MINNESOTA
DEPARTMENT OF
COMMERCE

85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
651.296.4026 FAX 651.297.1959 TTY 651.297.3067

May 9, 2003

The Honorable Beverly Jones Heydinger
Administrative Law Judge
Office of Administrative Hearings
100 Washington Square, Suite 1700
Minneapolis, Minnesota 55401-2138

RE: In the Matter of the Application of Faribault Energy Park, LLC for a Certificate of Need
OAH Docket No. 15-2500-15301-2
MPUC Docket No. IP6202/CN-02-2006

Dear Judge Heydinger:

Enclosed for filing please find the Final Environmental Report prepared by the Energy Division of the Minnesota Department of Commerce. Also enclosed is our affidavit of service.

Respectfully Submitted:

STEVE RAKOW
RATES ANALYST

SR/ja
Enclosures

This summary and three attachments constitute the Final Environmental Report for Faribault Energy Park, a Combined Cycle project in Faribault, Minnesota proposed by Faribault Energy Park, LLC (FEP). Minnesota Statute § 216B.243 states that no large energy facility shall be sited or constructed in Minnesota without the issuance of a Certificate of Need (CN) by the Public Utilities Commission (Commission). According to Minnesota Statute § 216B.2421, any electric generating facility of 50 MW or more qualifies as a Large Electric Generating Facility (LEGF). Since Faribault Energy Park, as proposed, has a capacity of 250 MW, it qualifies as a LEGF.

Minnesota Rule 4410.7100 requires the Commission to prepare an Environmental Report during the LEGF's CN application process. In the Commission's ORDER FINDING APPLICATION SUBSTANTIALLY COMPLETE AND REFERRING MATTER FOR CONTESTED CASE PROCEEDING, dated January 27, 2003, the Commission delegated its responsibilities for the preparation, distribution, and sponsorship of the Environment Report to the Department of Commerce (Department).

Minnesota Rule 4410.7100 requires that the Environmental Report not be as exhaustive or detailed as an Environmental Impact Statement. Specifically, Minnesota Rules require the Environmental Report to contain the following areas of information:

- a brief description of the proposed facility;
- an identification of reasonable alternative facilities including, as appropriate, the alternatives of different sized facilities, facilities using different fuels, different facility types, and combinations of alternatives;
- a general evaluation, including the availability, estimated reliability, economic, employment, and environmental impacts of the proposal and reasonable alternative facilities; and
- a general analysis of the alternatives of no facility, different levels of capacity, and delayed construction of the facility, which analysis shall include consideration of conservation and load management measures that could be used to reduce the need for the proposed facility.

On March 18, 2003 the Department issued a Draft Environmental Report for Faribault Energy Park. The Department accepted written comments on the Draft Environmental Report through April 30, 2003. In addition, oral comments were accepted at public hearings that took place on April 30, 2003 in Faribault, Minnesota. While no oral comments were made directly on the Draft Environmental Report, environmental concerns were expressed at the public hearing. The Draft Environmental Report is reproduced as Attachment 1. The written and oral concerns conveyed to the Department are summarized in Attachment 2. The Department's response to the comments received is presented as Attachment 3.

The Draft Environmental Report, the comments received, and the Department's responses to these comments constitute the Final Environmental Report. The Commission will consider the Final Environmental Report when deliberating on the CN application.

STATE OF MINNESOTA)
) ss
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, **Kathy Aslakson**, being first duly sworn, deposes and says: than on the **9th** day of **May, 2003,** served the attached **Minnesota Department of Commerce Final Environmental Report**

MPUC DOCKET NUMBER: IP6202/CN-02-2006
OAH DOCKET NUMBER: 15-2500-15301-2

XX by depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid
XX by personal service (MN PUC)
by express mail
by delivery service

to all persons on the attached service list or at the address indicated below:

see attached service list

Kathy Aslakson

Subscribed and sworn to before me

this 9th day of May, 2003

Karen L Santori

KAREN L. SANTORI
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2005

IP6202/CN-02-2006

Burl W. Haar, Exec Sec
MN Public Utilities Commission
350 Metro Square Bldg
121 7th Place East
St. Paul, MN 55101

Kathy Aslakson **(4)**
MN Dept of Commerce
85 7th Place, Ste. 500
St. Paul, MN 55101-2198

Julia Anderson
Attorney General's Office
525 Park St, Ste 200
St. Paul, MN 55103-2106

Curt Nelson
Attorney General's Office-RUD
900 NCL Tower
445 Minnesota Street
St. Paul, MN 55101

Suan Heffron
Pollution Control Agency
520 Lafayette Rd.
St. Paul, MN 55155

William Grant, Director
Izaak Walton League, Midwest Off.
1619 Dayton Ave., Ste. 202
St. Paul, MN 55104-6206

Allan Klein
Administrative Law Judge
Office of Administrative Hearings
100 Washington Sq., Ste. 1700
Minneapolis, MN 55401-2138

Alan R. Mitchell
Environmental Quality Board
658 Cedar St., Room 300
St. Paul, MN 55155

J. Drake Hamilton
Minnesotans for an Energy
Efficient Economy
46 E. 4th St., Ste. 600
St. Paul, MN 55101

James D. Larson
Dahlen, Berg & Co.
200 S. 6th St., Ste. 300
Minneapolis, MN 55402

Paula Maccabee
Project Coordinator
Sierra Club MN Air Toxics Campaign
1961 Selby Ave.
St. Paul, MN 55104

Matt Norton
26 E. Exchange St., Ste. 206
St. Paul, MN 55101-1667

Russell J. Wagner
Center Point Energy, Minnegasco
800 LaSalle Ave., Floor 11
PO Box 59038
Minneapolis, MN 55459-0038

IP6202/CN-02-2006
DRAFT ENVIRONMENTAL REPORT

Burl W. Haar, Exec Sec (12)
MN Public Utilities Commission
350 Metro Square Bldg
121 7th Place East
St. Paul, MN 55101

Kathy Aslakson
MN Dept of Commerce
85 7th Place, Ste. 500
St. Paul, MN 55101-2198

Priti Patel
Attorney General's Office
525 Park St, Ste 200
St. Paul, MN 55103-2106

Randy Porter
Dahlen Berg & Company
200 S. 6th St.
Minneapolis, MN 55402

Bill Storm (2)
Environmental Quality Board
Centennial Bldg.
658 Cedar St., Room 300
St. Paul, MN 55101

Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

MN Legislative Reference Library
645 State Office Bldg.
St. Paul, MN 55155-1050

NW Regional Development Comm.
115 S. Main Ave.
Warren, MN 56762

Headwaters Regional Development Comm.
403 4th St. NW
PO Box 906
Bemidji, MN 56609-0906

Arrowhead Regional Development Comm.
221 W. 1st St.
Duluth, MN 55802

Region Five Development Commission
611 Iowa Ave.
Staples, MN 56479

Mid-Minnesota Development Commission
333 W. 6th St.
Willmar, MN 56201

Upper Minnesota Valley Regional
Development Commission
323 W. Schlieman Ave.
Appleton, MN 56208

East Central Regional Development Comm.
100 S. Park St.
Mora, MN 55051

Southwest Regional Development Comm.
2401 Broadway Ave., Ste. 1
Slayton, MN 56172

Region Nine Development Commission
410 E. Jackson St.
PO Box 3367
Mankato, MN 56002

Metropolitan Council
Mears park Centre
230 E. 5th St.
St. Paul, MN 55101-1633

Dan Medenblik
Minnesota Department of Health
450 Metro Square Bldg.
121 7th Place E., Ste 230 – Box 64975
St. Paul, MN 55164

Minnesota Dept. of Labor and Industry
443 Lafayette Rd.
St. Paul, MN 55155

Gerald Larson
Minnesota Dept. of Transportation
395 John Ireland Blvd.
St. Paul, MN 55155

Rebecca Wooden
Minnesota Dept. of Natural Resources
500 Lafayette Rd., Box 10
St. Paul, MN 55155-4010

Beverly Jones Heydinger (2)
Administrative Law Judge
100 Washington Sq, Ste. 1700
Minneapolis, MN 55401-2138

Board of Electricity
1821 University Ave., Ste. S-128
St. Paul, MN 55104-2993

Susan Heffron
Pollution Control Agency
520 Lafayette Rd.
St. Paul, MN 55155

Bob Patton
Minnesota Dept. of Agriculture
90 W. Plato Blvd.
St. Paul, MN 55155

James D. Larson
Faribault Energy Park
200 S. 6th St., Ste. 300
Minneapolis, MN 55402

Buckham Memorial Library
11 Division St. E.
Faribault, MN 55021

Jim Haertel
BWSR
1 W. Water St., Ste. 200
St. Paul, MN 55107

Crookston Public Library (Reg. 1)
110 N. Ash St.
Crookston, MN 56716

Bemidji Public Library (Reg. 2)
602 Bletrami
Bemidji, MN 56601

Duluth Public Library (Reg. 3)
520 W. Superior St.
Duluth, MN 55802

Fergus Falls Public Library (Reg. 4)
205 E. Hampden
Fergus Falls, MN 56537

Kitchigami Regional Library (Reg. 5)
403 Barclay Ave.
PO Box 84
Pine River, MN 56474

Willmar Public Library (Reg. 6)
410 Fifth St. SW
Willmar, MN 56201-3298

Montevideo/Chippewa Cnty. Library
(Reg. 6W)
224 S. First St.
Montevideo, MN 56265

East Central Regional Library (Reg. 7E)
244 S. Birch St.
Cambridge, MN 55008

Great River Regional Library (Reg. 7W)
405 St. Germain
St. Cloud, MN 56301-3697

Marshall-Lyon County Library (Reg. 8)
301 W. Lyon St.
Marshall, MN 56258

Minnesota Valley Regional (Reg. 9)
Library, Reference Dept.
100 E. Main, PO Box 3446
Mankato, MN 56002

Rochester Public Library (Reg. 10)
Reference Dept.
101 2nd Se. SE
Rochester, MN 55904

Minneapolis Public Library (Metro Area)
Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

ATTACHMENT 1

Draft Environmental Report

MINNESOTA
DEPARTMENT OF
COMMERCE

85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
651.296.4026 FAX 651.297.1959 TTY 651.297.3067

March 18, 2003

The Honorable Beverly Jones Heydinger
Administrative Law Judge
Office of Administrative Hearings
100 Washington Square, Suite 1700
Minneapolis, Minnesota 55401-2138

RE: **In the Matter of the Application of Faribault Energy Park, LLC for a Certificate of Need**
OAH Docket No. 15-2500-15301-2
MPUC Docket No. IP6202/CN-02-2006

Dear Judge Heydinger:

Enclosed for filing please find the Draft Environmental Report prepared by the Minnesota Department of Commerce. Also enclosed is our affidavit of service.

Respectfully submitted,

STEVE RAKOW
Rates Analyst

SR/ja
Enclosures

STATE OF MINNESOTA)
) ss
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, **Kathy Aslakson**, being first duly sworn, deposes and says: than on the **17th** day of **March, 2003,** served the attached **Minnesota Department of Commerce Draft Environmental Report**

MN DOC DOCKET NUMBER: IP6202/CN-02-2006

XX by depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid
XX by personal service (MN PUC)
by express mail
by delivery service

to all persons on the attached service list or at the address indicated below:

see attached list

Kathy Aslakson

Subscribed and sworn to before me

this 17th day of March, 2003

Karen L Santori

KAREN L. SANTORI
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2005

IP6202/CN-02-2006
AFT ENVIRONMENTAL
PORT

Burl W. Haar, Exec Sec (12)
MN Public Utilities Commission
350 Metro Square Bldg
121 7th Place East
St. Paul, MN 55101

Kathy Aslakson
MN Dept of Commerce
85 7th Place, Ste. 500
St. Paul, MN 55101-2198

Priti Patel
Attorney General's Office
525 Park St, Ste 200
St. Paul, MN 55103-2106

Randy Porter
Dahlen Berg & Company
200 S. 6th St.
neapolis, MN 55402

Bill Storm (2)
Environmental Quality Board
Centennial Bldg.
658 Cedar St., Room 300
St. Paul, MN 55101

Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

MN Legislative Reference Library
645 State Office Bldg.
St. Paul, MN 55155-1050

NW Regional Development Comm.
115 S. Main Ave.
Warren, MN 56762

Headwaters Regional Development Comm.
403 4th St. NW
PO Box 906
Bemidji, MN 56609-0906

Arrowhead Regional Development Comm.
221 W. 1st St.
Duluth, MN 55802

Region Five Development Commission
611 Iowa Ave.
Staples, MN 56479

Mid-Minnesota Development Commission
333 W. 6th St.
Willmar, MN 56201

Upper Minnesota Valley Regional Development Commission
323 W. Schlieman Ave.
Appleton, MN 56208

East Central Regional Development Comm.
100 S. Park St.
Mora, MN 55051

Southwest Regional Development Comm.
2401 Broadway Ave., Ste. 1
Slayton, MN 56172

Region Nine Development Commission
410 E. Jackson St.
PO Box 3367
Mankato, MN 56002

Metropolitan Council
Mears park Centre
230 E. 5th St.
St. Paul, MN 55101-1633

Dan Medenblik
Minnesota Department of Health
450 Metro Square Bldg.
121 7th Place E., Ste 230 – Box 64975
St. Paul, MN 55164

Minnesota Dept. of Labor and Industry
443 Lafayette Rd.
St. Paul, MN 55155

Gerald Larson
Minnesota Dept. of Transportation
395 John Ireland Blvd.
St. Paul, MN 55155

Rebecca Wooden
Minnesota Dept. of Natural Resources
500 Lafayette Rd., Box 10
St. Paul, MN 55155-4010

Beverly Jones Heydinger (2)
Administrative Law Judge
100 Washington Sq, Ste. 1700
Minneapolis, MN 55401-2138

Board of Electricity
1821 University Ave., Ste. S-128
St. Paul, MN 55104-2993

Susan Heffron
Pollution Control Agency
520 Lafayette Rd.
St. Paul, MN 55155

Bob Patton
Minnesota Dept. of Agriculture
90 W. Plato Blvd.
St. Paul, MN 55155

James D. Larson
Faribault Energy Park
200 S. 6th St., Ste. 300
Minneapolis, MN 55402

Buckham Memorial Library
11 Division St. E.
Faribault, MN 55021

Jim Haertel
BWSR
1 W. Water St., Ste. 200
St. Paul, MN 55107

Crookston Public Library (Reg. 1)
110 N. Ash St.
Crookston, MN 56716

Bemidji Public Library (Reg. 2)
602 Bletrami
Bemidji, MN 56601

Duluth Public Library (Reg. 3)
520 W. Superior St.
Duluth, MN 55802

Fergus Falls Public Library (Reg. 4)
205 E. Hampden
Fergus Falls, MN 56537

Kitchigami Regional Library (Reg. 5)
403 Barclay Ave.
PO Box 84
Pine River, MN 56474

Willmar Public Library (Reg. 6)
410 Fifth St. SW
Willmar, MN 56201-3298

Montevideo/Chippewa Cnty. Library
(Reg. 6W)
224 S. First St.
Montevideo, MN 56265

East Central Regional Library (Reg. 7E)
244 S. Birch St.
Cambridge, MN 55008

Great River Regional Library (Reg. 7W)
405 St. Germain
St. Cloud, MN 56301-3697

Marshall-Lyon County Library (Reg. 8)
301 W. Lyon St.
Marshall, MN 56258

Minnesota Valley Regional (Reg. 9)
Library, Reference Dept.
100 E. Main, PO Box 3446
Mankato, MN 56002

Rochester Public Library (Reg. 10)
Reference Dept.
101 2nd Se. SE
Rochester, MN 55904

Minneapolis Public Library (Metro Area)
Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

MINNESOTA
DEPARTMENT OF
COMMERCE

85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
651.296.4026 FAX 651.297.1959 TTY 651.297.3067

March 18, 2003

TO: Parties on attached service list

RE: **In the Matter of the Application of Faribault Energy Park, LLC for a Certificate of Need**
OAH Docket No. 15-2500-15301-2
MPUC Docket No. IP6202/CN-02-2006

Dear Library Staff:

Enclosed is a copy of the Draft Environmental Report (the Draft) prepared by the Energy Division of the Minnesota Department of Commerce. The Draft provides information on a power plant proposed by Faribault Energy Park, LLC and on a variety of alternatives to the proposed project. Also enclosed is our affidavit of service.

Minnesota Rules 4410.7100 and 4410.2600 require that the Draft be provided to the Environmental Conservation Library, the Legislative Reference Library, the Regional Development Libraries, and public libraries or public places where the Draft will be available for public review in each county where the proposed project will take place. The proposed project would be located near the city of Faribault, Minnesota in Rice County.

Oral comments on the Draft will be accepted at the hearings scheduled for April 30, 2003 in Faribault, Minnesota. Written comments on the Draft may be submitted to the Department of Commerce through April 30, 2003 at the following address:

Steve Rakow
Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, Minnesota 55101

Please retain the enclosed Draft Environmental Report for public review at your library through April 30, 2003. Thank you for your cooperation.

