UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Debbye Balcaen Lathrop
Laramie County Clerk
P.O. Box 608
Cheyenne, WY 82003

Re: Black Hills Corp./Cheyenne Light Fuel & Power - Cheyenne Prairie Generating Station Draft Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001 - supplemental information for the record

Dear Ms. Lathrop:

Please amend the public notice file for the above named facility, transmitted to your office under cover letter dated 5/17/2012, with the enclosed documents (including supplemental correspondence and Endangered Species Act information). As with the documents you already have, please make these documents available (in the same file folder as the others) for the remainder of the public comments period (through June 21, 2012). Thank you so much for your help and please don't hesitate to call with any questions or concerns you may have at (303) 312-6648. I apologize for any inconvenience this may have created for you, thank you.

Sincerely,

Christopher Razzazian, Engineer
Air Program

Enclosures (2)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. William Allison
Air Division Director
Air Pollution Control Division (APCD-SS-B1)
Colorado Department of Public Health & Environment
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Mr. Allison:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through June 21, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

The public notice will be published in the Wyoming Tribune Eagle on Monday, May 21, 2012. The public comment period will end on June 21, 2012, at 8:30 p.m. All written or emailed comments submitted by the close of the public comment period will be considered by the EPA in making its final permit decision. Please refer to the enclosed copy of the public notice for details on the public comment period.

The Wyoming Department of Environmental Quality (WDEQ) will issue a draft PSD permit for PSD pollutants other than GHGs for this facility. The WDEQ will conduct a public comment period concurrent with the EPA's for its draft PSD permit.

The conditions contained in the permit will become effective and enforceable if the permit is issued as a final permit. If you wish to comment on the proposed action please submit your written comments to:

Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Virginia Riley
Executive Secretary to the Mayor of Cheyenne
City of Cheyenne
2101 O'Neil Ave.
Cheyenne, WY 82001

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Ms. Riley:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on the EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through June 21, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

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U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

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Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Debbye Balcaen Lathrop
Laramie County Clerk
P.O. Box 608
Cheyenne, WY 82003

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Ms. Lathrop:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice, permit application and related correspondence (including two letters dated November 22, 2011, and May 3, 2012). Please make this information available to the public until the close of business on June 21, 2012. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through June 21, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (6)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Gus Lopez
Health Department Director
Cheyenne-Laramie County Health Department
100 Central Ave.
Cheyenne, WY 82007

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Mr. Lopez:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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DENVER, CO 80202-1129
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Honorable Richard L. Kaysen
Mayor of Cheyenne
2101 O'Neil Ave.
Room 310
Cheyenne, WY 82001

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit
PSD-WY-000001-2011.001

Dear Honorable Kaysen:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

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http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Clark Smith
Permit Section Supervisor
Nebraska Department of Environmental Quality
1200 N. Street, Suite 400
Lincoln, NE 68508-8922

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Mr. Smith:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
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Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Susan Johnson, Chief
Policy, Planning and Permit Review
Air Resources Division
National Park Service
12795 W. Alameda Pkwy.
Lakewood, CO 80228

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Ms. Johnson:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Mr. Currit:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

Additionally, we will be requesting your written concurrence, by separate letter, on our analysis and conclusions with regard to the National Historic Preservation Act. We wish to thank you for working with us through this process. If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
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http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Ms. Silva:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

We wish to thank Julie Proell of your Cheyenne field office staff for working with us through this process. If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Jeff Sorkin
Air Program Manager
USDA Forest Service
Rocky Mountain Region
740 Simms Street
Golden, CO 80401

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit
PSD-WY-000001-2011.001

Dear Mr. Sorkin:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

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Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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http://www.epa.gov/region08

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Steven A. Dietrich
Air Quality Administrator
Air Quality Division
Wyoming Department of Environmental Quality
Herscher Building
122 West 25th Street
Cheyenne, WY 82002

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit
PSD-WY-000001-2011.001

Dear Mr. Dietrich:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through June 21, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

The public notice will be published in the Wyoming Tribune Eagle on Monday, May 21, 2012. The public comment period will end on June 21, 2012, at 8:30 p.m. All written or emailed comments submitted by the close of the public comment period will be considered by the EPA in making its final permit decision. Please refer to the enclosed copy of the public notice for details on the public comment period.

The conditions contained in the permit will become effective and enforceable if the permit is issued as a final permit. If you wish to comment on the proposed action please submit your written comments to:

Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Carl Daly, Director
Air Program

Enclosures (3)

Page	:	1 of 5 05/11/2012 12:53:03		**Ad Number**	:	57781637
				Ad Key	:	
Order Number	:	53765747		**Salesperson**	:	LGL - Nicki Romero
PO Number	:			**Publication**	:	Wyoming Tribune-Eagle
Customer	:	USEPAREG U.S. EPA REGION 8		**Section**	:	CLASSIFIED
Contact	:			**Sub Section**	:	CLASSIFIED
Address1	:	999 18TH ST		**Category**	:	800 Legal Notices
Address2	:	T&MS FIN MGMT PROGRAM		**Dates Run**	:	05/21/2012-05/21/2012
City St Zip	:	DENVER CO 80202		**Days**	:	1
Phone	:	(303) 312-7089		**Size**	:	1 x 23.38, 241 lines
Fax	:	(303) 294-1199		**Words**	:	971
Credit Card	:			**Ad Rate**	:	Open2009
Printed By	:	1F		**Ad Price**	:	312.36
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PUBLIC NOTICE OF A DRAFT PERMIT WHICH REGULATES THE EMISSIONS OF AIR POLLUTANTS

The Region 8 office of the United States Environmental Protection Agency (EPA) is hereby providing opportunity through June 21, 2012, 8:30pm, for public comment on a draft permit which would grant conditional approval, under Title I, Parts A and C, of the Federal Clean Air Act, as amended, and under Federal Prevention of Significant Deterioration of Air Quality (PSD) permitting rules at 40 CFR 52.21, to the following permit applicant, to construct a new facility:

Cheyenne Light, Fuel & Power
(Black Hills Corporation)
Cheyenne Prairie Generating Station
Section 1, Township 13 North, Range 66 West
Latitude: 41º 07' 27.83" North
Longitude: 104º 43' 13.34" West
Cheyenne, Laramie County, Wyoming

Corporate Address:
Black Hills Corporation
P.O. Box 1400
625 Ninth Street
Rapid City, South Dakota 57709

The proposed facility will be a nominal 220 MW gross electric generating utility, to be located approximately 7 miles east of Interstate-25 in Cheyenne, Wyoming. Pursuant to a national Federal Implementation Plan (FIP), EPA is the PSD permitting authority for greenhouse gases (GHGs) in Wyoming. Pursuant to the Wyoming State Implementation Plan (SIP), the Wyoming Department of Environmental Quality (WDEQ) is the permitting authority implementing PSD requirements for all other regulated New Source Review

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(NSR) pollutants. Therefore, EPA will issue a PSD permit which covers only GHGs and WDEQ will issue a separate PSD permit covering all other NSR pollutants.

The proposed generating station would consist of five 40 MW natural gas fired combustion turbines. Three turbines will be operated in simple cycle mode, while the remaining two will operate in combined cycle mode (powering a single steam turbine). Additional equipment will include six natural gas fired inlet air heaters, two natural gas fired fuel heaters, one diesel emergency generator, one diesel fire pump, one wet cooling tower, and three electric chillers (each with a cooling tower). Energy efficiency is proposed to minimize the emissions of GHGs. Potential GHG emissions from the proposed generating station, on a mass basis, are estimated at 962,929 tons per year of carbon dioxide, 34.25 tons per year of methane, 1.86 tons per year of nitrous oxide and 5.4 pounds per year of sulfur hexafluoride. The combined GHG emissions, taking into account global warming potentials for each pollutant, is estimated to be 964,289 tons per year of carbon dioxide equivalent. No emissions of the remaining two GHG pollutants, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs), are anticipated from this source.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection between 8:30 am and 4:00 pm Mountain Standard Time, through June

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21, 2012, at:
US EPA Region 8
Air Program Office (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129
Permit Contact:
Christopher Razzazian
email:
razzazian.christopher@epa.gov
phone: 303-312-6648
toll-free: 800-227-8917
fax: 303-312-6064

All documents will be available for review at the U.S. EPA Region 8 office on Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). A copy of the administrative record is also available for public inspection at the Laramie County Clerk's Office in Cheyenne, Wyoming. A copy of the draft permit and draft Statement of Basis is also available on EPA website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

In accordance with 40 CFR 52.21(q), Public participation, any interested person may submit written or emailed comments on the draft permit during the public comment period and may request a public hearing. A public hearing will be held for this action on June 21, 2012 from 7:30 pm to 8:30 pm in the Cottonwood Room of the Laramie County Library located at 2200 Pioneer Avenue, Cheyenne, WY 82001. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed generating station. All persons

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desiring to be heard on this matter are hereby notified to appear at the designated time and place. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants there will be a hearing held prior to the EPA GHG permit from 6:00 pm to 7:00 pm at the aforementioned date and location regarding the WDEQ draft PSD permit. All comments regarding pollutants other than GHGs from the proposed facility must be submitted to the WDEQ, which is running a concurrent public notice for this facility.

All written and emailed comments received before the close of the public hearing will be considered as well as all verbal comments received during the public hearing. All comments, written and emailed, should be addressed to the Permit Contact at the US EPA Region 8 address or email address listed above.

In accordance with 40 CFR 124.15, Issuance and effective date of permit, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision, unless review is requested on the permit under 40 CFR 124.19. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

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May 21, 2012

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The proposed generating station would consist of five 40 MW natural gas fired combustion turbines. Three turbines will be operated in simple cycle mode, while the remaining two will operate in combined cycle mode (powering a single steam turbine). Additional equipment will include six natural gas fired inlet air heaters, two natural gas fired fuel heaters, one diesel emergency generator, one diesel fire pump, one wet cooling tower, and three electric chillers (each with a cooling tower). Energy efficiency is proposed to minimize the emissions of GHGs. Potential GHG emissions from the proposed generating station, on a mass basis, are estimated at 962,929 tons per year of carbon dioxide, 34.25 tons per year of methane, 1.86 tons per year of nitrous oxide and 5.4 pounds per year of sulfur hexafluoride. The combined GHG emissions, taking into account global warming potentials for each pollutant, is estimated to be 964,289 tons per year of carbon dioxide equivalent. No emissions of the remaining two GHG pollutants, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs), are anticipated from this source.

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US EPA Region 8
Air Program Office (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129
Permit Contact: Christopher Razzazian
email: razzazian.christopher@epa.gov
phone: 303-312-6648
toll-free: 800-227-8917
fax: 303-312-6064

All documents will be available for review at the U.S. EPA Region 8 office on Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). A copy of the draft permit, draft Statement of Basis, and permit application is also available for public inspection at the Laramie County Clerk's Office in Cheyenne, Wyoming. These documents are also available on EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person may submit written or emailed comments on the draft permit during the public comment period and may request a public hearing. A public hearing will be held for this action on June 21, 2012 from 7:00 pm to 8:30 pm in the Cottonwood Room of the Laramie County Library located at 2200 Pioneer Avenue, Cheyenne, WY 82001. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed generating station. All persons desiring to be heard on this matter are hereby notified to appear at the designated time and place. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants there will be a hearing held prior to the EPA GHG permit from 5:30 pm to 7:00 pm at the aforementioned date and location regarding the WDEQ draft PSD permit. All comments regarding pollutants other than GHGs from the proposed facility must be submitted to the WDEQ, which is running a concurrent public notice for this facility.

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United States Department of the Interior

FISH AND WILDLIFE SERVICE

Ecological Services
5353 Yellowstone Road, Suite 308A
Cheyenne, Wyoming 82009

SEP 13 2011

In Reply Refer To:
ES-61411/WY11SL0365

Christopher Razzazian, Mechanical/Environmental Engineer
U.S. EPA Region 8 Air Program
8OC-EISC
1595 Wynkoop Street
Denver, CO 80202-1129

RECEIVED
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Dear Mr. Razzazian:

Thank you for your email dated August 11, 2011, regarding the proposed Cheyenne Generating Station (CGS) to be located in T13N, R66W, Section 1, in Cheyenne, Laramie County, Wyoming. We understand that a permit from the U.S. Environmental Protection Agency has been requested by the project proponent, Cheyenne Light, Fuel, and Power, a subsidiary of Black Hills Power, for the proposed project activity. The purpose of the proposed CGS is to produce electricity for the City of Cheyenne and Black Hills Power areas in Wyoming and South Dakota. The proposed project includes the installation of five 40-mega-watt natural gas combustion turbine generators (CTGs) along with associated towers, heaters, emergency generator, and infrastructure including electrical transmission lines, natural gas pipelines, and wastewater pipelines. Current land use in the area is undeveloped grassland bounded by a wastewater treatment plant, Interstate 80, and ranchland.

You have requested information regarding species listed under the Endangered Species Act of 1973, as amended (Act), 16 U.S.C. 1531 *et seq*. In response to your request, the U.S. Fish and Wildlife Service (Service) is providing you with recommendations for protective measures for threatened and endangered species in accordance with the Act. We are also providing recommendations concerning migratory birds in accordance with the Migratory Bird Treaty Act (MBTA), 16 U.S.C. 703, and the Bald and Golden Eagle Protection Act (BGEPA), 16 U.S.C. 668. Wetlands are afforded protection under Executive Orders 11990 (wetland protection) and 11988 (floodplain management), as well as section 404 of the Clean Water Act. Other fish and wildlife resources are considered under the Fish and Wildlife Coordination Act, as amended, 16 U.S.C. 661 *et seq*., and the Fish and Wildlife Act of 1956, as amended, 16 U.S.C. 742a-742j.

In accordance with Section 7(c) of the Act, we have determined that the following species or their designated habitat may be present in the proposed CGS project area. We would appreciate receiving information as to the current status of each of these species within the proposed project area.

Listed, Proposed, Candidate Species and their Designated and Proposed Critical Habitat that may be in the proposed Project Area

Species/Critical Habitat	**Scientific Name**	**Status**	**Habitat**
Preble's Meadow Jumping Mouse	*Zapus hudsonius preblei*	Threatened	Heavily vegetated streamside areas and in adjacent grassland cover
Colorado Butterfly Plant	*Gaura neomexicana coloradensis*	Threatened	Wet meadows and riparian areas
Colorado Butterfly Plant Critical Habitat	Designated for Colorado butterfly plant in specific wet meadows and riparian areas within Laramie and Platte Counties of Wyoming (see 50 CFR 17.96(a))		
Ute Ladies'-tresses	*Spiranthes diluvialis*	Threatened	Seasonally moist soils and wet meadows of drainages below 7,000 ft. elevation

Preble's meadow jumping mouse: In 2008, the Service removed ESA protection for the Preble's meadow jumping mouse (*Zapus hudsonius preblei*) (Preble's) in Wyoming but continued them in Colorado, based on an interpretation of the law that allowed the agency to apply ESA protections to those portions of a species' range where the Service believed it was most threatened, rather than in all the places where it is found. On August 6, 2011, the Service relisted the Preble's in order to comply with a requested court order. Preble's populations throughout the species' range in Colorado and Wyoming will be federally protected, with a special rule in place to allow rodent control, agricultural operations, landscape maintenance, noxious weed control, ditch maintenance, and other specified activities to occur provided they are conducted in accordance with the requirements of the special rule.

Preble's is a small rodent in the Zapodidae family and is 1 of 12 recognized subspecies of the species *Z. hudsonius*, the meadow jumping mouse. Preble's are 7 to 10-inches in length including a 4 to 6-inch bicolor tail, large hind feet adapted for jumping, and a distinct dark stripe down the middle of its back that is bordered on either side by gray to orange-brown fur. The diet of the Preble's consists of seeds, fruits, fungi, and insects. Preble's are primarily nocturnal or crepuscular, but have been observed during daylight. Hibernation occurs from October to May in small underground burrows the mouse excavates several centimeters underground.

Preble's exhibits a preference for lush vegetation along watercourses or herbaceous understories in wooded areas with close proximity to water. They occur in low undergrowth consisting of grasses, forbs, or a mix of both; in wet meadows and riparian corridors; or where tall shrubs and low trees provide adequate cover. Additionally, Preble's have been documented to use uplands at least as far out as 330 feet beyond the 100-year floodplain. In Wyoming, Preble's has been documented in Albany, Laramie, Platte and Converse Counties, and may occur in Goshen County. If a proposed project will result in a disturbance to suitable habitat within any of these five counties, surveys should be conducted prior to any action. Due to the difficulty in identifying the Preble's, surveys should be conducted by knowledgeable biologists trained in conducting these surveys.

Colorado Butterfly Plant: The Colorado butterfly plant (*Gaura neomexicana coloradensis*) is a perennial herb endemic to moist soils in wet meadows of flood plain areas. This plant occurs in southeastern Wyoming, north-central Colorado, and extreme western Nebraska between elevations of 5,000 and 6,400 feet. These plants are often found in low depressions or along bends in wide meandering stream channels a short distance upslope of the actual channel. Threats to the plant include non-selective herbicide spraying, haying and mowing schedules that inhibit the setting of seed, land conversion for cultivation, and competition from noxious weeds. Low numbers and limited distribution contribute to the plant's vulnerability. Surveys should be conducted during flowering season, which normally occurs in July and August. Temporal variability in the flowering period exists from site to site and from year to year depending on annual climatic conditions. Surveys should be conducted by knowledgeable botanists trained in conducting rare plant surveys. The Service does not maintain a list of "qualified" surveyors but can refer those wishing to become familiar with the Colorado butterfly plant to experts who can provide training/services. Critical habitat is designated for Colorado butterfly plant in specific wet meadows and riparian areas within Laramie and Platte Counties of Wyoming (see 50 CFR 17.96(a)).

Ute Ladies'-tresses: Ute ladies'-tresses (*Spiranthes diluvialis*) is a perennial, terrestrial orchid, 8 to 20 inches tall, with white or ivory flowers clustered into a spike arrangement at the top of the stem. Ute ladies'-tresses typically blooms from late July through August; however, depending on location and climatic conditions, it may bloom in early July or still be in flower as late as early October. Ute ladies'-tresses is endemic to moist soils near wetland meadows, springs, lakes, and perennial streams where it colonizes early successional point bars or sandy edges. The elevation range of known occurrences is 4,200 to 7,000 feet (although no known populations in Wyoming occur above 5,500 feet) in alluvial substrates along riparian edges, gravel bars, old oxbows, and moist to wet meadows. Soils where Ute ladies'-tresses have been found typically range from fine silt/sand, to gravels and cobbles, as well as to highly organic and peaty soil types. Ute ladies'-tresses is not found in heavy or tight clay soils or in extremely saline or alkaline soils. Ute ladies'-tresses seems intolerant of shade and small scattered groups are found primarily in areas where vegetation is relatively open. Surveys should be conducted by knowledgeable botanists trained in conducting rare plant surveys. Ute ladies'-tresses is difficult to survey for primarily due to its unpredictability of emergence of flowering parts and subsequent rapid desiccation of specimens. The Service does not maintain a list of "qualified" surveyors but can refer those wishing to become familiar with the orchid to experts who can provide training or services.

