	424.5

Cases A and B Include Minneapolis and St. Paul Operations

The University's Case A and B projects include construction and operating costs for both the Minneapolis and St. Paul Campuses. Although some costs, like the fuel charge and ash disposal charge, can be separated by campus, other costs, like the monthly operating and maintenance charge, cover both campuses. .

All Combinations of University Alternatives Have Lower Costs Than Cases A and B

Since each of the Minneapolis alternatives can be combined with each of the St. Paul alternatives, ten combinations of Minneapolis and St. Paul alternatives can be made from the five Minneapolis alternatives and the two St. Paul alternatives.

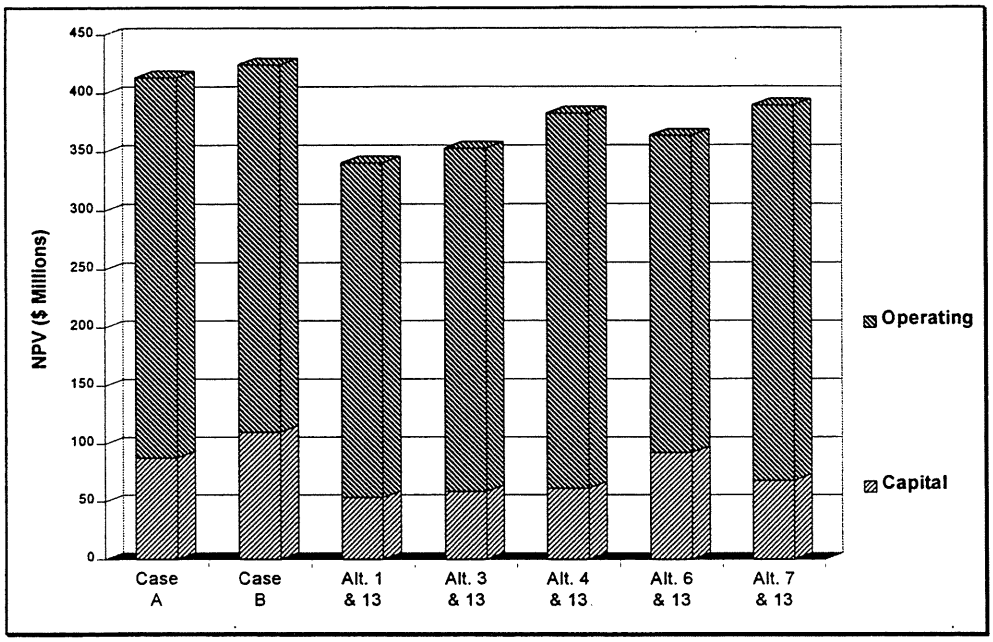
All ten combinations of the University's alternatives have lower projected present value costs than the University's proposed Case A or Case B.

Table 4 and Figure 1 below shows the projected present value costs for the ten combinations of alternatives and for Cases A and B.

TABLE 4. PRESENT VALUE OF COMBINED ALTERNATIVES
($ in Millions)

	Minneapolis	St. Paul	Total
Alt. Nos. 1 & 11	239.8	78.8	318.6
Alt. Nos. 1 & 13	239.8	100.8	340.6
Alt. Nos. 3 & 11	252.4	78.8	331.2
Alt. Nos. 3 & 13	252.4	100.8	353.2
Alt. Nos. 4 & 11	282.1	78.8	360.9
Alt. Nos. 4 & 13	282.1	100.8	382.9
Alt. Nos. 6 & 11	262.9	78.8	341.7
Alt. Nos. 6 & 13	262.9	100.8	363.7
Alt. Nos. 7 & 11	288.6	78.8	367.4
Alt. Nos. 7 & 13	288.6	100.8	389.4
Case A			413.3
Case B			424.4

Figure 1. Present Value Costs of Minneapolis Alternatives and St. Paul Alt. 13, Compared to Case A and Case B ($ Millions)



Use of Coal Results in Lower PV Costs

The combination of Deferred Construction Alternative Nos. 1 and 11 have the lowest projected present value cost; however, that combination of alternatives is projected to have two or more times higher emissions of most air pollutants than Case A or any other EIS alternative.

The combination of Alternatives 3 and 13 have the lowest projected present value cost of the alternatives of alternatives that do not use coal at the St. Paul campus. This combination is projected to cogenerate approximately 3 times more electricity than would be cogenerated under Case A, but slightly less than Case B. Total construction costs for this combination are low because it uses existing Southeast Plant coal boilers (see Chapter 3).

Comparative Cost Rankings Don't Change Under Most Sensitivity Scenarios

Seven different cost scenarios were prepared to test each alternative's sensitivity to changes in key assumptions. Still, under each scenario, all combinations of the University's alternatives have lower projected present value costs than Case A. The following seven scenarios were based on changes in the following key assumptions:

- Price escalation rates: plus and minus 1%
- Discount rate: plus and minus 1%
- Steam loads: high conservation and no conservation
- decrease in the spread between the escalation rates for fuel and electricity

Case B is the most expensive alternative under all but one of the scenarios; when the difference between fuel and electricity escalation rates is decreased by 1%, Case A is the most expensive alternative. This occurs because as the relative value of electricity increases compared to the cost of fuel, cogeneration becomes more valuable, and Case B produces the most electricity of all the facilities assessed.

The seven scenarios and the base case set of assumptions applied to each of the ten combinations of the University's alternatives and to Cases A and B, produce a total of 96 different results. A table showing the 96 results is contained in Appendix B of the report, *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, dated July 29, 1994.

In Scenarios, Low Variability of Results Preferable to High Variability of Results

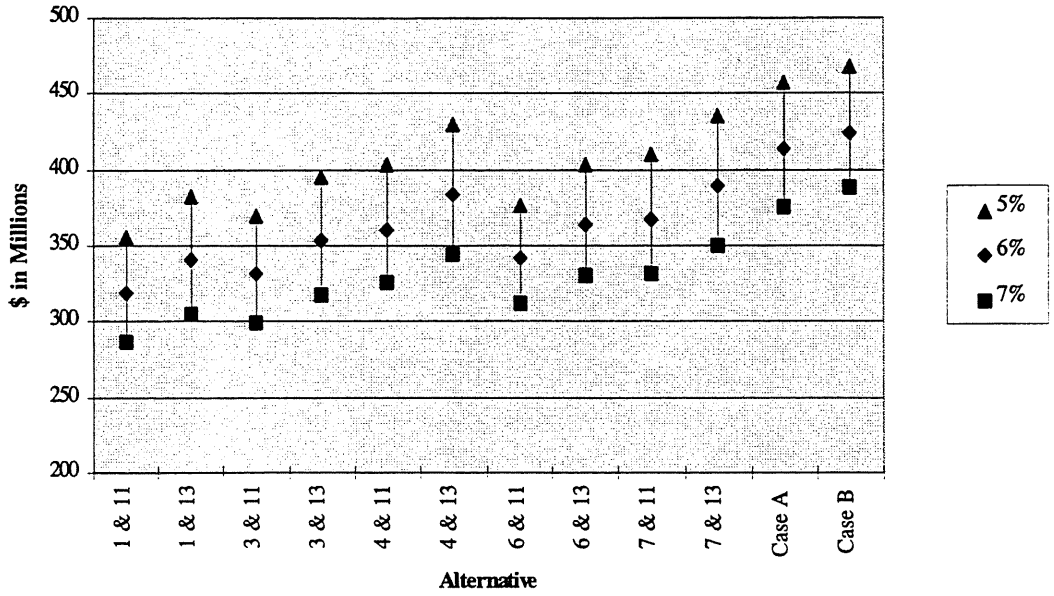
The variability of results under scenarios shows how sensitive the alternatives are to changes in key assumptions. One alternative is preferable to another if its costs remain stable under various scenarios, while the costs of the other alternative fluctuate widely under the same scenarios. In this scenario analysis, key assumptions are changed to show how sensitive each alternative is to that assumption.

The remainder of this section discusses and shows graphically the variability of results under each scenario for all of the University alternatives and Cases A and B.

Changing the Discount Rate Does Not Change the Ranking of the Alternatives

Changing the discount rate in the present value analysis from 6% per year to either 5% or 7% per year does not change the relative ranking of the alternatives. Further, the following graph shows that the variability of results is similar for all of the alternatives under different discount rates.