Sincerely,

Steve Rakow

STEVE RAKOW
Rates Analyst

SR/ja
Enclosures

STATE OF MINNESOTA)
) ss
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, **Kathy Aslakson**, being first duly sworn, deposes and says: than on the **17th** day of **March, 2003,** served the attached **Minnesota Department of Commerce Draft Environmental Report**

MN DOC DOCKET NUMBER: IP6202/CN-02-2006

XX by depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid
XX by personal service (MN PUC)
by express mail
by delivery service

to all persons on the attached service list or at the address indicated below:

see attached list

Kathy Aslakson

Subscribed and sworn to before me

this 17th day of March, 2003

Karen C Santori

KAREN L. SANTORI
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2005

IP6202/CN-02-2006
RAFT ENVIRONMENTAL
_.EPORT

Burl W. Haar, Exec Sec (12)
MN Public Utilities Commission
350 Metro Square Bldg
121 7th Place East
St. Paul, MN 55101

Kathy Aslakson
MN Dept of Commerce
85 7th Place, Ste. 500
St. Paul, MN 55101-2198

Priti Patel
Attorney General's Office
525 Park St, Ste 200
St. Paul, MN 55103-2106

Randy Porter
Dahlen Berg & Company
200 S. 6th St.
'inneapolis, MN 55402

Bill Storm (2)
Environmental Quality Board
Centennial Bldg.
658 Cedar St., Room 300
St. Paul, MN 55101

Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

MN Legislative Reference Library
645 State Office Bldg.
St. Paul, MN 55155-1050

NW Regional Development Comm.
115 S. Main Ave.
Warren, MN 56762

Headwaters Regional Development Comm.
403 4th St. NW
PO Box 906
Bemidji, MN 56609-0906

Arrowhead Regional Development Comm.
221 W. 1st St.
Duluth, MN 55802

Region Five Development Commission
611 Iowa Ave.
Staples, MN 56479

Mid-Minnesota Development Commission
333 W. 6th St.
Willmar, MN 56201

Upper Minnesota Valley Regional
Development Commission
323 W. Schlieman Ave.
Appleton, MN 56208

East Central Regional Development Comm.
100 S. Park St.
Mora, MN 55051

Southwest Regional Development Comm.
2401 Broadway Ave., Ste. 1
Slayton, MN 56172

Region Nine Development Commission
410 E. Jackson St.
PO Box 3367
Mankato, MN 56002

Metropolitan Council
Mears park Centre
230 E. 5th St.
St. Paul, MN 55101-1633

Dan Medenblik
Minnesota Department of Health
450 Metro Square Bldg.
121 7th Place E., Ste 230 – Box 64975
St. Paul, MN 55164

Minnesota Dept. of Labor and Industry
443 Lafayette Rd.
St. Paul, MN 55155

Gerald Larson
Minnesota Dept. of Transportation
395 John Ireland Blvd.
St. Paul, MN 55155

Rebecca Wooden
Minnesota Dept. of Natural Resources
500 Lafayette Rd., Box 10
St. Paul, MN 55155-4010

Beverly Jones Heydinger (2)
Administrative Law Judge
100 Washington Sq, Ste. 1700
Minneapolis, MN 55401-2138

Board of Electricity
1821 University Ave., Ste. S-128
St. Paul, MN 55104-2993

Susan Heffron
Pollution Control Agency
520 Lafayette Rd.
St. Paul, MN 55155

Bob Patton
Minnesota Dept. of Agriculture
90 W. Plato Blvd.
St. Paul, MN 55155

James D. Larson
Faribault Energy Park
200 S. 6th St., Ste. 300
Minneapolis, MN 55402

Buckham Memorial Library
11 Division St. E.
Faribault, MN 55021

Jim Haertel
BWSR
1 W. Water St., Ste. 200
St. Paul, MN 55107

Crookston Public Library (Reg. 1)
110 N. Ash St.
Crookston, MN 56716

Bemidji Public Library (Reg. 2)
602 Bletrami
Bemidji, MN 56601

Duluth Public Library (Reg. 3)
520 W. Superior St.
Duluth, MN 55802

Fergus Falls Public Library (Reg. 4)
205 E. Hampden
Fergus Falls, MN 56537

Kitchigami Regional Library (Reg. 5)
403 Barclay Ave.
PO Box 84
Pine River, MN 56474

Willmar Public Library (Reg. 6)
410 Fifth St. SW
Willmar, MN 56201-3298

Montevideo/Chippewa Cnty. Library
(Reg. 6W)
224 S. First St.
Montevideo, MN 56265

East Central Regional Library (Reg. 7E)
244 S. Birch St.
Cambridge, MN 55008

Great River Regional Library (Reg. 7W)
405 St. Germain
St. Cloud, MN 56301-3697

Marshall-Lyon County Library (Reg. 8)
301 W. Lyon St.
Marshall, MN 56258

Minnesota Valley Regional (Reg. 9)
Library, Reference Dept.
100 E. Main, PO Box 3446
Mankato, MN 56002

Rochester Public Library (Reg. 10)
Reference Dept.
101 2nd Se. SE
Rochester, MN 55904

Minneapolis Public Library (Metro Area)
Environmental Conservation Library
300 Nicollet Mall
Minneapolis, MN 55401

Draft Environmental Report

Faribault Energy Park, LLC

250 MW Combined Cycle Power Plant

Docket No. IP6202/CN-02-2006

March 18, 2003

Table of Contents

List of Tables

List of Figures

1 Introduction

Faribault Energy Park, LLC (FEP or the Company) submitted an application for a Certificate of Need (CN) to the Minnesota Public Utilities Commission (Commission) on November 17, 2002.[1] FEP's proposal is to construct a nominal 250 MW natural gas-fired combined-cycle generating plant near Faribault, Minnesota for intermediate electric load serving (proposed Project).

Pursuant to Minnesota Rules part 4410.7100, subp. 1, the Commission is responsible for preparing an environmental report on each application for a certificate of need (CN) for a large electric generating facility (LEGF). Minnesota Statutes section 116C.52, subd. 5, states that any electric generating facility of 50 megawatts (MW) or more qualifies as a LEGF. The proposed Project qualifies as a LEGF because it will result in the construction of a 250 MW electric generating facility; significantly greater than the 50 MW threshold. In an Order dated January 27, 2003 the Commission delegated to the Energy Division of the Minnesota Department of Commerce (Department) the preparation of the environmental report for inclusion in the CN hearing record.

Without being as exhaustive or detailed as an environmental impact statement (Minnesota Rule 4410.7100, subp. 4), this draft environmental report includes, as required by Minnesota Rule 4410.7100, subp. 3:

- a brief description of the proposed facility;
- an identification of reasonable alternative facilities including, as appropriate, the alternatives of different sized facilities, facilities using different fuels, different facility types, and combination of alternatives;
- a general evaluation, including the availability, estimated reliability, and economic, employment, and environmental impacts, of the proposal and reasonable alternative facilities identified; and
- a general analysis of the alternatives of no facility, different levels of capacity, and delayed construction of the facility, which analysis shall include consideration of conservation and load management measures that could be used to reduce the need for the proposed facility.

In the remainder of this introductory chapter, the Department provides some background information regarding the proposed Project. The Department then presents the proposed purpose of the Plant as well as the list of the alternatives considered. Finally, the Department describes the factors used to evaluate and contrast the proposed Project with its alternatives.

[1] Docket No. IP6202/CN-02-2006.

1.1 Background of the Project

Faribault Energy Park is a nominal 250 MW combined-cycle power plant fueled by natural gas with No. 2 fuel oil as the back-up fuel. Natural gas will be burned to drive a single combustion turbine to produce electricity. Then, heat output from the single combustion turbine will be captured to drive a single steam turbine. The resulting process is estimated to produce energy efficiencies in excess of 50%.

The proposed Project will be located immediately north of the existing corporate limit of the City of Faribault, Minnesota. Faribault Energy Park, LLC will own and operate the proposed Project. The Company is owned by the Minnesota Municipal Power Agency (MMPA or the Agency), a Minnesota municipal corporation.

1.2 Purpose of the Project

The proposed Project's mission is to provide reliable, low-cost electric capacity and energy to the Mid-Continent Area Power Pool (MAPP) region and MMPA member municipalities while protecting the environment. Being able to access available, dispatchable and reliable resources is a key objective in meeting this mission. The MAPP-US region is forecasted to have a 492 megawatt (MW) capacity deficit by 2006, the year the proposed Project is projected to come on-line. MMPA is projected to have a capacity deficit of 113 MW in 2006 if the proposed Project is not completed.

1.3 Considered Alternatives

In addition to discussing the proposed Project, this report provides information on the following classes of alternatives:

Alternative Approaches:

- purchased power,
- energy conservation and load management,
- new transmission line capacity,
- smaller facility,
- delayed construction,
- no facility, and
- alternate site.

Fossil Fuel Technologies:

- coal-fired boiler, and
- dual-fuel simple-cycle combustion turbine.

Combination of Alternatives:

- natural gas fired combustion turbine and wind

Renewable Resources:

- hydropower,
- wind,
- solar,
- biomass,
- landfill gas, and
- geothermal.

Emerging Technology Alternatives:

- fuel cells, and
- energy storage.

These alternatives will be described and evaluated in Chapters 3 through 7.

1.4 Evaluation Factors

Minnesota Rule 4410.7100, subp. 3 requires that the environmental report provide a general evaluation of the proposed facility and reasonable alternative facilities, based on the following factors: availability, reliability, economic impacts, and environmental impacts. The factors used for evaluating the proposed Project and the alternatives are described below.

1.4.1 Availability

The availability of an electric generating resource usually refers to the percentage of time during any given year that the facility would be available for service. The North American Electric Reliability Council (NERC) defines "availability" as follows:[2]

> *A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.*

The availability of a facility depends on maintenance requirements and availability of fuel, among other factors.

The availability of an alternative also relates to the ability to site, permit and construct an alternative in time to meet FEP's need in 2006.

1.4.2 Reliability

It is critical for consumers to have reliable electric service. NERC defines "reliability" as follows:[3]

[2] "Glossary of Terms" NERC, www.nerc.com/glossary, March 1999.

The degree of performance of the elements of the bulk electric system that results in electricity being ... delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system Adequacy and Security.

Adequacy
The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security
The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

1.4.3 Energy Efficiency

Energy efficiency is a measure of how completely one form of energy (such as the chemical energy contained in a fossil fuel, the potential energy available in water stored above a dam, or the kinetic energy in the wind which passes through the blades of a wind turbine) can be transformed into another form of energy which is more useful for a given purpose (such as electric energy for lighting or motor operation, or heat energy for space heating).

Typically, for fossil-fueled electric power generation facilities, efficiency is expressed in terms of a heat rate.[4] Energy-conversion projects with lower heat rates use energy resources more efficiently than projects with high heat rates.[5] However, energy efficiency alone is not a sufficient measure to determine the best technology to provide a given type of energy. Environmental and economic factors must be considered before an appropriate technology can be selected.

1.4.4 Environmental Effects

This section discusses the effects that the proposed Project and each alternative are expected to have on the environment, including (where possible) factors such as air pollution, land use, water use, liquid and solid wastes, noise, aesthetics, and traffic.

1.4.4.1 Air Pollution

---

[3] "Glossary of Terms" NERC, www.nerc.com/glossary, March 1999.

[4] Minn. Rules pt. 7849.0010 subp. 12 defines "heat rate" to mean "a measure of average thermal efficiency of an electric generating facility expressed as the ratio of input energy to the net kilowatt hour produced, computed by dividing the total energy content of fuel burned for electricity generation by the resulting net kilowatt hour generation."

[5] The heat rate can be converted into an efficiency (expressed as a percentage) by dividing 3,413 by the heat rate (given in units of British thermal units per kilowatt-hour) and multiplying the result by 100.

Operation of electric generators causes emissions of particulate matter, nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOCs), and trace amounts of hazardous air pollutants (HAPs). These emissions contribute to the deterioration of ambient air quality. This section includes information on the emissions and the resulting ambient air quality.

1.4.4.2 Land Use

This analysis assesses the estimated range of land requirements of the proposed Project and each alternative.

1.4.4.3 Water Use

This assessment discusses the necessary water appropriations, water use and potential sources of water of the proposed Project and each of the alternatives.

1.4.4.4 Liquid and Solid Wastes

This assessment considers, for the proposed Project and each alternative, the types, volumes and/or quantities of liquid and solid wastes generated and options for their treatment and/or disposal.

1.4.4.5 Noise

This section provides information on the potential sources and types of audible noise attributable to operation of the proposed Project and each alternative.

1.4.4.6 Aesthetics

The aesthetics of the proposed Project and the alternatives are discussed, focusing on the size and number of physical features and how they may fit into the pre-existing environment.

1.4.4.7 Traffic

This assessment considers potential traffic induced during construction and ongoing operation.

1.4.5 Economic Effects

The final assessment qualitatively discusses the potential economic effects of the proposed Project and the alternatives, focusing whenever possible on potential jobs created during construction and during ongoing operation, effects on regional economic development, and effects on tax revenues generated. While there may be advantages to some people in increasing employment, regional economic development and tax revenues, these factors may also increase the rates that consumers would pay for electricity generated by such means. Increased energy costs may also negatively affect economic development. Therefore, the economic effects must be weighed carefully.

This report includes seven chapters. The next chapter describes and presents a general evaluation of the proposed Project. Subsequent chapters apply the same evaluation to the different classes of alternatives to the proposed Project.

2 Analysis of Project

2.1 Project Description

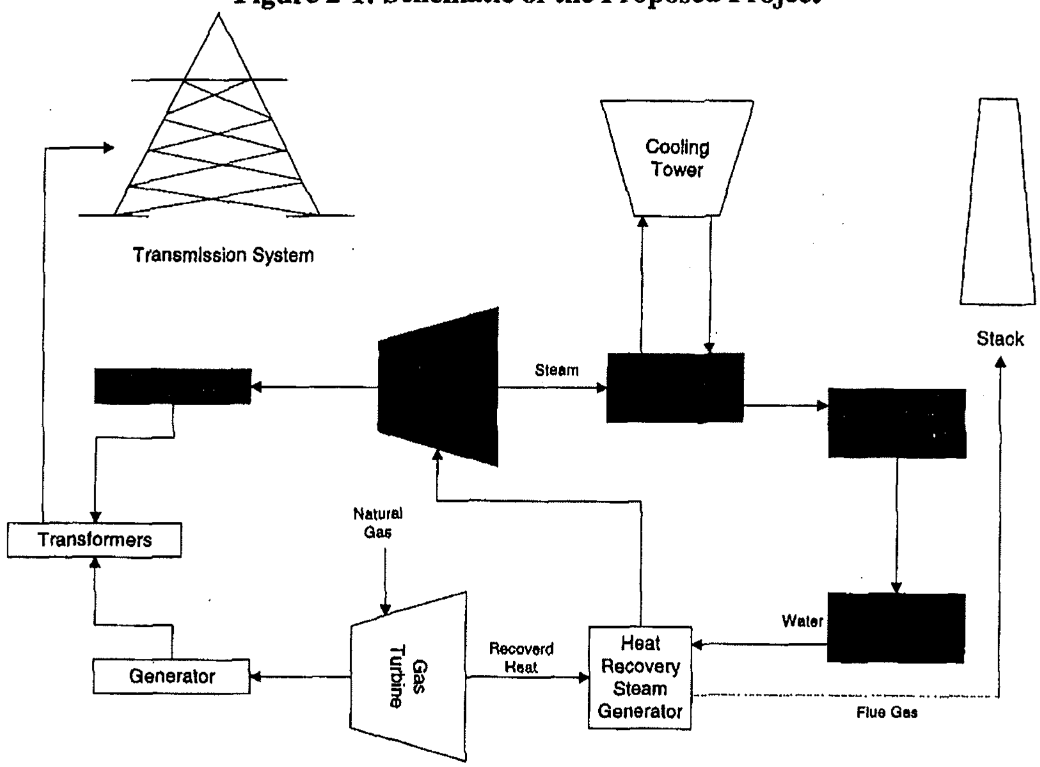
2.1.1 General

Faribault Energy Park, LLC has submitted an application to the Minnesota Public Utilities Commission to request a CN for a nominal 250 MW combined-cycle power plant fueled by natural gas with No. 2 fuel as back-up fuel. The project is located immediately north of the existing corporate limit of the City of Faribault, Minnesota and is owned by the Minnesota Municipal Power Agency, a Minnesota municipal corporation.

2.1.2 Operating Cycle

A natural gas-fired combined-cycle power plant consists of combustion turbine generators that burn natural gas as fuel. It uses two cycles to produce electricity. The combined cycle generating process for the proposed Project is shown schematically below in Figure 2-1.

Figure 2-1: Schematic of the Proposed Project



In the first cycle, air is compressed and mixed with natural gas in the combustion chamber. The mixture is combusted and the combustion products are expanded in a power turbine, which turns an electrical generator. In the second cycle, the heat from the hot exhaust gases exiting the combustion turbine is recovered in the Heat Recovery Steam Generator (HRSG). The steam produced in the HRSG is used to turn a steam turbine connected to an electrical generator.

2.1.3 Fuel Use

The Project is proposed to be fueled by natural gas, with No. 2 fuel oil as the back-up fuel. During peak periods (described as "combustion turbine peak firing mode with HRSG duct firing during summer conditions"), the proposed Project is expected to consume 1.823 million standard cubic feet (SCF) of natural gas per hour. Under the expected annual operating conditions, 50% capacity factor, it could consume up to 7,986 million SCF of natural gas each year.

Natural gas will be provided to the plant by tapping the Northern Natural Gas (NNG) mainline. The NNG mainline traversing the property consists of two 30-inch pipes.

The new 16-inch line to the combustion turbine will be routed completely within plant property.

The proposed Project is expected to experience maximum natural gas consumption during the summer to meet peak summertime demand and energy needs. Sufficient excess natural gas is available since gas consumption is winter peaking and the gas supply system is designed around that wintertime peak. Thus, the proposed Project will attain its maximum natural gas usage rate during the off-peak (for gas) summer season when sufficient excess natural gas is expected to be available.

2.2 Evaluation of the Project

2.2.1 Availability

Properly operated and maintained, a combined-cycle facility is expected to be available for service more than 95 percent of the year. The use of the proposed Project, measured by its annual capacity factor, is expected to be in the range of 40 to 80 percent.

2.2.2 Reliability

Combined-cycle facilities are generally reliable. The technology has been installed for utility-scale operations in Minnesota. For example, see Northern States Power Company d/b/a Xcel Energy's (Xcel Energy) Black Dog Station.[6] More importantly, the technology is fully dispatchable, being available when the customers' need is greatest.

2.2.3 Energy Efficiency

The proposed Project is expected to operate at a heat rate of about 6,600 Btu/kWh at summer peak-firing conditions. This level equates to a thermal efficiency of 53-56% percent.

[6] Docket No. E002/CN-99-1815.

2.2.4 Environmental Effects

2.2.4.1 Air Emissions

The emissions from the combustion of natural gas will be particulate matter, nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOCs), and trace amounts of water (H_2O) and hazardous air pollutants (HAPs). The proposed Project will use combustion turbines equipped with selective catalytic reduction (SCR). Table 2-1 (see below) presents the estimated expected air emissions from the proposed Project. It is important to note that the expected air emissions in Table 2-1 are equal to or lower than expected Air Permit Levels.

A comparison of estimated impacts on ambient air quality of the proposed Project with ambient air quality standards shows that the proposed Project will be in compliance with state or federal ambient air quality standards.[7]

2.2.4.2 Land Use

The proposed Project will be entirely on land currently used for farming. A pipeline that currently exists on the property will be tapped to provide natural gas for the project.

2.2.4.3 Water Use

The proposed Project is expected to increase the annual groundwater use by 788 million gallons. Its maximum groundwater pumping rate is expected to be 1,500 gpm.

[7] Minnesota Rule 7009.0080 describes the state's ambient air quality standards.

Pollutant	Table 2-1: Expected Combustion Turbine Emissions					Support	FACILITY
	Natural Gas		Distillate Oil		Total	Facilities	TOTAL
	lbs/hr [1]	tons/yr [2]	lbs/hr [1]	tons/yr	tons/yr	tons/yr	tons/yr
NO_X	15.74	38.38	91.80	50.49	88.87	23.68	112.55
CO	15.97	180.43	39.60	21.78	202.21	16.05	218.26
PM	18.76	39.10	34.00	18.70	57.80	1.60	59.40
PM_{10}	18.76	39.10	34.00	18.70	57.80	1.60	59.40
VOC	1.82	83.38	7.50	4.13	87.51	1.26	88.77
SO_X	1.88	3.33	64.95	35.72	39.06	0.32	39.37
HAPS	**lb/hr**	**lb/yr**	**lb/hr**	**lb/yr**	**lb/yr**	**lb/yr**	**lb/yr**
Benzene	0.02258	71.37	0.10718	107.18	178.55	50.35	228.90
PAH	0.00414	13.08	0.07795	77.95	91.03	12.05	103.08
Formaldehyde	1.33626	4222.58	0.54564	545.64	4768.22	50.37	4818.59
Toluene	0.24467	773.15	0.54759	547.59	1320.74	20.41	1341.15
Xylenes	0.12045	380.63	0.37611	376.11	756.73	13.28	770.01
Acetaldehyde	0.07528	237.89	0.04911	49.11	287.00	14.63	301.63
Acrolein	0.01205	38.06	0.01536	15.36	53.42	1.97	55.39
Dichlorobenzene	0.00000	0.00	0.00000	0.00	0.00	0.42	0.42
Hexane	0.00000	0.00	0.00000	0.00	0.00	627.58	627.58
Naphthalene	0.00245	7.73	0.06821	68.21	75.94	1.71	77.65
Ethylbenzene	0.06023	190.31	0.00000	0.00	190.31	0.00	190.31
Arsenic	0.00037	1.18	0.02144	21.44	22.62	0.33	22.94
Beryllium	0.00002	0.07	0.00060	0.60	0.68	0.16	0.83
Cadmium	0.00206	6.51	0.00935	9.35	15.86	1.03	16.90
Chromium	0.00262	8.28	0.02144	21.44	29.72	4.56	34.28
Cobalt	0.00000	0.00	0.00000	0.00	0.00	0.03	0.03
Lead	0.00094	2.96	0.02728	27.28	30.24	1.02	31.26
Manganese	0.00071	2.25	1.53950	1539.50	1541.75	0.31	1542.06
Mercury	0.00049	1.54	0.00234	2.34	3.88	1.19	5.06
Nickel	0.00393	12.43	0.00896	8.96	21.39	1.27	22.66
Selenium	0.00004	0.14	0.04872	48.72	48.86	1.52	50.38

Regarding a surface water permit, no surface water will be appropriated.