Species or Resource of Concern

Black-tailed Prairie Dog: The range of the black-tailed prairie dog (*Cynomys ludovicianus*) once spanned the short and mixed grass prairies of North America east of the Rockies from southern Canada to northern Mexico. This species still occurs over much of its historic range, although in more widely scattered large colonies. Black-tailed prairie dogs occur within the eastern third of Wyoming. A population thought to have been intentionally introduced outside of this range also occurs in the Bighorn Basin. We encourage the conservation of prairie dog colonies for their value to the prairie ecosystem and the many species that rely on them. Threats that may be significant to conserving black-tailed prairie dog populations include disease (sylvatic plague) and some control programs (poisoning). Prairie dogs serve as the primary prey species for the black-footed ferret and several raptors, including the golden eagle (*Aguila chrysaetos*) and ferruginous hawk (*Buteo regalis*). Prairie dog colonies and burrows also provide shelter or nest sites for species like the mountain plover (*Charadrius montanus*) and burrowing owl (*Athene cunicularia*). Because black-tailed prairie dog colonies in Wyoming do not currently support any ferret populations, black-footed ferret surveys are not necessary within Wyoming. However, we do encourage evaluating black-tailed prairie dog colonies for the potential reintroduction of black-footed ferrets.

Wetlands/Riparian Areas: Wetlands or riparian areas may be impacted by the proposed project, including Crow Creek and its associated wetlands. Wetlands perform significant ecological functions which include: (1) providing habitat for numerous aquatic and terrestrial wildlife species, (2) aiding in the dispersal of floods, (3) improving water quality through retention and assimilation of pollutants from storm water runoff, and (4) recharging the aquifer. Wetlands also possess aesthetic and recreational values. If wetlands may be destroyed or degraded by the proposed action, those wetlands in the project area should be inventoried and fully described in terms of their functions and values. Acreage of wetlands, by type, should be disclosed and specific actions should be outlined to avoid, minimize, and compensate for all unavoidable wetland impacts.

Riparian or streamside areas are a valuable natural resource and impacts, including discharge of wastewater, to these areas should be avoided whenever possible. Riparian areas are the single most productive wildlife habitat type in North America. They support a greater variety of wildlife than any other habitat. Riparian vegetation plays an important role in protecting streams, reducing erosion and sedimentation as well as improving water quality, maintaining the water table, controlling flooding, and providing shade and cover. In view of their importance and relative scarcity, impacts to riparian areas should be avoided. Any potential, unavoidable encroachment into these areas should be further avoided and minimized. Unavoidable impacts to streams should be assessed in terms of their functions and values, linear feet and vegetation type lost, potential effects on wildlife, and potential effects on bank stability and water quality. Measures to compensate for unavoidable losses of riparian areas should be developed and implemented as part of the project.

Plans for mitigating unavoidable impacts to wetland and riparian areas should include mitigation goals and objectives, methodologies, time frames for implementation, success criteria, and monitoring to determine if the mitigation is successful. The mitigation plan should also include a contingency plan to be implemented should the mitigation not be successful. In addition, wetland restoration, creation, enhancement, and/or preservation does not compensate for loss of stream habitat; streams and wetlands have different functions and provide different habitat values for fish and wildlife resources.

Best Management Practices (BMPs) should be implemented within the project area wherever possible. BMPs include, but are not limited to, the following: installation of sediment and erosion control devices (*e.g.*, silt fences, hay bales, temporary sediment control basins, erosion control matting); adequate and continued maintenance of sediment and erosion control devices to insure their effectiveness; minimization of the construction disturbance area to further avoid streams, wetlands, and riparian areas; location of equipment staging, fueling, and maintenance areas outside of wetlands, streams, riparian areas, and floodplains; and re-seeding and re-planting of riparian vegetation native to Wyoming in order to stabilize shorelines and streambanks.

Migratory Birds

MBTA and BGEPA Prohibitions: The MBTA, enacted in 1918, prohibits the taking of any migratory birds, their parts, nests, or eggs except as permitted by regulations, and does not require intent to be proven. Section 703 of the MBTA states, "Unless and except as permitted by regulations ... it shall be unlawful at any time, by any means or in any manner, to ... take, capture, kill, attempt to take, capture, or kill, or possess ... any migratory bird, any part, nest, or eggs of any such bird...." The BGEPA prohibits knowingly taking, or taking with wanton disregard for the consequences of an activity, any bald or golden eagles or their body parts, nests, or eggs, which includes collection, molestation, disturbance, or killing.

The term "disturb" under the BGEPA has recently been defined as "to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior (72 FR 31332)." In addition to immediate impacts, this definition also covers impacts that result from human-induced alterations initiated around a previously used nest site during a time when eagles are not present, if upon the eagle's return, such alterations agitate or bother an eagle to a degree that injures an eagle or substantially interferes with normal breeding, feeding, or sheltering habits and causes, or is likely to cause, a loss of productivity or nest abandonment. Removal or destruction of such nests or causing abandonment of a nest could constitute violation of one or both of the above statutes.

No permits will be issued for an active nest of any migratory bird species, unless removal of an active nest is necessary for reasons of human health and safety. Therefore, if nesting migratory birds are present on or near the project area, timing is a significant consideration and needs to be addressed in project planning. If nest manipulation is proposed for this project, you should contact the Service's Migratory Bird Office in Denver at 303-236-8171 to see if a permit can be issued for this project. If a permit cannot be issued, the project may need to be modified to ensure take of a migratory bird or eagle, young, eggs, or nest will not occur.

Additionally, the Service recommends that the proposed CGS be included within the scope of analysis of the April 5, 2011 Avian Protection Plan (APP) by Black Hills Power to minimize and avoid potential impacts to bird and bat species. Specifically, we recommend that the proposed project comply with Section 5.7: Construction and Modification to Avian-Safe Standards as well as additional practices to prevent birds from utilizing heaters and cooling towers associated with the project.

For our internal tracking purposes, the Service would appreciate notification of any decision made on this project (such as issuance of a permit or signing of a Record of Decision or Decision Memo). Notification can be sent in writing to the letterhead address or by electronic mail to FW6_Federal_Activities_Cheyenne@fws.gov.

We appreciate your efforts to ensure the conservation of Wyoming's fish and wildlife resources. If you have questions regarding this letter or your responsibilities under the Act and/or other authorities or resources described above, please contact Julie Proell of my office at the letterhead address or phone (307) 772-2374, extension 232.

Sincerely,

for R. Mark Sattelberg
Field Supervisor
Wyoming Field Office

cc: WGFD, Non-game Coordinator, Lander, WY (B. Oakleaf)
WGFD, Statewide Habitat Protection Coordinator, Cheyenne, WY (M. Flanderka)

Black Hills Corporation (Black Hills)

Cheyenne Prairie Generating Station (CPGS), Cheyenne Wyoming

Endangered Species Impacts Assessment

In Support of USEPA Review of the Cheyenne Prairie Generating Station Greenhouse Gas (GHG) Air Permit Application

May 3, 2012

The following will summarize Black Hills' response to the species of interest and other resource concerns identified by the U.S. Fish and Wildlife Service (USFWS), Cheyenne office in an undated letter from mid-September 2011.

Exhibit A - Study:

- February 14, 2012 – Evaluation Endangered Species Habitat (Thompson and Johnson, WEST, Inc.)

Exhibit B - Surveys:

- April 16, 2012 – Survey for raptor nests and prairie dog colonies (David Phillips, CH2M HILL, Inc). USFWS will be notified of the results of the survey.
- Planned Survey for June-July 2012 for the Colorado butterfly plant and the Ute ladies'-tresses orchid between the project site and the Crow Creek riparian area to determine presence of these species. Colorado butterfly plant surveys will be completed on the natural gas pipeline corridor at the location where it crosses Porter's Draw.
- Planned survey in the spring of 2013 to assess raptor nesting along Crow Creek to determine course of action.

Exhibit C - Black Hills Corporation – Wyoming Avian Protection Plan

Prebble's Meadow Jumping Mouse (PMJM): Black Hills intends to directionally bore underneath Crow Creek and the adjacent riparian habitat and portions of the adjacent upland area thus avoiding the PMJM habitat. The setback distance for the drill angle from the edge of the riparian area is intended to satisfy the USFWS's setback requirements. It is Black Hills' assessment that any impact to the potential PMJM habitat and the PMJM, if present, will be avoided.

Colorado Butterfly Plant (CBP): Black Hills intends to directionally bore underneath Crow Creek thus avoiding any potential CBP habitat. It is Black Hills' assessment that any impact to the potential CBP habitat and the CBP, if present, will be avoided in this area. Black Hills will conduct a one-time survey of the facility site to the riparian area and the location where the gas line will cross Porter's Draw to verify the presence or absence of the CBP. If the plant is found, avoidance measures will be taken, otherwise, no impact to the species is expected. USFWS will be notified of the results of the Survey.

Ute Ladies'-tresses (ULT): Black Hills intends to directionally bore underneath Crow Creek thus avoiding the ULT habitat. It is Black Hills assessment that any impact to the ULT habitat and the ULT, if present, will be avoided. Black Hills will conduct a one-time survey of the facility site to the riparian area to verify the presence or absence of the ULT. If the species are found, avoidance measures will be taken. USFWS will be notified of the results of the Survey.

Black-tailed Prairie Dog: In a survey completed on April 16, 2012 by CH2M HILL, there were no prairie dogs, colonies, or individual burrows present at or within 500 feet of the project site or the pipeline corridor path. USFWS will be notified of the results of the Survey.

Wetlands/Riparian Areas on Crow Creek: Black Hills intends to directionally bore underneath Crow Creek and the adjacent riparian area thus avoiding the wetlands and riparian areas bordering Crow Creek. Black Hills will secure a Storm Water Construction Permit from Wyoming Department of Environmental Quality (WDEQ) and develop a Storm Water Pollution Prevention Plan (SWPPP) implementing Best Management Practices (BMPs) to control storm water run-off during construction. The facility will also have an active Industrial Storm Water Control Permit when operation commences with a SWPPP that requires BMPs.

Migratory Birds Treaty Act and Bald and Golden Eagle Protection Act: There are currently five known raptor nests in the project area (see map in April 16, 2012 survey report for location).

1. Active Spring of 2012 with red-tailed hawk. Southwest of project area on Crow Creek.
2. Active Spring of 2012 with great horned owl. South Southwest of project area on Crow Creek.
3. Inactive Spring of 2012. Immediately south of project site – unknown raptor.
4. Nest confirmed gone Spring 2012 (nest branch broke) – unknown raptor.
5. Inactive Spring of 2012. Southwest of project area next to nest #1 – unknown raptor.
6. Inactive Spring of 2012. Northwest of project area – across I-80 – unknown raptor.

	Distance to Project fence-line (ft)	**Distance to Plant (miles)**	**Elevation (ft asl)**	**Elevation Relative to Plant (plant average 5,950 ft asl)**
Nest 1	2,060	0.39	5,927	-23
Nest 2	2,570	0.49	5,918	-32
Nest 3	1,905	0.36	5,915	-35
Nest 4	na	na	na	Na
Nest 5	2,060	0.39	5,927	-23
Nest 6	4,420	0.84	5,985	+35

Project Construction Schedule

Start Site Construction – April 1, 2013 (14-month duration)
Gas-line Construction – winter 2013 (4-month duration)
Commercial Operation (end of construction) – June 1, 2014

Black Hills will take the following measures to minimize impacts to raptors during nesting season in the immediate area (Crow Creek riparian area):

1. Avoid disturbance of any active raptor nests during nesting season by staying outside of the recommended disturbance buffer as identified by USFWS guidelines for the given species nesting
2. If work must occur within the avoidance buffer of the nest, confirm through survey that bird(s) have fledged the nest , or
3. If work must occur within the avoidance buffer of the nest, confirm through survey that the nest is inactive.

Black Hills will take the following measures to minimize impacts to migratory birds during nesting season in the immediate area in the pipeline corridor extending from the project site to the interconnection with the main gas line near the Wyoming/Colorado border, if there is a need to use the measure.

1. Employ ground preparation practices to discourage ground nesting at the project site and natural gas line corridor. This could involve mowing or tilling prior to nesting season or documenting the absence of nesting birds where disturbance will occur.
2. Avoiding the nesting seasons, or
3. Abiding by USFWS construction setback distance recommendations during the pipeline construction.

Avian Protection Plan (Exhibit C): In cooperation with the USFWS, Black Hills has developed an Avian Protection Plan for all Wyoming operations. The plan requires avian protection measures for new electrical line construction. Those measures will be employed for the applicable components of the project (e.g., substation, transmission line).

Other Environmental related issues:

Industrial Surface Water Discharge to Dry Creek or Crow Creek: There will be no industrial wastewater discharge to Dry Creek or Crow Creek. Black Hills will discharge wastewater directly to the Dry Creek Wastewater Facility adjacent to the plant through a sewer line.

Storm Water Discharge: Black Hills will secure Construction Storm Water Permit for construction activities and an Industrial Storm Water Permit for commercial activity after construction is completed. The permits will have associated Storm Water Pollution Prevention Plans that will require the implementation of Best Management Practices.

Septic System: There will be no septic system. Black Hills will discharge sanitary waste directly to the Dry Creek Wastewater Facility adjacent to the plant.

Raptor Nest and Prairie Dog Colony Survey -Cheyenne Prairie Generating Station Project

TO: Black Hills Corporation

FROM: David Phillips, Senior Biologist, CH2M HILL Engineers, Inc.

DATE: April 19, 2012

CH2M HILL Engineers, Inc. (CH2M HILL) completed a survey to identify black-tailed prairie dog colonies (*Cynomys ludovicianus*) and raptor nests that could be potentially affected by construction of the Cheyenne Prairie Generating Station (CPGS) ("facility") and associated natural gas pipeline ("pipeline"), collectively referred to as the Project, proposed by Black Hills Corporation. Raptor nest surveys were completed within 1 mile, and prairie dog surveys were completed within 500 feet, of planned construction activity for the Project.

Project Description

The facility site is located in Laramie County, Wyoming, approximately 5 miles east of downtown Cheyenne, and within the city limits. The facility would occupy approximately 30 acres within a 250-acre parcel located adjacent to and south of Interstate 80 (I-80). The parcel is located just west of the Dry Creek Wastewater Treatment Plant. Elevation at the facility is approximately 5,950 feet above mean sea level (amsl); the pipeline ranges from 5,950 to 6,200 feet amsl. Approximately 1.75 miles of 115-kilovolt (kV) transmission line will be installed to connect the facility to the grid at a point east of the facility. The Project would be supplied by an approximately 9-mile natural gas pipeline originating at a metering station in southern Laramie County and terminating at the Project site. The majority of the pipeline is outside the Cheyenne City limits and located on private and state lands within Laramie County. Figure 1 displays the Project location.

Methods

Raptor Nest Survey

A survey to determine presence or absence of raptor nests were completed on April 16, 2012, by visually inspecting all potential raptor nesting habitat within 1 mile of the Project. Potential nesting habitat included trees (and tree cavities if present or detectable), large shrubs, rock outcrops, cliffs, ridges, knolls, and artificial nest structures such as transmission towers, windmills, and other human structures. Additionally, raptors detected during the survey were observed to determine if behavior indicated any association with potential nest sites (e.g., courtship or defensive behavior, stick delivery). For all nests detected, location, status, condition, substrate, height, and photographs were recorded. Locations were recorded in the field using a Garmin eTrex Legend HCx Global Positioning System (GPS) unit. Nests were considered active if adult raptors were observed exhibiting courtship, stick delivery or incubating behavior, or if eggs, nestlings, or fledglings were observed. The raptor nest survey area included 15,447 acres (24.1 square miles).

Prairie Dog Survey

Surveys to determine the presence or absence of black-tailed prairie dog colonies were completed by visually inspecting the ground within 500 feet of the Project. If prairie dog colonies or individual burrows were identified, the location and status was recorded. Colonies were reported as active if prairie dogs or recent sign (droppings, digging) were evident. The prairie dog survey area included 1,634 acres (2.6 square miles).

The surveys were completed by Dave Phillips, Senior Biologist, CH2M HILL. Mr. Phillips is a Certified Wildlife Biologist by The Wildlife Society with extensive experience surveying for wildlife species in this region, including but not limited to raptors and prairie dogs. He has implemented large scale survey and habitat mapping efforts for special-status wildlife in Wyoming, Colorado, Montana, Idaho, Utah, and California since 2005.

Results

Raptor Nest Survey

The raptor nest survey was completed between 0830-1700 hrs on April 16, 2012. All potential nesting habitat within 1 mile of the proposed project was directly accessible with the exception of a portion of the pipeline corridor for which access permission could not be obtained (Figure 2). Due to the topography of this inaccessible area and the presence of a public road bisecting the northern portion of this private parcel, the area was able to be evaluated completely for the presence or absence of nesting raptors using binoculars.

Five raptor nests (2 active and 3 inactive) were detected during the survey and are shown on Figure 2 and Table 1. One additional nest documented in fall 2011 (Nest 4 in Table 1 and Figure 2) was no longer present as its supporting branch had broken off since last evaluated. All nests recorded during the survey are presented in Figure 2.

TABLE 1

Raptor Nest Survey Results, April 16, 2012

Cheyenne Prairie Generating Station and Pipeline Project

Nest ID	Species	Status	Condition	Substrate	Approx. Nest Height (m)	Photo IDs	Comments
1	Red-tailed hawk	Active	Good	Live cottonwood	13	1,2	Adult incubating
2	Great horned owl	Active	Good	Live cottonwood	9	3,4	Adult and 2 nestlings observed
3	Unknown raptor	Inactive	Good	Live cottonwood	13	5	
4	-	-	Gone	Live cottonwood	-	-	Nest recorded in fall 2011. Nest branch broken and nest material observed on ground during this survey
5	Unknown raptor	Inactive	Good	Live cottonwood	4	6,7	-
6	Unknown raptor	Inactive	Good	Live cottonwood	8	8,9	-

Nest 1 was determined active. An adult red-tailed hawk (*Buteo jamaicensis*) was observed in incubating position (Photograph 1) and a second adult red-tailed hawk was observed perched in a live cottonwood tree approximately 0.25 mile east of the nest. No vantage was available to view into the nest to verify presence or count eggs in the nest; however, the adult was observed in incubating position for approximately 30 minutes between 0945 and 1015 hrs, and this or the other member of the nesting pair was observed on the nest in incubating position during a return visit to the nest at 1700 hrs.

Nest 2 was determined active. An adult great horned owl (*Bubo virginanus*) and two nestlings were observed in Nest 2 at 1045 hrs (Photograph 3). The nestlings were approximately 50 percent feathered.

Prairie Dog Survey

The prairie dog survey was completed between 0830-1700 hrs on April 16, 2012. All areas proposed for disturbance within 500 feet of the proposed project were directly accessible with the exception of a portion of the pipeline corridor for which access permission could not be obtained (see Figure 2). Due to the topography of this inaccessible area and the presence of a public road bisecting the northern portion of this private parcel, the area was able to be completely evaluated for the presence or absence of prairie dogs using binoculars.

With the exception of the Crow Creek Riparian area and associated irrigated hay fields, the project area is comprised almost entirely of open shortgrass prairie habitat. Representative habitat along the pipeline corridor is presented in Photograph 10. No prairie dogs, colonies, or individual burrows are present in or near the project area.