Scenario 1: Discount Rate

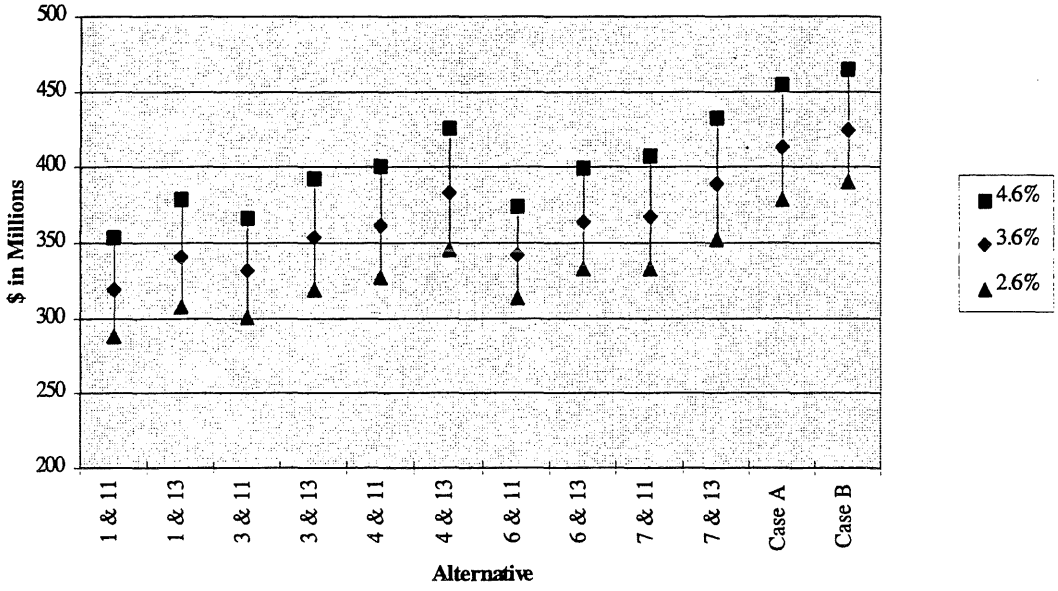


Because the cash flow patterns of the alternatives and Cases A and B are similar, changing the discount rate affects neither the ranking of the alternatives nor the relative variability of the results.

Changing Price Escalation Rates Has Similar Effects on Alternatives

Changing price escalation rates has a similar effect on all of the University's alternatives and Cases A and B. The following graph shows the present value cost projections prepared with a general price escalation rate of 3.6%, plus or minus 1%.

Scenario 2: General Price Escalation Rate



Fuel is the single largest cost in each of the alternatives. Because the fuel prices and escalation rate assumptions are the same in each alternative and in Cases A and B (fuel is a pass-through cost to the University in the contract), changing the escalation rates has a similar effect on each alternative and Cases A and B.

Changing the Steam Load Affects High Marginal Cost Alternatives More Than Others

Changing the steam load assumptions affects the alternatives with high marginal costs for steam more than the alternatives with low marginal costs for steam. The marginal cost is the cost for each incremental Mlb of steam. Therefore, increasing or decreasing steam loads causes larger swings in the total costs of high marginal cost alternatives than in the total costs of low marginal cost alternatives. Or, from an energy planning viewpoint, the higher the marginal cost of steam, the greater the financial incentive to reduce demand.

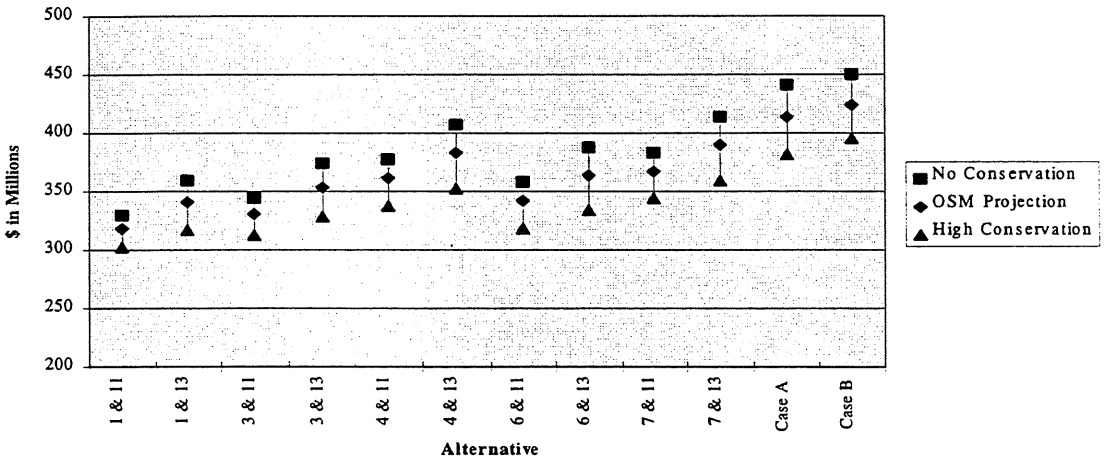
Three steam load scenarios were used in this analysis. The steam load projection used in the base case set of assumptions was prepared by University's consultants, Orr Schelen Mayeron & Associates (OSM), in February 1994. OSM's projection includes a moderate level of conservation and also assumes that in FY 1998 the University's steam load would decline by 220,000 Mlbs because the University's contracts to

supply steam to third party customers would expire and would not be renewed.

The high conservation steam load case is OSM's projection with double the conservation projected by OSM in its base case. The no conservation steam load case is OSM's projection without the conservation projected by OSM in its base case.

The following graph shows the variability of results under the different steam load scenarios.

Scenario 3: Steam Load



Changing the steam load has a relatively small effect on Alternative Nos. 1 and 11 because, with coal as their primary fuel, the marginal cost of production is low. The low marginal cost of production is also reflected in the relatively small cost changes occurring when other alternatives are combined with either Alternative No. 1 or Alternative No. 11.

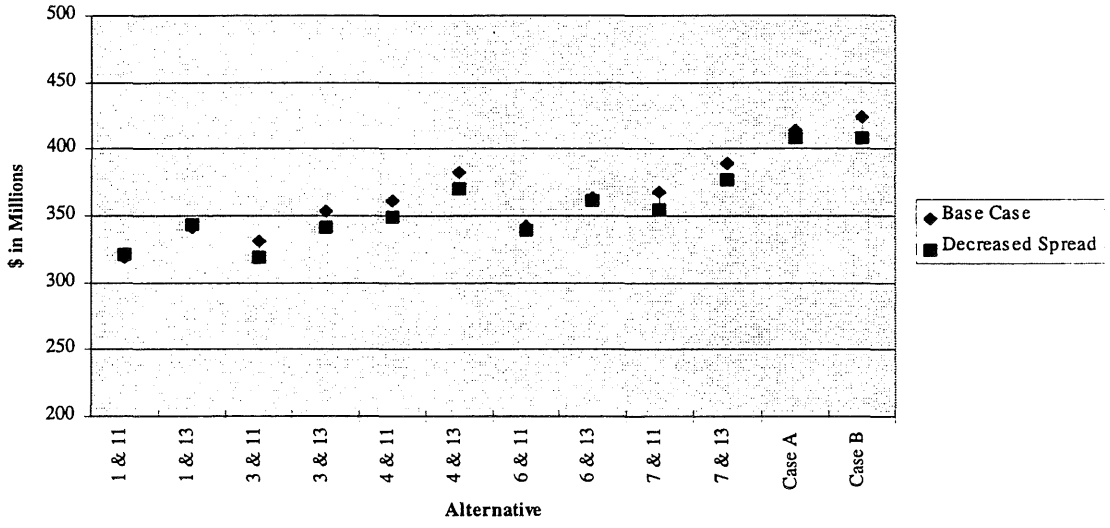
The figure above indicates that Cases A and B have larger ranges of results than do the other alternatives. The larger ranges are a result of Case A's and Case B's higher marginal costs of steam, which include a rate paid per Mlb of steam in addition to incremental fuel costs. Under the other alternatives, no rate per Mlb of steam is paid; only incremental costs for fuel, ash disposal costs, and other operating costs are incurred. Natural gas based alternatives have higher marginal steam costs than primarily coal facilities.

Decreased Spread in Fuel and Electricity Escalation Rates Makes Cogeneration More Valuable

Decreasing the spread between the escalation rates for fuel and electricity makes cogeneration more valuable. In the base case analyses, we used a 2% spread between the escalation rates of fuel and electricity. Because fuel costs are a large part of electric costs and because Northern States Power Company's costs could increase more rapidly than projected, a second scenario was prepared where the spread between the escalation rates of fuel and electricity was decreased to 1%.

Decreasing the spread between the escalation rates for fuel and electricity makes the alternatives that include cogeneration relatively more attractive than those alternatives that do not include cogeneration. Also, alternatives that are projected to generate more kWhs benefit more than alternatives that are projected to generate fewer kWhs. The following graph shows the costs under the two scenarios of fuel and electricity escalation rate spreads.