Regarding surface water runoff conditions, at this time the preferred alternative is to direct stormwater to constructed wetlands on-site to allow for sediment removal, infiltration, controlled release of stormwater and for the creation of additional natural habitat for the area. After construction, the proposed Project and the rest of the Plant site will be covered under the Minnesota General Stormwater Permit for Industrial Activity (MNG 11000).

2.2.4.4 Liquid and Solid Wastes

The largest volumes of processed wastewater will be discharged into a created wetland located on site.

Sanitary wastewater will be discharged to an on-site septic system.

2.2.4.5 Noise

FEP will minimize noise during construction by using properly muffled equipment, by routing truck traffic to minimize disturbances to area residents and by restricting some activities to daytime hours.

Noise levels due to operation of the proposed Project are anticipated to be slightly higher at site boundaries than background noise levels. New noise sources from the proposed Project will be limited to the movement of great quantities of air into the compressor section and being exhausted from the stack. These components have far field noise ratings (400 feet from the components) of less than 70 dBA. Sound mitigation features of these components and their locations far from any off-site receptors are expected to reduce noise impacts. The proposed Project is expected to meet all applicable Minnesota Pollution Control Agency noise standards.

2.2.4.6 Aesthetics

The Plant will be located adjacent to an existing Industrial Park and a Park demonstrating alternative energies is inherent in the proposed Project's design. The exhaust stack will be about 130 feet tall. The main plant building will be approximately 75 feet tall. A new gas compressor station may be added pending the results of the gas supply bidding process.

2.2.4.7 Traffic

During the construction of the proposed Project, the increase in traffic on the local county and township roads will be intermittent and will vary during the various phases of the construction period.

Operation of the proposed Project should result in no significant increased traffic from current traffic levels. In the event of frequent or extended operation of the units on fuel oil, traffic increases due to fuel oil deliveries will be managed to ensure safe conditions.

2.2.5 Economic Effects

The proposed Project is expected to require $600/kW in capital costs. An estimated 250 construction workers will be required over the 24 months allocated as the construction period of the proposed Project. It is estimated that they will have a payroll of $13 million over this period. Operation of the unit would require 17 full-time positions at the plant on an ongoing basis.

3 Analysis of Alternative Approaches

3.1 Purchased Power

Purchased power is accomplished through executing power purchase agreements, i.e., contracts between a wholesale supplier of electrical energy and an entity that sells the energy to retail consumers. The following discusses the advantages and disadvantages of purchased power as an option under the assumption that, over time, capacity deficits will increase if demand for electricity continues to rise and new generation plants are not built.

3.1.1 Availability

Power purchase agreements can be entered into in a relatively short period of time, provided there is a ready source of energy to be sold. However, without capacity additions, as electrical demands increase and supplies become more difficult to identify, the cost of power on the market increases, and power purchases are not expected to be an economical means to address shortfalls in generating capacity. As MAPP reserve margins continue to shrink, the availability of purchased power at a given price will naturally decline. Relying on today's energy supply market would expose the Agency to social and financial risks that it cannot control particularly since MAPP forecasts indicate that utilities will experience capacity deficits beginning in 2005.

Purchased power for intermediate resources is not a viable solution for MMPA until later in the next decade. The capacity shortage in MAPP is likely to stimulate construction of new peaking capacity. The additional capacity may result in a short-term surplus and may be a cost-effective capacity resource for MMPA's future needs beyond those being met by the proposed Project. This assumed surplus may not occur in time to meet MMPA's existing needs, but it may be considered for future capacity needs, if available.

3.1.2 Flexibility

Generally speaking, power purchase agreements are fairly flexible, since they can be tailored to meet the needs of the purchaser. Under many scenarios, power purchases would likely offer more flexibility than construction of a plant. However, purchased power tends to be less flexible than desired for an intermediate type of resource. Purchase transactions require scheduling energy on a day-ahead basis and usually for all the on-peak hours whereas the proposed Project can be controlled to follow load in a manner a power purchase usually cannot.

3.1.3 Reliability

As generating capacity becomes limited, a utility's priority should be to serve its native load. Therefore, energy sales contracts to address contingency and peak consumption needs would likely include provisions to allow power interruptions as needed to meet the needs of the utility's own customers. Thus, while protections are likely to be built into firm power purchase contracts, interruptible purchases may become less reliable.

3.1.4 Energy Efficiency

The efficiency of energy provided through a power purchase agreement depends on the source of the energy, which may vary over the term of the agreement. As capacity deficits increase, it is likely that use of relatively low efficiency generation will increase. This development may in turn increase the cost of power purchases.

3.1.5 Environmental Effects

Environmental effects of purchased power depend on the source of the energy, which may vary over the term of the agreement. As capacity deficits increase, there may be greater use of generation sources that emit higher pollutants. However, the extent of environmental effects cannot be fully assessed without knowing the source of the power in power contracts.

3.1.6 Economic Effects

Purchased power may provide economic benefits to the seller of the power, particularly if demand for energy exceeds supply. The energy consumer will ultimately pay the increased cost associated with limited energy supplies. MMPA is a municipal power agency that has the advantage of relatively low cost financing and is not required to earn a profit. These factors further add to the cost of certain purchased power alternatives compared to the cost of the proposed Project. Thus, purchasing intermediate capacity is not cost-effective. The regional economy may also suffer if purchased power is relied on extensively and adequate and reliable sources of energy are not available to business and industry for normal or expanded operations.

3.2 Additional Energy Conservation and Load Management Efforts

Energy conservation and load management is the practice of implementing programs to reduce consumers' demand for energy so that the need for additional generation capacity is reduced or eliminated. It includes measures to use electricity more efficiently and measures which shift the use of electricity away from peak hours of usage.

3.2.1 Availability

The Company estimates that cost-effective demand reduction and conservation programs reduced its summer peak load by over 8.3 MW in 2001. This represents nearly 4% of the Agency's member peak loads. By the end of 2006, conservation programs are expected to reduce the peak load by an additional 2.2 representing a total of 10.5 MW. However, it can take many years for conservation efforts to deliver maximum results. Thus, these programs cannot provide enough capacity in time to defer the proposed Project past the 2006 summer season. While continuing expansion of the load management program is expected, it will not provide enough capacity to avoid building the proposed Project.

3.2.2 Reliability

Energy conservation and load management can be reliable means to reduce consumers' energy demand, especially if these sources are responsive and dispatchable. However, it is difficult to determine the exact reduction in energy due to energy conservation programs. Moreover, since many conservation programs are voluntary and may provide participating consumers with flexibility in energy use, there is no guarantee that consumers will conserve energy at the periods when conservation is most needed. Customer receptivity may limit a program's effectiveness. On the other hand, load management devices do provide some control over consumers' use of electricity. Therefore, load management is more predictable than energy conservation and provides more reliable reductions in energy use.

3.2.3 Energy Efficiency

Energy conservation and load management is the most energy efficient means to meet demand because it does not use additional energy resources.

3.2.4 Environmental Effects

Energy conservation and load management programs cause minimal negative environmental effects.[8] However, load-shifting measures may mean higher air pollution emissions than pure energy conservation if there is a shift in demand from peak to off-peak periods, as it may shift electricity generation from gas-fired peaking turbines to coal-fired base load plants.

3.2.5 Economic Effects

Energy conservation and load management efforts can lower energy consumers' bills by reducing their consumption of electrical energy and by controlling rate increases associated with utilities' capital investment in new facilities. However, if such efforts are not sufficient to bring demand into line with supply, regional economies may suffer from inadequate or unreliable electrical energy sources.

3.3 New Transmission Lines

New transmission lines would provide access to existing or new generation outside the region and allow that source of energy to be used to meet regional demands for electricity.

3.3.1 Availability

Even if generating capacity were available in the Midwest region or elsewhere, it is unlikely that a new transmission line could be sited, permitted, constructed and enter commercial operation in time to meet the projected and timeline projected for the proposed Project. According to NERC, "Even with revised processes, it is likely that transmission facilities to connect the generation and reinforce the bulk electric system will not be available when required due to longer lead times for transmission projects."[9]

[8] "Environmental Costs of Electricity," the Pace University Center for Environmental Legal Studies, 1991.

[9] "Reliability Assessment: 1998-2007, NERC, p. 40.

MAPP is nearing a generating capacity deficit situation. Building additional transmission facilities in the region would only help provide additional capacity if excess generation capacity is available.

3.3.2 Reliability

The reliability of new transmission lines is dependent on the reliability of the generation source at the supply end of the line. As generating capacity becomes limited, reliability of power in the region decreases.

One benefit of the proposed Project is that it is sited to provide the most benefits to the regional and local area transmission system, while minimizing construction of new facilities. It is expected that the proposed Project will help to mitigate some of the transmission constraints which impede regional and inter-regional transactions. The proposed Project may improve the reliability of the regional transmission system by reducing possible overloads of nearby transmission facilities that can presently occur during high load conditions and facility outages. For instance, the proposed Project should counteract the prevailing flow and reduce loading on the MAPP-defined constrained interfaces in southern Minnesota, central Wisconsin, and North Dakota.

3.3.3 Energy Efficiency

The efficiency of energy provided through a transmission line varies, depending on the source of the energy and the distance that the energy is transported. As capacity deficits increase, it is likely that there will be more use of both relatively low efficiency generation and more distant sources of energy. As energy is transmitted over greater distances, line losses increase and energy efficiency declines.

3.3.4 Environmental Effects

Environmental effects of transmission lines depend upon the source of the energy, which varies based upon the location. As capacity deficits increase, there may be greater use of generation sources that emit higher pollutants. However, the extent of environmental effects cannot be fully assessed without knowing the source of the power providing power via a transmission line. Also, transmission lines can have environmental effects along their route. However, such effects would be addressed during the siting process.

3.3.4.1 Air Emissions

Transmission lines in and of themselves do not emit air pollutants. The generation source at the supply end of the line emits pollutants, depending on the source's fuel.

3.3.4.2 Land Use

Clearance requirements for a high-voltage transmission line could result in a right-of-way corridor up to 200 feet wide and up to several hundred miles long. Land use within that corridor would be restricted.

3.3.4.3 Water Use

Transmission lines do not generate wastewater. Stormwater runoff and the associated soil erosion may be issues depending on the specific design and maintenance of right of ways.

3.3.4.4 Liquid and Solid Wastes

Transmission lines do not generate solid or liquid wastes.

3.3.4.5 Noise

Transmission lines produce a humming sound and occasional cracking sounds that are generally audible only in immediate proximity to the line.

3.3.4.6 Aesthetics

Transmission lines require transmission towers ranging from 80-150 feet tall (depending on whether they support a single or double circuit) that are visible for several miles in rural Minnesota.

3.3.4.7 Traffic

A transmission line would generate limited traffic after its initial construction. Traffic during operation would be minimal.

3.3.4.8 Electromagnetic Fields

There have been concerns raised about electromagnetic fields (EMF) from transmission lines. While there is no proof of negative effects of EMF, a recent report prepared by the Minnesota State Interagency Working Group[10] suggests that utilities seeking to site new transmission lines in Minnesota use low-cost engineering measures, wherever possible, to minimize EMF exposure. Even though it appears that, typically, such measures are already considered in designing transmission lines, EMF issues may need to be specifically addressed at least for some transmission line proposals.

3.3.4.9 Economic Effects

Electric transmission lines can require expensive siting and permitting. If the size and length of the lines exceed certain limits, these processes can be significantly involved. Once the lines are sited, they can also be expensive to construct. While there may be increased employment during construction, these jobs are temporary. Additionally, as the distance of a transmission line increases, there is a commensurate increase in the cost to build the line. It is possible that any new transmission line construction of sufficient capacity to meet the need would cost more than the proposed Project.

---

[10] The report can be found at http://www.health.state.mn.us/divs/eh/radiation/emf/index.html.

3.4 Smaller Facility Alternative

The size of combined-cycle facilities is limited by the availability of commercial combustion turbine sizes.

3.4.1 Availability

The selection of the proposed combustion turbine for the proposed Project was based on size, economics and availability. In a typical combined-cycle plant, the combustion turbine is sized to be about double the steam turbine capacity. Supplemental firing of the HRSG to increase its steaming rate will allow the proposed Project to capture the full load capability of the steam turbine during periods when peak output is needed. With a smaller combustion turbine unit, the facility is expected to have reduced operating flexibility.

3.4.2 Reliability

The reliability of the smaller facility should be similar to the proposed Project. However, the smaller facility would be less able to meet a larger demand for electricity than the larger facility.

3.4.3 Energy Efficiency

The use of a smaller combustion turbine may require additional duct firing to take advantage of the steam turbine. This would result in an increase of the heat rate, thus a decrease in energy efficiency. In general, smaller combustion turbines have higher heat rates and are therefore less efficient.

3.4.4 Environmental Effects

Air emissions, water use and, solid and liquid wastes from the smaller facility are expected to be reduced compared to the proposed Project. However, land use, noise levels, aesthetics and traffic would be similar to the proposed Project.

3.4.5 Economic Effects

The use of a smaller combustion turbine is expected to increase unit energy costs (due to lower efficiencies) that would not be fully offset by the savings in capital costs. Increased energy costs would have a negative effect on consumers and economic development. Additionally, even though a smaller combustion turbine would have a lower overall total capital cost, the capital cost per unit of capacity generally increases as the total turbine size decreases. This relationship favors building the larger proposed Facility instead of a smaller, less economic turbine.

3.5 Delayed Construction

Delay of the proposed Project by one, two or three years would increase the risk that the Agency's customers could be subject to higher energy prices in those years. Delay would also adversely affect the region's power supply security, increase the use of less efficient peaking facilities, reduce electric system reliability, and decrease the Agency's likelihood of meeting its capacity obligations at MAPP.

Once the decision is made to construct a delayed facility, the availability, reliability and efficiency would be similar to the proposed Project.

In the interim period, less efficient or less environmentally preferred alternatives would likely be used to meet electrical contingencies and peak electrical consumption demands, or loss of service may occur if no capacity is available.

3.6 No-Facility

The no-build alternative would mean not constructing the proposed Project at all and not addressing the projected capacity deficit of the Agency and the region. Negative impacts to the natural and economic environments would be realized if demand needs cannot be met in the future.

Capacity margins in the long term, according to NERC, are eroding to dangerously low levels thereby diminishing the ability of the bulk electric supply systems in North America to respond to higher-than-projected customer demand caused by extreme weather and unexpected equipment shutdowns or outages.[11]

The no-build alternative would have negative environmental effects similar to delaying the proposed Project—continued dependence on less efficient and more polluting generation to meet peak capacity needs.

3.7 Alternate Site

The proposed Project is being sited to minimize the length of gas pipeline and transmission line construction, which limits the potential environmental impacts. In addition, the transmission improvements associated with the proposed Project will help improve the transmission system reliability. Locating new generation south of the Twin Cities, where generation is lacking, helps to balance the electrical system and reduce loading on the MAPP-defined constrained interfaces in southern Minnesota, central Wisconsin, and North Dakota.

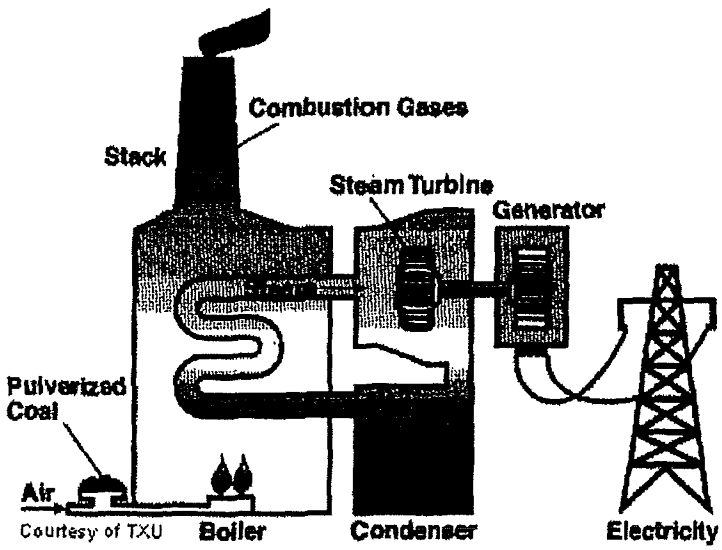
[11] "Reliability Assessment: 1998-2007, NERC.

4 Analysis of Alternative Fossil Fuel Technologies

4.1 Coal-Fired Boiler

A coal-fired steam power plant consists of a boiler that burns pulverized coal converting the resulting thermal energy into steam. The steam from the boiler turns a steam turbine, which is connected to an electrical generator (see Figure 4-1 below).

Figure 4-1: A Coal-Fired Boiler



In addition to the boiler, steam turbine, and electrical generator, a coal-fired plant has coal handling equipment, cooling water systems, and pollution control equipment.

- *Coal handling equipment*: Coal is typically transported to the boiler via a conveyor system. Typically, the coal is pulverized into small pieces that aid in uniform combustion. There are four main types of coal: lignite, sub-bituminous, bituminous, and anthracite. Each type of coal has different properties such as heat content and sulfur content that impact the efficiency and emissions of the plant.
- *Cooling Water Systems*: Cooling water systems, such as a cooling tower, are used to condense and cool the waste steam exhausted from the steam turbine.
- *Pollution Control Equipment*: Many byproducts are created through the combustion of coal, including fly ash and various air emissions like sulfur dioxide and nitrogen dioxide. Precipitators, scrubbers, baghouse, and SCR are all types of pollution control equipment utilized at coal plants. This equipment can chemically transform or physically trap many of the gases and particles released during combustion.

4.1.1 Availability

Pulverized coal facilities have an annual availability of about 85 percent.[12] A pulverized coal plant requires more than three years to build and is not well suited for meeting intermediate resource needs. Coal-fired facilities are usually associated with baseload resources due to their high capital costs, slower start-up times, and lengthy construction times. Due to their immense size and level of complexity compared to gas-fired plants, construction of a coal-fired plant generally takes about three or more years.

4.1.2 Reliability

Pulverized coal facilities are generally reliable.[13] Typically, coal-fired generation operates as baseload capacity, a role that only a reliable resource can fill.

4.1.3 Energy Efficiency

A pulverized coal facility is expected to operate at a heat of rate of about 11,000 Btu/kWh at full-firing conditions.[14] This level equates to a thermal efficiency of about 31 percent. Due to the benefits inherent in combined cycle operation, the proposed Facility has a much higher efficiency than a coal facility.

4.1.4 Environmental Effects

A pulverized coal facility will have significantly higher NO_x, SO_2, PM_{10}, CO_2 and CO emissions than the proposed Project. The level of emissions will depend upon the type of coal burned and the pollution control equipment installed at the plant, such as scrubber, SCR equipment, etc. It would consume water at a higher rate, discharge more wastewater, and generate tens of thousands tons of ash per year. Noise levels and visual impacts are expected to be higher as well.

4.1.5 Economic Effects

A coal-fired steam power plant is expected to require $1,079/kW in capital costs and $15.90/kW in operating and maintenance costs.[15] The capital costs of a coal-fired facility are expected to be greater than the proposed Facility. Operating costs for coal-fired facilities are typically 25% higher on a per kW basis than a gas-fired combined cycle plant. Much of the increase in operating costs can be attributed to fuel handling and emissions control.

---

[12] "Policy Office Electricity Modeling System (POEMS) Model Documentation," in support of the DOE Comprehensive Electricity Competition Plan, 1998.

[13] Electric Power Annual 2000 Volume I, Energy Information Administration (EIA), August 2001, Page 5.