Other wildlife

During the course of the survey, the following wildlife species were observed within the survey area: American robin (*Turdus migratorius*), Canada goose (*Branta canadensis*), common raven (*Corvus corax*), European starling (*Sturnus vulgaris*), ferruginous hawk (*Buteo regalis*), great horned owl, horned lark (*Eremophila alpestris*), loggerhead shrike (*Lanius ludovicianus*), mallard (*Anas platyrhynchos*), western meadowlark (*Sturnella neglecta*), mule deer (*Odocoileus hemionus*), pronghorn (*Antilocapra americana*), red-tailed hawk, Swainson's hawk (*Buteo swainsonii*), white-tailed deer (*Odocoileus virginianus*).

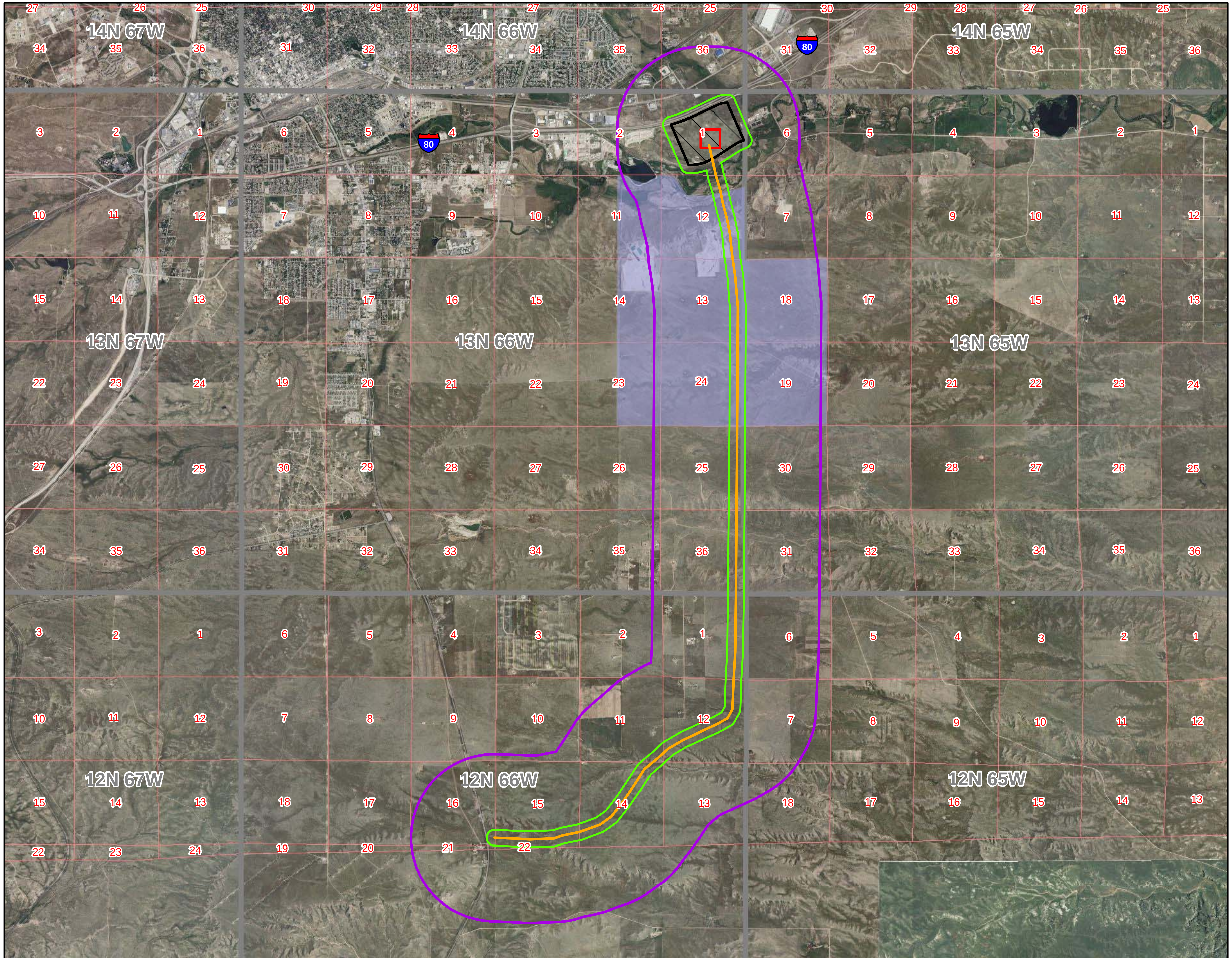
Discussion and Recommendations

Due to the presence of an active red-tailed hawk nest (2,041 feet [0.39 miles] from the plant) and great horned owl nest (1,611 feet [0.31 miles] from the pipeline) of the Project, consideration should be given to timing and location of construction activities to avoid impacts to these or other potentially nesting raptors in the Crow Creek riparian area. It is evident based on the presence of active and inactive raptor nests that the Crow Creek cottonwood riparian area is important to nesting raptors. Therefore, nest surveys during the year of construction are recommended if construction is to occur during the nesting season, to allow implementation of impact avoidance measures.

Based on nesting chronology of the species nesting this year, the red-tailed hawk nest can be expected to fledge young on or before July 1, 2012, and the great horned owl nest can be expected to fledge young prior to May 15, 2012. In future years, raptor nest location, status, species, and timing may differ from that observed during this survey; however, data from this survey indicate that construction planning should allow avoidance of the great horned owl nest from late February until late May and of the red-tailed hawk nest from early March through mid July. More conservative planning could simply avoid impacts within 0.25 miles of all mature cottonwoods located within the Crow Creek riparian area, recognizing that additional nests may be constructed in future years by red-tailed hawks or other raptors, or by late-nesting species not recorded in this survey, such as Swainson's hawk.

Based on the negative survey results for raptor nests along the pipeline corridor to the south of Crow Creek, it is unlikely that raptors will use this area for nesting in future years. However, potential nesting habitat does exist for ferruginous hawks in the form of rugged topography along drainages, and for this and other raptor species in the form of transmission line structures and windmills; therefore surveys during the year of construction are recommended if construction is to occur during the nesting season.

No prairie dogs were present at the combustion turbine facility site or along the pipeline route during this survey. Current land use consists almost entirely of cattle grazing, with some hay farming near Crow Creek, which makes it unlikely that landowners would allow prairie dogs to become established within the project area; therefore, consideration of measures to avoid or minimize impact prairie dogs can reasonably be considered not necessary for this project.



LEGEND
- Proposed Pipeline Route
- One-mile Buffer
- Private (No Access)
- Cheyenne Prairie Generating Station
- Project Parcel
- Township/Range
- Sections

N

0 0.25 0.5 1
Miles

FIGURE1
Project Area
Cheyenne Prairie Generating Station
Black Hills Corporation
Cheyenne, Wyoming

I:\BLACKHILLS_PUC_WY\GIS\MAPFILES\SITING\REVISED\RAPTOR_PDOG_SURVEY_FIGURES\FIGURE1_RAPTOR_PDOG_PROJECT_AREA_11X17.MXD SCUTLER1 4/19/2012 1:15:17 PM

LEGEND

Raptor Nests

- Active - Great Horned Owl
- Active - Red-tailed Hawk
- Inactive - Unknown Raptor
- Nest Confirmed Gone - Unknown Raptor
- Proposed Pipeline Route
- One-mile Buffer
- Private (No Access)
- Cheyenne Prairie Generating Station
- Project Parcel
- Township/Range
- Sections

Note: All lands shown are private.

N

0 250 500 1,000
Feet

FIGURE 2
Survey Results
Cheyenne Prairie Generating Station
Black Hills Corporation
Cheyenne, Wyoming

Attachment 1

Survey Photographs

Photograph 1 – Nest 1. Active red-tailed hawk nest with adult in incubating position.

Photograph 2 – Nest 1. Landscape perspective.

Photograph 3 - Nest 2. Active great horned owl nest with adult and two nestlings present on nest.

Photograph 4 – Nest 2. Landscape perspective.

Photograph 5 - Nest 3. Inactive stick nest.

Photograph 6 - Nest 5. Inactive stick nest.

Photograph 7 - Nest 5. Landscape perspective.

Photograph 8 - Nest 6. Inactive stick nest

Photograph 9 - Nest 6. Landscape perspective.

Photograph 10 – representative habitat along the pipeline corridor

BLACK HILLS POWER & LIGHT CO.
BLACK HILLS GENERATION
A Black Hills Corporation Enterprise

Tim Rogers **605•721•2286**
Environmental Manager

March 2, 2012

Chris Razzazian
USEPA Region 8
1595 Wynkoop Street
Mail Code 8P-AR
Denver, CO 80202-1129

RE: Black Hills Corporations (BHC) Cheyenne Prairie Generating Station (CPGS) – Endangered Species and Migratory Birds

Chris,

This letter is being submitted to the Environmental Protection Agency (EPA) for consideration during the GHG Prevention of Significant Deterioration permit evaluation of the Cheyenne Prairie Generating Station in Cheyenne, Laramie County, Wyoming and the anticipated EPA consultation with the U.S. Fish and Wildlife Service (USFWS) under Section 7 of the Endangered Species Act (ESA).

Project Description:

BHC plans to construct a new nominal 220-megawatt (MW) gross simple and combined-cycle combustion turbine power plant. There will be five 40-MW LM 6000 combustion turbine generators (CTGs). Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode. Operating in combined-cycle will provide approximately 20-MW.

The CTGs will be developed on a 40-acre Project Site on private land plotted in the middle of a 250-acre parcel owned by BHC in Township 13N, Range 66W, Section 1. The parcel is bordered on the north by Interstate 80 (I-80), Crow Creek to the south, the Dry Creek Wastewater Plant to the east, and the HR Residential complex to the west. The access road will run north approximately ¼ mile from the Project Site to an existing road that runs parallel to I-80. The transmission line interconnect will run north from the Project Site to I-80 and then run east parallel and next to an existing transmission line for approximately 1.5 miles to the interconnect location.

The CTGs will be fired by pipeline quality natural gas. The natural gas pipeline will extend from the Project Site approximately 10 miles south to the Wyoming/Colorado Border. BHC ownership of the pipeline will end on the Wyoming side of the border. A Natural Gas Transmission company will be selected and they will provide a gas-line interconnect from their transmission line in Colorado to our pipeline in Wyoming. This transmission interconnect will extend south from our pipeline in Wyoming to approximately 5 miles south to their main transmission line.

In this letter, BHC provides a summary of our consultants findings (enclosed West Inc. report), lists our understanding of the USFWS recommendations (based upon phone conversations, meetings, and guidance documents), and BHC's approach to avoid impacts to these resources to enable the USFWS to make a finding of no adverse effect to the federally listed species and resources for the Project. BHC hopes that our proactive efforts assist EPA in its consultation with USFWS.

USFWS Candidate Species or Critical Habitat: Preble's Meadow Jumping Mouse (PMJM - *Zapus hudsonius preblei*), **Colorado Butterfly Plant** (CBP - *Gaura neomexicana ssp. coloradensis*) **and Ute Ladies'-tresses** (ULT - *Spiranthes diluvalis*).

Project Site: The WEST Report finds the habitat is not suitable for PMJM or the two listed plants indicating that a no effect determination is appropriate since the habitat is not suitable for these species at the Project Site.

Natural Gas Pipeline Corridor:
Crow Creek: WEST determined that potential habitat may exist in the Crow Creek riparian area for PMJM, CBP, and ULT. BHC intends to bore under the potential Crow Creek riparian habitat, thus resulting in no impact to these species or their potential habitat. The bore hole, entry and exit, will be 300 ft outside the 100-year flood plain and will be less than 1/10 acre. The bore holes are 30 ft x 30 ft excavation, therefore BHC anticipates no impact to critical habitat or for the species if they were to be present. USFWS recommends that a one-time survey for the CBP and ULT be completed in Crow Creek during summer 2012 to confirm or deny the presence of the species where the pipeline will cross. BHC will conduct the study and provide the results to the USFWS.

Porter Draw: The USFWS indicated they do not expect PMJM or ULT to occur in Porter Draw, an ephemeral drainage approximately 4 miles south of Crow Creek. However, habitat may be suitable for CBP. Therefore, USFWS recommends that a one-time survey for the CBP be completed in Porter Draw during summer 2012 to confirm or deny the presence of the species where the pipeline will cross. BHC will complete the survey and submit to USFWS. If the CBP are present in the vicinity of where the pipeline will cross, BHC will avoid or drill under the plants to avoid impact to the species.

Transmission Line in Colorado: BHC ownership of the natural gas transmission line will end at the Wyoming border and BHC will not own the pipeline that extends into Colorado. This will be owned by a natural gas transmission company that has not been selected at this point. It has been conveyed to BHC that the selected transmission company will conduct a Biological Assessment on the pipeline they will construct.

Species or Resources of Concern: The USFWS letter noted the ecological importance of black-tailed prairie dog colonies, and the benefits of their preservation.

Project Site: WEST Surveys have not found any prairie dog colonies within the Project Site area, and therefore impacts to that species are not expected.

Natural Gas Line: BHC will conduct a survey on the gas line path owned by BHC in the summer of 2012 for prairie dog colonies. This information will be provided to the USFWS. If colonies are discovered, BHC commits to avoiding impacts to the colonies as discussed with USFWS.

The USFWS also noted the ecological importance of wetlands and riparian areas, and recommended measures to proactively protect these potential habitats from Project impacts.

Project Site: There are no wetlands or riparian areas in the Project Site area. BHC is securing a storm water construction permit for the Project Site from WDEQ that will provide protections of sediment run-off to these resources. Therefore, there will be no impact to these resources.

Natural Gas Line: The only riparian areas of concern are associated with Crow Creek where the pipeline will cross the creek. BHC intends to directional bore beneath Crow Creek, leaving the riparian corridor intact; therefore avoiding adverse impacts. Additionally, BHC will secure a storm water construction permit for the gas line construction that will provide protections of sediment run-off to these resources.

Migratory Birds: Migratory Bird Treaty Act (MBTA) and the Bald and Golden Eagle Protection Act (BGEPA) Recommendations: The USFWS letter notes the Project should proactively consider recommendations concerning migratory birds in accordance with the MBTA and the BGEPA in Project planning. With respect to those resources near the Project area, the report identifies two potential raptor nests and one known historical raptor nest in the trees along Crow Creek, all located some distance away from construction activity at the Project Site. The one known historical nest supported Swainson's hawk (*Buteo swainsoni*) and great-horned owl (*Bubo virginianus*). The USFWS recommended that construction activity be located greater than 0.125 mi from active great horned owl nests and 0.25 mi for Swainsons' hawk and red-tailed hawk (*Buteo jamaicensis*) nests.

> Project Site: The closest existing raptor nest to the Project Site is 0.36 miles. The USFWS confirmed that these raptor nests were outside the distance where disturbance during plant construction would be of concern, assuming the nests were occupied by the great horned owl and Swainson's hawk or by other species (e.g., red-tailed hawk, ferrugious hawk, or eagles). These raptor nests and the area surrounding the project site will be further evaluated in spring 2012 and 2013, prior to and during construction. BHC will provide this information to the USFWS. Based upon the available information, at the present time, the Project Site does not pose impacts to Raptor nests. If the circumstances change based upon the surveys conducted in 2012 or 2013, BHC will employ measures to avoid the nesting season or the spatial distance requirements established for the avian species of concern as discussed with USFWS.
>
> Natural Gas Line: The USFWS recommended that BHC avoid disturbance of any active raptor nests during nesting season either by avoiding construction during the nesting season or conducting construction at the spatial recommendations identified for the specific avian species of concern. BHC intends to avoid the nests by the distances recommended by the USFWS or will plan construction of the pipeline, in proximity to these nests to occur, outside the nesting season resulting in no impact to the species. BHC will use the survey discussed above to evaluate the potential avian species located near the planned pipeline crossing of Crow Creek to determine if further discussions are needed with USFWS due to nest occupancy or a change in avian species type.
>
> Ground Nesting Birds: The USFWS also recommended that measures be taken to avoid or minimize risk of impact to MBTA protected ground and grassland/shrub nesting birds nesting along the gas line. If ground nest are discovered along the natural gas pipeline corridor, BHC will employ measures of avoidance (nesting season or spatial distances) or other acceptable practices that result in a no impact to the nesting birds.

With respect to migratory birds in general, the USFWS letter indicates the BHC Avian Protection Plan (WY-APP enclosed) should guide Project Site design. BHC is in agreement with the USFWS, and per the APP, the Project will employ techniques recommended by the Avian Power Line Interaction Committee (APLIC). This will include compliance with Section 5.7 of the APP, Construction and Modification to Avian-Safe Standards in design aspects of the transmission line and substation to minimize impacts to birds.

BHC believes the results of this study and coordination with the USFWS, coupled with responsible construction practices, clearly demonstrate there will be no significant adverse impacts to ESA-listed species, species and resources of concern, or migratory birds, including raptors and eagles. During the construction phase of the project involving federally protected species, BHC will consult with the USFWS as appropriate and necessary to ensure protection.

If you have any questions on these materials, please contact me at (605) 721-2286 or Tim.Rogers@blackhillscorp.com.

Sincerely,

Tim Rogers
Environmental Manager

cc: Fred Carl, Black Hills Corporation

Enclosures:
Attachment 1: Figure 1 – Crow Creek Raptor Nests
Attachment 2: BHC Avian Protection Plan for Wyoming
Attachment 3: Evaluation of Habitat for Ute Ladies'-tresses, Colorado butterfly plant, and Preble's meadow jumping mouse at the proposed Cheyenne Prairie Generating Station and Pipeline. February 14, 2012.

Evaluation of Habitat for Ute Ladies'-tresses, Colorado butterfly plant, and Preble's meadow jumping mouse at the proposed Cheyenne Prairie Generating Station and Pipeline

Laramie County, WY

Prepared for:

CH2M HILL Engineers, Inc.
9191 S Jamaica Street
Englewood, CO 80112-5946

Prepared by:

Joel Thompson and Gregory Johnson
Western **E**co**S**ystems **T**echnology (WEST), Inc.
2003 Central Avenue
Cheyenne, Wyoming 82001

February 14, 2012

INTRODUCTION

CH2M HILL Engineers, Inc. (CH2M HILL) contracted with Western EcoSystems Technology, Inc. (WEST) to assess the habitat suitability for three federally listed threatened species, Preble's meadow jumping mouse [PMJM; *Zapus hundsonius preblei*]), Ute ladies'-tresses orchid (*Spiranthes diluvialis*), and Colorado butterfly plant (*Gaura neomexicana* ssp. *coloradensis*) at the site of a proposed natural gas plant and pipeline to be constructed in Laramie County, just east of Cheyenne, Wyoming. This report is based on a site visit to the proposed gas plant development site and pipeline corridor by qualified WEST personnel (J. Thompson who holds a USFWS permit for Preble's meadow jumping mouse and G. Johnson who is highly experienced with both listed plant species), in which the area proposed for development was evaluated for potential habitat for each listed species. The purpose of the survey was to assess the potential for these species to occur and determine if additional presence/absence surveys or mitigation strategies developed through federal Endangered Species Act (ESA)(16 USC § 1531 et seq.) consultation may be warranted.