Scenario 4: Decrease Spread Between Fuel and Electricity Escalation Rates by 1%



Higher Projected Electricity Values Improve Costs of Cogeneration Alternatives

The costs of alternatives that do not include cogeneration increase when the spread between the escalation rates in fuel and electricity is decreased. However, since cogenerated electricity becomes relatively more valuable when the spread is decreased, costs decline for alternatives that include cogeneration. The decline in costs is more pronounced for combinations including Alternatives No. 3, 4, and 7 and for Case B, because those alternatives are projected to generate more electricity than the other alternatives. The overall shifts, however, are small compared to other sensitivity variables.

Section 11.4. Fuel Price Projections

Because fuel costs constitute 50% to 70% of the lifetime costs of any alternative, this section will briefly summarize the work on the fuel-cost component of operating costs. Some major assumptions used to calculate the value of cogenerated electricity are also described.

Fuel Price Projections Valid for this Study Only

Fuel prices, which dominate the operating costs of steam-generating facilities, can change rapidly, with wide swings both up and down, thereby causing tremendous uncertainty in all long-term fuel price forecasts.

The fuel price forecasts in this report were developed using a consistent methodology and reflect a common crude oil price forecast. Because of the uncertainty in long-term fuel price forecasts, however, they should only be used for evaluating alternatives to the University's proposed project. Actual prices will inevitably differ from forecast prices.

Fuel Prices Projected Over 25 Year Period

Fuel prices were projected for 25 years, 1994 through 2018, and were based on the following considerations.

- World Energy Balances
- Supply and Demand for Crude Oil
- Adjustments to Apply to Local Situation

World Energy Balances Adjusted from U.S. Government Data

World energy demand and supply forecasts were based on data supporting the Department of Energy's *International Energy Outlook (IEO) 1993*, the U. S. Government's major annual review and forecast of world energy markets.

World energy demand depends on economic growth, usually estimated as Gross Domestic Product (GDP) and energy-economic efficiency, usually expressed as the Btu's of primary energy used per real dollar of GDP. This government data was then adjusted to take into account the sensitivity of demand to changes in fuel prices, and more recent World Bank projections of world economic trends. All adjustments in government data gave results consistent with other widely accepted sources

Supply and Demand for Crude Oil Estimated

Supply and demand for crude oil was estimated, and price forecasts were checked for consistency with government and

major private energy price forecasts. Prices for specific fuels usable in Minneapolis-area steam facilities were then forecast based on Refinery Acquisition Costs (RAC) crude oil prices.

Prices Adjusted to Apply to Local Situation

Price estimates based on RAC crude oil prices were adjusted to take into account local fuel price quotations, the influence of the dual fuel market, transportation rates for different fuels, possible low sulfur premiums from the Emissions Allowance Market, and gas and oil seasonality adjustments, all of which contribute to determining local burner-tip prices.

Section 11.5. Value of Cogenerated Electricity

The value of cogenerated electricity is the margin between the price of electricity and the cost of generating electricity.

The price of electricity could be either the retail price of purchases that would be offset by cogenerated electricity, or the wholesale price received were the electricity sold.

The cost of generating electricity includes fuel, capital, maintenance. The projected values of cogeneration in this analysis include the cost of backup power.

The projected value of cogenerated electricity is based on baseload operation 95% of the hours of the year.

Value of Cogenerated Electricity Is Higher When Used to Offset Retail Purchases

Since the retail price of electricity is higher than the average wholesale price, the value of cogenerated electricity is higher for the University when the electricity is used to offset retail purchases from NSP, even when adjusted for the cost of backup power.
Copies of NSP's current General Time of Day Service tariff and Standby Service Rider are contained in appendices of the separate *Value of Cogenerated Electricity* report.

Electricity Prices Assumed to Increase by 4.7% per Year

NSP's prices were assumed to increase by 4.7% per year through fiscal year 2019. This assumption is based on a general inflation rate of 3.6% per year and a fuel cost escalation rate of 6.5% per year. The 4.7% escalation assumes no change in the relationship between demand and energy charges.

Because fuel and purchased power are approximately thirty percent of NSP's total electric revenues, it was assumed that thirty percent of the price of electricity would increase at the fuel cost escalation rate and that the remaining seventy percent would increase at the general inflation rate. Any changes to the fuel cost escalation rate would also change the escalation rate of electricity prices. Frequent Rate case requests by NSP could cause a higher rate of price escalation than is assumed in this report.

Various Factors Affect Value of Cogenerated Electricity

Factors that could affect the value of cogenerated electricity may be summarized as follows.

- Spread between escalation rates of electricity prices and fuel costs affects the value of cogenerated electricity (see section 5)
- Summer production is more valuable than winter production.
- On-peak production is worth more than off-peak production.
- Higher summer steam requirements increases the value of cogeneration.
- Retail wheeling could increase the value of cogeneration.
- Minimum demand charges on remaining purchases could reduce the value of cogeneration.

For Detailed Information, See Separate Report

For detailed information on the value of cogenerated electricity, see the separate report, *Alternatives to the University of Minnesota's Projected Steam Service Facilities Renovation: Value of Cogenerated Electricity*, dated April 1, 1994.

Chapter 12. Permits Required For the Proposed Project

STATE

MPCA	Air Emissions Facility Permits	Applied For*
MPCA	Ash Storage Permits	To Be Applied For
MPCA	Stormwater Discharge Permits	To Be Applied For
MPCA	Hazardous Waste Contingency and Spill Prevention Plan	To Be Completed if Necessary
Minn Dept Labor Industry/ University	Boiler and High Pressure Piping Permits	To Be Applied For
Mn/DOT and City of Minneapolis	Utility Crossing Permits	To Be Applied For

LOCAL

MCWS	Sewer Discharge Permits	To Be Applied For
University	Critical Areas Plan Consistency	To Be Applied For*
University	Floodplain Certification of Occupancy	To Be Applied For
University	Shoreland Alternation Permit	To Be Applied For if Needed
University	Building Permit	To Be Applied For
University	Electrical Inspection	To Be Applied For
University	Liquid Storage Permits	To Be Applied For
University	Storage Tank Response Plan	To Be Developed if Needed

* Permits for which a record of decision is required pursuant to Minn. Rules pt. 4410.2100, subp. 6, item D and 4410.2900.

Appendix A: Emission Factors

The criteria pollutant air emission factors used in the preparation of the EIS, along with other data and assumptions, are listed in this part of Appendix A.

Existing Minneapolis Boilers

	SE Blr 3 Coal - PC lb/MMBtu	SE Blr 4 Coal - SS lb/MMBtu	
SO 2	0.2100	0.2100	Based on 70% scrubber removal efficiency.
CO	0.0340	0.2800	Reference (2): 0.6 lbs/ton PC and 5 lbs/ton SS.
PM #	0.1000	0.1000	Reference (3)
NO X	1.2000	0.8000	Reference (2): 21 lbs/ton PC and 14 lbs/ton SS.
VOC	0.0040	0.0040	Reference (2): 0.07 lbs/ton.

PC = Pulverized Coal
SS = Spreader Stoker

Existing Minneapolis Boilers

	Natural Gas lb/MMBtu	No. 2 Oil lb/MMBtu	Gas/Oil Note (a) lb/MMBtu	
SO 2	0.0006	0.5000	0.0420	Reference (2): 0.6 lbs/MMCF gas and all oil sulfur converted to SO2.
CO	0.0400	0.0400	0.0400	Reference (2): 40 lbs/MMCF gas and 5 lb/Mgal oil.
PM #	0.0030	0.0072	0.0034	Reference (2): 3 lbs/MMCF gas and 1 lb/Mgal oil.
NO X	0.2400	0.2500	0.2400	Reference (4): Standard burner.
VOC	0.0014	0.0014	0.0014	Reference (2): 1.4 lbs/MMCF gas and 0.2 lbs/Mgal oil.

Existing St. Paul Boilers, other than Boiler No. 7.

	Natural Gas lb/MMBtu	No. 2 Oil lb/MMBtu	Gas/Oil Note (a) lb/MMBtu	
SO 2	0.0006	0.5000	0.0420	Reference (2): 0.6 lbs/MMCF gas and all oil sulfur converted to SO2.
CO	0.0400	0.0400	0.0400	Reference (2): 40 lbs/MMCF gas and 5 lb/Mgal oil.
PM #	0.0030	0.0072	0.0034	Reference (2): 3 lbs/MMCF gas and 1 lb/Mgal oil.
NO X	0.2400	0.2500	0.2400	Reference (4): Standard burner.
VOC	0.0014	0.0014	0.0014	Reference (2): 1.4 lbs/MMCF gas and 0.2 lbs/Mgal oil.

Existing St. Paul Boiler No. 7.