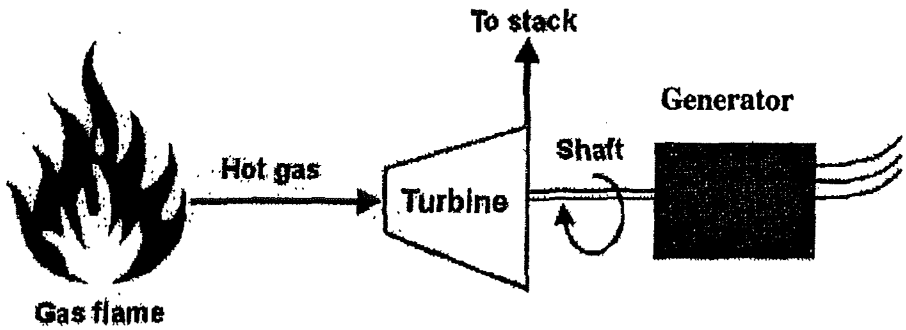
[14] See Docket No. IP3/CN-98-1453.

[15] "Policy Office Electricity Modeling System (POEMS) Model Documentation," in support of the DOE Comprehensive Electricity Competition Plan, 1998. Costs are in 1996 dollars.

4.2 Dual-fuel simple-cycle combustion turbine

The dual-fuel simple-cycle power plant generally uses natural gas as its primary fuel and fuel oil as a backup fuel during times of gas supply interruption. This plant has the same technology as the proposed Project except that, in simple cycle, the heat from the combustion turbine exhaust gases is not recovered (see Figure 4-2 below).

Figure 4-2: A Combustion Turbine



4.2.1 Availability

A dual-fired simple-cycle power plant is expected to be available for service greater than 90 percent of the time. However, it is generally used as a peaking plant due to its relatively high operating costs as compared to more energy efficient baseload plants. As primarily a peaking resource, simple cycle turbines must be available when demand is high and often very quickly. As such, they have very short start-up times, on the order of 10 minutes. Building a simple-cycle power plant requires about 12 months of actual construction time, not including the time required for siting, planning, and permitting.

4.2.2 Reliability

Due to their relative simplicity (compared to more complex coal-fired and combined-cycle plants), simple cycle plants have a high degree of reliability. Improvements in combustion turbine technology have increased the efficiency of these plants, as well as increased their overall reliability. The primary component is the turbine itself, which is well developed and has wide commercial application.

4.2.3 Energy Efficiency

A dual-fuel simple-cycle power plant is expected to operate at a heat of rate of about 12,000 Btu/kilowatt-hour at peak-firing conditions.[16] This level equates to a thermal efficiency of 28 percent. The major drawback of a simple-cycle alternative is the dramatic loss of efficiency, which would preclude it from having the high capacity factor needed of the proposed Project.

[16] See Docket No. ET2/CN-99-976.

4.2.4 Environmental Effects

A simple-cycle combustion-turbine facility is expected to have similar discharges, solid wastes, noise, traffic, as well as identical transmission resources as the proposed Project. With regards to land requirements, this alternative would need approximately five less acres than the proposed Project. Vehicular and rail traffic generated by the construction and operation of this alternative would be the same as for the proposed Project.

However, the lower efficiency of this alternative would result in higher air emissions due to increased consumption of fuel for the same electrical output.

4.2.5 Economic Effects

Although a combined-cycle plant has higher capital costs than a simple-cycle plant, the number of construction workers required would be similar. However, a simple-cycle unit fired with natural gas would require 2 or 3 staff during normal operations.

5 Analysis of a Combination of Alternatives

5.1 Combination of Wind and Natural Gas-fired Generation[17]

It is possible that a combination of alternatives could provide adequate power supplies instead of relying upon one single alternative. The only alternative identified is a combination of wind and natural gas-fired generation in which less natural gas-fired generation would be constructed than the proposed Project. Wind generation would replace the natural gas-fired generation not constructed.

Wind power's low correlation of wind output to summer peaking conditions must be taken into account when analyzing the cost-effectiveness of wind meeting resource needs. For example, under MAPP's capacity accreditation procedures, approximately 6-10 MW of wind nameplate capacity would be required to replace 1 MW of gas-fired capacity for a utility's peak hour.

5.1.1 Availability

Although modern wind turbines can be expected to have an availability factor of 97 percent, it is an intermittent resource that depends upon the wind to blow to produce electricity. Actual construction time for a utility-scale wind system is 6 to 12 months.

Gas-fired generation is expected to be available greater than 90 percent of the time. Construction times for a simple cycle turbine requires about 12 months.

5.1.2 Reliability

The reliability of a wind-turbine-based generating facility is expected to be relatively low due to its dependence on, and lack of control over, the wind. In a small application, as envisioned here, a limited number of wind generators spread over a limited geographic area would provide little diversity in wind speed, further reducing the reliability of the wind resource.

Gas-fired generation, on the other hand, has a high degree of reliability.

A key objective of the proposed Project is to have a dispatchable resource. The amount of capacity that is dispatchable would be reduced by the amount of wind generation capacity constructed.

5.1.3 Energy Efficiency

Wind turbines have a higher efficiency than simple cycle gas-fired turbines.

5.1.4 Environmental Effects

[17] Information in this section has been adopted from Xcel Energy's 2002 Integrated Resource Plan, Docket No. E002/RP-02-2065, filed December 2, 2002.

Wind energy is generally considered to be environmentally benign. However, the environmental effects associated with wind generation include visual appearance, low-level noise, and avian mortality.

Any wind generation that replaced gas-fired generation would reduce the consumption of natural gas. However, wind speeds are best in the Spring and Fall when natural gas prices are lower than their winter peak and electric demand is at its lowest point of the year. In a gas/wind combination alternative, wind's strongest possibility to replace natural gas fired generation tends to occur precisely when replacement power is needed the least.

5.1.5 Economic Effects

The capital cost to install wind and gas-fired generation to achieve the same capacity as the proposed Project would be higher. Pursuit of a gas/wind combination alternative for small applications, such as Faribualt Energy Park, would result in a small number of wind generators over a limited geographic area which cannot provide the needed diversity in wind speed. Also, wind generation receives the benefit of a federal production tax credit that, under current law, will expire in 2003. Without the benefit of the production tax credit, wind energy prices would increase.

6 Analysis of Alternative Renewable Resource Technologies

This section discusses the following renewable energy alternatives: hydropower, wind energy, solar energy, biomass, landfill gas and geothermal energy.

In contrast to fossil fuels, which draw on finite resources, renewable energy resources, such as wind and solar energy, are constantly replenished. Renewable energy resources accounted for 7.9 percent of the 2001 electric generating capacity in the United States.[18]

6.1 Hydropower[19]

Hydropower represented more than 73 percent of the total kilowatt hour (kWh) generation by renewables in the United States in 2001.[20]

Hydroelectric power plants convert the potential energy in water pooled at a higher elevation into electricity by passing the water through a turbine and discharging it at a lower elevation. The water turns the turbine which is connected to an electric generator thus producing electrical energy. The turbines and generators are installed either in or adjacent to dams, or use pipelines (called penstocks) to carry the pressurized water below the dam or diversion structure to the powerhouse. Hydropower projects are generally operated in a run-of-river, peaking, or storage mode.

Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and stream flow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases and power production to be more constant. Many projects combine the modes.

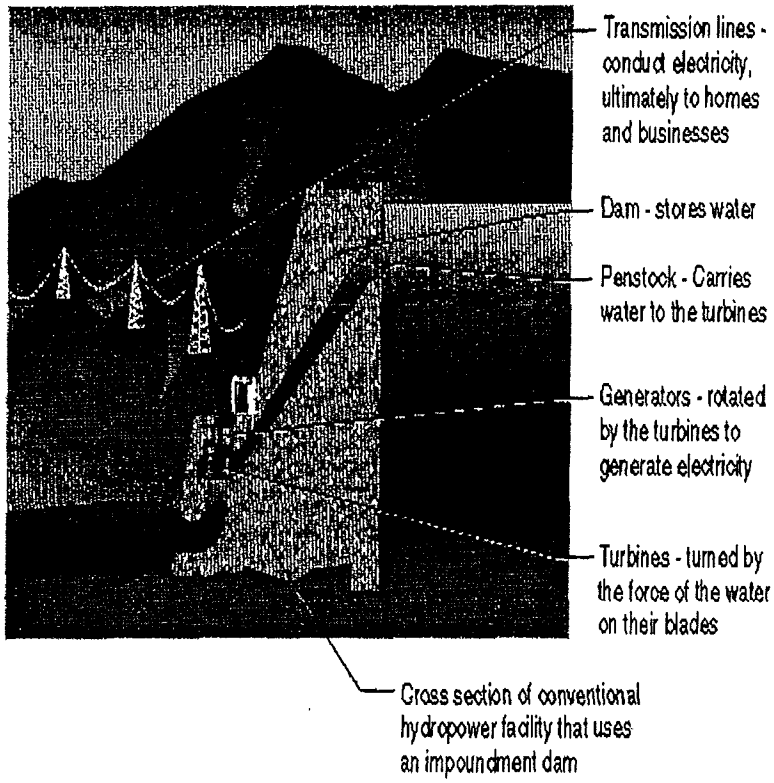
The capacity of a hydropower plant is primarily a function of two variables: (1) flow rate expressed in cubic feet per second (cfs), and (2) the hydraulic head, which is the elevation distance the water falls in passing from the reservoir through the turbine. Most conventional hydropower plants include six major components (see Figure 6-1 below):

[18] Energy Information Administration (EIA), Electric Power Monthly (EPM), March 2000, Table 3, available at www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

[19] Unless otherwise noted, information provided in this section has been adapted from the U.S. Department of Energy (DOE) Hydropower Program web site: hydropower.inel.gov/.

[20] EIA Annual Energy Review, 2001 Table 8.2a, available at www.eia.doe.gov

Figure 6-1: A Hydropower Plant



- *Dam:* Controls the flow of water and increases the elevation to create the head. The reservoir that is formed is, in effect, stored energy.

- *Penstock:* Carries water from the reservoir to the turbine in a power plant.

- *Turbine:* Turned by the force of water pushing against its blades.

- *Generator:* Connects to the turbine and rotates to produce electrical energy.

- *Transformer:* Converts electricity from the generator to usable voltage levels.

- *Transmission lines:* Conduct electricity from the hydropower plant to the electric distribution system.

The principal advantages of using hydropower are its large renewable domestic resource base, the absence of polluting emissions during operation, its capability in some cases to respond quickly to utility load demands, and its very low operating costs. Disadvantages can include high initial capital cost, unavailability when ice or long-term droughts affect production, and potential site-specific and cumulative environmental impacts.

6.1.1 Availability

During periods of normal precipitation, and when ice is not a problem, the availability of a hydroelectric plant is expected to be very high, in excess of 95 percent. The DOE Hydropower Program has studied the hydroelectric power resource base in the MAPP-US region. The study suggests an availability of undeveloped hydropower potential in the states partially or wholly included within the MAPP region. It shows an estimated hydroelectric potential of about 2,500 MW to be available at 471 sites located throughout the identified states (Montana, Wisconsin and South Dakota are not entirely within the MAPP region).[21] The total includes an estimated additional capacity of 835 MW that could be obtained from 82 existing hydroelectric plants. Approximately 1,260 MW is thought to be available at 255 existing dams that do not currently have any turbines installed. The remaining 405 MW has been identified at sites which would require the development of a dam.

The MMPA is in the process of developing two small Hydro plants in the Northern Metro area suburbs. While desirable, these small plants cannot meet all the Agency's needs. Additionally, hydro resources are typically baseload resources rather than the intermediate load resources needed by MMPA.

Practical development of this capacity requires that the supporting infrastructure (transmission lines, site access, dam development, etc.) is either present or readily developed. There are no sites in Minnesota, Wisconsin, North Dakota or Iowa with more than 52 MW of potential capacity.[22] South Dakota has three sites with more than 129 MW of potential capacity but two of these sites are beyond the jurisdiction of the Commission and the third one could not be developed before 2006, as it has no dam or power generating capacity.[23]

The Canadian part of the MAPP region includes southern Manitoba and southern Saskatchewan. A total hydroelectric potential of over 5,000 MW is available in Manitoba.[24] However, the current transmission export capability from Manitoba to Minnesota of 1,975 MW is in use.[25] Therefore, any new Canadian hydropower project would require an expensive, new transmission line from Manitoba to Minnesota.

The development of a new hydroelectric project can be expected to take many years due to the need to acquire land, conduct environmental studies, obtain water use rights, obtain necessary permits and licenses, construct a reservoir, and fill it. In addition, the potential need for transmission line construction or upgrading may add further delays. Therefore, even if adequate hydropower resources were identified, they would likely not be available in time to meet the Agency's need in 2006.

---

[21] See Docket No. IP3/CN-98-1453.

[22] DOE; "U.S. Hydro power Resource Assessment for Minnesota," 1996;
"U.S. Hydro power Resource Assessment for Wisconsin," 1996;
"U.S. Hydro power Resource Assessment for North Dakota," 1993; and
"U.S. Hydro power Resource Assessment for Iowa," 1995.

[23] "U.S. Hydro power Resource Assessment for South Dakota," DOE, 1993.

[24] "Manitoba: The Power Advantage," June 1995.

[25] Docket No. E002/RP-98-32.

6.1.2 Reliability

Component parts of a hydroelectric generating plant include well-developed technologies that have been widely applied in commercial service. The reliability of the equipment and, therefore, the reliability of the entire plant, is expected to be very high. The presence of ice may reduce the availability and reliability of the facility.

6.1.3 Energy Efficiency

Conversion of the potential energy in water, represented by the height of the water above the turbine, is a very efficient process. Losses associated with the mechanical operation of the turbine and generator result in an overall energy efficiency of about 80 percent.

6.1.4 Environmental Effects

Although a hydroelectric power project may not be a significant source of pollutant releases to the environment, it nonetheless can have significant environmental effects. Potential environmental impacts include altered flow regimes below storage reservoirs or within diverted stream reaches, water quality degradation, mortality of fish that pass through hydroelectric turbines, blockage of upstream fish migration, and flooding of terrestrial ecosystems by new impoundments. However, in many cases, proper design and operation of hydropower projects can mitigate these impacts.

6.1.4.1 Air Emissions

No air pollutant emissions are expected to occur during the normal operation of a hydroelectric generating station. Air emissions from associated activities, such as the use of auxiliary space heaters and certain types of maintenance, may produce small air pollutant releases.

6.1.4.2 Land Use

The construction of hydroelectric dams and ancillary facilities can have significant impacts on land within the project area. The pooling of water in a reservoir behind the dam can result in the permanent flooding of large areas of land. After the creation of the reservoir, during the operational phase of the project, land impacts would be expected to be limited to the effects of reservoir management (i.e., the raising and lowering of the water level in the reservoir).

6.1.4.3 Water Use

Generation of electricity using hydropower technology does not require a consumptive use of water. As noted previously, the power developed is the result of taking water from a higher elevation and draining it through a turbine and discharging it at a lower elevation. Under typical operations, water discharged from the turbine is placed back into the waterway from which it was withdrawn.

6.1.4.4 Liquid and Solid Wastes

The operation of a hydroelectric facility does not result in the discharge of significant quantities of wastewater. Very limited wastewater quantities, associated with sanitary facilities and service water uses, would require treatment and/or disposal. These quantities would be readily manageable through onsite treatment. More significant water quality impacts would be expected as the result of siltation due to stagnation of water in the reservoir, and as the result of low water flows below the dam during periods when water is being pooled.

6.1.4.5 Noise

No nuisance noise is expected to be evident outside of the powerhouse.

6.1.4.6 Aesthetics

The construction of a dam, and the creation of a reservoir, will have a significant impact on the appearance of the project area. This change in appearance may be considered undesirable by some. The reservoir may be viewed by others as having a positive impact due to its potential recreational value. However, the appearance of a muddy riverbank, due to the raising and lowering of water levels, may also be undesirable to many people.

6.1.4.7 Traffic

Traffic would be expected to be impacted by project development. While the construction of a dam may actually result in a new bridge across the affected waterway, the inundation of large areas may significantly alter regional traffic patterns. The reservoir may enhance marine navigation upstream of the dam, but the dam may be viewed as an obstruction to existing traffic.

6.1.5 Economic Effects

The capital costs for constructing a hydropower facility, most likely multiple smaller facilities in the region, is expected to be in the range of several thousand dollars per kW.[26] Operating costs would likely be lower than the proposed Project because the "fuel" for hydropower (flowing river water) has no direct cost associated with its use.[27]

The economic effects of a hydroelectric plant include a very small increase in employment, some property tax revenues for counties, and its recreational value if fisheries and surrounding land area are developed to attract the public.

6.2 Wind Without Backup[28]

Wind energy describes the process by which the wind is used to generate mechanical power or electricity. Wind turbines, like aircraft propeller blades, turn in the moving air and power an

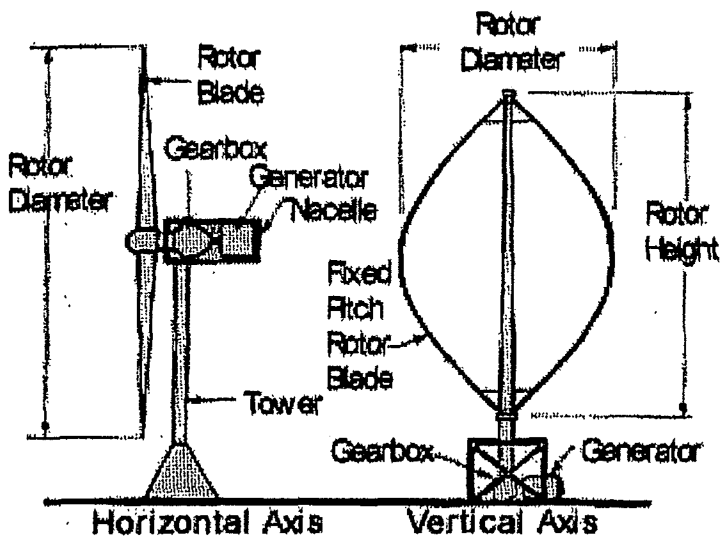
[26] DOE provides the following range for the capital cost of a hydropower facility in 1996 dollars, $1700-$2300 per kW, see hydropower.inel.gov/facts/costs.htm.

[27] DOE provides the following operation and maintenance cost for a hydropower facility in 1996 dollars, $0.007 per kWh, see hydropower.inel.gov/facts/costs.htm.

[28] Unless otherwise noted, information provided in this section has been adapted from the U.S. Department of Energy Wind Energy Program web site: www.eren.doe.gov/wind

electric generator which supplies an electric current. Modern wind turbines fall into two basic groups: the horizontal-axis variety, like the traditional farm windmills used for pumping water; and the vertical-axis design (see Figure 6-2 below). Utility-scale turbines typically range in size from 50 to 750 kilowatts. Wind turbines are often grouped together into a single wind power plant, also known as a wind farm, and generate bulk electrical power. Electricity from these turbines is fed into the local utility grid and distributed to customers just as it is with conventional power plants.

Figure 6-2: Wind Turbine Technologies



Wind Turbine Configurations

6.2.1 Availability

Modern wind turbines can be expected to have an availability of 97 percent.[29] The major challenge to using wind as a source of power is that it is intermittent and it does not always blow when electricity is needed. Wind cannot be stored and not all wind can be harnessed to meet the timing of electricity demands. Further, good wind sites are often located in remote locations far from areas of electric power demand (such as cities). Thus, the impact of the development of wind energy on the transmission system must be considered, especially as transmission constraints grow.

Wind resources are abundant in many parts of the United States. Wind resources are characterized by wind-power density classes, ranging from class 1 (the lowest) to class 7 (the highest). Good wind resources (class 3 and above) which have an average annual wind speed of at least 13 miles per hour, are found along the east coast, the Appalachian Mountain chain, the Great Plains, the Pacific Northwest, and some other locations. North Dakota alone has enough

[29] "Renewable Energy Technology Characterizations," USDOE and EPRI, Report TR-109496, 1997. This report is also available at www.eren.doe.gov/power/techchar.html.

wind resources from class 4 and higher to supply 36 percent of the electricity consumed by the lower 48 states.