The proposed development site (Figure 1) was visited by WEST personnel on December 16, 2011 to assess the habitat suitability for the three threatened species. Areas surveyed included the parcel that will contain the plant, as well as the three primary drainages that intersect the proposed pipeline corridor. The primary area of concern for potential occurrence of any of the three listed species is along Crow Creek within the pipeline corridor. The gas plant project site, located to the northeast of the pipeline corridor was determined to not contain any suitable habitat for the three species; all of which are dependent upon moist riparian habitats which are nonexistent within the gas plant project site. Therefore, the gas plant project site is not discussed further in this report.

Additionally, the gas plant access road and transmission interconnection site (Figure 1) were visited on January 31 and February 2 to assess habitat suitability for the three listed species. The access road follows a previously developed access road (gravel-based) which parallels Interstate 80. There are two ditch crossings along its route to the project site, both of which utilize a series of high-strength concrete culverts. At the westernmost crossing, the culverts run under Interstate 80. At the eastern ditch crossing, the culverts do not extend under Interstate 80, but are rip-rapped on both sides of the access road (see photos Appendix A). Based on the field evaluation of the two ditch crossings, it was determined that habitats were not suitable for the three listed species. With the exception of small areas of heavy, sandy sedimentation at the downstream edge of each series of culverts caused by occasional high runoff flows (see photos Appendix A), both ditches have incised channels bordered by dense vegetation (primarily upland vegetation, not wetland species) all the way the channel edge. The areas immediately downstream of the culverts are more open; however the sandy sediment comprising the substrate in these areas is not conducive to establishment of riparian vegetation, including Utes ladies'-tresses orchid or Colorado butterfly plant. Neither ditch has riparian habitats considered suitable for Preble's meadow jumping mouse. Due to the lack of suitable habitats along the access road, there should be no effect on listed species due to the use or upgrading of the road and it is not addressed further in this report.

The transmission interconnection site is located approximately 1.5 miles east of the project area, south of Interstate 80 and east of Campstool Rd (Figure 1). The interconnection site is located on a gently sloping prairie hillside, with no suitable habitat for listed species occurring in close proximity. Development at the interconnection site will have no effect on listed species and is not discussed further in this report.

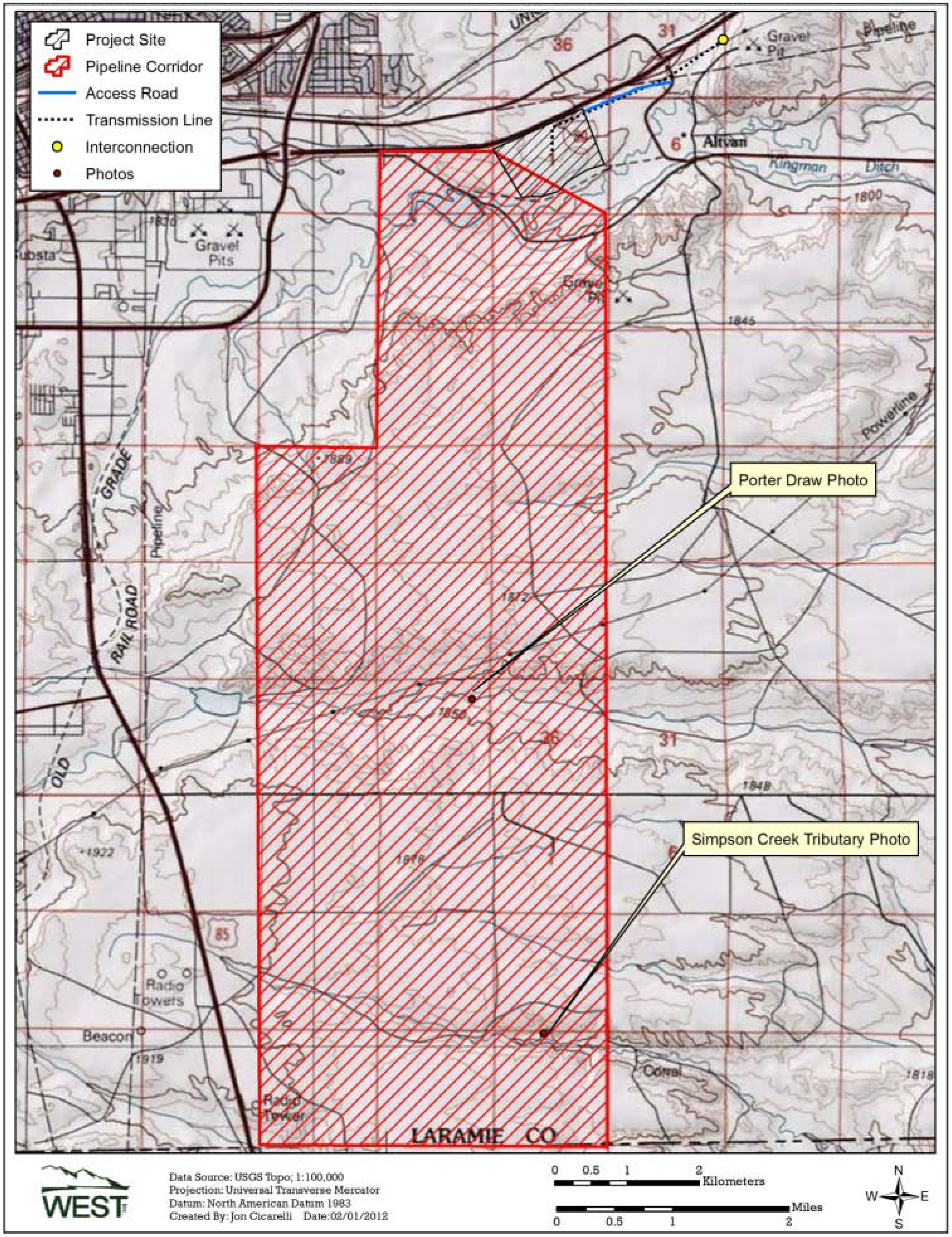


Figure 1. Proposed Cheyenne Prairie Generation Station and pipeline project area.

Ute Ladies'-tresses

Ute ladies'-tresses orchid is a perennial forb in the orchid family. It was first described as a species in 1984. It generally blooms from late July through August; however, depending on location and climatic conditions, may bloom in early July or still be in flower as late as early October (USFWS 1995). Its seeds are very small and require specific symbiotic association with mycorrhizal fungi for germination (Arditti 1992). Like other orchids, some plants may germinate and remain underground in a saprophytic state for many years before emerging. After emerging, individual plants may be dormant for many years and bloom only rarely. Reproduction appears to be strictly sexual, with bumblebees as the primary pollinators (Dressler 1981, Sipes et al. 1993).

Utes Ladies'-tresses is found in 60 locations representing at least 30 distinct biological populations (Fertig 2000a). Locations are in Wyoming, Nebraska, Colorado, Utah, Idaho, Montana, and Washington. In Wyoming, there are nine known populations of Ute ladies'-tresses spread across Laramie, Goshen, Niobrara, and Converse Counties (Fertig et al. 2005). In Laramie County, Ute ladies'-tresses is only known from the Horse Creek drainage. No populations have been found within the Crow Creek drainage, although numerous surveys along Crow Creek have been conducted (Heidel 2007).

This species inhabits moist soils in mesic or wet meadows, gravel bars, wet streambanks, and old oxbows at elevations of 4,300 to 7,000 feet (Stone 1993). Jennings (1990) and Coyner (1989) observed that the orchid seems to require "permanent sub-irrigation," indicating a close affinity with floodplain areas where the water table is near the surface throughout the growing season and into the late summer or early autumn. This orchid colonizes early successional riparian habitats subject to seasonal flooding from snowmelt and intermittent heavy thunderstorms. It is not tolerant of long-term standing water and emergent vegetation development. It is generally found with grasses, sedges, rushes, shrubs and riparian trees such as willows. It rarely occurs in deeply shaded sites and prefers partially shaded open glades or pastures and meadows in full sunlight (USFWS 1992). In Wyoming this species occurs primarily on low, flat floodplain terraces or abandoned oxbows within 0.5 to 50 m of small perennial streams or rivers at elevations of 4,750 to 5,400 feet. The terrace sites are typically sub-irrigated, often seasonally flooded, and remain moist well into the summer. Associated vegetative cover is usually 75-90%, and is typically short (i.e., <18 inches; Fertig and Heidel 2007).

A draft recovery plan for this species was prepared in 1995. This draft does not include population and habitat recovery goals and delisting criteria. The recovery plan direction focuses on restoring natural stream dynamics (hydrologic patterns). Critical habitat has not been designated for this species.

Colorado Butterfly Plant

Colorado butterfly plant is a short-lived biennial (sometimes perennial) herb that grows 19.7-31.5 inches tall. Leaves are lanced shaped with smooth edges and are 2 to 5.9 inches long. The Colorado butterfly plant has small (5-14 mm) white flowers that turn pink or reddish with age. This species flowers from June through October and produces fruit from July to October. This plant will continue to flower until the first frost of the year. Non-flowering plants consist of a prostrate rosette of oblong, mostly glabrous entire or toothed leaves 4-18 cm long (Fertig 2000b).

Colorado butterfly plant is found in moist meadows typified by sub-irrigated, alluvial soils of streams surrounded by mixed grass prairie. It is found at elevations of 5,000 to 6,400 feet. Colonies are often found in low depressions or along bends in wide, meandering stream channels (Fertig 2000b). The Colorado butterfly plant prefers open habitat without dense or overgrown vegetation (USFWS 2010). Establishment and survival of seedlings is enhanced where tall and dense vegetation has been removed by some form of disturbance (Fertig 2000b).

Since 1977, over 20 populations have been discovered in Colorado, Wyoming and Nebraska. Currently, this plant is restricted to Laramie and Platte Counties, Wyoming, Kimball County, Nebraska, and Weld County, Colorado (Jennings et al. 1997). Current populations occur along Bear, Crow, Horse, Lodgepole and Spring Creeks (Fertig 2000b). The populations along Crow Creek and its tributaries occur west of Cheyenne. No populations have been found along these drainages east of Cheyenne. The nearest known populations are located on F.E. Warren Air Force Base approximately five miles west of the project.

Loss of habitat and the small population are the main issues of concern regarding this species. Critical habitat for this species has been designated in Laramie and Platte Counties along Tepee Ring Creek, Bear Creek, Little Bear Creek, Horse Creek, Lodgepole Creek, and Lone Tree Creek (Figure 2), but no critical habitat has been designated in the project area (USFWS 2010). The nearest critical habitat is located along Diamond Creek approximately eight miles west of the project (USFWS 2010; Figure 2).

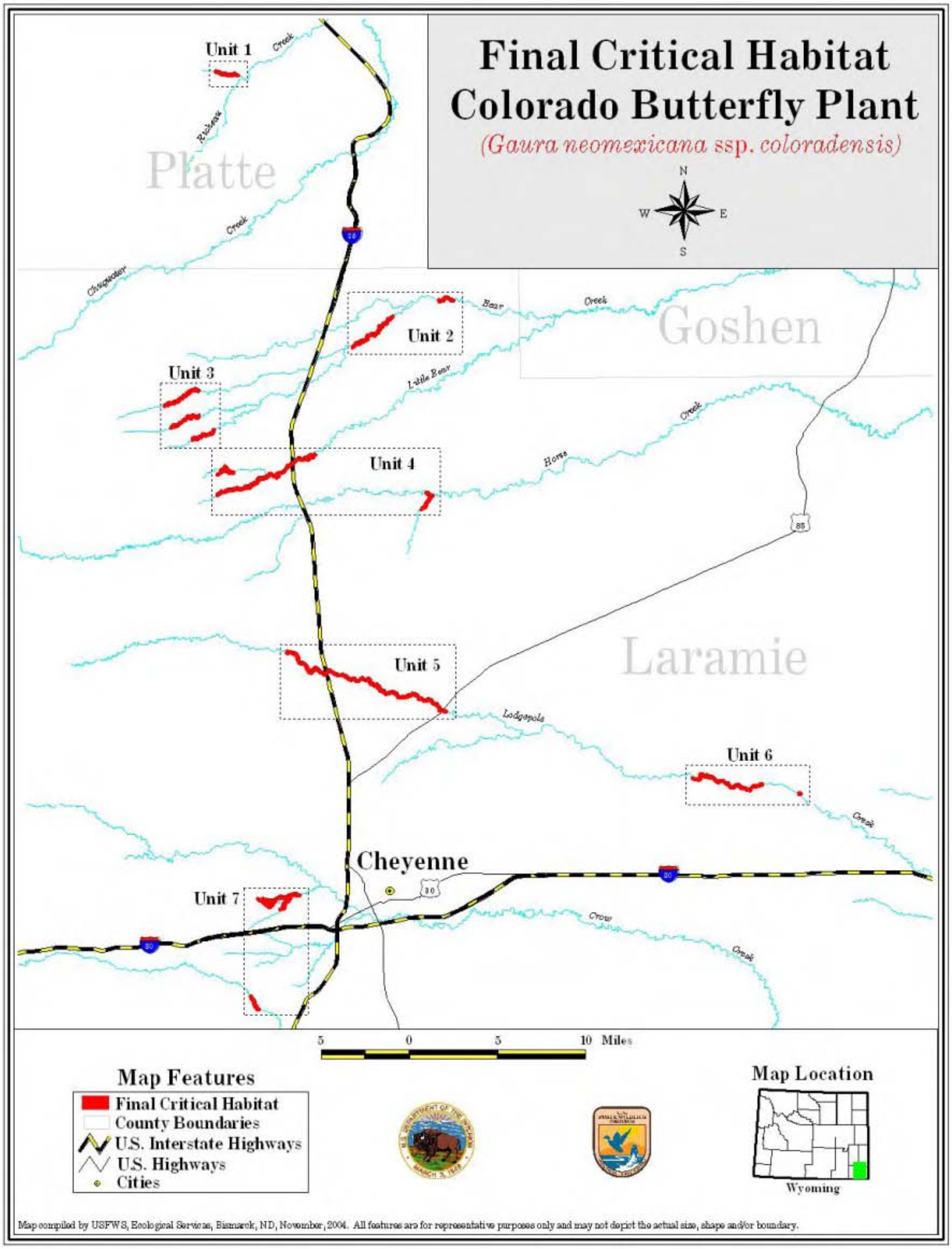


Figure 2. Designated critical habitat for Colorado Butterfly plant in Laramie County, Wyoming (from USFWS 2010).

Preble's Meadow Jumping Mouse

Meadow jumping mice (*Zapus hudsonius*) are small rodents with large hind feet, long back legs, and long tails which typically occur in moist habitats consisting of a low undergrowth of grasses and/or forbs, in open wet meadows and riparian corridors, or where shrubs and trees provide adequate cover (USFWS 2007). Preble's meadow jumping mouse (Preble's) is a subspecies which occurs primarily in riparian corridors along the Front Range of northern Colorado and southeastern Wyoming. Preble's typically enter hibernation in the early fall (September-October) and emerge during the spring (May). Due to the timing of hibernation, trapping protocols designed to document the presence/absence of Preble's focus on the period of greatest activity, which occurs from June through the end of August.

Preble's were listed as threatened under the Endangered Species Act in May 1998 (USFWS 1998). Citing a presumed lower prevalence and severity of threats in Wyoming relative to its range in Colorado, the USFWS delisted Preble's in the Wyoming portion of its range in 2008 (USFWS 2008). In August 2011, the USFWS again revised the status of Preble's, reinstating its status as Threatened in the Wyoming portion of its range (USFWS 2011). Currently, Preble's is listed at Threatened throughout its entire range in Wyoming and Colorado. Designated Critical Habitat for the species only occurs in Colorado. Those areas previously designated as Critical Habitat in Wyoming prior to its delisting were not reinstated with the 2011 revision reinstating its Threatened status in Wyoming.

Typical Preble's habitat has been described as well-developed plains riparian vegetation with relatively undisturbed grassland with a water source in close proximity (USFWS 2007). It has also been noted that Preble's apparently lacks a preference for any single plant species and instead favored sites which are structurally diverse (Shenk and Eusen 1999 in USFWS 2007). Although Preble's are rarely trapped in uplands adjacent to riparian areas, detailed studies of Preble's movements using radio telemetry have documented them feeding and resting in adjacent uplands (USFWS 2007). These studies reveal that the Preble's regularly uses uplands at least as far out as 100 meters beyond the 100-year floodplain (USFWS 2007). Preble's can also move considerable distances along streams, with travel as great as 1.6 km (1.0 miles) documented in one evening (Ryon 1999 in USFWS 2007).

METHODS

All drainages containing potentially suitable habitat that could be crossed by the pipeline were examined. These included Crow Creek, Porter Draw and a northern branch of Simpson Creek (Figure 1). The riparian area and associated wetlands along Crow Creek potentially affected by construction of the pipeline were visually inspected on foot on December 16, 2011 to determine habitat suitability for all three species. Transects were walked within and adjacent to all wetland areas. Plant species observed and general habitat notes were recorded during the site visit. Photos were taken of representative sections of all drainages surveyed (Appendix A). Porter Draw and the Simpson Creek tributaries were assessed on foot at readily accessible points

(Figure 1) within the pipeline corridor and visually from a distance (i.e., with binoculars) from public roads.

RESULTS

With the exception of Crow Creek, which is a perennial stream, all drainages in the project area are ephemeral. Based on the field visit all drainages were determined to present hydrology that would not support either Ute's ladies'-tresses or Colorado butterfly plant (see photographs in Appendix A). Additionally, due to the lack of well-developed riparian habitat in the drainages other than Crow Creek, it was determined that Porter Draw and the Simpson Creek tributary were unsuitable for supporting populations of Preble's meadow jumping mice.

Plants

The riparian area along Crow Creek in the project area is dominated almost entirely by reed canarygrass (*Phalaris arundinacea*). This grass forms dense, tall mats along Crow Creek which would greatly restrict habitat for the two listed plant species, as they do not tolerate dense, tall vegetation and extreme shading. Wetter depressions along Crow Creek not dominated by reed canarygrass were dominated by broadleaf cattail (*Typha latifolia*) and softstem bulrush (*Scirpus validus*), both of which also form dense, tall mats of vegetation that would preclude establishment of Ute's ladies'-tresses or Colorado butterfly plant. Other species occurring in the understory along Crow Creek included licorice (*Glycyrrhiza lepidota*), Canada thistle (*Cirsium arvense*), kochia (*Kochia scoparia*), curly dock (*Rumex crispus*), smooth brome (*Bromus inermis*), and wheatgrass (*Agropyron* spp.). Overstory plants along the riparian area included sandbar willow (*Salix exigua*), peachleaf willow (*Salix amygdaloides*), and plains cottonwood (*Populus deltoides*).