	Natural Gas lb/MMBtu	No. 2 Oil lb/MMBtu	Gas/Oil Note (a) lb/MMBtu	
SO 2	0.0006	0.5000	0.0420	Reference (2): 0.6 lbs/MMCF gas and all oil sulfur converted to SO2.
CO	0.0400	0.0400	0.0400	Reference (2): 40 lbs/MMCF gas and 5 lb/Mgal oil.
PM #	0.0030	0.0072	0.0034	Reference (2): 3 lbs/MMCF gas and 1 lb/Mgal oil.
NO X	0.1400	0.1400	0.1400	Reference (3).
VOC	0.0014	0.0014	0.0014	Reference (2): 1.4 lbs/MMCF gas and 0.2 lbs/Mgal oil.

Appendix A: Cogeneration Credit

The calculation of the cogeneration credit is presented in this part of Appendix A. The credit was estimated base on pollutant emissions and electric generation associated with NSP power plants located in the seven county metropolitan area and Sherburne County.

	A.S. King (Tons/Yr)	Riverside (Tons/Yr)	Sherco (Tons/Yr)	Highbridge (Tons/Yr)	Black Dog (Tons/Yr)	MN Valley (Tons/Yr)	Total (Tons/Yr)	Avr. Emission Factor Lb/mWh
SO2	25994	5678	19635	2635	4001	655	58550	6.194
CO	576	259	2531	189	322	8	3886	.411
PM10	458	131	2089	470	199	8	3357	.355
NOx	24061	7818	29492	3713	5007	157	70250	7.4313
VOC	76.8	30	295	21	27	1	452	.0478
Generation, mWh	3,430,540	1,446,297	12,042,741	740,927	1,207,396	38,351	18,906,252	

References:

(1) Emissions information extracted from 1992 Emission Inventories prepared by NSP and submitted to the Minnesota Pollution Control Agency.

(2) Generation information extracted from NSP's 1982 FERC Form 1.

Appendix A: Predicted Emission Rates for Criteria Pollutants

The "predicted" criteria pollutant air emission rates based on economic fuel dispatch and predicted steam loads that were used in the preparation of the EIS, along with other data and assumptions, are listed in this part of Appendix A.

Case A - Minneapolis University of Minnesota Project		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	CO2 lb/MMBtu	CO2 TPY
New	HP CFB	Coal	268	2,200,443	0.1370	150.7	0.1400	154.0	0.0220	24.2	0.2000	220.0	0.0150	16.5	6.72E-06	14.8	2.10E+02	230,496.4
New	HP Conv	Gas/No. 2	266	769,634	0.0420	16.2	0.0400	15.4	0.0058	2.2	0.1400	53.9	0.0014	0.5	2.79E-07	0.2	1.25E+02	48,102.1
New	MP Conv	Gas/No. 2	332	14,803	0.0420	0.3	0.0400	0.3	0.0058	0.0	0.1400	1.0	0.0014	0.0	2.79E-07	0.0	1.25E+02	925.2
Existing	SE Blr 3	Coal - PC	169	132,229	0.2100	13.9	0.0340	2.2	0.1000	6.6	1.2000	79.3	0.0040	0.3	6.72E-06	0.9	2.10E+02	13,851.0
Existing	SE Blr 4	Coal - SS	187	212,784	0.2100	22.3	0.2800	29.8	0.1000	10.6	0.8000	85.1	0.0040	0.4	6.72E-06	1.4	2.10E+02	22,289.1
Total				3,329,893		203.4		201.8		43.7		439.4		17.7		17.3		315,663.8

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	Mercury lb/mWh	Mercury LB/YR	CO2 lb/mWh	CO2 TPY
Cogeneration Credit	73,708	6.1938	228.3	0.4111	15.2	0.3551	13.1	7.4313	273.9	0.0478	1.8	7.01E-05	5.2	2,186.5	80,581.6
Emissions Net of Cogeneration Credit			(24.8)		186.6		30.6		165.5		16.0		12.2		235,082.2

Case B - Minneapolis University of Minnesota Project		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	CO2 lb/MMBtu	CO2 lb/Year
New	Comb Turb	Gas/No. 2	250	1,606,516	0.0420	33.7	0.1300	104.4	0.0034	2.7	0.1500	120.5	0.0130	10.4	2.79E-07	0.4	1.25E+02	100,407.3
New	HP WHB	Gas/No. 2	186	394,722	0.0420	8.3	0.0400	7.9	0.0058	1.1	0.1400	27.6	0.0014	0.3	2.79E-07	0.1	1.25E+02	24,670.1
New	HP CFB	Coal	268	1,945,326	0.1370	133.3	0.1400	136.2	0.0220	21.4	0.2000	194.5	0.0150	14.6	6.72E-06	13.1	2.10E+02	203,772.9
New	MP Conv	Gas/No. 2	332	14,532	0.0420	0.3	0.0400	0.3	0.0058	0.0	0.1400	1.0	0.0014	0.0	2.79E-07	0.0	1.25E+02	908.3
Existing	SE Blr 3	Coal - PC	169	64,548	0.2100	6.8	0.0340	1.1	0.1000	3.2	1.2000	38.7	0.0040	0.1	6.72E-06	0.4	2.10E+02	6,761.4
Existing	SE Blr 4	Coal - SS	187	153,124	0.2100	16.1	0.2800	21.4	0.1000	7.7	0.8000	61.2	0.0040	0.3	6.72E-06	1.0	2.10E+02	16,039.7
Total				4,178,768		198.4		271.3		36.2		443.6		25.8		15.1		352,559.7

		Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	Mercury lb/mWh	Mercury LB/YR	CO2 lb/mWh	CO2 TPY
		110,530														
Cogeneration Credit		222,602	6.1938	689.4	0.4111	45.8	0.3551	39.5	7.4313	827.1	0.0478	5.3	7.01E-05	15.6	2,186.5	243,360.7
Emissions Net of Cogeneration Credit				(490.9)		225.6		(3.3)		(383.5)		20.4		(0.5)		109,199.0

Alternative No. 3 - Southeast Plant Using Coal with NG Cogen		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	CO2 lb/MMBtu	CO2 lb/Year
5 New	Comb Turb	Gas/No. 2	270	2,426,494	0.0420	51.0	0.1300	157.7	0.0034	4.1	0.1500	182.0	0.0130	15.8	2.79E-07	0.7	1.25E+02	151,655.9
5 New	MP WHB	Gas/No. 2	188	272,551	0.0420	5.7	0.0400	5.5	0.0034	0.5	0.1300	17.7	0.0014	0.2	2.79E-07	0.1	1.25E+02	17,034.4
Existing	SE Blr 3	Coal - PC	169	408,644	0.2100	42.9	0.0340	6.9	0.1000	20.4	1.2000	245.2	0.0040	0.8	6.72E-06	2.7	2.09E+02	42,703.3
Existing	SE Blr 4	Coal - SS	187	991,899	0.2100	104.1	0.2800	138.9	0.1000	49.6	0.8000	396.8	0.0040	2.0	6.72E-06	6.7	2.09E+02	103,653.4
New	MP Conv	Gas/No. 6	154	39,276	0.0420	0.8	0.0400	0.8	0.0088	0.2	0.0620	1.2	0.0014	0.0	5.71E-07	0.0	1.25E+02	2,454.8
New	MP Conv	Gas/No. 6	154	3,081	0.0420	0.1	0.0400	0.1	0.0088	0.0	0.0620	0.1	0.0014	0.0	5.71E-07	0.0	1.25E+02	192.6
Total				4,141,945		204.6		309.8		74.8		843.0		18.8		10.2		317,694.4

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	Mercury lb/mWh	Mercury LB/YR	CO2 lb/mWh	CO2 TPY
Cogeneration Credit	187,245	6.1938	579.9	0.4111	38.5	0.3551	33.2	7.4313	695.7	0.0478	4.5	7.01E-05	13.1	2,186.5	204,706.5
Emissions Net of Cogeneration Credit			(375.3)		271.3		41.6		147.2		14.3		(2.9)		112,987.9

79,576

Alternative No. 4 - Southeast Plant w/o Coal with NG Cogen		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	lb/MMBtu	Mercury lb/Year
5 New	Comb Turb	Gas/No. 2	270	2,426,494	0.0420	51.0	0.1300	157.7	0.0034	4.1	0.1500	182.0	0.0130	15.8	2.79E-07	0.7	1.25E+02	151,655.9
5 New	MP WHB	Gas/No. 2	188	1,216,587	0.0420	25.5	0.0400	24.3	0.0034	2.1	0.1300	79.1	0.0014	0.9	2.79E-07	0.3	1.25E+02	76,036.7
New	MP Conv	Gas/No. 6	222	333,682	0.0420	7.0	0.0400	6.7	0.0088	1.5	0.0620	10.3	0.0014	0.2	5.71E-07	0.2	1.25E+02	20,855.1
New	MP Conv	Gas/No. 6	222	34,943	0.0420	0.7	0.0400	0.7	0.0088	0.2	0.0620	1.1	0.0014	0.0	5.71E-07	0.0	1.25E+02	2,183.9
New	MP Conv	Gas/No. 6	222	-	0.0420	-	0.0400	-	0.0088	-	0.0620	-	0.0014	-	5.71E-07	-	1.25E+02	-
Total				4,011,706		84.2		189.4		7.8		272.5		16.9		1.2		250,731.6