The Department has assessed the wind resource in Minnesota and has documented several class 4 and 5 wind regimes in southwestern Minnesota.[30] However, Minnesota's largest wind power plant has an accredited wind capacity of only 15 MW.[31]

The actual construction time for a utility-scale system is estimated to be approximately 6 to 12 months. The installation of individual wind turbines can be accomplished in a much shorter time frame. But the overall development of a utility-scale wind energy project may require several years to complete feasibility assessments, obtain regulatory approvals, complete land lease/purchase agreements, and complete construction and commissioning of the system. For example, Xcel Energy's Wind Phase III request for proposals (RFP) took 21 months from filing of the proposed RFP to the approval of the resulting Power Purchase Agreement. Construction time required an additional 9 months.[32]

6.2.2 Reliability

The reliability of a wind-turbine-based generating facility is expected to be relatively low because of dependence on, and lack of control over, the wind. Theoretically, wind system reliability can be improved by creating a hybrid system which combines wind turbines, photovoltaic arrays, backup fossil-fired generators, and energy storage systems. Although the reliability of the actual generating equipment should be quite good, the reliability of the wind resource typically governs the overall facility reliability. A measure of the reliability can be seen by looking at typical annual capacity factors which have been achieved in practice. Capacity factors are site specific because they reflect the fraction of the time that the wind blows strong enough to generate electricity. A typical capacity factor of 20 to 35 percent would be expected at wind installations in the area.

[30] Wind Resource Analysis Program (WRAP) Report , Minnesota Department of Commerce, October 2002. This report is available on the Department's web site at: www.commerce.state.mn.us.

[31] NSP Phase II has a nameplate wind capacity of 107.25 MW. Assuming an accreditation factor of 13.5 percent for wind, this translates into about 15 MW of accredited wind capacity.

[32] Docket No. E002/M-00-311.

MAPP has defined a procedure to accredit capacity to account for the intermittent nature of the resource. The accredited value for wind is the median of all the hourly output from the plant over a four-hour period that includes the expected peak hour. Based on that procedure, the DOC calculated the July MAPP accreditation to be 16.8 percent of the maximum output (three hour period from 4:00 p.m. to 7 p.m.). Using this estimate, 6 MW of nameplate wind would need to be installed to receive 1 MW of accredited wind capacity. Achieving 250 MW of accredited capacity would require installing almost 1,500 MW of nameplate wind capacity.

Thus, wind generation without a backup source of energy is not an effective resource to meet intermediate resource needs because of its intermittent nature and low correlation of wind output to summer peaking conditions. Having to build nearly six times the installed capacity to achieve the needed accredited capacity reflects that wind generation is not reliable.

A key objective of the proposed Project is having a dispatchable resource. Wind, due to its intermittent nature, is not a dispatchable resource and thus fails to meet a key objective of the proposed Project.

6.2.3 Energy Efficiency

The energy efficiency of a wind turbine can be expressed as the portion of the theoretical energy available in the area swept by the rotor that is transformed into electricity. This efficiency is typically about 40 percent.

6.2.4 Environmental Effects

Wind energy conversion systems are generally considered to be environmentally benign. The principal issues are typically visual appearance, low level noise, and avian mortality.

Avian mortality is an ongoing issue of concern for wind power developers. Bird death caused by wind turbine tends to be site specific, with greater numbers being killed when wind farms are sited in migratory pathways or areas where large bird populations are present. Design (such as the use of tubular towers to avoid providing perches for birds, and burying wires to avoid electrocution), siting (avoiding migratory pathways and population centers), and operation (limit operation during heavy migratory periods) are typical mitigation measures.

6.2.4.1 Air Emissions

No air pollutant emissions are expected to occur during the normal operation of a wind energy conversion system.

6.2.4.2 Land Use

The amount of land required for wind farms depends on turbine size and number, turbine spacing, and the number of rows. A typical wind farm may require from 47 to 114 acres per megawatt, depending on site-specific conditions.[33] However, gross land requirements can be

[33] "Renewable Energy Technology Characterizations," USDOE and EPRI, Report TR-109496, 1997.

misleading since only 5 to 10 percent of the area is actually used by wind turbines, leaving the remaining free for other uses such as planting crops.

6.2.4.3 Water Use

Wind energy conversion systems require no water for operation. Small amounts of water might be used to clean wind turbine rotor blades.

6.2.4.4 Liquid and Solid Wastes

The operation of a hydroelectric facility does not result in the discharge of significant quantities of wastewater. Very limited quantities of wastewater, associated with sanitary facilities and service water uses, would require treatment and/or disposal. These quantities would be readily manageable through onsite treatment.

6.2.4.5 Noise

Noise is caused by the wind moving over turbine blades and by the mechanical components of the wind turbines. Noise may be a concern to people living near wind projects. However, much of the turbine noise is masked by the sound of the wind itself, and the turbines only run when the wind blows. Noise from wind turbines has diminished as the technology has improved. As blades have become more efficient, more of the wind is converted into rotational torque and less into acoustic noise.

6.2.4.6 Aesthetics

Wind turbines are available in a variety of sizes, and therefore power ratings.[34] A small home-sized wind machine has rotors between 8 and 25 feet in diameter and stands upwards of 30 feet. Such a turbine could supply the power needs of an all-electric home or small business. Wind projects have different visual impacts than most other electric generation technologies, in part because wind projects usually are located in rural or even remote areas, often with few nearby homes and only occasional human visits and use.

6.2.4.7 Traffic

Very little traffic, beyond periodic maintenance visits, is expected during normal operation. Construction traffic would be heavier but not unreasonable.

This report is also available at www.eren.doe.gov/power/techchar.html.

[34] The largest machine, such as the one built in Hawaii, has propellers that span more than the length of a football field and stands 20 building stories high, and produces enough electricity to power 1400 homes.

6.2.5 Economic Effects

The cost of a wind power facility, most likely multiple smaller facilities in the region, is estimated to be in the range of $965/kW for capital costs and $25.60/kW for operating and maintenance costs.[35]

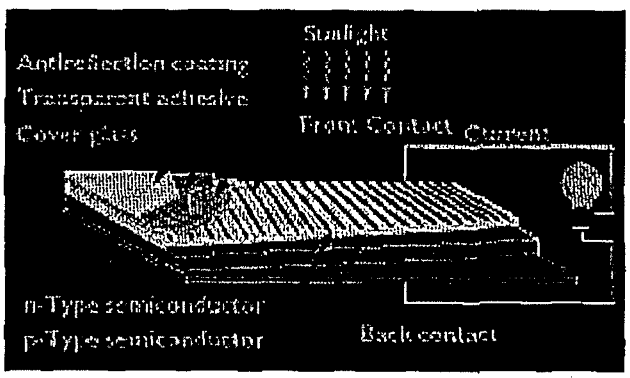
The economic effects of wind farm construction and operation include construction employment, employment of operation and maintenance personnel (an estimated 4 operators per shift for a utility-scale operation, and one maintenance worker for every 20 to 80 machines[36]), increased property taxes to the surrounding community, and lease payments to land owners.

6.3 Solar[37]

Solar energy technologies used to generate electricity include solar cells (photovoltaics or PV) and solar thermal electric power plants (concentrating solar power technologies).

Photovoltaic technology directly converts sunlight into electricity, using semiconductor materials in solar panels (see Figure 6-3 below). Sunlight is composed of photons, or particles of solar energy. These photons contain various amounts of energy corresponding to the different wavelengths of the solar spectrum. When photons strike a PV cell, they may be reflected or absorbed, or they may pass right through. The energy of the absorbed photon is transferred to an electron in an atom of the cell (which is actually a semiconductor). With its newfound energy, the electron is able to
escape from its normal position associated with that atom to become part of the current in an electrical circuit. Special electrical properties of the PV cell, a built-in electric field, provide the voltage needed for the current.

Figure 6-3: A Photovoltaic Cell



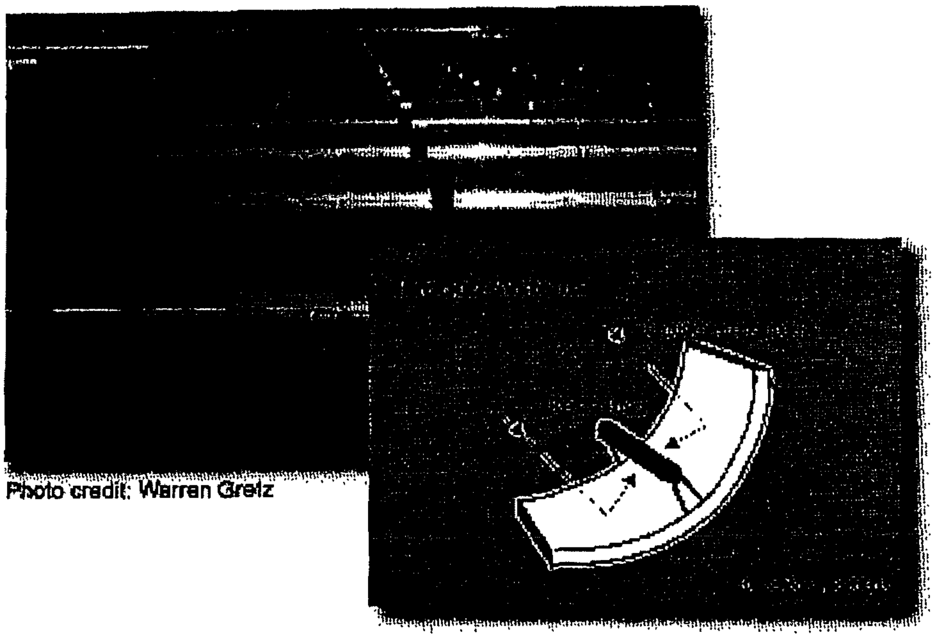
[35] "Policy Office Electricity Modeling System (POEMS) Model Documentation," in support of the DOE Comprehensive Electricity Competition Plan, 1998. Costs are in 1996 dollars.

[36] Working Group II of the Intergovernmental Panel on Climate Change, September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

[37] Unless otherwise noted, information provided in this section has been adapted from the USDOE Photovoltaics Program web site: www.eren.doe.gov/pv, and Concentrating Solar Program web site www.eren.doe.gov/csp.

Concentrating solar power technologies use reflective devices such as troughs or mirror panels to concentrate the sun's energy (see Figure 6-4 below). The resulting heat energy is used to power a conventional turbine to produce electricity. Because of their parabolic shape, troughs can focus the sun at 30 to 60 times its normal intensity on a receiver pipe located along the focal line of the trough. Synthetic oil captures this heat as the oil circulates through the pipe, reaching temperatures as high as 390°C (735°F). The hot oil is pumped to a generating station and routed through a heat exchanger to produce steam. Finally, electricity is produced in a conventional steam turbine.

Figure 6-4: A Concentrating Solar Power Plant



6.3.1 Availability

The availability for solar power systems depends on the availability of sunlight. There are regional differences within the United States as far as the amount of solar energy available throughout the year. The National Renewable Energy Laboratory (NREL) has developed maps of solar resources, allowing precise assessment of potential sites.[38] The best solar energy opportunities are in the southwestern United States, which is where the majority of the large-scale research projects have been constructed. By grouping single PV cells into arrays, and then placing many arrays together, PV generation plants of up to 8 MW have been built (Sacramento Municipal Utility District).[39] Individual solar thermal systems currently can generate about 80 megawatts of electricity (Southern California Edison).[40]

---

[38] US Solar Radiation Maps, NREL.
These maps are available at http://rredc.nrel.gov/solar/old_data/nsrdb/redbook/atlas. See also the US DOE "Solar Resource" map at www.eren.doe.gov/csp/csp_tech.html#map.

[39] "PV facilities in the US", DOE Renewable Electric Power Information System (REPIS) Database, October 1999. This database is available at www.eren.doe.gov/repis.

[40] "Solar Thermal facilities in the US," DOE Renewable Electric Power Information System (REPIS) Database, October 1999. This database is available at www.eren.doe.gov/repis.

Creating hybrids of solar with wind, fossil or storage is one way to improve their availability. However, the technical viability of large-scale solar power has not been proven in the upper Midwest.[41]

The estimated time to construct a PV energy system is approximately 1 year. The estimated time for design and construction of a concentrating solar power system is about 2 years, with up to 5 years needed to design and construct a hybrid solar/fossil station of 200 MW.[42]

6.3.2 Reliability

PV cells were originally developed for use in space, where repair is extremely expensive, if not impossible. PV powers nearly every satellite circling the earth because it operates reliably for long periods of time with virtually no maintenance.

As with wind energy systems, although the equipment may be reliable, the solar resource is not continuously available, therefore, overall reliability is not high. Solar is another intermittent resource, not well-suited to meeting intermediate resource needs. Under the MAPP capacity accreditation process, solar also receives a relatively low ratio of accredited capacity to nameplate rating, requiring substantially greater amounts of solar capacity to meet the proposed Project's capacity objectives.

6.3.3 Energy Efficiency

For both solar technologies discussed here, it is estimated that only about 15 percent of the solar energy falling on a collector surface will be converted to electricity.[43]

6.3.4 Environmental Effects

Because they burn no fuel and have no moving parts, PV systems are clean and silent. If concentrating solar power systems are constructed as hybrid solar/fossil plants, they will release air emissions of the same type as a conventional fossil plant. However, the total emissions should be lower in proportion to the use of the solar thermal system.

6.3.4.1 Air Emissions

As discussed above, solar technologies will not release any air pollutants unless they are operated as hybrid solar/fossil plants.

---

[41] "Solar Thermal facilities in the US," DOE Renewable Electric Power Information System (REPIS) Database, October 1999. This database is available at www.eren.doe.gov/repis.

[42] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

[43] "About Solar Energy", NREL Clean Energy Basics web site: www.nrel.gov/clean_energy/solar.html.

6.3.4.2 Land Use

Solar power plants can have considerable impacts on land due the very large land areas required to construct plants of any significant size. For example, a parabolic trough system uses about 5 acres for each megawatt of installed capacity.

6.3.4.3 Water Use

PV systems have no water requirement besides small amounts of water that are used to clean photovoltaics panels. Solar thermal systems require water to operate the steam cycle. A solar thermal plant is estimated to need 560 gallons of water per MWh.[44]

There will be no wastewater discharges associated with the operation of a PV power plant. Depending on the specific heat transfer fluids used, a solar thermal plant may have the potential for wastewater problems and possibly the need for solid waste disposal. Hybrid plants could be expected to have discharges from water treatment facilities.

6.3.4.5 Noise

The operation of a PV plant would be expected to be quiet. Solar thermal plants would also be relatively quiet.

6.3.4.6 Aesthetics

There would be an obvious visual impact due the vast areas covered by the solar collector arrays if a large plant were built.

6.3.4.7 Traffic

Traffic would generally not be significant due to the relatively small work force required.

6.3.5 Economic Effects

A solar photovoltaic facility is expected to require $3,185/kW for capital costs and $9.70/kW for operating and maintenance costs.[45] A solar thermal facility has lower capital costs, $1,910/kW, but requires more operating and maintenance costs, $46/kW.

Xcel Energy, in its 1999 biennial Conservation Improvement Program (CIP) petition, estimated that a proposed 250 kW solar-power demonstration project would cost about 36¢ per kilowatt-hour.[46]

---

[44] Docket No. IP3/CN-98-1453.

[45] "Policy Office Electricity Modeling System (POEMS) Model Documentation", in support of the DOE Comprehensive Electricity Competition Plan, 1998. Costs are in 1996 dollars.

[46] Docket No. E002/CIP-99-1057.

6.4 Biomass[47]

Biomass power systems use biomass to produce electricity. Biomass is generally defined as any sort of organic matter available on a renewable basis. There are several different definitions of "biomass." For example, for purposes of the biomass mandate that placed requirements on Xcel Energy, "biomass" was originally defined as herbaceous crops, trees, agricultural waste, and aquatic plant matter, that meets the following criteria: [48]

(1) is intentionally cultivated, harvested, and prepared for use, in whole or in part, as a fuel for the generation of electricity;

(2) when combusted, releases an amount of carbon dioxide that is less than or approximately equal to the carbon dioxide absorbed by the biomass fuel during its growing cycle; and

(3) is fired in a new or substantially retrofitted electric generating facility that is:

  (i) located within 400 miles of the site of the biomass production; and
  (ii) designed to use biomass to meet at least 75 percent of its fuel requirements.

Specific biomass that would qualify under this definition include poplar, aspen, willow, switch grass, sorghum, alfalfa and cultivated prairie grass. The definition was later expanded to include agricultural waste, including animal, poultry, and plant wastes.

Most of the biomass power plants currently in existence use direct-fired combustion technologies. Direct combustion involves the oxidation of biomass with excess air, producing hot flue gases which produces steam in the heat exchange sections of boilers. The steam is usually captured by a turbine, and a generator then converts it into electricity.

6.4.1 Availability

The availability of biomass-fired units is expected to be around 80 percent. The electricity production from biomass is being used, and is expected to continue to be used, as baseload power.[49] Therefore, it does not meet the intermediate resource need of the Agency.

Biomass fuels are widely available throughout the MAPP region due to the significant agricultural and forest products presence in the area. However, some of these fuels may have an annual fluctuation in supply, thus requiring either alternate fuels, stockpiling, or curtailment of plant operations. The availability of a biomass-fired steam electric plant tends to be less than that

[47] Unless otherwise noted, information provided in this section has been adapted from the USDOE Biopower Program web site: www.eren.doe.gov/biopower, and from NREL "Introduction to Biopower" web site: www.nrel.gov/clean_energy/biopower.html.
[48] Biomass power mandate, Minnesota Statutes section 216B.2424, subd. 1.
[49] "Renewable Energy Technology Characterizations," USDOE and EPRI, Report TR-109496, 1997. This report is also available at www.eren.doe.gov/power/techchar.html.

of a comparable coal-fired plant due to the increased difficulty of handling the biomass fuels. The current largest biomass-fired facility (Blandin Paper plant) in Minnesota has a capacity of only 32 MW.

Typical development of a large biomass-fired electric generation project can be expected to take 4 to 5 years. Actual construction time may vary from 18 to 36 months.[50] Given the development times above, a biomass-fired electric plant would not be available by the summer of 2006.

6.4.2 Reliability

The reliability of a biomass-fired plant would be expected to be similar to other solid-fueled steam electric plants except for the potential problems associated with fuel handling and/or fuel availability. Therefore, although overall reliability would be expected to be high, it would be less than a coal- or gas-fired plant.

6.4.3 Energy Efficiency

The overall energy efficiency of this type of plant would be in the range of 15 to 30 percent depending on fuel quality.[51] Dry, low-ash biomass fuels could yield higher efficiencies than wet, high ash feedstocks.

6.4.4 Environmental Effects

Environmental effects can vary, depending on the source of the biomass to be burned. The effects may be similar to other steam plants, although some biomass fuels typically have lower sulfur, and "cleaner" ash.

Waste streams from the furnace include stack gases, which will pass through the boiler where steam will be generated, bottom ash, and boiler water blowdown. The stack gases will contain particulate matter (PM), as well as gaseous pollutants (volatile organic compounds (VOCs), sulfur dioxide (SO2), carbon monoxide (CO), and nitrogen oxides (NOx)). Typically, stack gases will pass through an air pollution control device where PM is removed. Bottom ash produced in many biomass combustion plants is often of a quality that can be sold, or disposed of, as a soil conditioner/fertilizer (due to the lack of many trace metals which often contaminate coal ash). Boiler blowdown, along with other process wastewater streams, would typically be treated to remove solids, oils, and grease, and then discharged.