From a hydrologic perspective, the Crow Creek channel is heavily incised with relatively steep banks along most of its length, resulting in a very narrow riparian area and groundwater tables that are far below the adjacent bank during most of the growing season. Based on presence of flood debris in uplands, Crow Creek may occasionally flood in the spring during extremely high runoff years, but the incised channel likely prevents flooding during most years, especially late in the growing season after spring runoff. This hydrologic regime along with steep banks do not allow for formation of areas in the riparian corridor where groundwater tables are near the surface. Therefore, conditions are not suitable for establishment of either Ute ladies'-tresses or Colorado butterfly plant along this reach of Crow Creek. The ephemeral drainages in the project area between Crow Creek and the Colorado State Line were dry at the time of the site visit and did not have any wetland vegetation or other characteristics typically associated with presence of either Ute ladies'-tresses or Colorado butterfly plant (Appendix A).

According to maps showing probability of occurrence for both Ute ladies'-tresses and Colorado butterfly plant created by the Wyoming Natural Diversity Database, there is no probability of occurrence of Ute ladies'-tresses in the project area (Figure 3), which is consistent with our field observations. However, the map predicting potential probability of occurrence of Colorado butterfly plant indicates high probability of occurrence of Colorado butterfly plant within the project area along Crow Creek and Porter Draw (Figure 4), which is not supported by our onsite evaluation of habitat and hydrologic features. It should be noted that this map indicates high probability of occurrence for Colorado butterfly plant in a substantial area within Laramie County, even though very few populations are actually known to occur in Laramie County.

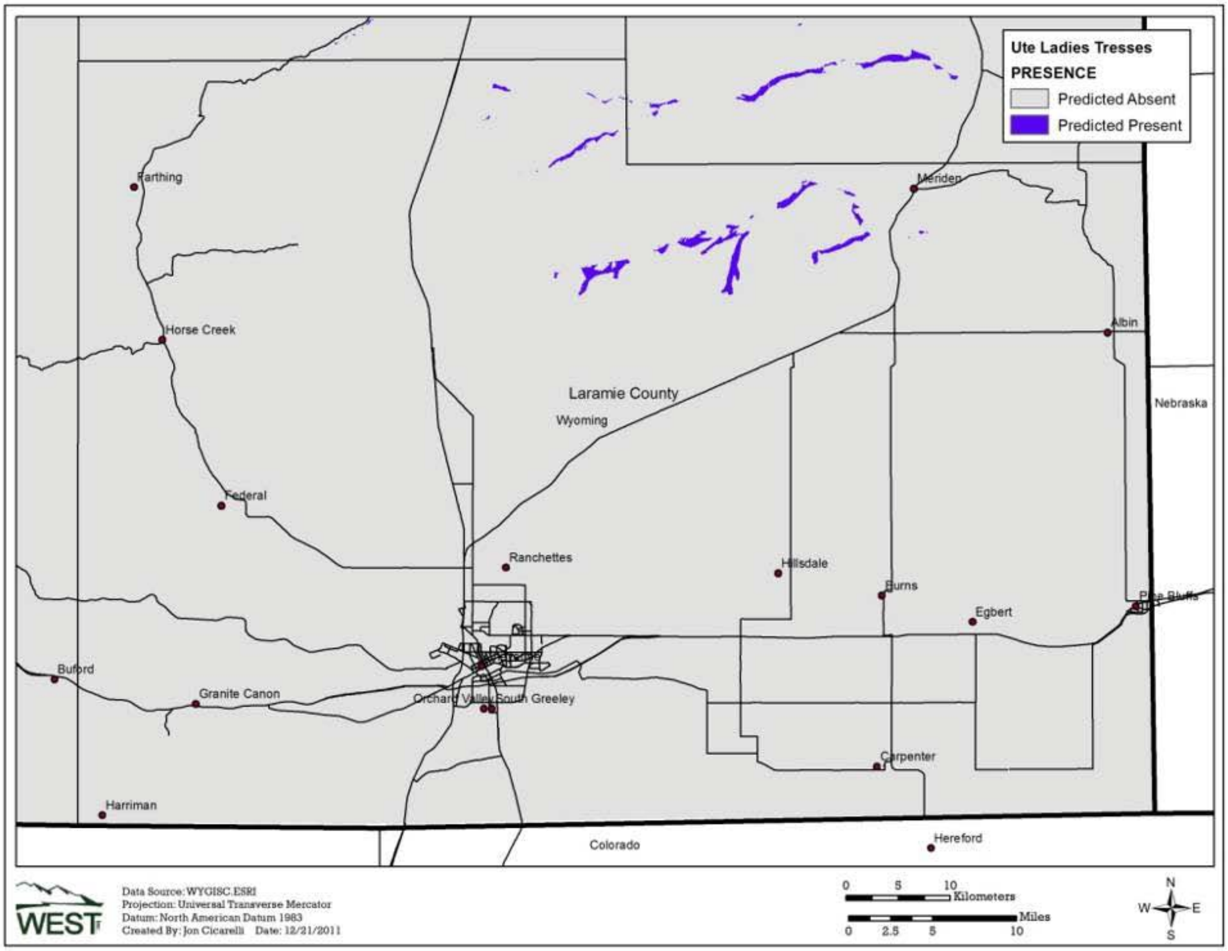


Figure 3. Predicted probability of occurrence of Ute ladies'-tresses in Laramie County, Wyoming

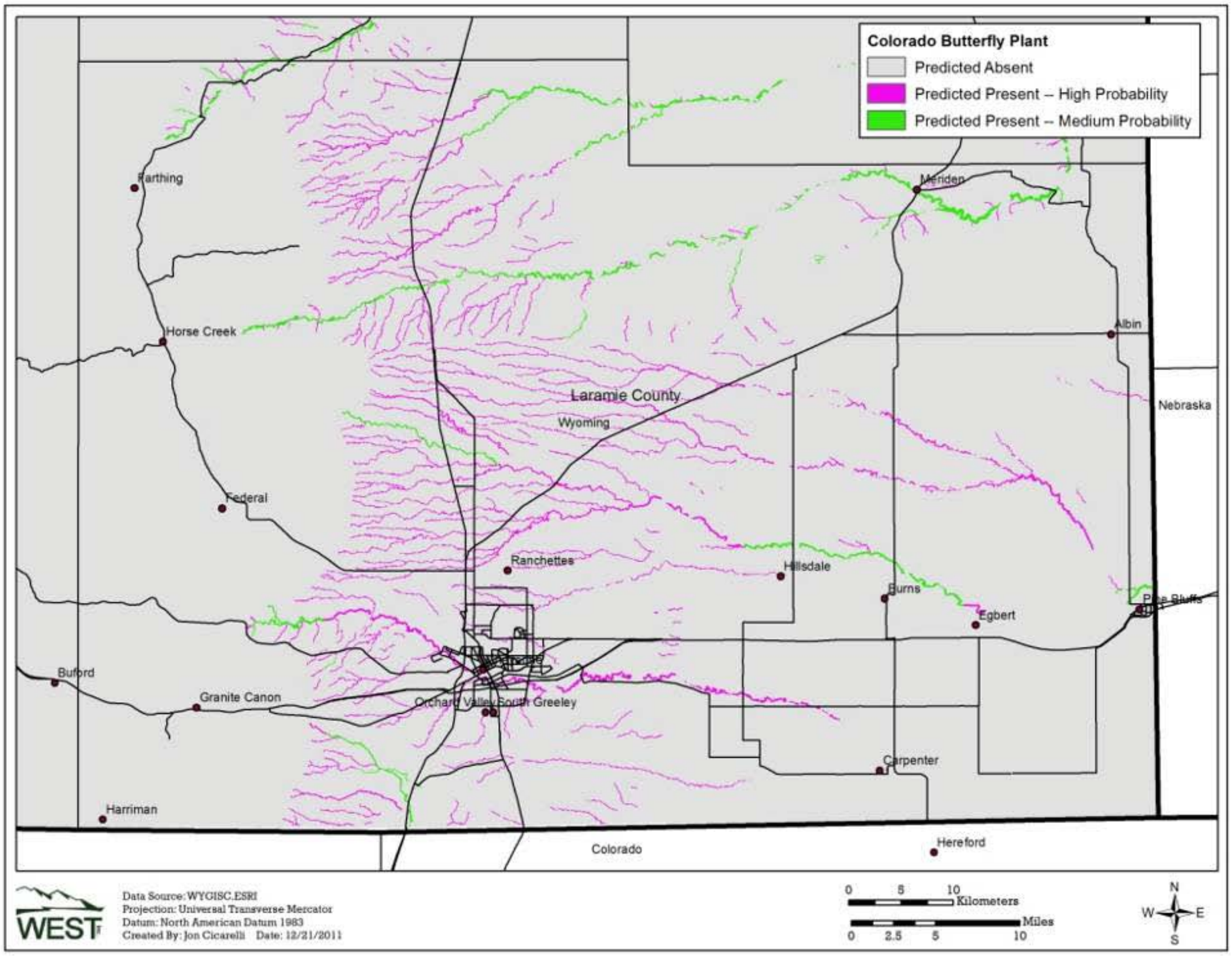


Figure 4. Predicted probability of occurrence of Colorado butterfly plant in Laramie County, Wyoming.

Preble's Meadow Jumping Mouse

The riparian corridor along Crow Creek is dominated by dense stands of reed canarygrass, with scattered clusters of woody shrubs and trees (e.g., willow and cottonwood) intermixed along its length. Other riparian species (e.g., cattail, bulrush) occur in some of the wider, lower lying wetland areas along the creek. Unlike the two plant species discussed previously, which would not likely occur in the dense vegetation along Crow Creek, Preble's tend to occupy this type of habitat, and based on the availability, could potentially occur anywhere along the length of Crow Creek that lies within the pipeline corridor. Much of the grasslands adjacent to Crow Creek appear to be cut for hay (Figure 5) and in some areas that lack woody cover, hay swathing comes quite close to the creek channel which may affect habitat quality for Preble's later in the season. There are sections along Crow Creek where there is a lack of willow and other woody species, and the channel and associated riparian habitats are quite narrow. These stretches, (identified in Figure 5 with photos included in Appendix A) may provide areas where the pipeline could cross the creek while minimizing potential direct impacts to Preble's and higher-quality Preble's habitat.

It is unknown if trapping for Preble's has occurred along this section of Crow Creek in the past. Based on data available from the Wyoming Natural Diversity Database (WYNDD), Preble's have been documented along Crow Creek approximately eight miles upstream on F.E. Warren Air Force Base (WYNDD 2009); however, several other trapping efforts in the Cheyenne area (not necessarily along Crow Creek) apparently failed to document the presence of Preble's (USFWS 2007).

Based on the presence of potentially suitable habitat for Preble's along Crow Creek, it is recommended that consultation under the ESA be initiated early in the process of permitting to determine the options available for dealing with potential Preble's issues. Four possible scenarios may provide compliance with the ESA:

1) Avoidance of impacts to Preble's habitat along Crow Creek. Habitat at the specific crossing location would need evaluation to determine the distance from the channel that would be considered potentially used by Preble's.

2) Directionally bore the pipeline beneath Crow Creek in consultation with the USFWS.

3) Complete a protocol-level trapping survey during the June 1- August 31 time period to assess the presence/absence of Preble's within the proposed crossing area. If absence is confirmed, no further compliance measures would be necessary. If presence is confirmed, develop adequate avoidance measures, or implement appropriate impact minimization and mitigation measures to allow take of the species.

4) Presence of Preble's could be assumed and suitable mitigation measures could be developed through consultation to allow construction to proceed.

Other Wildlife

Three potential raptor nest sites (Figure 5, Nests 1, 3, and 4) and one known historical raptor nest (Figure 5, Nest 2) were also observed while on site conducting the habitat assessment. All were located along the riparian corridor of Crow Creek. One (Nest 2) is known to historically support both great-horned owls (*Bubo virginianus*) and Swainson's hawks (*Buteo swainsoni*), while the historical status of the others are unknown. To avoid/minimize impacts to nesting raptors BH will work with the USFWS and WYGFD to determine the appropriate timing and distance buffers should these nests be active during the construction period of the natural gas pipeline.

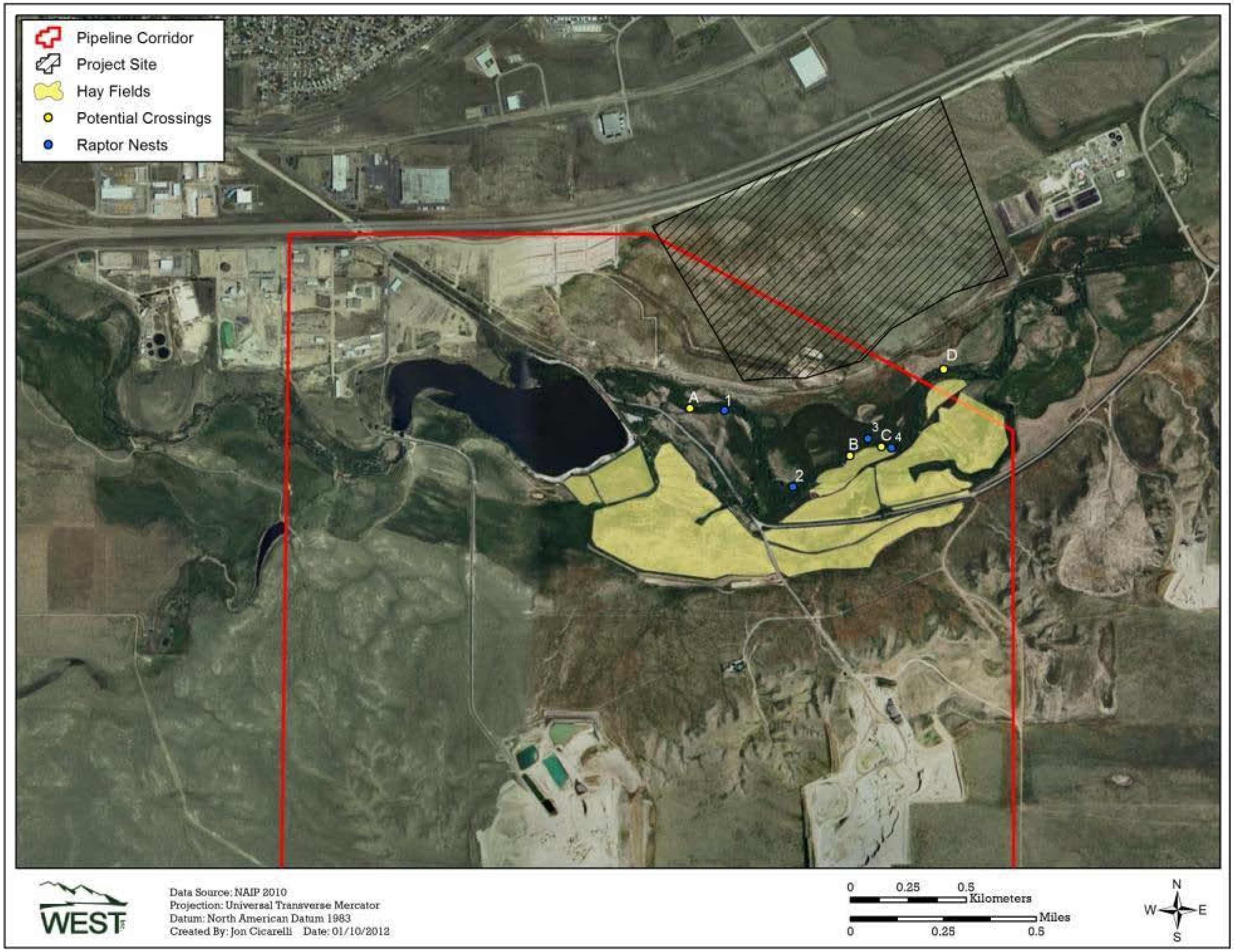


Figure 5. Raptor nests and potential creek crossings with lower quality Preble's jumping mouse habitat.

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Appendix A. Photographs of drainages in project area

Crow Creek riparian area dominated by reed canarygrass and scattered patches of willow.

Crow Creek riparian corridor dominated by reed canarygrass. Lengthy stretch of narrow riparian corridor lacking woody cover exists in this area (Point A on figure 5).

Crow Creek riparian corridor dominated by reed canarygrass. Area east of foot-bridge lacks developed woody cover (Point B on figure 5).

Crow Creek riparian corridor at Point D in southwest portion of project area, east side of pipeline corridor.

Representative photo of incised stream channel along Crow Creek.

Photograph of Crow Creek riparian corridor with incised stream channel

Porter Draw. Ephemeral channel in central portion of pipeline corridor. Location identified on Figure 1.

Tributary to Simpson Creek. Ephemeral channel near Colorado state line in southern portion of pipeline corridor. Location identified on Figure 1.

Raptor nest (Nest 2 on figure 5). Historically used by great-horned owl and/or Swainson's hawk.

Potential raptor nest (Nest 1 on Figure 5). Historical status unknown.

Potential raptor nest (Nest 3 on Figure 5). Historical status unknown.

Potential raptor nest (Nest 4 on Figure 5). Historical status unknown.

Western ditch crossing on access road.

Eastern ditch crossing on access road.

Avian Protection

Avian Protection Plan

Black Hills Corporation

Wyoming Operations

Improving life with energy

Black Hills Corporation

September 6, 2011

BLACK HILLS CORPORATION
COMPANY PROCEDURE

Procedure Name: Avian Protection Plan – Black Hills Wyoming Operations	DATE ISSUED 2011-04-05	POLICY NO. E-01-01-02
	DATE EFFECTIVE 2011-04-05	PAGE NO. i
PROCEDURE NO. DATED SUPERSEDES	DEPARTMENT Environmental	APPROVED
History Log: Revisions made 07/07/11 to USFWS permit requirements, clarification of terms, revised definitions	REVIEWED BY Joe Jenkins	REVIEW DATE 2011-09-02

Avian Protection Plan – Wyoming

Table of Contents

1. **PURPOSE**

The Company's Wyoming Avian Protection Plan (APP or "Plan") provides guidance to mitigate the impact of company operations on protected bird species. Various federal treaties, acts, federal and state regulations and laws protect migratory birds, eagles and endangered species. These laws apply a strict liability approach to the "taking" of protected species, their parts, nests and habitat. Implementation of this Plan will reduce bird mortalities, incidents and negative interactions, and impacts to habitat. This Plan identifies actions needed to comply with legal requirements while continuing to provide the safe and reliable services provided by the company.

2. **SCOPE**

The Plan applies to all Company operations in Wyoming including Electric Distribution and Transmission, Generation, Mining, and Oil and Gas Exploration, Production and Midstream activities which may impact protected bird species.

NOTE: A separate Plan covers BHP Electric Distribution and Transmission, Generation Operations in South Dakota, Montana, and Nebraska.

3. **RESPONSIBILITY**

The personnel of the various Wyoming operations are responsible for implementing the Plan within their individual projects or systems.

Avian Protection Program Coordinator: The Avian Protection Program Coordinator (APPC) or designee is responsible for developing and documenting Program Standards, Procedures, and Practices, developing and implementing the Plan, communicating with regulatory agencies, and monitoring the implementation of the Plan.

Power Generation, Mining, Exploration and Production (E&P)/Midstream: Environmental personnel are responsible for managing aspects of the Plan including monitoring, incident investigation, reporting, and mitigation design and operational changes needed to appropriately reduce the risk of negative interactions with protected avian species.

Electrical Transmission/Distribution: Transmission/Distribution will delegate personnel who are responsible managing all aspects of the Plan including monitoring, incident investigation, reporting, and mitigation design and operational changes needed to appropriately reduce the risk of negative interactions with protected avian species.