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	Mercury lb/mWh	Mercury LB/YR	CO2 lb/mWh	CO2 TPY
Cogeneration Credit	187,245	6.1938	579.9	0.4111	38.5	0.3551	33.2	7.4313	695.7	0.0478	4.5	7.01E-05	13.1	2,186.5	204,706.5
Emissions Net of Cogeneration Credit			(495.6)		150.9		(25.4)		(423.2)		12.4		(11.9)		46,025.1

Alternative No. 6 - New Mpls Plant at Alternate Location with Coal		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	lb/MMBtu	CO2 lb/Year
New	HP CFB	Coal	256	2,279,115	0.1370	156.1	0.1400	159.5	0.0220	25.1	0.2000	227.9	0.0150	17.1	6.72E-06	15.3	2.10E+02	238,737.3
New	HP Conv	Gas/No. 6	259	825,348	0.0420	17.3	0.0400	16.5	0.0088	3.6	0.0620	25.6	0.0014	0.6	5.71E-07	0.5	1.25E+02	51,584.3
New	MP Conv	Gas/No. 6	259	236,009	0.0420	5.0	0.0400	4.7	0.0088	1.0	0.0620	7.3	0.0014	0.2	5.71E-07	0.1	1.25E+02	14,750.6
New	MP Conv	Gas/No. 6	259	-	0.0420	-	0.0400	-	0.0088	-	0.0620	-	0.0014	-	5.71E-07	-	1.25E+02	-
Total				3,340,472		178.4		180.8		29.7		260.8		17.8		15.9		305,072.1

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	lb/mWh	LB/YR	lb/mWh	TPY
Cogeneration Credit	71,955	6.1938	222.8	0.4111	14.8	0.3551	12.8	7.4313	267.4	0.0478	1.7	7.01E-05	5.0	2,186.5096	78,665.1
Emissions Net of Cogeneration Credit			(44.4)		166.0		17.0		(6.5)		16.1		10.9		226,407.0

Alternative No. 7 - Mpls Plant at Alternate Location without Coal		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	lb/MMBtu	Mercury lb/Year
5 New	Comb Turb	Gas/No. 2	270	2,426,494	0.0420	51.0	0.1300	157.7	0.0034	4.1	0.1500	182.0	0.0130	15.8	2.79E-07	0.7	1.25E+02	151,655.9
5 New	MP WHB	Gas/No. 2	188	1,216,587	0.0420	25.5	0.0400	24.3	0.0034	2.1	0.1300	79.1	0.0014	0.9	2.79E-07	0.3	1.25E+02	76,036.7
New	MP Conv	Gas/No. 6	222	257,201	0.0420	5.4	0.0400	5.1	0.0088	1.1	0.0620	8.0	0.0014	0.2	5.71E-07	0.1	1.25E+02	16,075.1
New	MP Conv	Gas/No. 6	222	102,550	0.0420	2.2	0.0400	2.1	0.0088	0.5	0.0620	3.2	0.0014	0.1	5.71E-07	0.1	1.25E+02	6,409.4
New	MP Conv	Gas/No. 6	222	8,874	0.0420	0.2	0.0400	0.2	0.0088	0.0	0.0620	0.3	0.0014	0.0	5.71E-07	0.0	1.25E+02	554.6
Total				4,011,706		84.2		189.4		7.8		272.5		16.9		1.2		250,731.6
Ratio to Case A						0.4		0.9		0.2		0.6		1.0				

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	lb/mWh	LB/YR	lb/mWh	TPY
Cogeneration Credit	187,245	6.1938	579.9	0.4111	38.5	0.3551	33.2	7.4313	695.7	0.0478	4.5	7.01E-05	13.1	2,186.5096	204,706.5
Emissions Net of Cogeneration Credit			(495.6)		150.9		(25.4)		(423.2)		12.4		(11.9)		46,025.1

Case A - St. Paul University of Minnesota Project	Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	lb/MMBtu	Mercury lb/Year
New MP Conv	Gas/No. 2	292	839,387	0.0420	17.6	0.0400	16.8	0.0034	1.4	0.1400	58.8	0.0014	0.6	2.79E-07	0.2	2.87E-07	0.2
Existing Blr 1	Gas/No. 2	44	422	0.0420	0.0	0.0400	0.0	0.0034	0.0	0.2400	0.1	0.0014	0.0	2.79E-07	0.0	2.87E-07	0.0
Existing Blr 2	Gas/No. 2	44	1,379	0.0420	0.0	0.0400	0.0	0.0034	0.0	0.2400	0.2	0.0014	0.0	2.79E-07	0.0	2.87E-07	0.0
Existing Blr 5	Gas/No. 2	85	14,717	0.0420	0.3	0.0400	0.3	0.0034	0.0	0.2400	1.8	0.0014	0.0	2.79E-07	0.0	2.87E-07	0.0
Existing Blr 6	Gas/No. 2	85	34,127	0.0420	0.7	0.0400	0.7	0.0034	0.1	0.2400	4.1	0.0014	0.0	2.79E-07	0.0	2.87E-07	0.0
Existing Blr 7	Gas/No. 2	99	95,603	0.0420	2.0	0.0400	1.9	0.0034	0.2	0.1400	6.7	0.0014	0.1	2.79E-07	0.0	2.87E-07	0.0
Total			985,635		20.7		19.7		1.7		16.33		0.7		0.3		0.3

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	lb/mWh	LB/YR	lb/mWh	TPY
Cogeneration Credit	-	6.1938	-	0.4111	-	0.3551	-	7.4313	-	0.0478	-	7.01E-05	-	2,186.5096	-
Emissions Net of Cogeneration Credit			20.7		19.7		1.7		16.3		0.7		0.3		0.3

Alternative No. 13 - St. Paul without Coal	Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
New MP Conv	Gas/No. 2	59	454,759	0.0420	9.5	0.0400	9.1	0.0034	0.8	0.0450	10.2	0.0014	0.3
Existing Blr 1	Gas/No. 2	44	4,538	0.0420	0.1	0.0400	0.1	0.0034	0.0	0.2400	0.5	0.0014	0.0
Existing Blr 2	Gas/No. 2	44	22,253	0.0420	0.5	0.0400	0.4	0.0034	0.0	0.2400	2.7	0.0014	0.0
Existing Blr 5	Gas/No. 2	85	46,353	0.0420	1.0	0.0400	0.9	0.0034	0.1	0.2400	5.6	0.0014	0.0
Existing Blr 6	Gas/No. 2	85	105,667	0.0420	2.2	0.0400	2.1	0.0034	0.2	0.2400	12.7	0.0014	0.1
Existing Blr 7	Gas/No. 2	99	366,410	0.0420	7.7	0.0400	7.3	0.0034	0.6	0.1400	25.6	0.0014	0.3
Total			999,980		21.0		20.0		1.7		57.3		0.7

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY
Cogeneration Credit	-	6.1938	-	0.4111	-	0.3551	-	7.4313	-	0.0478	-
Emissions Net of Cogeneration Credit			21.0		20.0		1.7		57.3		0.7

Alternative No. 1A - Minneapolis Deferred Coal Primary	Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY	Mercury lb/MMBtu	Mercury lb/Year	CO2 lb/MMBtu	CO2 TPY
Existing SE Blr 3	Coal - PC		947,141	0.2100	99.4	0.0340	16.1	0.1000	47.4	1.2000	568.3	0.0040	1.9	6.72E-06	6.4	2.10E+02	9.92E+04
Existing SE Blr 4	Coal - SS		1,140,593	0.2100	119.8	0.2800	159.7	0.1000	57.0	0.8000	456.2	0.0040	2.3	6.72E-06	7.7	2.10E+02	1.19E+05
Existing Main 5	Coal - PC		420,054	0.7000	147.0	0.0340	7.1	0.1000	21.0	1.2000	252.0	0.0040	0.8	6.72E-06	2.8	2.10E+02	4.40E+04
Existing Main 4	Coal - PC		172,587	0.7000	60.4	0.0340	2.9	0.1000	8.6	1.2000	103.6	0.0040	0.3	6.72E-06	1.2	2.10E+02	1.81E+04
Existing Main 3	Coal - SS		60,997	0.7000	21.3	0.2800	8.5	0.1000	3.0	0.8000	24.4	0.0040	0.1	6.72E-06	0.4	2.10E+02	6.39E+03
Existing Main 2	Coal - SS		73,789	0.7000	25.8	0.2800	10.3	0.1000	3.7	0.8000	29.5	0.0040	0.1	6.72E-06	0.5	2.10E+02	7.73E+03
Existing Main 1	Coal - SS		45,081	0.7000	15.8	0.2800	6.3	0.1000	2.3	0.8000	18.0	0.0040	0.1	6.72E-06	0.3	2.10E+02	4.72E+03
Existing Main 6	Gas/No. 2		57,801	0.0420	1.2	0.0400	1.2	0.0034	0.1	0.2400	6.9	0.0040	0.1	2.79E-07	0.0	1.25E+02	3.61E+03
			2,918,043		491		212		143		1,459		5.8		19.2		3.03E+05
Ratio to Case A			162,000		2.4		1.1		3.3		3.3		0.3				

	Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY	Mercury lb/mWh	Mercury LB/YR	CO2 lb/mWh	CO2 TPY
Cogeneration Credit	-	6.1938	-	0.4111	-	0.3551	-	7.4313	-	0.0478	-	7.01E-05	-	2,186.5	-
Emissions Net of Cogeneration Credit			490.8		212.2		143.1		1,459.0		5.8		19.2		303,222.9
															1.3

Alternative No. 1B - Minneapolis Deferred Natural Gas Primary	Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
Existing SE Blr 3	Coal - PC		55,542	0.2100	5.8	0.0340	0.9	0.1000	2.8	1.2000	33.3	0.0040	0.1
Existing SE Blr 4	Coal - SS		65,912	0.2100	6.9	0.2800	9.2	0.1000	3.3	0.8000	26.4	0.0040	0.1
Existing Main 5	Gas/No. 2		709,178	0.0420	14.9	0.0400	14.2	0.0068	2.4	0.2400	85.1	0.0040	1.4
Existing Main 4	Gas/No. 2		197,794	0.0420	4.2	0.0400	4.0	0.0068	0.7	0.2400	23.7	0.0040	0.4
Existing Main 3	Gas/No. 2		139,229	0.0420	2.9	0.0400	2.8	0.0068	0.5	0.2400	16.7	0.0040	0.3
Existing Main 2	Coal - SS		39,148	0.7000	13.7	0.2800	5.5	0.1000	2.0	0.8000	15.7	0.0040	0.1
Existing Main 1	Coal - SS		16,820	0.7000	5.9	0.2800	2.4	0.1000	0.8	0.8000	6.7	0.0040	0.0
Existing Main 6	Gas/No. 2		1,694,420	0.0420	35.6	0.0400	33.9	0.0034	2.9	0.2400	203.3	0.0040	3.4
Total			2,918,043		90		73		15		411		5.8
Ratio to Case A					0.4		0.4		0.4		0.9		0.3
			Generation mWh	Sulfur Dioxide lb/mWh	Sulfur Dioxide TPY	Carbon Monoxide lb/mWh	Carbon Monoxide TPY	Particulate (PM10) lb/mWh	Particulate (PM10) TPY	Nitrogen Oxides lb/mWh	Nitrogen Oxides TPY	Volatile Organic Compounds lb/mWh	Volatile Organic Compounds TPY
Cogeneration Credit			-	6.1938	-	0.4111	-	0.3551	-	7.4313	-	0.0478	-
Emissions Net of Cogeneration Credit					89.9		72.8		15.3		411.0		5.8
Ratio to Case A					(3.6)		0.4		0.5		2.5		0.4

Appendix A: Potential Emission Rates for Criteria Pollutants

The "potential" criteria pollutant air emission rates based on worst-case fuel and maximum boiler capacity that were used in the preparation of the EIS, along with other data and assumptions, are listed in this part of Appendix A.

Case A - Minneapolis University of Minnesota Project		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
New	HP CFB	Coal	268		0.1370	160.8	0.1400	164.3	0.0220	25.8	0.2000	234.8	0.0150	17.6
New	HP Conv	No. 2 Oil	266		0.5000	582.5	0.0400	46.6	0.0145	16.9	0.1450	168.9	0.0014	1.6
New	MP Conv	No. 2 Oil	332		0.5000	727.1	0.0400	58.2	0.0145	21.1	0.1450	210.9	0.0014	2.0
Existing	SE Blr 3	Coal - PC	169		0.2100	155.4	0.0340	25.2	0.1000	74.0	1.2000	888.3	0.0040	3.0
Existing	SE Blr 4	Coal - SS	187		0.2100	172.0	0.2800	229.3	0.1000	81.9	0.8000	655.2	0.0040	3.3
Total						1,797.9		523.6		219.7		2,158.1		27.5

Case B - Minneapolis University of Minnesota Project		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
New	Comb Turb	No. 2 Oil	250		0.5000	547.5	0.3400	372.3	0.0072	7.9	0.1600	175.2	0.0160	17.5
New	HP WHB	No. 2 Oil	186		0.5000	407.3	0.0400	32.6	0.0145	11.8	0.1450	118.1	0.0014	1.1
New	HP CFB	Coal	268		0.1370	160.8	0.1400	164.3	0.0220	25.8	0.2000	234.8	0.0150	17.6
New	MP Conv	No. 2 Oil	332		0.5000	727.1	0.0400	58.2	0.0145	21.1	0.1450	210.9	0.0014	2.0
Existing	SE Blr 3	Coal - PC	169		0.2100	155.4	0.0340	25.2	0.1000	74.0	1.2000	888.3	0.0040	3.0
Existing	SE Blr 4	Coal - SS	187		0.2100	172.0	0.2800	229.3	0.1000	81.9	0.8000	655.2	0.0040	3.3
Total						2,170.2		881.9		222.5		2,282.5		44.5

Alternative No. 3 - Southeast Plant Using Coal with NG Cogen		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Compounds lb/MMBtu	Volatile Compounds TPY
5 New	Comb Turb	No. 2 Oil	270		0.5000	591.3	0.3400	402.1	0.0072	8.5	0.1600	189.2	0.0160	18.9
5 New	MP WHB	No. 2 Oil	188		0.5000	411.7	0.0400	32.9	0.0072	5.9	0.2200	181.2	0.0014	1.2
Existing	SE Blr 3	Coal - PC	169		0.2100	155.4	0.0340	25.2	0.1000	74.0	1.2000	888.3	0.0040	3.0
Existing	SE Blr 4	Coal - SS	187		0.2100	172.0	0.2800	229.3	0.1000	81.9	0.8000	655.2	0.0040	3.3
New	MP Conv	No. 6 Oil	154		0.5000	337.3	0.0400	27.0	0.0730	49.2	0.3000	202.4	0.0014	0.9
New	MP Conv	No. 6 Oil	154		0.5000	337.3	0.0400	27.0	0.0730	49.2	0.3000	202.4	0.0014	0.9
Total				-		2,005.0		743.5		268.9		2,318.6		28.2

Alternative No. 4 - Southeast Plant w/o Coal with NG Cogen		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
5 New	Comb Turb	No. 2 Oil	270	2,365,200	0.5000	591.3	0.3400	402.1	0.0072	8.5	0.1600	189.2	0.0160	18.9
5 New	MP WHB	No. 2 Oil	188	1,646,880	0.5000	411.7	0.0400	32.9	0.0072	5.9	0.2200	181.2	0.0014	1.2
New	MP Conv	No. 6 Oil	222	1,944,720	0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0014	1.4
New	MP Conv	No. 6 Oil	222	1,944,720	0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0014	1.4
New	MP Conv	No. 6 Oil	222	1,944,720	0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0014	1.4
Total				91,759		2,461.6		551.7		227.4		1,245.5		24.2

Alternative No. 6 - New Mpls Plant at Alternate Location with Coal		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Compounds lb/MMBtu	Volatile Compounds TPY
New	HP CFB	Coal	256		0.1370	153.6	0.1400	157.0	0.0220	24.7	0.2000	224.3	0.0150	16.8
New	HP Conv	No. 6 Oil	259		0.5000	567.2	0.0400	45.4	0.0730	82.8	0.3000	340.3	0.0014	1.6
New	MP Conv	No. 6 Oil	259		0.5000	567.2	0.0400	45.4	0.0730	82.8	0.3000	340.3	0.0014	1.6
New	MP Conv	No. 6 Oil	259		0.5000	567.2	0.0400	45.4	0.0730	82.8	0.3000	340.3	0.0014	1.6
Total				-		1,855.2		293.1		273.1		1,245.2		21.6

Alternative No. 7 - Mpls Plant at Alternate Location without Coal		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Compounds lb/MMBtu	Volatile Compounds TPY
5 New	Comb Turb	No. 2 Oil	270		0.5000	591.3	0.3400	402.1	0.0072	8.5	0.1600	189.2	0.0160	18.9
5 New	MP WHB	No. 2 Oil	188		0.5000	411.7	0.0400	32.9	0.0072	5.9	0.2200	181.2	0.0014	1.2
New	MP Conv	No. 6 Oil	222		0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0019	1.8
New	MP Conv	No. 6 Oil	222		0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0019	1.8
New	MP Conv	No. 6 Oil	222		0.5000	486.2	0.0400	38.9	0.0730	71.0	0.3000	291.7	0.0019	1.8
Total				-		2,461.6		551.7		227.4		1,245.5		25.6