6.4.4.1 Air Emissions

Air emissions will be typical of a solid-fuel-fired steam boiler plant with the exception of lower SO_2 emissions. When close-looped biomass fuels are used, carbon dioxide that is emitted during biomass combustion is equal to the amount of carbon dioxide absorbed from the atmosphere

---

[50] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

[51] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

during the biomass growth phase. Thus, such biomass fuels "recycle" atmospheric carbon, minimizing global warming impacts. Specific levels of other emissions will depend on the particular fuel and firing method.

6.4.4.2 Land Use

The use of waste biomass may reduce the volume of material sent to landfills, extending the life of existing landfills.

Perennial energy crops (grasses and trees) have distinctly lower environmental impacts than conventional farm crops that are replanted annually. Energy crops require less fertilization and herbicides and provide much more vegetative cover throughout the year, providing protection against soil erosion and watershed quality deterioration, as well as improved wildlife cover.

6.4.4.3 Water Use

Water used to condense the steam exhausted from the turbine would most likely be cooled using a direct contact (evaporative) cooling tower. The use of a cooling tower represents a significant consumptive use of water. An estimated water use of 600 gallons per MWh will be required to operate the plant.[52]

6.4.4.4 Liquid and Solid Wastes

Biomass combustion results in less ash than coal, reducing ash disposal costs and landfill space requirements. The biomass ash may potentially be used as a fertilizer in farmland.

6.4.4.5 Noise

Noise will result from fuel handling and other plant operations. The noise would not be expected to be significantly different from other steam plants.

6.4.4.6 Aesthetics

Aesthetically, the plant would appear similar to other steam electric plants.

6.4.4.7 Traffic

Due to the relatively large plant crew at a larger steam plant, traffic volumes would probably be noticeable in the more rural areas in which such a plant would likely be constructed. Estimates for plant crews are about 22 workers for a 50 MW plant, with an additional 95 workers engaged in fuel handling operations.[53]

---

[52] Docket No. IP3/CN-98-1453.

[53] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

6.4.5 Economic Effects

A biomass-fired electric generating facility is expected to require $1,476/kW for capital costs and $66.30/kW for operating and maintenance costs.[54] The average price per MWH for 3 biomass contracts signed by Xcel Energy was between $85.97 and $129.83. Those prices are substantially above the typical price for other sources.[55]

Biomass operations may increase employment, provide energy crops as a potentially profitable alternative for farmers, and increase property tax revenues for communities in which the facilities would be operating. If the biomass has an alternative use (such as a crop fertilizer), its use to produce electricity may decrease the supply of biomass for other uses and may increase the cost of its use for alternative purposes.

6.5 Landfill Gas[56]

Significant quantities of methane gas and other volatile organic compounds are emitted from municipal solid waste deposited in landfills. Landfill gas (LFG) can be used for on-site electricity generation. An electric generating plant using LFG is similar to one using natural gas or diesel fuel, aside from the need for more extensive gas processing and more careful monitoring of equipment because of the potentially corrosive nature of landfill gas.

An LFG-to-electricity system has three basic components: (1) the gas collection system, which gathers the gas being produced within the landfill, (2) the gas processing and conversion system, which cleans the gas and converts it into electricity, and (3) the interconnection equipment, which delivers the electricity from the project to the final user.[57]

6.5.1 Availability

A 1996 U.S. EPA study concluded that LFG based electric generation potential in Minnesota is about 14.3 MW.[58] A more recent 1999 EPA study indicated that Minnesota has 30 MW of existing LFG generation and the potential to add an additional 10 MW of capacity.[59] LFG-based electrical generation in Minnesota could add about 2 MW per year in additional generating capacity if all LFG opportunities could be developed.[60] This small amount cannot meet the Agency's needs.

---

[54] "Policy Office Electricity Modeling System (POEMS) Model Documentation," in support of the DOE Comprehensive Electricity Competition Plan, 1998. Costs are in 1996 dollars.

[55] See the information made public by Commission's December 1, 2001 Order in Docket No. E002/M-00-1169.

[56] Unless otherwise noted, information provided in this section has been adapted from Docket Nos. IP3/CN-98-1453 and E002/CN-99-1815.

[57] "Tomorrow's Energy Today for Cities and Counties," USDOE, available at: www.eren.doe.gov/cities_counties/landfil.html.

[58] USEPA. "Opportunities for Landfill Gas Energy Recovery in Minnesota," EPA 430-B-96-033. July 1996.

[59] USEPA. "Landfill Gas-to-Energy Project Opportunities: Landfill Profiles for the State of Minnesota," EPA 430-K-99-017, January 1999.

[60] Docket No. IP3/CN-98-1453.

The availability of the entire generating system would be expected to be similar (availability greater than 90 percent) to internal combustion based systems firing natural gas, except more frequent maintenance would be expected due to the corrosive character of the LFG.

The estimated time to develop a LFG generating system is approximately 1 to 3 years, largely due to the requirement to design and construct the gas collection system.[61]

6.5.2 Reliability

The reliability of the system would be expected to be reasonably high.

6.5.3 Energy Efficiency

The overall efficiency of a LFG generating plant is a combination of gas collection efficiency and energy conversion efficiency. Gas collection efficiency is expected to be in the range of 70 to 80 percent of gas generated in the landfill. Engine/generator efficiencies are typically between 35 and 45 percent. Therefore, overall energy conversion efficiencies would be approximately 25 to 35 percent.[62]

6.5.4 Environmental Effects

LFG electric generation projects are undertaken primarily as air pollution control projects. Therefore, it is expected that there is a net benefit to the environment due to the reduced emissions of greenhouse gases.

6.5.4.1 Air Emissions

Air emissions from the project will yield a net reduction in the greenhouse gases emitted from landfills. Operation of the internal combustion engine will produce additional emissions of nitrogen oxides (NOx) and lesser amounts of other air pollutants (including sulfur dioxide (SO2), carbon monoxide (CO), and particulate matter (PM)). However, the overall emissions are expected to provide a net benefit to the atmospheric environment.

6.5.4.2 Land Use

The system would be expected to be sited on an operating or closed landfill.

6.5.4.3 Water Use

Water consumption would be largely limited to closed system uses (principally engine cooling), therefore, consumptive uses are small. The addition of an evaporative cooling tower, as opposed to an air cooled radiator, would increase water consumption.

---

[61] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

[62] Working Group II of the Intergovernmental Panel on Climate Change. September 1995. "Inventory of Technologies, Methods and Practices for Reducing Emissions of Greenhouse Gases," 3rd External Review Draft.

6.5.4.4 Liquid and Solid Wastes

The limited consumptive water uses will significantly reduce wastewater generation. Small amounts of leachate are expected to be collected as condensing vapors in the gas collection system. The leachate would be collected and disposed/treated in accordance with the landfill operator's leachate management program.

6.5.4.5 Noise

Noise due to system operation would result from blower and engine operation. Prudent siting of equipment and the use of enclosures around equipment can limit noise.

6.5.4.6 Aesthetics

Aesthetically, the installation and operation of a LFG generating system may be viewed favorably by the surrounding community. System operation would be expected to reduce LFG migration off the landfill property, reduce malodorous emissions, and reduce the potential for explosions on and off the site.

6.5.4.7 Traffic

Traffic impacts would not be different from the normal operation of the landfill. Landfill operators would provide for routine operation. Periodic visits by maintenance mechanics may result in an additional vehicle being present from time to time.

6.5.5 Economic Effects

The capital costs for constructing a LFG facility is expected to be less than $1,000/kW. Annual operating expenses may be less than for a typical fuel-fired power plant because the LFG is not typically a purchased input. An economic effect due to operation of this system would be a reduction in the overall cost of LFG abatement. The addition of maintenance labor would have a small contribution to wages paid in the community. The Federal tax credit which allows many LFG projects to operate economically will expire in 2007.

6.6 Geothermal[63]

Geothermal energy is the natural heat within the earth, extracted from hot water or rocks.

Geothermal resources come in five forms: hydrothermal fluids, hot dry rock, geopressured brines, magma, and ambient ground heat. Only hydrothermal fluids have been developed commercially for power generation. Three technologies can be used to convert hydrothermal fluids to electricity. The type of conversion used depends on the state of the fluid (whether steam or water) and its temperature:

- *Steam*—Conventional steam turbines are used with hydrothermal fluids that are wholly or primarily steam. The steam is routed directly to the turbine, which drives an electric generator, eliminating the need for the boilers and fossil fuel of conventional power plants.

- *High-temperature water*—For hydrothermal fluids above 200° C that are primarily water, flash steam technology is usually employed. In these systems, the fluid is sprayed into a tank held at a much lower pressure than the fluid, causing some of the fluid to rapidly vaporize, or flash, to steam. The steam is used to drive a turbine, which again, drives a generator. Some liquid remains in the tank after the fluid is flashed to steam; if it's still hot enough, this remaining liquid can be flashed again in a second tank to extract even more energy for power generation.

- *Moderate-temperature water*—For water with temperatures less than 200° C, binary cycle technology is generally most cost effective. In these systems, the hot geothermal fluid vaporizes a secondary—or working—fluid, which then drives a turbine and generator.

Steam resources are the easiest to use, but they are rare. The only steam field in the United States that is commercially developed, The Geysers, is located in Northern California.

Hot water plants, using high- or moderate-temperature geothermal fluids, are a relatively recent development. However, hot water resources are much more common than steam. Hot water plants are now the major source of geothermal power in both the United States and the world. In the United States, hot water plants are operating in California, Hawaii, Nevada, and Utah.

[63] Unless otherwise noted, information provided in this section has been adapted from
USDOE Geothermal Energy Technical Site ,
"About Geothermal Energy," USDOE, at www.nrel.gov/clean_energy/geothermal.html, and
USDOE Geothermal Energy Program at www.eren.doe.gov/geothermal.

6.6.1 Availability

Geothermal plants are typically used for base load applications, with capacity factors above 90 percent.

Geothermal generating sites are concentrated in the western United States.

Minnesota has vast low-temperature resources suitable for geothermal heat pumps, but electricity generation is not possible with these resources.[64] In addition, exploration and reservoir confirmation can require 3 to 8 years of development work before installation of a power plant on a reservoir.[65] Thus, geothermal is not a feasible or suitable resource to meet the intermediate resource needs of the Agency in the time period being considered.

6.6.2 Reliability

Geothermal electric generating facilities, where they are currently in commercial operation, are generally reliable source of generating capacity.

6.6.3 Environmental Impacts

Geothermal generating facilities are generally considered to have low impacts on the environment.

6.6.3.1 Air Emissions

Air emissions from geothermal generating plants are negligible.

6.6.3.2 Land Use

Land needs for geothermal generating plants are similar to other steam generating plants.

6.6.3.3 Water Use

Water needs for binary (separate loops for the geothermal source and the steam generation) geothermal generating facilities are for makeup water in the steam cycle and for cooling, similar to other steam generating plants.

6.6.3.4 Liquid and Solid Wastes

Solid wastes generated from geothermal plants are minimal. Water used in the geothermal generating process is typically injected back into the geothermal reservoir from which it was obtained.

---

[64] "Minnesota Geothermal Resources," USDOE at www.eren.doe.gov/state_energy/tech_geothermal.cfm?state=MN.

[65] "Renewable Energy Technology Characterizations," USDOE and EPRI, Report TR-109496, 1997. This report is also available at www.eren.doe.gov/power/techchar.html.

6.6.3.5 Noise

Noise from geothermal plants are similar to those generated at other steam generating facilities.

6.6.3.6 Aesthetics

The visual impact of a geothermal generating facility would be similar to other steam generating plants.

6.6.3.7 Traffic

Traffic would not be significant during plant operation. Local traffic would likely increase during construction, but would not be expected to cause significant problems.

6.6.4 Economic Effects

The initial cost for geothermal development (the field and power plant) is around $2,000 per installed kilowatt in the United States. The operating and maintenance costs for geothermal power plants cover a range from 1.5 cents to 4.5 cents per kilowatt hour.[66]

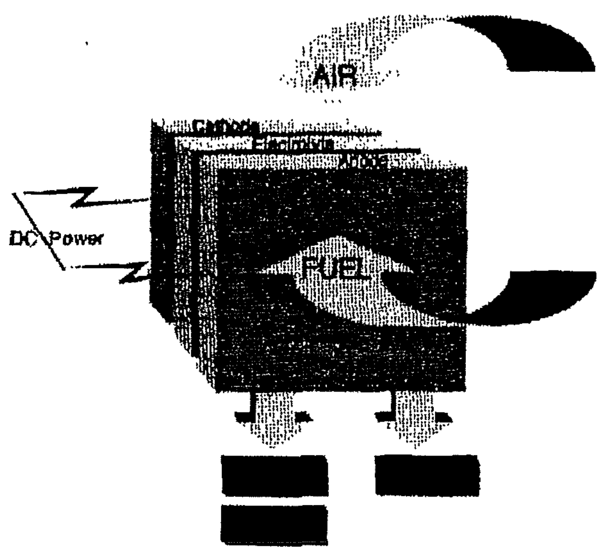
[66] USDOE Geothermal Energy Technical Site at http://id.inel.gov/geothermal/faq/q03.html.

7 Analysis of Other Alternatives

7.1 Fuel Cells[67]

Fuel cells work without combustion. Power is produced electrochemically by passing a hydrogen-rich fuel over an anode and air over a cathode and separating the two by an electrolyte (see Figure 7-1 below).[68]

Figure 7-1: Fuel Cell Technology



The general design of most fuel cells is similar except for the electrolyte. Several different substances have been used as the electrolyte in fuel cells, each with their own advantages and disadvantages. The five main types of fuel cells as defined by their electrolyte are: alkaline fuel cells (AFCs); solid polymer fuel cells (also known as proton exchange membrane fuel cells or PEMs); phosphoric acid fuel cells (PAFCs); molten carbonate fuel cells; and solid oxide fuel cells (SOFCs). Alkaline and solid polymer fuel cells operate at lower temperatures (50-260°C)

[67] Unless otherwise noted, information provided in this section has been adapted from the Department of Defense (DoF) Fuel Cell Demonstration Program web site: www.dodfuelcell.com, and Docket Nos. IP3/CN-98-1453 and E002/CN-99-1815.

[68] "Distributed Generation," National Energy Technology Laboratory, USDOE. This report is available at www.netl.doe.gov.

and are mainly designed for transportation applications. The other three operate at higher temperatures (up to 1,000°C for solid oxide fuel cells) and are being developed for use in co-generation and large central power plants.

A fuel cell power plant uses several of the individual cells. Most individual fuel cells are small in size and produce between 0.5 and 0.9 volts of DC electricity. The individual cells are often combined together in a "stack" configuration to produce the higher voltages more commonly found in low and medium voltage distribution systems. The stack is the main component of the power section in a fuel cell power plant. The other two components are the fuel processor and the power conditioner.

The fuel processor or reformer extracts hydrogen-rich gas from natural gas or other fuel, emitting carbon dioxide and trace amounts of carbon monoxide. There are three common methods of processing fuels to create the hydrogen required by the fuel cells. Steam reforming is a simple process involving the reaction of light hydrocarbon fuels with steam. Partial oxidation is the incomplete burning of a fuel and is used to process heavier hydrocarbon liquids. The third reforming method, gasification, causes coal to be "gasified" by reacting coal with oxygen and steam at high temperatures.

Finally, the power conditioner section of a fuel cell power plant most often consists of an inverter, which converts the DC electricity to AC electricity. The power conditioner can also regulate the voltage and current output from the fuel cells to accommodate variations in load requirements.

7.1.1 Availability

Current manufacturing capacity of fuel cells is not established to the point where fuel cell installations are expected to address significant demand. Phosphoric acid fuel cells (PAFC) are currently available in 200 kW unit sizes. Molten carbonate (MCFC) and solid oxide fuel cells (SOFC) are not yet commercially available, although developers are hopeful they will become available in the next several years. Proton exchange membranes (PEM) fuel cells have created interest primarily for automotive and transit applications; they are also under development for stationary power applications. However, PEM fuel cells are not yet commercially available.

Construction time for large (> 1 MW) fuel cell plants is unknown at this time but is estimated to be 3 years for a gas/oil fuel plant or 5-7 years for a coal-gas fueled cell. The longer coal-gas construction times are largely due to the requirements for coal handling and gasification systems.

While there is much interest in fuel cells and great expectations for commercial availability of various fuel cell technologies, it is unreasonable to expect them to be available in sufficient quantity to meet the identified need by 2006.

7.1.2 Reliability

Fuel cells have demonstrated high reliability in pilot industry settings.

7.1.3 Energy Efficiency

Energy efficiency is estimated to be in the range of 40-60 percent, depending on fuel cell types.[69] Even in small plant sizes, fuel cells are very efficient.

7.1.4 Environmental Effects

Operation of a fuel cell produces no air emissions other than water vapor and carbon dioxide since it is not a combustion process. However, production of the hydrogen-rich fuel creates the main environmental impacts. The environmental effects of fuel cells will be dependent on the fuel selected and would largely be attributable to the fuel processing operation. The effects detailed below primarily relate to production of the fuel, not the operation of the fuel cell itself.

7.1.4.1 Air Emissions

Due to low temperature operation of the fuel cell, the emissions will be primarily oxygen (O_2), nitrogen (N_2), water (H_2O), and carbon dioxide (CO_2). Very low levels of SO_2 and CO may be present. Operation of a gasifier to process coal into a hydrogen rich fuel may produce significant emissions of air pollutants.

7.1.4.2 Land Use

No significant land effects are expected with operation of the fuel cell. However, fuel processing and residue management associated with use of solid fuels are expected to require land area equivalent to a solid, fossil-fuel-fired facility.

7.1.4.3 Water Use

Water consumption would not be significant for this technology, except when coal gasification is used to produce fuel.

7.1.4.4 Liquid and Solid Wastes

Liquid and solid wastes are expected to be insignificant in the case of natural gas, while wastewater and solid waste streams result from coal gasification.

7.1.4.5 Noise

Operation of the fuel cell itself would be relatively silent. Fuel processing noise would be equivalent to that of a fossil fuel plant.

7.1.4.6 Aesthetics

Fuel cell plants can be constructed to fit into almost any setting.

---

[69] DoF Fuel Cell Demonstration Program web site: www.dodfuelcell.com/fcdescriptions.html.

7.1.4.7 Traffic

Traffic would not be significant during plant operation.

7.1.5 Economic Effects

The capital costs for constructing a fuel cell facility is estimated to be in the range of several thousand dollars per kW, thereby making them uneconomical. Additionally, most fuel cells are also baseload in nature and would not be cost effective at the capacity factors typical of an intermediate resource.

A fuel cell facility is not expected to have a noticeable impact on local employment.

7.2 Energy Storage[70]

Energy storage technologies have long been considered as a means of leveling the load on existing generating plants thus allowing them to operate closer to their peak efficiencies. Four storage technologies are discussed here - battery energy storage systems (BESS), compressed air energy storage (CAES), pumped storage hydroelectric, and flywheel energy storage.

Battery Energy Storage System (BESS) – There are currently a wide variety of types of batteries available for use in energy storage applications. In a chemical battery, charging causes reactions in electrochemical compounds to store energy charged to the battery in a chemical form. When a load is applied to the battery, reverse chemical reactions allow the energy to be drawn from the battery. Commercially available batteries range in size from kilowatts to modular configurations of several megawatts.

Compressed Air Energy Storage (CAES) – CAES plants are designed to use off-peak energy from existing power plants to compress air and store it in air tight underground caverns. When called upon, the air is released, heated, and expanded through a gas turbine to recover the energy. Although manufacturers offer equipment to construct CAES systems ranging up to 350 MW, to date only a 110 MW plant has been constructed in Alabama. The Electric Power Research Institute (EPRI) has estimated that a large percent of the United States may have geological characteristics which would allow for CAES construction.