Environmental Services: Environmental Services (ES) personnel assist operations to implement the plan including monitoring, incident investigation, reporting, and mitigation design and operational changes needed to appropriately reduce the risk of negative interactions with protected avian species.

Electric Construction Standards Committees: The Company's electrical design standards committees are responsible for the approval of electrical structure and electrical design modifications needed to meet Plan requirements.

4. DEFINITIONS

Active Nest – A nest that has eggs or young present at the time of observation. A nest is considered inactive when eggs or young are not present, such as in the fall or winter, or if the nest is not used during breeding season. The term occupied nest is used synonymously.

AITS – Avian Incident Tracking System is a Company electronic database.

APP – Avian Protection Plan

APPC – Avian Protection Program Coordinator which is a role assigned in the Environmental Services Department.

APP-WY - Company's Avian Protection Plan for its Wyoming operations.

BGEPA – the Bald and Golden Eagle Protection Act. The BGEPA prohibits knowingly taking, or taking with wanton disregard for the consequences of an activity, any bald or golden eagle or their body parts, nests, chicks or eggs, which includes collection, molestation, disturbance, or killing. The term "disturb" is defined as "to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior

ESA – Endangered Species Act. The Endangered Species Act protects plants and animals that are listed by the federal government as "endangered" or "threatened.

Inactive Nest – A nest that does not have eggs or young at the time of observation. Term is used synonymously with unoccupied nest.

Lek: A lek is a gathering of males, of certain animal species, for the purposes of competitive mating display. Leks assemble before and during the breeding.

MBTA – Migratory Bird Treaty Act. The MBTA prohibits the taking of any migratory birds, their parts, nests, or eggs except as permitted by regulations and does not require intent to be proven.

Migratory Bird – The definition of the migratory birds that are protected by federal law were identified through various conventions. Migratory birds for purposes of the Migratory Bird Treaty Act include those defined in the Convention of Mar. 4, 1972, concluded with Government of Japan and the Convention of Nov. 19, 1976, concluded with Union of Soviet Socialist Republics. 1966 - Pub. L. 89-669 inserted "(39 Stat. 1702)" and defined migratory birds to include those defined in the Treaty of Feb. 7,1936 (50 Stat. 1311) with the United Mexican States.

The list of the Migratory Birds and bird species of concern identified can be found in Appendix D. The entire list of migratory birds can be forum at: http://migratorybirds.fws.gov

Negative Interaction – a situation that could or has resulted in take of a bird protected by the MBTA, BGEPA, and or ESA.

Occupied Nest – A nest with an incubating adult (sitting on eggs), or eggs or young present. Term is used synonymously with active nest. Nests may be occupied during the breeding season (approximately February through August).

Problem Nest – A nest that may cause electrocution and death to the birds, electrical outage, property damage, or otherwise interfere with power operations.

Raptors – Birds of prey with exceptionally keen eyesight, a sharp, hooked beak for tearing flesh, and strong grasping feet with large, sharp talons for killing and holding prey; includes eagles, hawks, falcons, owls, buteos, osprey, and vultures. Raptors frequently use power poles for perching or nesting.

Raptor Safe – A power line configuration designed to eliminate raptor electrocution by having sufficient spacing between phases and phase to ground which provides safe perching areas on the pole.

Take/Taking: As defined by 50 CFR 10.12, take means to pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to pursue hunt, shoot, wound, kill, trap, capture, or collect.

Tended nest – Prior to egg-laying, birds construct or add materials to nests that they will occupy during the nesting season.

Threatened & Endangered Species – ESA-listed species and those that are threatened with extinction and protected by federal law. Specifically, an "endangered species" is one that is "in danger of extinction" throughout all or a significant portion of its range. A "threatened" species is one that is "likely to becomeendnagered" within the forseable future".

Unoccupied Nest – A nest that does not have eggs or young at the time of observation. Term is used synonymously with inactive nest.

USFWS – United States Fish and Wildlife Service, which is the regulatory agency that oversees the protection of wildlife and is a service under the Department of Interior.

- Wyoming Ecological Services, Cheyenne, Wyoming: This office can assist you with avoiding, minimizing and mitigating impacts to migratory birds, and may provide assistance in obtaining migratory bird permits from the Migratory Bird Permit Office.

- Migratory Bird Permit Office, Denver, Colorado: This office provides information about migratory bird permits and issues permits when appropriate.

- Law Enforcement, Wyoming. Law enforcement will provide you with information as to how to avoid violations under the ESA, MBTA, and BGEPA. Mortalities and injuries should be reported to law enforcement. Eagle mortalities need to be reported within 24 hours.

WGFD – Wyoming Game and Fish Department, which is the wildlife regulatory agency in Wyoming.

PROCEDURE

5.1 Communication of the Avian Protection Plan (APP)

5.1.1 Communicating the Plan

The Plan will be communicated throughout affected company operations to assure that personnel are aware of the company's avian protection policy and procedures. The Plan will be communicated through formal training, periodic management reports, electrical standards committee meetings, and ongoing environmental and operational meetings.

5.1.2 Training

Training will be provided to all affected employees who may discover or investigate avian incidents, engineers responsible for the design of raptor safe structures, and operational personnel who may be responsible for mitigating incidents through operation and maintenance activities. Training will be provided as part of the initial communication of the plan and thereafter as often as needed to assure compliance with the plan. The training will include:

- Identification of protected and non-protected species.
- Review of applicable regulations including the Migratory Bird Treaty Act (MBTA), the Bald and Golden Eagle Protection Act (BGEPA), the Endangered Species Act (ESA), and state regulations to ensure personnel are aware of the legal requirements and the potential liability associated with non-compliance.
- Bird biology and behavior related to interactions (collision or electrocution) with power structures including bird sizes, perching, and nesting, hunting and feeding habits, as well as habitat preferences and flight path tendencies.
- Bird biology and behavior related to interactions with facility buildings and other structures that may provide perching, nesting, hunting or feeding habitats.
- Discussion of the state and federal agencies that may need to be contacted and how soon following the incident they should be contacted.
- Proper procedures to follow when an avian incident is encountered.
- Internal and external reporting requirements for all incidents.
- Use of the US Fish and Wildlife Service (USFWS) Bird Fatality/Injury Reporting Program for incidents related to electrical systems.
- Use of the AITS Company electronic database system.

- A discussion regarding "High Use Areas" where high year-round and seasonal bird concentrations may occur.
- Emphasis is to be placed on specific examples and corrective actions that are operations specific. For example: Electric operations should discuss separation and insulation concepts and applications, perch preventers, substitute perches, and nest platforms; expectations for corrective actions on lines and equipment where mortalities have occurred; and circumstances where no meaningful remedial steps can be reasonably taken such as weather, unavoidable biological interactions, or other contributory factors. Exploration and Production should discuss descriptions of when and how to apply exclusionary devices such as caps or nets, and describe how to maintain open water to keep it clean from contaminants.
- Use of additional training videos or other materials when available from the USFWS, the Avian Power Line Interaction Committee or the Edison Electric Institute, and other resources as identified.

5.1.3 External Communication of the APP

The APP will be provided upon request to federal and state agencies. A copy of this plan will be maintained and available at all affected company facilities.

5.2 Investigating Avian Incidents

Operations personnel will ensure that the causes of “negative interactions” are investigated; and the implementation of mitigation or preventative measures are completed where needed. Appendix A provides a general flowchart of steps to take when incidents occur. Appendix C provides a list of company personnel, and state and federal contacts.

5.2.1 Identification of Dead or Injured Birds

Employees will immediately report to their supervisor and ES Coordinator all protected birds found dead or injured within the company's operation areas or right-of-ways.

5.2.2 Bird Handling Restrictions and Public Safety Considerations

Field personnel will not attempt to handle, capture, collect, move, or transport any injured or dead protected bird.

Safety Exception: If required to ensure public safety, the safety of company personnel, and/or its operations, equipment or electrical systems, a bird may be moved away from a structure or piece of electrical equipment provided the proper personnel and agencies are notified as soon as possible after removal.

USFWS Authorization: Specific permission from an authorized agent of the USFWS is required to transport, collect, or capture a protected bird or eggs. Injured birds should only be handled by the USFWS, the State agency or a local rehabilitator (see Appendix C, Contact List) who has the appropriate authorization to handle protected birds.

5.2.3 Transportation of Injured Birds

To facilitate transportation of all injured birds to a rehabilitator, call the FWS Law Enforcement or Ecological Services Office to report the injury. Per communication with the FWS, BHC has been given permission to transport the bird to one of the listed rehabilitators as soon as possible. Contact the selected rehabilitator to ensure they will be able to receive and have capacity to care for the injured bird.

After the injured bird is transported to the rehabilitator, provide documentation to FWS Law Enforcement or Ecological Services Office, preferably by email. Documentation should include:

1. Who found the bird,
2. When and where the bird was found,
3. The date and time the Service was notified,
4. Suspected cause of injury and bird species involved,
5. Type and severity of injury,
6. Who transported the bird,
7. Name of the rehabilitator, and
8. When it arrived at the rehabilitation center.

5.2.4 Photographic Documentation

Whenever feasible, the incident investigator will take picture sufficient to support the findings of the investigation. Take photos of the bird and it's location as initially found and the surrounding area. If electric systems are involved, the structure and any electrical equipment involved or suspected to be involved; the line including other structures to show that similar conditions exist or not. If feasible, take photos from above and below the equipment and top of structure.

5.2.5 Field Report Form

When obtaining information related to a negative interaction or nesting situation, use the Field Report Form available on the ES MyBHC Avian protection webpage. Provide as much information as possible to facilitate communication with agencies regarding the incident.

5.3 Tracking, Monitoring, and Reporting Negative Interactions and Corrective Actions

The Company will track information about "negative interactions" between protected birds and Company facilities.

5.3.1 USFWS Bird Fatality/Injury Reporting Program

Responsible personnel will report all negative interactions involving the fatality of any protected bird species associated with electrical systems to the USFWS through an online program available at https://birdreport.fws.gov and/or report directly to a field agent as requested. This reporting program also provides a clearinghouse of information for the electric utility industry to mitigate the impact of electrical systems in the loss of birds.

This program is ONLY applicable to reporting negative avian interactions from electric operations. It is not to be used for reporting incidents at either coal mining or E&P facilities.

5.3.2 Avian Incident Tracking System (AITS)

The AITS is an electronic database used for recording all avian interactions including fatalities, injuries, and nesting situations.

ES will administer the tracking system. Operations personnel or ES will enter all incidents, record investigation findings and document actions taken to mitigate future impacts.

5.4 Evaluation of Avian High Use Areas

Evaluations of company territory, operations and facilities for high bird use areas may be performed to minimize impacts. Evaluations may include scientific studies and literature, breeding bird surveys, winter bird counts, observations and other relevant information. The evaluations may be used to identify areas where mitigation efforts can reduce negative interactions before they occur. The APPC or designee will be responsible for obtaining evaluations as warranted.

5.5 Nest Management

Company personnel will ensure that active and inactive nests are properly managed and permits are obtained, from the USFWS and WGFD as required before action is taken. Any nest, active or inactive, that is moved by company personnel will be documented in AITS. Impacts to existing nest sites during construction of new projects or systems will be evaluated.

5.5.1 Active Nests

Active nests of protected bird species are regulated under the Migratory Bird Treaty Act. Moving active nests requires approval from USFWS and WGFD and has to be completed under permits issued by the USFWS and WGFD. ES can assist with communications and obtaining permits, if needed.

5.5.2 Tended Nests

Although only active/occupied nests of species other than eagles are protected under the MBTA, awareness of tended nests on or near company property provides time to address the need for nest management action before eggs or hatchlings are present. The presence of eggs or hatchlings reduce the options and increase the potential for negative interactions.

5.5.3 Inactive Nests

<u>Except for eagle nests</u>, unoccupied nests that need to be removed, can be removed without a reporting requirement or permit from the USFWS but a permit is still required from the WGFD. Note that many bird species will continue to use the same location for nesting year after year. Annually, a review of locations known to be nesting sites should be inspected for nesting activity. If activity is identified, ES should be contacted immediately.

Eagles may reuse nests for decades and they have been granted special status under the Bald and Golden Eagle Protection Act. All operations will consult with ES before moving an eagle nest. Permits will have to be obtained from the USFWS and WGFD before an active or inactive eagle nest can be moved. However, if there is a clear, imminent danger posed to workers, the provision of safe and reliable electrical service, or other operations, a nest may be moved, provided that the USFWS and WGFD are consulted prior to the move and permits obtained for the incident after the fact.

5.6 Permit Requirements

The USFWS no longer issues permits for the removal of live or dead birds. Permits may be required to move nests, eggs or young. The permit process generally takes a substantial amount of time which may exacerbate the situation so every attempt should be made to obtain immediate verbal permission from an agency to rectify situations which are within their authorization.

Operations is responsible to report incidents immediately to ES. Operations and ES will then coordinate and provide the information to the USFWS and to the State agency, input into AITS, and obtain permits, if required.

Agency contacts are provided in Appendix C of this APP.

5.6.1 US Fish and Wildlife (USFWS) Permits

Local USFWS personnel should be contacted when a mortality, injury or nesting incident occurs. For mortalities the USFWS can usually give verbal authorization to remove and properly dispose of a carcass but they may also want to investigate the situation. For injured birds the USFWS may also give verbal authorization to remove and transport a bird to a rehabilitator. For certain injured bird species such as raptors or T&E the agency may need to handle those birds themselves or request the WGFD or a permitted rehabilitator retrieve the birds.

When verbal approval is given or the incident is referred to the WGFD or authorized rehabilitator a permit should not be needed. For nest starts or unoccupied nests of all species except for eagles and T&E a permit is not required from the USFWS to remove those nests as long as eggs and young are not present. A USFWS permit is generally required to remove all bald or golden eagle nests (active or inactive) and all active nests of other species where eggs or young are present.

5.6.2 Wyoming Game and Fish Department (WGFD) Permits

Local WGFD personnel should be contacted when a mortality, injury or nesting incident occurs. Verbal approval from the WGFD may be obtained in many instances and in such case where verbal approval is given a permit should not be required. For mortalities the WGFD can usually give verbal authorization to remove and properly dispose of a carcass.

For injured birds, the WGFD may also give verbal authorization to remove and transport a bird to a rehabilitator. For certain injured bird species such as raptors or threatened or endangered (T&E) the agency may need to handle those birds themselves.

For new nest starts where eggs or young are not present and have never been produced, a permit may not be needed but that should be verified through contact with the WGFD prior to removal of the nest start. For existing nests where eggs or young are present or have been produced in the past a WGFD Chapter 33 Permit, as described in Section 7 of this APP, may be required. Again the WGFD should be first contacted and may be able to give verbal authorization for those activities without the need of a formal permit.

5.7 Avian Protection Measures for Company Operations

5.7.1 Electric Construction Design Standards

The Company's Electric Construction Design Standards Committee has developed Electrical Construction Standards. The Committee will utilize the following guidance in addressing avian protection measures.

- Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006, published by the Avian Power Line Interaction Committee (APLIC), the Edison Electric Institute and the California Energy Commission. 2006. Washington, D.C. and Sacramento, CA.
- Mitigating Bird Collisions with Power Lines - The State of the Art in 1994, published by the Edison Electric Institute, and the Raptor Research Foundation. 1994. Washington, D.C.

5.7.2 Avian Protection Measures for Electrical Structures

The Company will evaluate whether to apply avian protection measures utilizing available guidance documents as identified in Section 5.7.1, or by utilizing avian protection expertise.

Siting New Electrical Lines: Siting New Electrical Lines: Avian protection measures will be taken into consideration when siting new electrical lines.

New Line Construction: Avian-safe designs will be employed for all new construction. In areas with known populations of raptors or other birds of concern, new lines will be designed with adequate separations for birds.[1]

Retrofit of Existing Lines: Where studies or avian incidents have deemed necessary, lines will be rebuilt or retrofitted to avian-safe standards.

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[1] Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006, published by the Avian Power Line Interaction Committee (APLIC), the Edison Electric Institute and the California Energy Commission. 2006. Washington, D.C. and Sacramento, CA. Page 60.

Isolated incidents: If a death or injury of a bird is due to electrocution, the structure will be retrofitted to avian safe standards as soon as feasible.

5.7.3 Avian Protection Measures for Other Structures and Facilities

Every effort will be made to construct facilities and structures at generation facilities, drilling sites, compressor stations and other exploration and production facilities, and mining operations in such a manner as to minimize impact to protected avian species. Where feasible new facilities are typically designed and constructed to minimize access to protected species; and netting or mesh will be placed over containers, pits, tanks, lagoons and ponds to prevent access to oil, condensate, and other hydrocarbons, and hazardous or toxic substances.

Isolated incidents: If a death or injury of a bird is discovered, the structure, container, pit, tank, lagoon, pond or other feature will be evaluated and repaired or retrofitted to avian safe standards as soon as feasible.

5.7.4 Avian Protection Measures for Construction Sites

Every effort will be made to keep construction sites clean and free of debris and contaminants, including oil, condensate, and other hydrocarbons, and hazardous or toxic substances.

5.8 Periodic Inspections

The company performs a number of operational and maintenance inspections of facilities on a regularly scheduled basis (monthly, annually). These inspections are documented and include awareness of avian issues and provide for a random check of facilities. Employees finding evidence of negative interactions during these inspections are required to inform ES when such evidence is encountered. These inspections are performed for exploration and production, mining and electric operations and facilities.

5.9 Assessments

5.9.1 Annual Assessment

The APPC will compile an annual report of all incidents including fatalities, non-fatality and nesting incidents based upon information submitted to the AITS. The APPC will distribute the report to affected operations for review.

5.9.2 Electric Systems (USFWS Reporting Database)

The USFWS Bird Fatality/Injury Reporting Program at http://birdreport.fws.gov provides report development processes for all incidents involving the fatality of a protected bird. A report of this information to USFWS is not planned since this information is publically available.

5.9.3 Wyodak Mine

Annual wildlife monitoring, conducted since 1986, meets requirements of the Wyoming Department of Environmental Quality/Land Quality Division (WDEQ/LQD), WGFD, Office of Surface Mining (OSM) and the USFWS. Surveys are conducted periodically. Results are presented annually in the

Annual Mining Report submitted to the WDEQ/LQD and OSM and are also available for public review. The study area includes the Wyodak Mine permit boundary and one-mile perimeter which includes the Neil Simpson generation facilities. A review of mining activities will be summarized in the annual report described above in section 5.8.1 by reviewing this report and information submitted to AITS.

In addition to the annual monitoring report filed with the WDEQ/LQD, Wyodak submits a "Monitoring and Mitigation Plan for Raptors and Species of High Federal Interest" to the USFWS every five years. The current plan is included in Addendum MP-C of the Mine Plan and was approved by the USFWS on March 10, 2006.

Surveys conducted at Wyodak Mine include:

- **Winter – February & March**
  Raptor nesting surveys for the early nesting species including great horned owls and golden eagles.

- **Spring – March, April & May**
  - Surveys of raptors to monitor nests previously located and search for new nests.
  - Surveys of game birds to record lek locations and number of birds using leks.
  - Surveys for threatened or endangered ((T&E) and Migratory Birds of High Federal Interest (MBHFI) species.