Case A - St. Paul University of Minnesota Project		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
New	MP Conv	No. 2 Oil	292	2,557,920	0.5000	639.5	0.0400	51.2	0.0072	9.2	0.1000	127.9	0.0014	1.8
Existing	Blr 1	No. 2 Oil	44	385,440	0.5000	96.4	0.0400	7.7	0.0072	1.4	0.2500	48.2	0.0014	0.3
Existing	Blr 2	No. 2 Oil	44	385,440	0.5000	96.4	0.0400	7.7	0.0072	1.4	0.2500	48.2	0.0014	0.3
Existing	Blr 5	No. 2 Oil	85	744,600	0.5000	186.2	0.0400	14.9	0.0072	2.7	0.2500	93.1	0.0014	0.5
Existing	Blr 6	No. 2 Oil	85	744,600	0.5000	186.2	0.0400	14.9	0.0072	2.7	0.2500	93.1	0.0014	0.5
Existing	Blr 7	No. 2 Oil	99	867,240	0.5000	216.8	0.0400	17.3	0.0072	3.1	0.1400	60.7	0.0014	0.6
Total				5,685,240		1,421.3		113.7		20.5		471.1		4.0

Alternative No. 13 - St. Paul without Coal		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
New	MP Conv	No. 2 Oil	59		0.5000	129.2	0.0400	10.3	0.0072	1.9	0.1000	25.8	0.0014	0.4
Existing	Blr 1	No. 2 Oil	44		0.5000	96.4	0.0400	7.7	0.0072	1.4	0.2500	48.2	0.0014	0.3
Existing	Blr 2	No. 2 Oil	44		0.5000	96.4	0.0400	7.7	0.0072	1.4	0.2500	48.2	0.0014	0.3
Existing	Blr 5	No. 2 Oil	85		0.5000	186.2	0.0400	14.9	0.0072	2.7	0.2500	93.1	0.0014	0.5
Existing	Blr 6	No. 2 Oil	85		0.5000	186.2	0.0400	14.9	0.0072	2.7	0.2500	93.1	0.0014	0.5
Existing	Blr 7	No. 2 Oil	99		0.5000	216.8	0.0400	17.3	0.0072	3.1	0.1400	60.7	0.0014	0.6
Total				-		911.0		72.9		13.1		369.1		2.6

Alternative No. 12 - St. Paul Plant with Cogeneration		Fuel Type	Rated Capacity MMBtu/hr		Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
1 New	Comb Turb	No. 2 Oil	59		0.5000	129.2	0.3400	87.9	0.0072	1.9	0.1600	41.3	0.0160	4.1
1 New	MP WHB	No. 2 Oil	31		0.5000	67.9	0.0400	5.4	0.0072	1.0	0.2200	29.9	0.0014	0.2
Existing	Blr 1	Coal - PC	44		1.5000	289.1	0.0340	6.6	0.1000	19.3	1.2000	231.3	0.0040	0.8
Existing	Blr 2	Coal - PC	44		1.5000	289.1	0.0340	6.6	0.1000	19.3	1.2000	231.3	0.0040	0.8
Existing	Blr 5	Coal -SS	85		1.5000	558.5	0.2800	104.2	0.1000	37.2	0.8000	297.8	0.0040	1.5
Existing	Blr 6	Coal -SS	85		1.5000	558.5	0.2800	104.2	0.1000	37.2	0.8000	297.8	0.0040	1.5
Existing	Blr 7	No. 2 Oil	99		0.5000	216.8	0.0400	17.3	0.0072	3.1	0.1400	60.7	0.0014	0.6
Total				-		2,109.0		332.2		119.0		1,190.1		9.5

Alternative No. 1A - Minneapolis Deferred Coal Primary		Fuel Type	Rated Capacity MMBtu/hr	FY 94/95 Fuel MMBtu	Sulfur Dioxide lb/MMBtu	Sulfur Dioxide TPY	Carbon Monoxide lb/MMBtu	Carbon Monoxide TPY	Particulate (PM10) lb/MMBtu	Particulate (PM10) TPY	Nitrogen Oxides lb/MMBtu	Nitrogen Oxides TPY	Volatile Organic Compounds lb/MMBtu	Volatile Organic Compounds TPY
Existing	SE Blr 3	Coal - PC	169	947,141	0.2100	155.4	0.0340	16.1	0.1000	47.4	1.2000	568.3	0.0040	1.9
Existing	SE Blr 4	Coal - SS	187	1,140,593	0.2100	172.0	0.2800	159.7	0.1000	57.0	0.8000	456.2	0.0040	2.3
Existing	Main 5	Coal - PC	160	420,054	0.7000	490.6	0.0340	7.1	0.1000	21.0	1.2000	252.0	0.0040	0.8
Existing	Main 4	Coal - PC	107	172,587	0.7000	327.0	0.0340	2.9	0.1000	8.6	1.2000	103.6	0.0040	0.3
Existing	Main 3	Coal - SS	93	60,997	0.7000	286.2	0.2800	8.5	0.1000	3.0	0.8000	24.4	0.0040	0.1
Existing	Main 2	Coal - SS	80	73,789	0.7000	245.3	0.2800	10.3	0.1000	3.7	0.8000	29.5	0.0040	0.1
Existing	Main 1	Coal - SS	80	45,081	0.7000	245.3	0.2800	6.3	0.1000	2.3	0.8000	18.0	0.0040	0.1
Existing	Main 6	Gas/No. 2	240	57,801	0.0420	44.2	0.0400	1.2	0.1000	2.9	0.2400	6.9	0.0040	0.1
				2,918,043		1,966		212		146		1,459		5.8

Appendix A: Example Air Toxic Emission Rate Estimate

Air toxic emission factors and emission rates for Alternative 3, which uses all combinations of fuels assessed, along with other data and assumptions, are listed in this part of Appendix A.

Emission Sources	Alternate Fuel (MMBtu)	Alternate Fuel	Heating Value (Btu/lb)	Primary Fuel (MMBtu)	Primary Fuel	Ash Content (wt%)	Control Efficiency (%)	Notes
5 Combustion Turbines	202,208	No. 2 Fuel Oil	19,900	2,224,286	Natural Gas	—		No. 2 Fuel Oil based on 139,000 Btu/gal and 0.5 % wt. sulfur
5 Waste Heat Boilers	22,713	No. 2 Fuel Oil	19,900	249,838	Natural Gas	—		No. 2 Fuel Oil based on 139,000 Btu/gal and 0.5 % wt. sulfur
SE #3	408,644	Coal-PC	8,930	408,644	Coal-PC	6.00	99.25	
SE #4	991,899	Coal-SS	8,930	991,899	Coal-SS	6.00	99.25	
2 Conventional Boilers	3,530	No. 6 Fuel Oil	18,200	38,827	Natural Gas	—		No. 6 Fuel Oil based on 148,000 Btu/gal and 1 % wt. sulfur