Pumped Storage Hydroelectric - Pumped storage hydroelectric plants pump the water resource, usually through a reversible turbine, from a lower reservoir to an upper reservoir. While pumped storage facilities are net energy consumers, they can be rapidly brought on-line to operate in a peak power production mode. The pumping to replenish the upper reservoir is performed during off-peak hours when electricity costs are lowest. This process benefits utilities by increasing the load factor and reducing the cycling of their base load units. In most cases, pumped storage plants run a full cycle every 24 hours.

[70] Unless otherwise noted, information provided in this section has been adapted from Docket Nos. IP3/CN-98-1453 and E002/CN-99-1815.

Flywheel Energy Storage – The concept behind this technology is to store energy in a spinning flywheel. An integral motor/generator is connected to the flywheel and can be used to either charge energy to the flywheel or extract energy from it. This technology has been applied to mechanical systems and is now receiving attention towards applying it to electrical systems. Commercially available flywheels constructed of steel are limited in size. Advanced composite wheels have been designed but are not yet commercially available. Small demonstration systems, rated in the kilowatt range, have been constructed. Large scale application of the technology has not been demonstrated.

7.2.1 Availability

By their nature, energy storage systems have high availability so that power may be readily extracted and used. In spite of the high availability, these technologies typically only have enough energy storage capability to operate during peak hours. This characteristic tends to bias the technologies toward roles in meeting peaking needs, not intermediate needs. Availability may be lessened if stored energy levels are reduced for any reason. Pumped storage hydroelectric energy may be unavailable during periods when water cannot be released from the impoundment to a receiving waterway.

Implementation times for the energy storage technologies discussed here would be variable due to the differences in issues between them. Small, dispersed battery and flywheel systems could likely be installed within months, whereas CAES and pumped storage hydro facilities may require years of development effort followed by contentious approval processes. Additionally, no suitable pumped storage hydro sites have been identified in Minnesota, thereby limiting that as a supply option.

7.2.2 Reliability

As with availability, reliability is essentially a design feature of energy storage systems. These systems would typically back up less reliable parts of the overall electric supply system. As a result, they are not well-suited to meet intermediate resource needs.

In particular, batteries have a limited life, typically 1,500 to 2,000 charge-discharge cycles. Although reliable, their relatively short life limits their desirability as a resource option.

7.2.3 Energy Efficiency

Quantitative values for efficiency of each system have not been identified. A feature of all storage systems is that less energy will be extracted than was originally stored. The process of storage requires an energy expenditure which cannot be recovered.

7.2.4 Environmental Effects

7.2.4.1 Air Emissions

None of the four systems discussed here will directly release air pollutant emissions in significant amounts.

7.2.4.2 Land Use

Impacts on land are technology dependent. Small disperse battery and flywheel systems will have minimal impacts. Large CAES systems will have limited surface impacts but may raise concern over subterranean effects. Pumped storage hydro development will have impacts similar to any hydroelectric project development. Substantial areas of land and habitat may be lost due to hydro development.

7.2.4.3 Water Use

None of these technologies are direct consumers of water.

7.2.4.4 Liquid and Solid Wastes

None of these technologies would generate significant quantities of solid or liquid wastes.

7.2.4.5 Noise

Noise would likely not be an issue for these technologies.

7.2.4.6 Aesthetics

The aesthetic impacts would largely depend on the scale of the energy storage project. A large hydro project may be deemed aesthetically unacceptable whereas smaller battery and flywheel projects may be unnoticed.

7.2.4.7 Traffic

Traffic impacts would be slight with any of the four technologies discussed due to the minimal manpower requirements expected.

7.2.5 Economic Effects

The capital costs for constructing an energy storage facility are variable and dependent on technology selection. Operating costs are primarily dependent upon the operating costs associated with the original energy source. Specifically, batteries are not cost effective. Efforts are being made to develop advanced batteries that may increase the cycle life and lower costs, but no promising commercial technology yet exists. Compressed air is an immature technology with only one demonstration project in operation in the U.S.

The economic effects derived from development of energy storage projects may be limited to minor increases in employment levels and increases in property tax revenues.

ATTACHMENT 2

Comments on Draft Environmental Report

ORAL COMMENTS

Public hearings on the 250 MW combined-cycle natural gas fired power plant (Facility) proposed by Faribault Energy Park (FEP) were held on April 30, 2003 at 2 p.m. and 7 p.m. in Faribault, Minnesota. Several individuals raised concerns and questions regarding a variety of aspects of the Facility. None of the individuals directly addressed the Draft Environmental Report. However, some individuals expressed concerns and raised issues related to the environmental impacts of the Facility. The Department summarizes these concerns and issues below. The Department's response to these concerns is contained in Attachment 3. The environment-related concerns and issues were expressed by the following individuals:

- Gene Greden,
- Orlin Anderla, and
- Carol Overland.

Gene Greden lives near the area that FEP expects to propose as a site to the EQB and expressed concerns regarding the noise level of the Facility. Mr. Greden was concerned that the noise level of the plant, when combined with the noise due to Interstate 35, which is nearby, would produce an overall noise level that would be unacceptable.

Orlin Anderla expressed concern regarding the potential for the Facility to be transformed from a natural gas plant to a coal plant. Mr. Anderla was concerned that if Northern States Power Company d/b/a Xcel Energy's (Xcel) Prairie Island nuclear generating station shuts down then FEP may have an incentive to transform the Facility into a coal plant and sell some of the excess energy to Xcel. This could be possible, Mr. Anderla maintained, because FEP's preferred site is adjacent to a rail line.

Carol Overland indicated that biodiesel should be looked at as a fuel for the facility. Ms. Overland maintained that biodiesel is competitively priced and renewable and should be considered as a replacement for the fuel oil that the Facility will burn.

Stephen Rakow

From: Randall W. Porter [randall.porter@dahlen-berg.com]
Sent: Monday, March 17, 2003 1:02 PM
To: 'Stephen Rakow'
Subject: RE: Draft ER for Faribault Energy Park

Randall W. Porter.vcf (239 B)

Steve,

One small change for the draft ER that I hope won't cause you any problems. Page 11 under aesthetics- that stack height will be about 170 feet tall.

Thanks,
RandyRandall W. Porter PE
Dahlen, Berg & Co.
612-252-6526

MINNESOTA PLANNING ENVIRONMENTAL QUALITY BOARD

April 18, 2003

Steve Rakow
Rates Analyst
Minnesota Department of Commerce
85 7th Place East
Suite 500
St. Paul, Minnesota 55101-2198

Re: Draft Environmental Report
PUC Docket No. IP-6202/CN-02-2006
OAH Docket No. 15-2500-15301-2

Dear Mr. Rakow:

The purpose of this correspondence is to reiterate the Environmental Quality Board (EQB) staff's understanding of how our comments on the "Outline for the Draft Environmental Report" will be addressed in the record. The EQB staff originally commented on the outline for the draft environmental report (ER) in a letter to the Minnesota Department of Commerce (DOC) dated February 14, 2003. Since some of these concerns were not addressed in the Draft Environmental Report released on March 18, 2003, the DOC, Faribault Energy Park, LLC and the EQB agreed to have these items addressed as comments to the ER. In handling these issues in this manner, we will avoid the necessity of filing the appropriate information requests.

It is my understanding that the DOC will develop language to describe the selection of the "considered alternatives" evaluated within the outline for the draft ER. The original EQB staff comments concerning this issue stated:

> *Minnesota Rules, part 4410.7100, subpart 3, item B. states that the environmental report shall identify reasonable alternatives and provide a general evaluation of these alternatives. In the absence of a scoping process, some other criteria must be used to determine which alternatives are viable enough to be considered reasonable and consequently warrant subsequent consideration. A brief discussion should be included in the record describing the methods the DOC used in selecting those items to be incorporated into the "Considered Alternatives" listing. The purpose of this evaluation is to determine whether there is a more reasonable and prudent alternative in the consideration of size, type and timing. Consequently, enough detailed and specific information for each considered alternative should be provided within the environmental report to support a feasibility analysis.*

Additionally, it is my understanding that Mr. Randall Porter (Dahlen, Berg & Company) will provide a discussion addressing the reliability and potential implications of using natural gas to generate electricity. The original EQB staff comments concerning this issue stated:

> *A major consideration for electrical power generation through 2025 will be the availability of adequate natural gas supplies at competitive prices to meet growth in demand. The ER should include a discussion on natural gas domestic consumption trends relative to domestic production/reserves (i.e., forecasting data) and how these trends might impact the evaluation of this project in comparison to the considered alternatives. Additionally, the effect these trends may have on natural gas home heating supplies and pricing should be considered.*

658 Cedar St.
St. Paul, MN 551
Telephone:
612-296-3985
Facsimile:
612-296-3698
TTY:
800-627-3529
www.mnplan.
state.mn.us

Minnesota Rules, part 4410.7100, subpart 3, item C. states that the environmental report shall include an evaluation of the availability, reliability and economic impacts of the proposal. The record should include a discussion on natural gas domestic consumption trends (i.e., increasing reliance on natural gas for electrical power generation) relative to domestic production/reserves (i.e., forecasting data) and how these trends might impact the availability, reliability and economic evaluation of this project in comparison to the considered alternatives.

Information, such as that found within the Annual Energy Outlook 2003 Report produced by the Energy Information Administration (EIA), should be incorporated into the discussion on the availability, reliability and economic impacts of using natural gas to generate electricity. The EIA, created by Congress in 1977, is a statistical agency of the U.S. Department of Energy (DOE). The EIA provides policy-independent data, forecasts, and analyses to promote sound policy making, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment.

Forecasts from the EIA show domestic production providing a decreasing share of total natural gas supply. Currently, domestic natural gas consumption is met by domestic production and imports. The average natural gas prices (including spot purchases and contracts) are projected to move higher (from $2.75 per thousand cubic feet in 2002) as technology improvements prove inadequate to offset the impacts of resource depletion and increased demand. Natural gas prices are projected to increase in an uneven fashion as higher prices allow the introduction of major new, large-volume natural gas projects that temporarily depress prices when initially brought on line. Prices are projected to reach about $3.70 per thousand cubic feet by 2020 and $3.90 per thousand cubic feet by 2025 (equivalent to more than $7.00 per thousand cubic feet in nominal dollars). As demand for natural gas increases, expected technology improvements may not completely offset the economic effects of resource depletion.

Judge Heydinger has established a deadline of April 30, 2003, for filing comments on the draft ER. If we develop any additional comments, we will provide those to you quickly and before the deadline. If any additional information is required, or if there are any questions, please feel free to contact me at (651) 296-9535.

Sincerely,

William Cole Storm

cc: Mr. Randall Porter (Dahlen, Berg & Company)

G:\EQB\Power Plant Siting\Projects - Active\Faribault Energy Park CON Project\EQB Staff Corresponds\EQB Comment Ltr #2 ER.doc.

Minnesota Pollution Control Agency

RECEIVED
MAY 0 2003
MN Dept. of Commerce

April 30, 2003

Mr. Steve Rakow
Minnesota Department of Commerce
85 7th Place East
St. Paul, MN 55101

Re: Comments on the proposed Faribault Energy Center draft Environmental Report

Dear Mr. Rakow

The staff of the Minnesota Pollution Control Agency (MPCA) would like to thank you for the opportunity to comment on the Faribault Energy Center (FEC) draft Environmental Report (ER). The MPCA staff submits the following comments:

1) Many of the statements made are conclusury with few notes on where the information was gathered or how the conclusion was reached. Assuming FEC did analysis to support their conclusions, it would have been helpful to see the analysis, as appendices for example.

   a. Specifically, the MPCA requests much more detailed information on how FEC chose this size facility as the optimal size from an environmental standpoint. There is some discussion on page 17 of the ER of the efficiencies of this size combustion turbine. However, there is little discussion of how FEC reached the conclusion that the size of the facility was related to the immediate (or even projected) need in this area.

   b. We also request that the document be changed to reflect changing forecasts and realities in wholesale electric markets, and list the following sections: purchased power, facility size, facility timing, fit to the timing of deployment of alternatives like wind.

   c. In May 2003, the Mid-continent Area Power Pool (MAPP) will be releasing their revised forecast of projected capacity deficit. We expect that this capacity deficit will be smaller than the figures used in Faribault's ER. The smaller capacity deficit may have a significant impact on the calculations used by FEC to reach their conclusions on the size of facility needed. We suggest FEC wait to submit their final ER until the new projections are released by MAPP. This may have a bearing on their size calculations.

d. We are also concerned about the absence of real hard analysis of the costs of alternatives, and especially as these depend on the cost of money, capital cost escalation or de-escalation (depending on the demand in society for construction materials and expertise or manufactured parts like gas turbine units), labor cost (going out in time) and fuel costs. There has been substantial discussion in the state of official fuel price forecasts, particularly with regard to natural gas. Therefore, there is a real need for FEC to explicitly address their assumptions about future fuel prices and price volatility. Wholesale electricity price will also be a factor. If the notion behind their over-sizing of the plant is to sell the electricity onto the grid is that high wholesale price will support it economically, we would like to see the wholesale price forecasts that they are using.

2) In general, we are disappointed at the lack of detail in the alternatives section of the report. In response to your e-mail request dated January 16, 2003, MPCA staff requested that FEC consider a combination wind/natural gas powered facility. There is less than a full page of text devoted to the notion of a combination of wind and natural gas. Again, the statements made are conclusory, with no references or footnotes indicating what led to the conclusion. We ask that they document their conclusions so we can see how they reached them.

   a. In section 5.1.1 the ER states that construction time for a utility-scale wind system would be 6-12 months. The next paragraph states that construction time for a simple cycle turbine requires about 12 months. However, FEC is proposing a combined, not a simple cycle facility. On Page 11 of the report FEC states that they have allocated 24 months for construction. They seem be comparing two different things.

3) The lack of detail and documentation might lead to the conclusion FEC is not taking this report seriously. Rather than discussing the alternatives very generally and dismissing them, it would have been more useful to show us analysis to justify dismissing the alternatives.

4) We have a number of comments related to characterization of air emissions, presented in Table 2-1 and its accompanying discussion.

   a We are unfamiliar with the use of the term "expected" emissions as used in the table title. There is no explanation provided to describe what this scenario is. Air quality permitting and environmental/human health impact assessments are based on a facility's "potential to emit." For a facility of this type, PTE typically reflects operating at maximum capacity for 8,760 hours per year.

5) We have a number of comments related to characterization of air emissions, presented in Table 2-1 and its accompanying discussion.

   a. There is a column titled "support facilities" with no explanation of the emission source. Please describe. The support facilities are, in some cases, adding significantly to the emissions listed.

b. The discussion in section 2.2.4.1 titled Air Emissions mentions a comparison of ambient air impacts from the proposed project, however, there is no presentation of such results, and should be provided. At a minimum, the facility owners must demonstrate that the operation of the facility will not cause nor contribute to an ambient air violation. The MPCA will also be interested to learn what ambient air impacts result from burning distillate fuel oil.

6) The table on page 10 of the ER lists mercury levels at greater than five pounds per year. How did FEC arrive at that figure? Five pounds seems high.

7) There does not appear to be any ambient air data listed. This is important information for the purposes of comparison.

Thank you for the opportunity to comment on Faribault's Environmental Report. We look forward to a response. If we can be of any assistance please do not hesitate to contact me at (651) 297-1766.

Sincerely,

Cathy Jensen

Cathy Jensen
EQB Technical Representative
Regional Environmental Management Division

CJ:jae

ATTACHMENT 3

Responses to Comments on Draft Environmental Report

I. Written Comments

Written Comments on the Draft Environmental Report (Draft ER) were received from:

- Cathy Jensen on behalf of the Minnesota Pollution Control Agency (PCA),
- Randall W. Porter on behalf of Faribault Energy Park (FEP), and
- William Cole Storm on behalf of the Staff of the Minnesota Environmental Quality Board (EQB Staff).

Ms. Jensen signed the comment as "EQB Technical Representative" while the letterhead was that of the PCA. It is unclear how Ms. Jensen's position as EQB Technical Representative affects the comments.[1] Potentially, the document could be viewed as comments from the PCA, the Environmental Quality Board (EQB) itself, the EQB Staff, or a combination of the three. Based on the letterhead and the Department's view of the role of an EQB Technical Representative, the Department assumes these comments are intended to represent the opinions of the PCA. However, PCA, EQB, and/or EQB Staff can clarify this matter before the Commission, if necessary.

The written comments focused on several areas of the Draft ER. Specifically, written comments addressed:

- the data regarding aesthetics,
- the method used to select the alternatives,
- the operating cycle and reliability aspects of the proposed project,
- technical aspects of certain alternatives,
- the level of detail presented,
- ambient air and air emissions data, and
- the level of mercury emissions.

A. *Aesthetics*

1. Comment of FEP

FEP commented that the stack height data presented in the Draft ER was incorrect. The correct data is that the stack height is about 170 feet (compared to 130 feet indicated in the Draft ER).

2. Department Response

FEP is correct. The correct data is that the stack height is about 170 feet.

[1] The white pages available on the state's website list Ms. Jensen's title as "Pollution Cont Spec Sr."

B. Method Used to Select the Alternatives

1. Comment of EQB Staff

EQB Staff's comment begins by noting that the rules for preparing the Draft ER require that the Draft ER identify reasonable alternatives and provide a general evaluation of these alternatives. EQB Staff continues by stating that a brief discussion should be included as a forward to this section describing the methods the Department used in selecting those items to be incorporated into the Draft ER as alternatives. Finally, EQB Staff states that enough detailed information within each evaluation factor should be provided to support a feasibility analysis.

2. Department Response

The Department approached the question of which alternatives to consider by assuming that the primary role of the Draft ER is to provide the record with a single source of information regarding various generating technologies and their consequences in a general manner. First, the Department concluded that, in order to fulfill an informational role, the Draft ER should include as many technologies as possible, even if it is not possible to assemble high quality data on all aspects of some technologies. Since, as EQB points out, the rules require a general evaluation the Department does not view the lack of high quality data regarding aspects of certain technologies as a significant flaw in the Draft ER.

Second, again based on the informational role of the Draft ER, the Department concluded that a wide variety of categories of technologies should be included. This approach led the Department to include the following general categories of alternatives:

- Alternative approaches,
- Fossil-fuel technologies,
- Combination of alternatives,
- Renewable resources, and
- Emerging technologies.

Once the categories were selected the Department attempted to include alternatives from each category in the Draft ER. The published Draft ER had multiple alternatives in each category except the combination of alternatives category, where only one alternative was included.

C. Natural Gas Assumptions

1. Comment of the EQB Staff

EQB Staff indicated that further discussion on natural gas domestic consumption trends, how they might impact the project, and how they might impact the use of gas for home heating would be useful.

2. Department Response

In responding to this question, the Department concluded that a response from FEP detailing the Company's view along with a response from the Department providing a broader view would be useful. Therefore, this answer is provided in two sections.

a. Company's Response

The Department discussed this issue with Randy Porter of FEP. FEP responded that the primary fuel for the Project will be natural gas. Natural gas was chosen as the primary fuel because of its low air emissions, ready availability, and low commodity and demand price relative to alternatives. Natural gas supplies are expected to be available during most of the year and are projected to be available over the 30 year life of the facility. Natural gas will be delivered to the Project site via the Northern Natural Gas (NNG) system in southern Minnesota. Natural gas service to the Project will be secured through agreements with gas suppliers from market locations such as Ventura, Iowa into the NNG pipeline system. Gas prices for Ventura and other market locations are available on a daily, weekly, or monthly basis and can be priced on competitive indices.

Average natural gas prices are projected to rise over the life of the plant. FEP will remain an economic electric energy generation choice relative to other alternatives even if natural gas prices should rise significantly. Because FEP will be a state-of-the-art, very high efficiency installation, it will maintain its approximate place in the generation dispatch order regardless of natural gas price fluctuations. In the electricity market, electric generating plants are dispatched in order of their running cost. Nuclear and Hydro and large coal plants are dispatched first. At low ($2-$4, 2001 $) natural gas prices FEP will have a lower running cost than many older, small coal plants. If natural gas prices do increase dramatically, FEP may fall in the dispatch order behind some of these plants, but it will always (due to its technology and high efficiency) be dispatched before simple cycle natural gas and oil fired turbines.