- **Summer – June, July & August**
  - Survey of raptor production for nests previously located and search for nest sites of late nesting raptors.
  - Record opportunistic observations of all wildlife species and surveys for T&E species and MBHFI species.
  - Lagomorph density surveys of the permit area.

5.9.4 Exploration, Production and Midstream Operations

E&P personnel will record avian interaction observations when observed or monthly as part of the Spill Prevention Control and Countermeasure (SPCC) monthly inspection process. Annually in the first quarter, ES will compile information for the previous year, into a report that summarizes available information, distribute it in management reports, and share trends with the affected operations and company management. This information and information submitted to the AITS will be summarized in the annual report described in section 5.8.1.

5. RECORDS

- **Avian Incident Tracking System (AITS)**: The Company's internal database for tracking negative interactions

- **USFWS Bird Fatality/Injury Reporting Program** at http://birdreport.fws.gov.

6. REFERENCES

7.1 Regulatory References

7.1.1 Bald and Golden Eagle Protection Act, 16 U.S.C. §§ 668 to 668d

7.1.2 Migratory Bird Treaty Act, 16 U.S.C. §§ 703 to 712

7.1.3 Endangered Species Act, 16 U.S.C. §§ 1531 to 1544

7.1.4 Wyoming Game and Fish Department Chapter 33 Regulations

7.2 Technical References

7.2.1 Construction Standards

- Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006, published by the Avian Power Line Interaction Committee (APLIC), the Edison Electric Institute and the California Energy Commission. 2006. Washington, D.C. and Sacramento, CA.

- Mitigating Bird Collisions with Power Lines - The State of the Art in 1994, published by the Edison Electric Institute, and the Raptor Research Foundation. 1994. Washington, D.C.

- Avian Protection Plan Guidelines, published by the Edison Electric Institute's Avian Power Line Interaction Committee and the US Fish and Wildlife Service. 2005.

7.2.2 Other References

- A Pocket Guide To Kansas Raptors. This guide, which is published by the Friends of the Great Plains Nature Center, provides a reference to raptors found in the Midwest and West.

- Peterson Field Guide to Birds of Western North America. 2010. Fourth Edition. Houghton Mifflin Company. Boston, MA. Available from Amazon Books.

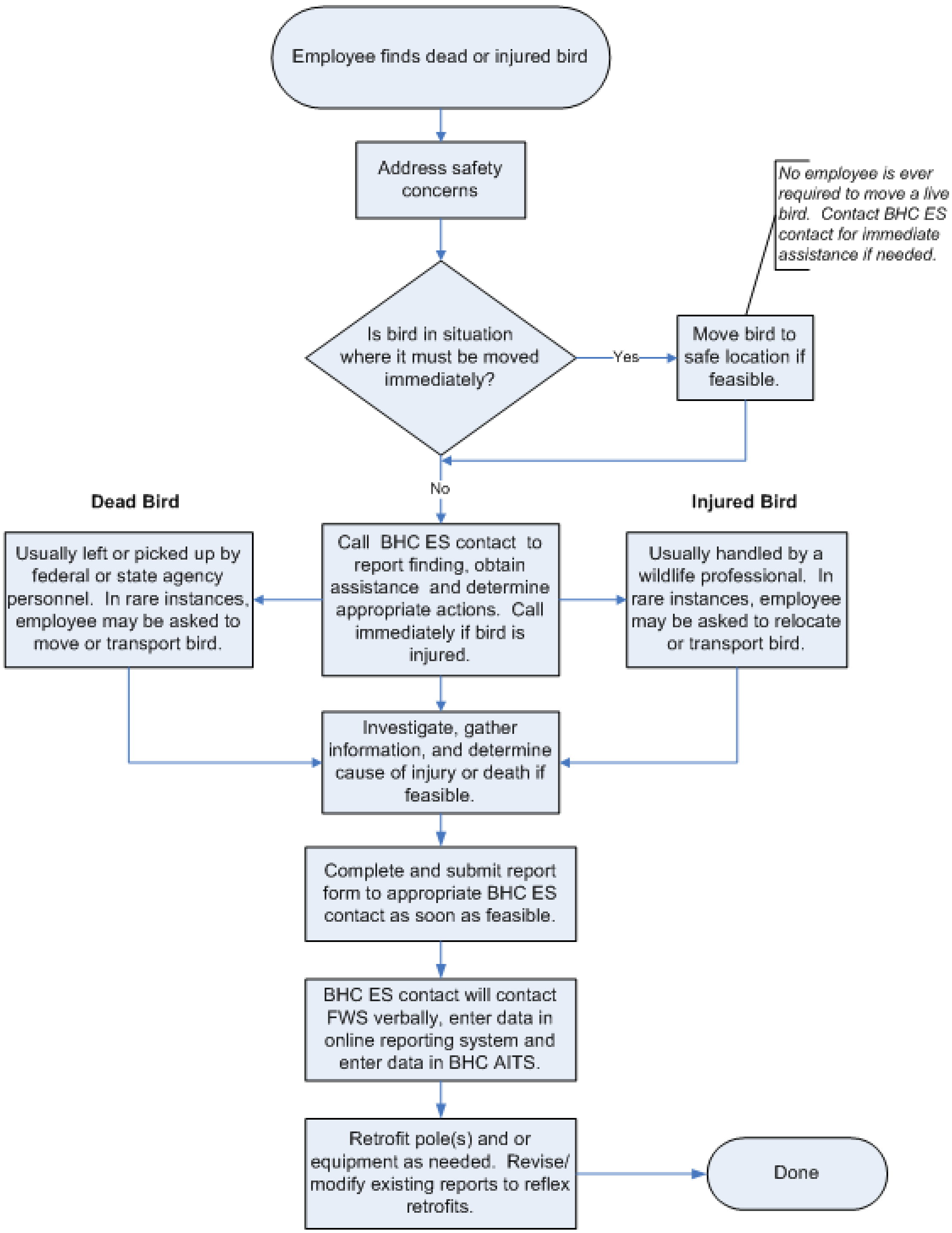
- Migratory Bird List: ***http://migratorybirds.fws.gov/***

  See Appendix D for the complete list of protected migratory bird species as of May 2010 in Wyoming.

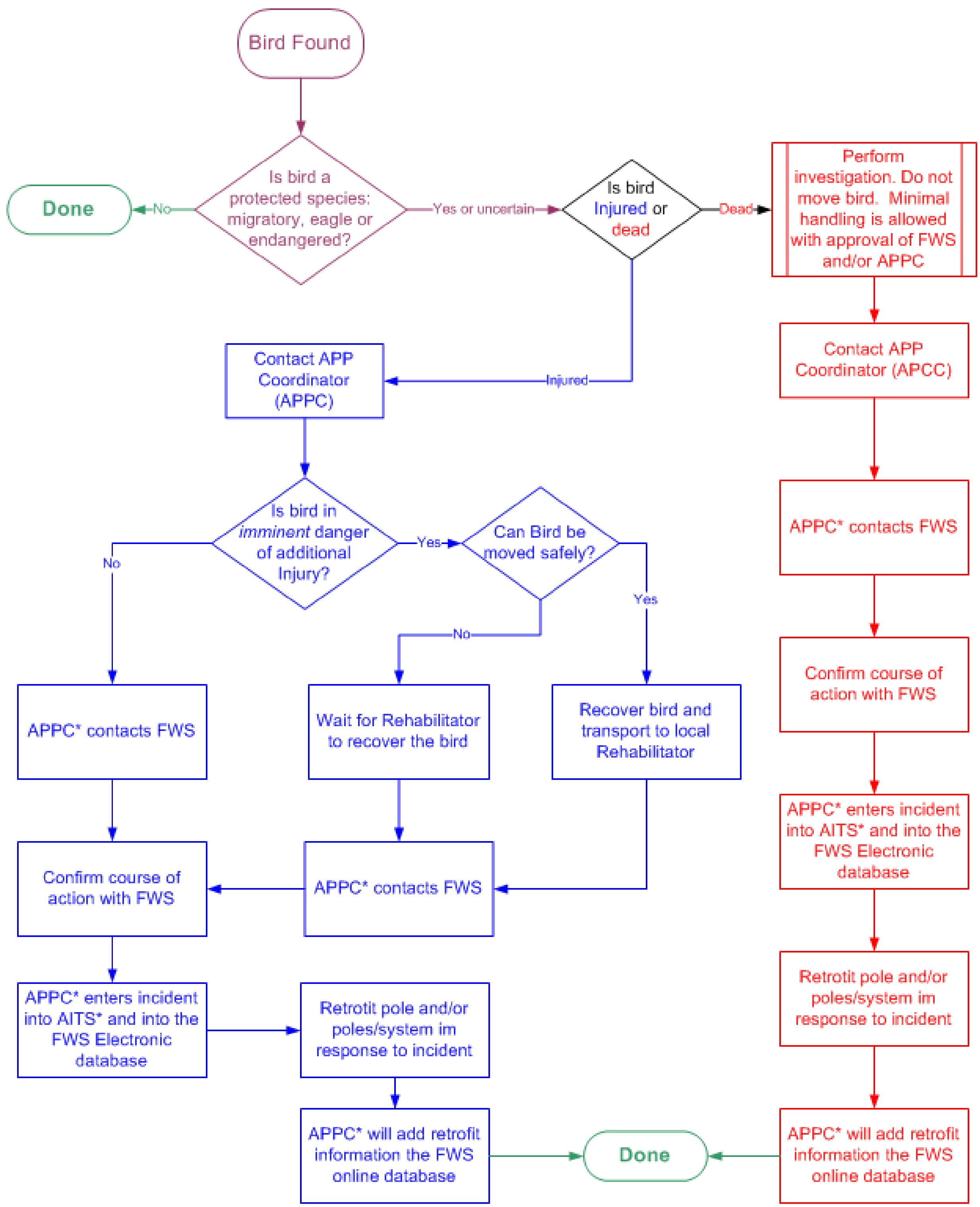
- Guidance on active nesting buffers: See Appendix B

APPENDIX A: RESPONSE AND REPORTING FLOWCHARTS

Response to Finding a dead or Injured Bird

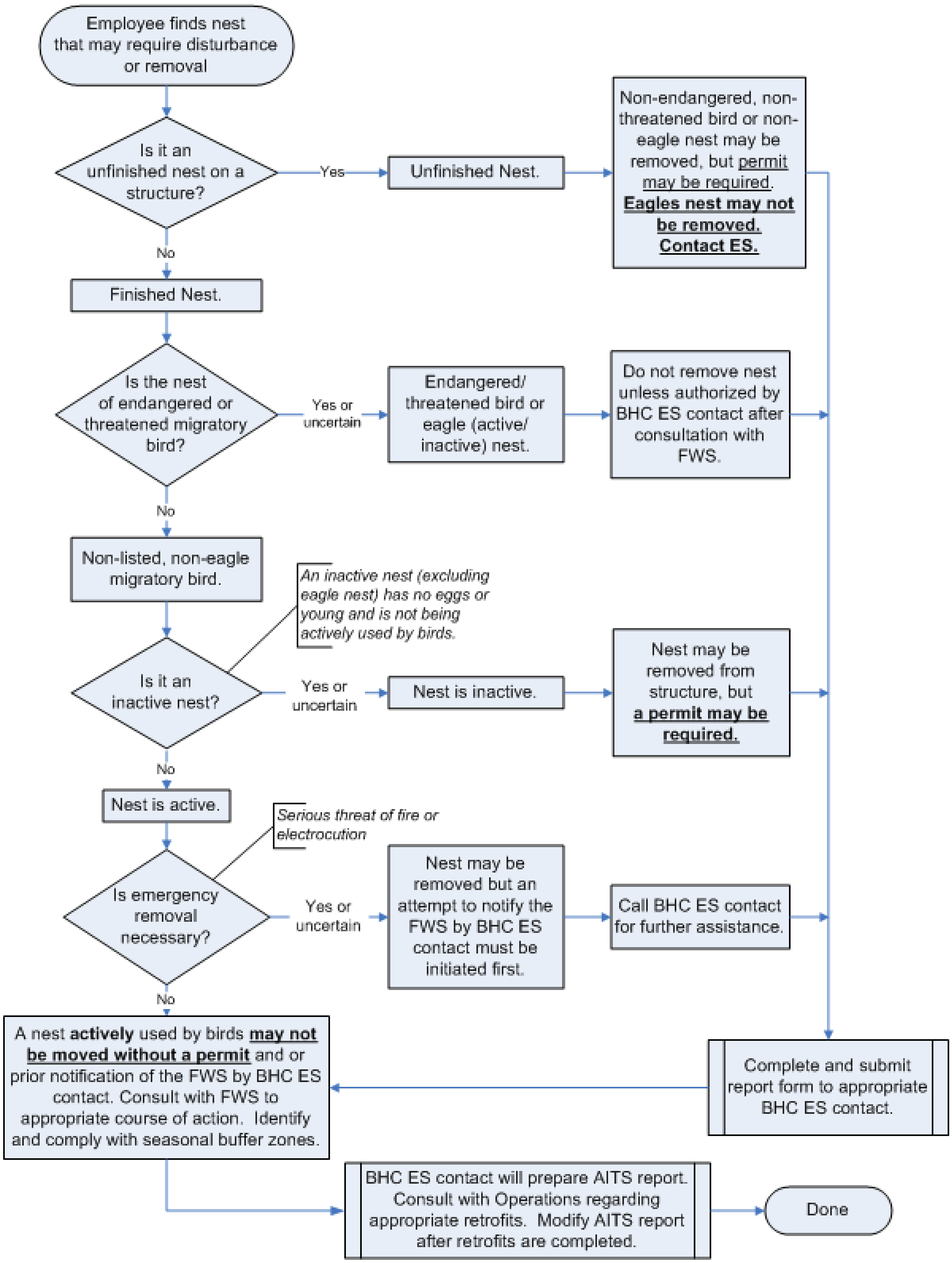


Detail for Responding to the Discovery of a Dead or Injured Bird



APP = Avian Protection Plan, APPC* = APPC and/or designee, AITS = Avian Incident Tracking System, FWS = Fish and Wildlife Service

Response to Finding a Nest



APPENDIX B: PROTECTIONS FOR RAPTORS/SEASONAL BUFFER ZONES

Raptors in Wyoming
(http://www.fws.gov/wyominges/Pages/Species/Species_SpeciesConcern/Raptors.html)

Raptors, or birds of prey, and the majority of other birds in the United States are protected by the Migratory Bird Treaty Act, 16 U.S.C. 703 (MBTA). A complete list of migratory bird species can be found in the Code of Federal Regulations at 50 CFR 10.13. Eagles are also protected by the Bald and Golden Eagle Protection Act, 16 U.S.C. 668 (Eagle Act).

The MBTA protects migratory birds, eggs and nests from possession, sale, purchase, barter, transport, import, export, and take. The regulatory definition of take, defined in 50 CFR 10.12, means to pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to hunt, shoot, wound, kill, trap, capture, or collect a migratory bird. Activities that result in the unpermitted take (e.g., result in death, possession, collection, or wounding) of migratory birds or their eggs are illegal and fully prosecutable under the MBTA. Removal or destruction of active nests (i.e., nests that contain eggs or young), or causing abandonment of an active nest, could constitute a violation of the MBTA, the Eagle Act, or both statutes. Removal of any active migratory bird nest or any structure that contains an active nest (e.g., tree) where such removal results in take is prohibited. Therefore, if nesting migratory birds are present on or near a project area, project timing is an important consideration during project planning. As discussed below, the Eagle Act provides additional protections for bald and golden eagles and their nests. For additional information concerning nests and protections under the MBTA, please see the U.S. Fish and Wildlife Service's (Service) Migratory Bird Permit Memorandum, MBMP-2.

The Service's Wyoming Ecological Services Field Office works to raise public awareness about the possible occurrence of birds in proposed project areas and the risk of violating the MBTA, while also providing guidance to minimize the likelihood that take will occur. We encourage you to coordinate with our office before conducting actions that could lead to the take of a migratory bird, their young, eggs, or active nests (e.g., construction or other activity in the vicinity of a nest that could result in a take). If nest manipulation is proposed for a project in Wyoming, the project proponent should also contact the Service's Migratory Bird Office in Denver at 303-236-8171 to see if a permit can be issued. Permits generally are not issued for an active nest of any migratory bird species, unless removal of the nest is necessary for human health and safety. If a permit cannot be issued, the project may need to be modified to ensure take of migratory birds, their young or eggs will not occur.

For infrastructure (or facilities) that have potential to cause direct avian mortality (e.g., wind turbines, guyed towers, airports, wastewater disposal facilities, transmission lines), we recommend locating structures away from high avian-use areas such as those used for nesting, foraging, roosting or migrating, and the travel zones between high-use areas. If the wildlife survey data available for the proposed project area and vicinity do not provide the detail needed to identify normal bird habitat use and movements, we recommend collecting that information prior to determining locations for any infrastructure that may create an increased potential for avian mortalities. We also recommend contacting the Service's Wyoming Ecological Services office for project-specific recommendations.

Additional Protections for Eagles

The Eagle Act protections include provisions not included in the MBTA, such as the protection of unoccupied nests and a prohibition on disturbing eagles. Specifically, the Eagle Act prohibits knowingly taking, or taking with wanton disregard for the consequences of an activity, any bald or golden eagle or their body parts, nests, chicks or eggs, which includes collection, possession, molestation, disturbance, or killing. The term "disturb" is defined as "to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior" (50 CFR 22.3 and see also 72 FR 31132).

The Eagle Act includes limited exceptions to its prohibitions through a permitting process. The Service has issued regulations concerning the permit procedures for exceptions to the Eagle Act's prohibitions (74 FR 46836), including permits to take golden eagle nests which interfere with resource development or recovery operations (50 CFR 22.25). The regulations identify the conditions under which a permit may be issued (i.e., status of eagles, need for action), application requirements, and other issues (e.g., mitigation, monitoring) necessary in order for a permit to be issued.

For additional recommendations specific to Bald Eagles please see our Bald Eagle information web page.

Recommended Steps for Addressing Raptors in Project Planning

Using the following steps in early project planning, agencies and proponents can more easily minimize impacts to raptors, streamline planning and permitting processes, and incorporate measures into an adaptive management program:

1. Coordinate with appropriate Service offices, Wyoming Game and Fish Department, Tribal governments, and land-management agencies at the earliest stage of project planning.

2. Identify species and distribution of raptors occurring within the project area by searching existing data sources (e.g., Wyoming Game and Fish Department, Federal land-management agencies) and by conducting on-site surveys.

3. Plan and schedule short-term and long-term project disturbances and human-related activities to avoid raptor nesting and roosting areas, particularly during crucial breeding and wintering periods

4. Determine location and distribution of important raptor habitat, nests, roost sites, migration zones and, if feasible, available prey base in the project impact area.

5. Document the type, extent, timing, and duration of raptor activity in important use areas to establish a baseline of raptor activity.

6. Ascertain the type, extent, timing, and duration of development or human activities proposed to occur, and the extent to which this differs from baseline conditions.

7. Consider cumulative effects to raptors from proposed projects when added to past, present, and reasonably foreseeable actions. Ensure that project mitigation adequately addresses cumulative effects to raptors.