Constituents	Fuel Oil No. 2 Content (wppm)	Fuel Oil No. 2 Emission Factor (lb/MMBtu)	Waste Heat Boilers & Turbines No. 2 Fuel Oil Emissions (tpy)	Coal Content (wppm)	SE #3 Emission Factor (lb/MMBtu)	SE #4 Emission Factor (lb/MMBtu)	Emissions from SE #3 (tpy)	Emissions from SE #4 (tpy)	Fuel Oil No. 6 Content (wppm)	Fuel Oil Boiler No. 6 & No. 2 Emission Factor (lb/MMBtu)	Conventional Boilers No. 6 Fuel Oil Emissions (tpy)	Natural Gas Emission Factor (lb/MMBtu)	Waste Heat Boilers & Turbines Natural Gas Emissions (tpy)	Conventional Boilers Natural Gas Emissions (tpy)	*TOTAL* (tpy)
Arsenic (1)	1.02	5.13E-05	5.76E-03	2.00	2.24E-04	1.68E-06	3.43E-04	6.25E-06	1.02	5.60E-05	9.89E-05				6.21E-03
Beryllium	1.27	6.38E-05	7.18E-03	1.36	1.52E-04	1.14E-06	2.33E-04	4.25E-06	1.27	6.98E-05	1.23E-04				7.54E-03
Cadmium	0.2	1.01E-05	1.13E-03	0.80	8.96E-05	6.72E-07	1.37E-04	2.50E-06	0.2	1.10E-05	1.94E-05				1.29E-03
Chromium-VI	0.18	9.05E-06	1.02E-03	0.80	8.96E-05	6.72E-07	1.37E-04	2.50E-06	0.18	9.89E-06	1.75E-05				1.17E-03
Chromium-tot	1.8	9.05E-05	1.02E-02	8.00	8.96E-04	6.72E-06	1.37E-03	2.50E-05	1.8	9.89E-05	1.75E-04				1.17E-02
Copper	0.2	1.01E-05	1.13E-03	22.80	2.55E-03	1.91E-05	3.91E-03	7.12E-05	0.2	1.10E-05	1.94E-05				5.13E-03
Iron	0.2	1.01E-05	1.13E-03	5283.74	5.92E-01	4.44E-03	9.07E-01	1.65E-02	0.2	1.10E-05	1.94E-05				9.24E-01
Lead	1	5.03E-05	5.65E-03	4.00	4.48E-04	3.36E-06	6.86E-04	1.25E-05	1	5.49E-05	9.70E-05				6.45E-03
Manganese	0.1	5.03E-06	5.65E-04	70.00	7.84E-03	5.88E-05	1.20E-02	2.19E-04	0.1	5.49E-06	9.70E-06				1.28E-02
Mercury	0.068	3.42E-06	3.84E-04	0.06	6.72E-06	6.72E-06	1.37E-03	3.33E-03	0.068	3.74E-06	6.59E-06	6.23E-09	7.71E-06	1.21E-07	5.10E-03
Nickel	0.5	2.51E-05	2.83E-03	11.30	1.27E-03	9.49E-06	1.94E-03	3.53E-05	0.5	2.75E-05	4.85E-05				4.85E-03
Selenium	0.38	1.91E-05	2.15E-03	4.00	4.48E-04	3.36E-06	6.86E-04	1.25E-05	0.38	2.09E-05	3.68E-05				2.88E-03
Vanadium	1	5.03E-05	5.65E-03	22.00	2.46E-03	1.85E-05	3.78E-03	6.87E-05	1	5.49E-05	9.70E-05				9.59E-03
Zinc	0.5	2.51E-05	2.83E-03	27.00	3.02E-03	2.27E-05	4.63E-03	8.43E-05	0.5	2.75E-05	4.85E-05				7.59E-03
Chlorine	120	6.90E-03	7.76E-01	135.10	1.56E-03	1.56E-03	3.19E-01	7.74E-01	120	6.90E-03	1.22E-02				1.88E+00
Fluorine	27	1.40E-03	1.57E-01	76.40	9.01E-04	9.01E-04	1.84E-01	4.47E-01	27	1.40E-03	2.47E-03				7.91E-01
Benzene	NA	1.60E-04	1.80E-02	NA	1.60E-04	1.60E-04	3.27E-02	7.94E-02	NA	1.60E-04	2.82E-04				1.30E-01
Dioxins/Furans	NA	1.40E-10	1.57E-08	NA	1.40E-10	1.40E-10	2.86E-08	6.94E-08	NA	1.40E-10	2.47E-10				1.14E-07
Formaldehyde (BLR)	NA	4.05E-04	4.60E-03	NA	2.21E-04	2.21E-04	4.52E-02	1.10E-01	NA	4.05E-04	7.15E-04	2.20E-04	2.75E-02	7.57E-04	1.48E+00
Formaldehyde (Turb)	NA	1.15E-04	1.16E-02	NA								1.15E-03	1.28E+00		
POM (PAH & Phenols)	NA	2.20E-05	2.47E-03	NA	2.40E-06	2.40E-06	4.90E-04	1.19E-03	NA	2.20E-05	3.88E-05				4.19E-03

Appendix B: Modeled Maximum Air Toxic Concentrations at Predicted Fuel Dispatch

Maximum Predicted Ambient Air Levels Based on Economic Fuel Dispatch

(ug/M^3)

Constituents	Case A Southeast	Case B Southeast	Alt. No. 3	Alt. No. 4	Alt. No. 6	Alt. No. 7	Case A St. Paul	Alt. 13 St. Paul
Arsenic	3.78E-05	3.81E-05	5.48E-05	**8.14E-05**	2.38E-05	6.20E-05	4.33E-05	5.86E-05
Beryllium	2.99E-05	3.29E-05	6.63E-05	**1.01E-04**	2.37E-05	7.72E-05	5.39E-05	7.29E-05
Cadmium	1.36E-05	1.27E-05	1.14E-05	**1.60E-05**	6.78E-06	1.22E-05	8.49E-06	1.15E-05
Chromium-VI	1.34E-05	1.25E-05	1.04E-05	**1.44E-05**	6.52E-06	1.09E-05	7.64E-06	1.03E-05
Chromium-tot	1.34E-04	1.25E-04	1.04E-04	**1.44E-04**	6.52E-05	1.09E-04	7.64E-05	1.03E-04
Copper	**3.46E-04**	2.96E-04	4.84E-05	1.60E-05	1.21E-04	1.22E-05	8.49E-06	1.15E-05
Iron	**7.99E-02**	6.80E-02	8.90E-03	1.60E-05	2.75E-02	1.22E-05	8.49E-06	1.15E-05
Lead	6.79E-05	6.36E-05	5.71E-05	**7.98E-05**	3.39E-05	6.08E-05	4.25E-05	5.74E-05
Manganese	**1.06E-03**	9.02E-04	1.23E-04	7.98E-06	3.65E-04	6.08E-06	4.25E-06	5.74E-06
Mercury	**1.21E-04**	1.04E-04	4.49E-05	5.53E-06	4.25E-05	4.21E-06	2.95E-06	3.98E-06
Nickel	**1.75E-04**	1.52E-04	4.42E-05	3.99E-05	6.53E-05	3.04E-05	2.12E-05	2.87E-05
Selenium	**6.33E-05**	5.61E-05	2.59E-05	3.03E-05	2.58E-05	2.31E-05	1.61E-05	2.18E-05
Vanadium	**3.40E-04**	2.95E-04	8.74E-05	7.98E-05	1.27E-04	6.08E-05	4.25E-05	5.74E-05
Zinc	**4.12E-04**	3.54E-04	7.06E-05	3.99E-05	1.47E-04	3.04E-05	2.12E-05	2.87E-05
Chlorine	**2.91E-02**	2.56E-02	1.65E-02	1.09E-02	1.13E-02	8.29E-03	5.83E-03	7.88E-03
Fluorine	**1.64E-02**	1.41E-02	6.96E-03	2.21E-03	5.91E-03	1.68E-03	1.18E-03	1.60E-03
Benzene (1)	**2.90E-03**	2.49E-03	1.15E-03	2.53E-04	1.03E-03	1.92E-04	1.35E-04	1.83E-04
Dioxins/Furans (2)	**2.54E-09**	2.18E-09	1.00E-09	2.21E-10	9.00E-10	1.68E-10	1.18E-10	1.60E-10
Formaldehyde (3)	4.40E-03	5.98E-03	1.30E-02	**1.42E-02**	1.57E-03	1.07E-02	2.41E-03	2.22E-03
POM (PAH & Phenols) (4	**4.64E-05**	4.21E-05	3.68E-05	3.48E-05	2.01E-05	2.64E-05	1.86E-05	2.51E-05

List of Preparers

Minnesota Environmental Quality Board 658 Cedar Street St. Paul, Minnesota, 55155	**Project Management**
Dahlen, Berg & Company 2150 Dain Bosworth Plaza 60 South Sixth Street Minneapolis, Minnesota 55402	**Alternatives Design, Fuel Price Projections, Cogeneration Value Projections, Criteria Emissions Estimates, Economic and Technical Feasibility, Demand Management, Cogeneration, Environmental and Material Handling Mitigation**
John R. Brady Associates, Inc P.O. Box 6 Oldwick, N.J.	**Construction Cost Estimates**
Syska and Hennesey, Consulting Engineers	**Alternatives Design, Detailed Engineering Construction Diagrams, Technical Feasibility Analysis**
Sharon Decker Planning and Research 4330 Woodale Avenue St. Louis Park, MN 55424	**Technical Writing; Land Use Planning**
Ronald E. Sundberg, P.E Consulting Engineer 3426 Harriet Avenue S Minneapolis, MN 55408	**Consultant Procurement, District Heating, Thermal Network, Demand Side Management**
Trinity Consultants Incorporated 9401 Indian Creek Parkway Suite 970, Overland Park, Kansas 66210	**Air Toxics Emissions Rate Estimates, Dispersion Modeling of Criteria Pollutants and Air Toxics**
B.A. Liesch Associates, Inc. 13400 15th Avenue North Minneapolis, MN 55441	**Water Quality, Natural Environment, Groundwater, Contamination Site Assessments**
Macromedia Technologies 4590 Scott Trail Eagan, MN 55122	**Photography, Photorealistic Computer Imaging**
Mr. James Robin Landscape Architect 23420 Park Street Excelsior, MN 55331	**Riverfront Trailway and Parkway Feasibility**