Gas deliveries will be arranged the day before normal operation is required, within the Gas Industry Standards Board (GISB) guidelines. Gas supply for a MAPP emergency situation will be secured through agreements with gas suppliers. However, FEP will have dual-fuel capability and, as such, will have the ability to switch between natural gas and fuel oil. Thus, several operation alternatives are available. If gas suppliers are unable to provide gas during an emergency, the backup low sulfur No. 2 fuel oil will be used. If the cost of running the unit on natural gas is high and the cost of running on low-sulfur fuel oil is low, FEP has the flexibility to fire on fuel oil for a large number of hours a year. If the price of electricity according to the dispatch order is lower than the cost of running FEP, its owners will buy from the market.

b. Department's Response

1. Overall Assessment

The Department notes that the proposed Facility's natural gas use should not have negative effects on the availability or the price of natural gas in Minnesota for the following reasons.

First, while FEP is an intermediate plant capable of use during winter-peaking periods, it will be capable of using either natural gas or fuel oil. This design allows fuel switching depending on the cost of the two fuels. As such, the Facility could reasonably be expected to use fuel oil during periods of higher natural gas prices such as those experienced during winter peaking periods. Second, as discussed in the Stipulation, the plant is located on a portion of the interstate natural gas system that is not constrained. As such, it should not negatively affect either prices or availability of natural gas supplies for Minnesota customers.

The Department provided extensive analysis of natural gas supplies in Minnesota in Docket No. E002/M-02-633. For ease of reference, the relevant portion of that analysis is provided as Appendix 1 to this response. The following provides more specific information regarding the proposed Facility.

2. *Natural Gas Use at FEP*

To analyze the magnitude of natural gas use by the FEP plant, the Department examined the facility's potential peak day gas consumption. The peak day comparison is an important comparison to consider because of the possible use of the FEP plant during winter-peaking periods. Peak days are the critical days when residential and other firm customers rely on natural gas, typically for space heating use. On peak days pipeline capacity is at a premium, to ensure the delivery of natural gas to residential and other firm customers.

In response to Department of Commerce Information Request No. 2, the Company stated that the anticipated maximum amount of natural gas required to operate the facility on a peak day is 43,750 Mcf/day. In fiscal year 2002, the actual total firm peak day usage in Minnesota was 1,444,754 Mcf.[2] Thus, the FEP plant peak day natural gas consumption would have represented approximately three percent of the total Minnesota peak day consumption. Assuming a firm residential customer's peak day use is approximately 1.3 Mcf/day, the FEP plant use of natural gas on a daily basis could serve the equivalent of over 33,650 residential customers' usage on a peak day. That amount of gas use on a peak day (and the percent of total Minnesota peak day consumption) is not significant.

D. Level of Detail Presented

1. Comment of Pollution Control Agency

The PCA commented that the level of detail presented was less than desired by PCA. Specifically, PCA requested more detail on the following issues:

- the size of the Facility,
- MAPP forecasts of regional supply and demand,
- cost of the alternatives and the underlying assumptions, and
- the lack of footnotes to support the information provided.

---

[2] Minnesota Department of Commerce's Review of the 2001-2002 Annual Automatic Adjustment Reports, Table G19.

PCA stated that the lack of detail led to the conclusion that FEP is not taking the Draft ER seriously. Finally, PCA also requested that FEP wait to submit the Final Environmental Report until the Mid-Continent Area Pool (MAPP) released the latest capacity deficit forecast.

2. Department Response

Regarding the level of detail in general, as explained in the Draft ER, Minnesota Rule 4410.7100 states that the Draft ER on a certificate of need application shall include:

- a brief description of the proposed facility;
- an identification of reasonable alternative facilities including, as appropriate, the alternatives of different sized facilities, facilities using different fuels, different facility types, and combinations of alternatives;
- a general evaluation, including the availability, estimated reliability, and economic, employment, and environmental impacts, of the proposal and reasonable alternative facilities identified in item B; and
- a general analysis of the alternatives of no facility, different levels of capacity, and delayed construction of the facility, which analysis shall include consideration of conservation and load management measures that could be used to reduce the need for the proposed facility (emphasis added).

The emphasis of the Rule is on general analysis, not a detailed environmental analysis. The Department requested information from FEP in order to conduct its evaluation of the application. The Department is satisfied with the amount and type of information requested and provided by the Company. However, if the PCA concludes that a level of analysis and detail greater than current rules is required, an option PCA could have pursued was to send information requests to FEP. PCA may also participate in the EQB's ongoing rulemaking regarding the rules for the Draft ER for future filings.

The Draft ER includes a set of reasonable alternatives to the Facility. To provide information on a wide array of general alternatives, the Draft ER includes many alternatives that may, in fact, not be feasible at this time. As required by Minnesota Rules, the review of these options is a general evaluation and a general analysis of the various alternatives.

Regarding the Size, as indicated by FEP during the public hearings and in the certificate of need application, the Facility was sized based on many factors such as engineering efficiency, availability of equipment, economies of scale, and so forth. No one factor predominated. Thus, it would be inappropriate to state that FEP optimally sized the Facility from an environmental standpoint.

PCA's suggestion to delay submission of the Final Environmental Report is without merit. The overall certificate of need timeframe is set by statute[3] and the specific procedural schedule has been set by the Administrative Law Judge (ALJ).

Moreover, the filing contained the relevant MAPP forecasts. Thus, these forecasts are already in the record. The updated forecasts will be somewhat different. However, in the Department's experience, the MAPP forecasts typically indicate a deficit at some point during the forecast period. In summary, the Department concludes that is would not be reasonable to violate the timelines set in Minnesota Statutes to obtain a second version of a forecast that is already in the record.

Regarding cost assumptions, the Department attempted to ensure that in the Draft ER economic factors were not granted any greater weight than other factors. The Department's view is that the level of detail presented on economic considerations is sufficient to perform a general economic evaluation of the proposal and reasonable alternative facilities. A detailed economic analysis is not necessary in the Draft ER, which is an informational document. Rather, to the extent necessary, the economic analysis is located in the Department's comments on the filing.

Regarding the amount of text devoted to the wind/natural gas combination facility, the Department agrees that this is a short section. However, further analysis on wind and natural gas in general is provided in the discussions of the wind alternative and the natural gas alternative. The discussion of the combination of these two options addresses only the information that is relevant when the two alternatives are combined.

Regarding the number of footnotes in the document, the Department disagrees with the PCA's conclusion that there was an insufficient attribution of sources in the Draft ER. The Draft ER is a 52-page document with 70 footnotes, the vast majority of which are to cites where the information was obtained and further information is available. In addition, some of the footnotes, for example #70, indicate that the source applies to the entire discussion of the alternative rather than repeating the same footnote multiple times. Thus, while the purpose of the document is to provide a general analysis, significant information and references have been provided.

E. Air Emissions and Ambient Air Data

1. Comment of Pollution Control Agency

PCA's comment indicates that the PCA is unfamiliar with the use of the term "expected" emissions in the title of Table 2-1; thus the scenario is inadequately described. Air quality permitting is based on the emissions resulting from continual operation at maximum capacity for the entire year. Also, PCA commented that further detail is necessary regarding the air emissions of support facilities.

[3] Minnesota Statutes § 216B.243 requires that "within six months of the submission of an application, the Commission shall approve or deny a certificate of need for the facility."

PCA also comments that, at a minimum, the facility owners must demonstrate that the operation of the facility will not cause nor contribute to an ambient air violation.

2. Department Response

The Department interpreted "expected" emissions as emissions that have a probable occurrence or the level of emissions that would likely occur in a typical year.[4] PCA observes that air quality permitting is based on the emissions resulting from continual operation at maximum capacity for the entire year. That may be an appropriate assumption for air permitting. However, in order for analysis to be useful in a certificate of need proceeding, it should not be based on operation year round. Instead, it should be based on a reasonable level of operation, given the facts of the case. Such an analysis would allow the overall best choice to be made for the expected level of operation. If worst case assumptions were used, the best option would be selected for that worst case scenario. However, the option that is best under the worst case assumptions may be inferior, economically and environmentally, under typical or expected conditions.

Regarding support facilities, in discussions with the Department, FEP indicated that these facilities are the 500 kW emergency diesel generator, the auxiliary boiler (used to heat the building), the cooling tower, the diesel storage tank, and the fire pump. If the Facility is built, these supporting facilities would be included in the design and, therefore, their emissions were included.

Regarding the need to demonstrate that the proposed Facility will not contribute to an ambient air violation, the rules for the content of a draft environmental report (Minnesota Rules 4410.7100, subp. 3) contain no such requirement. However, the Department presumes that if the Facility fails to comply with PCA's rules or policies, then the Facility would not be able to obtain a permit from the PCA regardless of the Commission's decision in this matter.

F. Mercury Emissions

1. Comment of the PCA

PCA commented that the 5 pounds of mercury emissions provided on page 10 of the Draft Environmental Report seems high. PCA asked how FEP arrived at the figure of 5 pounds.

2. Department Response

In discussions with the Department, FEP indicated that the emissions provided are, from FEP's perspective, a worst case scenario. For example, the mercury from the support facilities is a result of assuming the emergency generator was running year round. The actual level of operation is expected to be much lower. FEP also stated that mercury emissions were a result of fuel bound mercury, the vast majority of which comes from possible burning of back up fuel oil.

[4] See "The American Heritage College Dictionary", third edition published by Houghton Mifflin Company; "expected" is defined as "to look forward to the probable occurrence or appearance of."

II. Oral Comments

Oral Comments on the environmental impacts of the facility proposed by FEP were made at the April 30, 2003 public hearings in Faribault, Minnesota. The oral comments were made on a variety of concerns. However, there were three specific concerns related to environmental impacts: noise impacts, transforming the Facility into a coal plant, and using biodiesel. These concerns were expressed by:

- Mr. Gene Greden,
- Mr. Orlin Anderla, and
- Ms. Carol Overland.

A. Noise Impacts

1. Comment of Mr. Gene Greden

Mr. Greden was concerned about the noise level of the plant. When the noise of the Facility is combined with the noise due to Interstate 35, which is nearby, the result could be an overall noise level that would be unacceptable to the Facility's neighbors, including Mr. Greden.

2. Department Response

The level of noise at any particular house would depend on the site chosen for the Facility. The site is not chosen in these proceedings. Rather, the site is chosen during proceedings before the Environmental Quality Board. FEP's certificate of need application states the following regarding noise:

> The combustion turbine has a far field (400 feet from the unit) rating of 68 dBA. Additional sound mitigation equipment can be installed to further limit measured noise from the unit. Other noise sources associated with the Project include vehicles and electrical equipment... noise levels will meet all state noise standards for the applicable classification of land use surrounding the Project site.

B. Transformation into a Coal Plant

1. Comment of Mr. Orlin Anderla

Mr. Anderla was concerned that if Northern States Power Company d/b/a Xcel Energy's (Xcel) Prairie Island nuclear generating station shuts down at the same time FEP comes on-line, then FEP may have an incentive to transform the Facility into a coal plant and sell some of the resulting excess energy to Xcel. This could be possible, Mr. Anderla maintained, because FEP's preferred site is adjacent to a rail line.

2. Department Response

Regarding a sale to Xcel, the generation necessary to replace Xcel's Prairie Island (PI) nuclear generating station if PI were to shut down in 2007 is in the process of being acquired through a competitive bidding process. Two finalists have already been selected. When combined the two finalists can replace PI's capacity. Therefore, it is unlikely that FEP will sell generation to Xcel for purpose of replacing PI. However, it is possible for FEP to participate in a different competitive bidding procedure and sell energy to Xcel.

Regarding transforming the proposed natural gas-fueled combined cycle plant into a coal-fueled plant, that would likely be prohibitively expensive. Further, if such a transformation were desired in the future, a filing by FEP to modify the certificate of need would be required.

C. Biodiesel

1. Comment of Ms. Carol Overland

Ms. Overland maintained that biodiesel is competitively priced and renewable and should be considered as a replacement for the fuel oil that the plant will burn.

2. Department Response

FEP has designed the Facility to burn either natural gas or fuel oil. The Department does not know for certainty if biodiesel can be combusted in FEP's Facility. However, preliminary discussions with FEP indicate that it may not be possible. First, there are technical issues with burning biodiesel, such as a potentially higher flashpoint, that may result in biodiesel not being a viable fuel in this case. Second, there are economic issues such as the price, availability, and deliverability of biodiesel. These issues would have to be addressed before biodiesel could be considered.

Appendix 1: Background on Natural Gas

The Department provides the following background discussion and analysis on overall natural gas supplies, which shows that available, as of yet undeveloped, supply exists to serve the proposed plant. However, there will at times be price volatility because unexpectedly high demand (due to drastic weather changes, for example) can cause a temporary market imbalance between the then-current supply and any demand increase until production can "catch up" with the increased demand or demand slackens. This market imbalance is what usually causes the price volatility. Price volatility in the natural gas market is happening and will continue to happen, with or without the proposed plant.

Natural gas represented 24 percent of the energy consumed and 27 percent of the energy produced in the United States in 2000. In 2000, the industrial sector was the largest user of natural gas (39 percent), followed by the residential sector (24 percent), electric generation (21 percent), and the commercial sector (16 percent). Natural gas is the fastest growing energy source for electricity generation.[5] Natural gas consumption is expected to grow by 2.3 percent annually after 1999, faster than any other major fuel source, and is expected to reach 34.7 trillion cubic feet (Tcf) by 2020, mainly because of growth in natural gas fired electricity generation. More than half of the projected increase in consumption, which totals 13 Tcf, is expected in the electricity generation sector.[6]

The extreme natural gas price spike of 2000-2001 is still fresh in the collective memory of consumers, government, and industry. These natural gas price fluctuations intensify the consideration of a switch from coal or nuclear generation to a reliance on natural gas generation. While the future is not clear, two points can be made:

- There seem to be significant natural gas resources in the United States and Canada that have yet to be developed;
- The level of natural gas commodity prices affects the industry's long term desire to develop these resources.

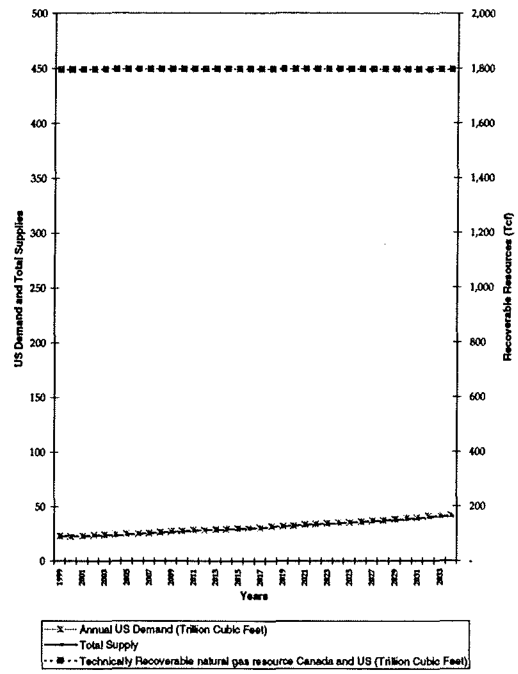
As of January 1, 1999, technically recoverable resources for the United States were 1,281 trillion cubic feet (Tcf). This information was developed by the U.S.

Geological Survey for onshore regions and by the Minerals Management Service for the offshore regions. Similar estimates from the National Energy Board of Canada range from 153 to 224 Tcf as of the end of 1997, with 362 Tcf of additional resources in other areas in unconventional formations.[7] Therefore, total Canadian and United States technically recoverable resources exceed 1.7 Tcf. Cumulative natural gas production from 1999 through 2020 is likely to total

[5] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001. Energy Information Administration, Executive Summary pg., vii., and pg., 5.
[6] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001. Energy Information Administration, Executive Summary pg., xiii.
[7] *U.S. Natural Gas Markers: Recent Trends and Prospects for the Future* May 2001. Energy Information Administration, pg., 35.

between 480 and 512 Tcf, well under the estimate of 1,281 Tcf for recoverable natural gas resources.[8] There are even more aggressive estimates for the United States that contend that this base supply amount should be larger. Geological experts can debate the science of natural gas supply, but all seem to agree that significant amounts of natural gas do exist. But it is not clear what prices are needed to encourage exploration and production (E&P).

Graph 1
Natural Gas Supply and Demand Through 2034[9]



The extreme price spikes of the winter of 2000-2001 were caused by the interaction of supply and demand factors. The natural gas industry experienced two consecutive years of extremely warm weather, which in turn depressed production and, more importantly, future productive capabilities. After two consecutive years of low prices, supplies were overwhelmed by the heightened demand caused by a vibrant economy and cold weather. As shown above, in the short-term natural gas producers have historically tended to refrain from producing significantly more gas in response to increase demand.

---

[8] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001. Energy Information Administration, pg., 34.

[9] Source of Annual Demand Data is the U.S. Natural Gas Markets: Recent Trends and Prospects for the Future. Energy Information Administration Executive Summary, page, viii. Table ES1.

Source of Production Data is the Annual Energy Review 2001. Energy Information Administration, page, 181. Table 6.1 Natural Gas Overview, 1949-2001. Data used in 2001 production and import number and is kept constant for the entire period.

Source of Recoverable Resources is the U.S. Natural Gas Markets: Recent Trends and Prospects for the Future. Energy Information Administration page 34. Canadian data is from the same report but can be found on page 35.

Higher relative prices provide the impetus for companies to expand their long-term E&P efforts. According to the Energy Information Administration (EIA), in 1996 natural gas prices rose by $0.60 to $2.21 per MMBtu and the number of wells drilled increased by more than 10 percent over their 1995 level. EIA also notes that in 1997 prices rose by an additional $0.11 to $2.32 per MMBtu and the number of wells increased by 26 percent above 1996.[10] According to Simmons & Company International on page 7 of their Revising Crude Oil and Natural Gas Prices 2Q02 Update, published April 25, 2002, **"Price expectations matter to E&P companies!"** (Emphasis in original).

While higher prices encourage more production long-run, there is a lag in the response of natural gas production to higher prices. During this lag, price volatility will be an issue because at times unexpectedly high demand (due to drastic weather changes, for example) can cause a temporary market imbalance between the then-current supply and any demand increase until production can "catch up" with the increased demand or demand slackens. This market imbalance is what usually causes the price volatility. Price volatility in the natural gas market is happening and will continue to happen, with or without the proposed plant. The question is to what extent prices have to rise to develop sufficient amounts of the natural gas resource base. The EIA, in its AEO2001 National Energy Modeling System, estimates that about 512 Tcf of the 1,281 Tcf estimated recoverable resource will be produced between 1999 and 2020 at prices less than $3.05 per MMBtu in 1999 dollars.[11] However, including weather, many factors can raise and lower this price from month-to-month and year-to-year.

The Department's overall assessment of the future viability of natural gas as a generation option is that supply resources, although as yet undeveloped, certainly exist, but the question is the price that natural gas will have to reach to bring new and more expensive resources on line. The Department acknowledges the price variability in the EIA's Annual Energy Outlook 2003 Report offers a range of wellhead prices of $3.83 to $4.50 per MMBtu for the range of natural gas prices in 2025. This wellhead price range seems reasonable, but risk is inherent in any commodity market and the last five years have shown that the natural gas market is as volatile as any commodity. Also, this price range represents <u>only</u> the cost to extract and process natural gas. Since Minnesota is a considerable distance from where natural gas is produced, there is a cost to transport it to Minnesota. For example, it would likely cost FEP approximately $1.20 per MMBtu to transport the natural gas to Minnesota.

---

[10] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001. Energy Information Administration, Executive Summary pg., viii.

[11] U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001. Energy Information Administration, pg. 34.