8. Minimize loss of raptor habitats and avoid long-term habitat degradation. Mitigate for unavoidable losses of high-valued raptor habitats, including (but not limited to) nesting, roosting, migration, and foraging areas.

9. Monitor and document the status of raptor populations and, if feasible, their prey base post project completion, and evaluate the success of mitigation efforts.

10. Document meaningful data and evaluations in a format that can be readily shared and incorporated into wildlife databases (contact the Service's Wyoming Ecological Services office for details).

Protection of nesting, wintering (including communal roost sites), and foraging activities is considered essential to conserving raptors. In order to promote the conservation of migratory bird populations and their habitats, Federal agencies should implement those strategies directed by Executive Order 13186, "Responsibilities of Federal Agencies To Protect Migratory Birds" (66 FR 3853).

Recommended Seasonal and Spatial Buffers to Protect Nesting Raptors

Because many raptors are particularly sensitive to disturbance (that may result in take) during the breeding season, we recommend implementing spatial and seasonal buffer zones to protect individual nest sites/territories (Table 1). The buffers serve to minimize visual and auditory impacts associated with human activities near nest sites. Ideally, buffers would be large enough to protect existing nest trees and provide for alternative or replacement nest trees. The size and shape of effective buffers vary depending on the topography and other ecological characteristics surrounding the nest site. In open areas where there is little or no forested or topographical separation, distance alone must serve as the buffer. Adequate nesting buffers will help ensure activities do not take breeding birds, their young or eggs. For optimal conservation benefit, we recommend that no temporary or permanent surface occupancy occur within species-specific spatial buffer zones. For some activities with very substantial auditory impacts (e.g., seismic exploration and blasting) or visual impacts (e.g., tall drilling rig), a larger buffer than listed in Table 1 may be necessary, please contact the Service's Wyoming Ecological Services office for project specific recommendations on adequate buffers.

As discussed above, for infrastructure that may create an increased potential for raptor mortalities, the spatial buffers listed in Table 1 may not be sufficient to reduce the incidence of raptor mortalities (for example, if a wind turbine is placed outside a nest disturbance buffer, but inadvertently still within areas of normal daily or migratory bird movements); therefore, please contact the Service's Wyoming Ecological Services office for project specific recommendations on adequate buffers.

Buffer recommendations may be modified on a site-specific or project-specific basis based on field observations and local conditions. The sensitivity of raptors to disturbance may be dependent on local topography, density of vegetation, and intensity of activities. Additionally, individual birds may be habituated to varying levels of disturbance and human-induced impacts. Modification of protective buffer recommendations may be considered where biologically supported and developed in coordination with the Service's Wyoming Ecological Services Field Office.

Because raptor nests are often initially not identified to species (e.g., preliminary aerial surveys in winter), we first recommend a generic raptor nest seasonal buffer guideline of January 15th – August 15th. Similarly, for spatial nesting buffers, until the nesting species has been confirmed, we recommend applying a 1-mile spatial buffer around the nest. Once the raptor species is confirmed, we then make species-specific and site-specific recommendations on seasonal and spatial buffers (Table 1).

Activities should not occur within the spatial/seasonal buffer of any nest (occupied or unoccupied) when raptors are in the process of courtship and nest site selection. Long-term land-use activities and human-use activities should not occur within the species-specific spatial buffer of occupied nests. Short-term land use and human-use activities proposed to occur within the spatial buffer of an occupied nest should only proceed during the seasonal buffer after coordination with the Service, State, and Tribal wildlife resources management agencies, and/or land-management agency biologists. If, after coordination, it is determined that due to human or environmental safety or otherwise unavoidable factors, activities require temporary incursions within the spatial and seasonal buffers, those activities should be planned to minimize impacts and monitored to determine whether impacts to birds occurred. Mitigation for habitat loss or degradation should be identified and planned in coordination with applicable agencies.

Please contact the Service's Wyoming Ecological Services Field Office if you have any questions regarding the status of the bald eagle, permit requirements, or if you require technical assistance regarding the MBTA, Eagle Act, or the above recommendations. The recommended spatial and seasonal buffers are voluntary (unless made a condition of permit or license) and are not regulatory, and they do not supersede provisions of the MBTA, Eagle Act, Migratory Bird Permit Memorandum (MBMP-2), and Endangered Species Act. Assessing legal compliance with the MBTA or the Eagle Act and the implementing regulations is ultimately the authority and responsibility of the Service's law enforcement personnel. Our recommendations also do not supersede Federal, State, local, or Tribal regulations or permit conditions that may be more restrictive.

Table 1. Service's Wyoming Ecological Services Field Office's Recommended Spatial and Seasonal Buffers for Breeding Raptors for construction projects, excluding wind energy. For information on wind energy projects please contact the Wyoming Ecological Services Office (307) 772-2374.

Raptors of Conservation Concern (see below for more information)

Common Name	Spatial buffer (miles)	Seasonal buffer
Golden Eagle	0.5	January 15 - July 31
Ferruginous Hawk	1	March 15 - July 31
Swainson's Hawk	0.25	April 1 - August 31
Bald Eagle	see Bald Eagle information web page	
Prairie Falcon	0.5	March 1 - August 15
Peregrine Falcon	0.5	March 1 - August 15
Short-eared Owl	0.25	March15- August 1
Burrowing Owl	0.25	April 1 – September 15
Northern Goshawk	0.5	April 1 - August 15

Additional Wyoming Raptors

Common Name	Spatial buffer (miles)	Seasonal buffer
Osprey	0.25	April 1 - August 31
Cooper's Hawk	0.25	March 15 – August 31
Sharp-shinned Hawk	0.25	March 15 – August 31
Red-tailed Hawk	0.25	February 1 – August 15
Rough-legged Hawk (winter resident only)	----	----
Northern Harrier	0.25	April 1 - August 15
Merlin	0.5	April 1 - August 15
American Kestrel	0.125	April 1 – August 15
Common Barn Owl	0.125	February 1 – September 15
Northern Saw-whet Owl	0.25	March 1 - August 31
Boreal Owl	0.25	February 1 – July 31
Long-eared Owl	0.25	February 1 – August 15

Great Horned Owl	0.125	December 1 – September 31
Northern Pygmy-Owl	0.25	April 1 – August 1
Eastern Screech -owl	0.125	March 1 – August 15
Western Screech-owl	0.125	March 1 – August 15
Great Gray Owl	0.25	March 15 – August 31

Raptors of Conservation Concern

The Service's Birds of Conservation Concern (2008) report identifies "species, subspecies, and populations of all migratory nongame birds that, without additional conservation actions, are likely to become candidates for listing" under the Endangered Species Act (16 U.S.C 1531 et seq.). This report is intended to stimulate coordinated and proactive conservation actions among Federal, State, and private partners. The Wyoming Partners in Flight Wyoming Bird Conservation Plan identifies priority bird species and habitats, and establishes objectives for bird populations and habitats in Wyoming. This plan also recommends conservation actions to accomplish the population and habitat objectives.

We encourage project planners to develop and implement protective measures for the Birds of Conservation Concern as well as other high-priority species identified in the Wyoming Bird Conservation Plan. For additional information on the Birds of Conservation Concern that occur in Wyoming, please see our Birds of Conservation Concern web page.

Additional Planning Resources

Avian Power Line Interaction Committee (APLIC). 2006. Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006. Edison Electric Institute, APLIC, and the California Energy Commission. Washington, D.C. and Sacramento, CA.

Edison Electric Institute and the Raptor Research Foundation. 1996. Suggested Practices for Raptor Protection on Power Lines - The State of the Art in 1996. Washington, D.C.

Edison Electric Institute's Avian Power Line Interaction Committee and U.S. Fish and Wildlife Service. 2005. Avian Protection Plan Guidelines.

Edison Electric Institute and the Raptor Research Foundation. 1994. Mitigating Bird Collisions with Power Lines - The State of the Art in 1994. Washington, D.C.

U.S. Fish and Wildlife Service. 2000. Siting, Construction, Operation and Decommissioning of Communications Towers and Tower Site Evaluation Form (Directors Memorandum September 14, 2000), Arlington, Virginia.

U.S. Fish and Wildlife Service. 2007. National Bald Eagle Management Guidelines. United States Department of Interior, Fish and Wildlife Service, Arlington, Virginia. 23 pp.

Wyoming Game and Fish Department Internet Link to Raptor Information

References

50 CFR 10.12 – Code of Federal Regulations. Title 50--Wildlife and Fisheries, Chapter I--United States Fish and Wildlife Service, Department of the Interior, Part 10--General Provisions.

50 CFR 10.13– Code of Federal Regulations. Title 50--Wildlife and Fisheries, Chapter I--United States Fish and Wildlife Service, Department of the Interior, Part 10--General Provisions.

50 CFR 22.3 – Code of Federal Regulations. Title 50--Wildlife and Fisheries, Chapter I--United States Fish and Wildlife Service, Department of the Interior, Part 22—Eagle Permits.

50 CFR 22.25– Code of Federal Regulations. Title 50--Wildlife and Fisheries, Chapter I--United States Fish and Wildlife Service, Department of the Interior, Part 22—Eagle Permits.

66 FR 3853 - Presidential Documents. Executive Order 13186 of January 10, 2001. Responsibilities of Federal Agencies to Protect Migratory Birds. Federal Register, January 17, 2001.

72 FR 31132 - Protection of Eagles; Definition of ‘‘Disturb’’. Final Rule. Federal Register, June 5, 2007.

74 FR 46836 - Eagle Permits; Take Necessary To Protect Interests in Particular Localities. Final Rule. Federal Register, September 11, 2009.

U.S. Fish and Wildlife Service. 2003. Migratory Bird Permit Memorandum, MBMP-2, Nest Destruction (Directors Memorandum April 15, 2003), Washington, D.C.

U.S. Fish and Wildlife Service. 2008. Birds of Conservation Concern 2008. United States Department of Interior, Fish and Wildlife Service, Division of Migratory Bird Management, Arlington, Virginia. 85 pp.

Last updated: July 1, 2010

APPENDIX C: CONTACTS (NAMES AND PHONE NUMBERS AS OF MAY 2010.)

Black Hills Corporation

Avian Protection Plan Coordinator (APPC)
Joe Jenkins, Fountain CO, Office 719-393-6685, Cell 719-650-2922

Environmental Services
Tim Rogers, Rapid City SD, Office 605-721-2286, Cell 605-484-0134

Wyodak Mine
Steve Mueller, Gillette WY, Office 307-682-3410, Cell 307-670-0368

Black Hills Power - Generation
Gary Theis, Gillette WY, Office 307-687-8705, Cell 307-670-2787

Black Hills Power – Electric Distribution and Transmission
Wade Hatch, Office 605-721-1470, Cell 605-786-5503

Cheyenne Light Fuel and Power
George Escobedo, Office 307-778-2150, Cell 307-631-0841
Sandy Fuller, Office 307-778-2177

Black Hills Exploration, Production, Midstream
Eric Barndt, Office 303-566-3446, Cell 303-775-9622

US Fish and Wildlife Service

Special Agent Scott Darrah, Casper WY, Office 307-261-6365
Ecological Services, Cheyenne WY, Office 307-772-2374
Migratory Bird Permit Office, Denver CO, 303-236-8171

Wyoming Game and Fish Department

Gillette Game Warden, Troy Achterhof, Gillette WY, 307-682-4353
Gillette Game Warden, Ira Leonetti, Gillette WY, 307-687-7157
Moorcroft Game Warden, John Davis, Moorcroft WY, 307-756-3357
Newcastle Game Warden, Dustin Shorma, Newcastle WY, 307-746-2248
Sundance Game Warden, Chris Teeter, Sundance WY, 307-283-1276
Cheyenne Game Warden, Mark Nelson, Cheyenne WY, 307-638-8354
Permitting Officer, Carol Havlik Casper WY, 307-233-6413
Cheyenne Office, Matt Withroder, 307-777-4585
Cheyenne Office, Joetta Osborne, 307-777-4582
Sheridan Regional Office, Sheridan WY, 307-672-7418
Casper Regional Office, Casper WY, 307-473-3400

Raptor Rehabilitators

Dr. Robert Farr, Cheyenne Pet Clinic, Cheyenne, 307-635-4121
Diane Morse, Gillette, 307-682-2532

APPENDIX D: PROTECTED SPECIES AND SCEPIES OF CONCERN, WYOMING

Wyoming Partners in Flight: Wyoming Bird Conservation Plan, Version 2.0, 1 May 2003

Table 1.

Level I (Conservation Action). Species clearly needs conservation action (CA). Declining population trend and/or habitat loss may be significant. Includes species of which Wyoming has a high percentage of and responsibility for the breeding population (R), monitoring (M), and the need for additional knowledge (K) through research into basic natural history, distribution, etc.

Species	Primary Habitat Type(s)
American Bittern	Wetlands
Trumpeter Swan[a]	Wetlands
Bald Eagle[a]	Montane Riparian, Plains/Basin Riparian
Northern Goshawk	High Elevation Conifer, Mid Elevation Conifer, Aspen
Swainson's Hawk	Plains/Basin Riparian
Ferruginous Hawk	Shrub-steppe, Shortgrass Prairie
Peregrine Falcon	Specialized (cliffs)
Greater Sage-Grouse[a]	Shrub-steppe
Columbian Sharp-tailed Grouse	Mountain-foothills Shrub
Mountain Plover	Shortgrass Prairie, Shrub-steppe
Upland Sandpiper	Shortgrass Prairie
Long-billed Curlew	Shortgrass Prairie, Meadows
Wilson's Phalarope	Wetlands
Franklin's Gull	Wetlands
Forster's Tern	Wetlands
Black Tern	Wetlands
Burrowing Owl	Shortgrass Prairie
Short-eared Owl	Shortgrass Prairie, Meadows
Brewer's Sparrow	Shrub-steppe, Mountain-foothills Shrub
Sage Sparrow	Shrub-steppe, Mountain-foothills Shrub
Baird's Sparrow[b]	Shortgrass Prairie
McCown's Longspur	Shortgrass Prairie, Shrub-steppe

[a]Specific management plans already exist for the Trumpeter Swan, Greater Sage-Grouse, and Bald Eagle in Wyoming.
[b]Species is peripheral in Wyoming.

Table 2.

Level II (Monitoring). The action and focus for the species is monitoring (M). Declining population trends and habitat loss are not significant at this point. Includes species of which Wyoming has a high percentage of and responsibility for the breeding population (R), species whose stability (S) may be unknown (S?), species that are peripheral (P) for breeding in the habitat or state, or additional knowledge (K) may be needed.

Species	Primary Habitat Type(s)
Common Loon	Wetlands, Aquatic
American White Pelican	Aquatic
Harlequin Duck Montane	Riparian
Merlin Low Elevation	Conifer
Snowy Plover[a]	Wetlands
Black-billed Cuckoo	Plains/Basin Riparian
Yellow-billed Cuckoo	Plains/Basin Riparian
Western Screech-Owl	Plains/Basin Riparian
Eastern Screech-Owl	Plains/Basin Riparian
Great Gray Owl	Mid Elevation Conifer, High Elevation Conifer
Boreal Owl	High Elevation Conifer
White-throated Swift	Specialized (cliffs and canyons)
Black-chinned Hummingbird[a]	Plains/Basin Riparian, Shrub-steppe
Calliope Hummingbird	Mid Elevation Conifer, Montane Riparian
Broad-tailed Hummingbird	Montane Riparian, Plains/Basin Riparian, Mid Elevation Conifer
Rufous Hummingbird	Mid Elevation Conifer
Lewis' Woodpecker	Low Elevation Conifer, Plains/Basin Riparian
Williamson's Sapsucker	Mid Elevation Conifer
Red-naped Sapsucker	Aspen
Three-toed Woodpecker	Mid Elevation Conifer, High Elevation Conifer
Black-backed Woodpecker	Mid Elevation Conifer, High Elevation Conifer
Olive-sided Flycatcher	High Elevation Conifer, Mid Elevation Conifer
Willow Flycatcher	Montane Riparian, Plains/Basin Riparian
Hammond's Flycatcher	High Elevation Conifer, Aspen, Montane Riparian
Gray Flycatcher Juniper	Woodland, Mountain-foothills Shrub
Dusky Flycatcher	Low Elevation Conifer, Aspen, Mountain-foothills Shrub
Cordilleran Flycatcher	Montane Riparian, Mid Elevation Conifer
Ash-throated Flycatcher	Juniper Woodland
Cassin's Kingbird[a]	Juniper Woodland, Plains/Basin Riparian
Loggerhead Shrike	Shrub-steppe
Plumbeous Vireo	Mid Elevation Conifer, Low Elevation Conifer
Western Scrub-Jay	Juniper Woodland
Juniper Titmouse	Juniper Woodland
Bushtit Juniper	Woodland
Pygmy Nuthatch	Low Elevation Conifer
Brown Creeper	Mid Elevation Conifer, High Elevation Conifer
Marsh Wren	Wetlands

Table 2. Continued

Species	Primary Habitat Type(s)
American Dipper	Montane Riparian
Golden-crowned Kinglet	High Elevation Conifer
Western Bluebird	Juniper Woodland, Low Elevation Conifer
Townsend's Solitaire	Mid Elevation Conifer, High Elevation Conifer, Juniper Woodland
Sage Thrasher	Shrub-steppe
Townsend's Warbler	High Elevation Conifer, Mid Elevation Conifer
MacGillivray's Warbler	Montane Riparian, Plains/Basin Riparian
Wilson's Warbler	Montane Riparian
Vesper Sparrow	Shrub-steppe
Lark Sparrow	Shrub-steppe
Lark Bunting	Shortgrass Prairie, Shrub-steppe
Grasshopper Sparrow	Shortgrass Prairie, Shrub-steppe
Chestnut-collared	Longspur Shortgrass Prairie
Dickcissel	Shortgrass Prairie
Bobolink	Shortgrass Prairie, Agricultural Lands, Meadows
Scott's Oriole	Juniper Woodland

[a]Species is peripheral in Wyoming.

Table 3.

Level III (Local Interest). Species that Wyoming Partners in Flight may recommend for conservation action (CA) that are not otherwise high priority but are of local interest (LI). Can include monitoring (M).

Species Primary	Habitat Type(s)
Western Grebe	Wetlands, Aquatic
Clark's Grebe	Wetlands, Aquatic
Northern Harrier	Wetlands, Meadows
Golden Eagle	Specialized (cliffs)
Prairie Falcon	Specialized (cliffs)
White-tailed Ptarmigan[a]	Alpine Tundra/Grassland
Blue Grouse[a]	Mid Elevation Conifer, High Elevation Conifer
American Avocet	Wetlands
Willet	Wetlands
Common Poorwill	Mountain-foothills Shrub, Shrub-steppe
Red-headed Woodpecker	Plains/Basin Riparian, Low Elevation Conifer
Say's Phoebe	Shrub-steppe
Clark's Nutcracker	High Elevation Conifer, Mid Elevation Conifer
Northern Rough-winged Swallow	Plains/Basin Riparian
Rock Wren	Specialized (rock outcrops)
Canyon Wren	Specialized (canyons)
Bewick's Wren	Juniper Woodland
Veery Montane	Riparian
Virginia's Warbler	Juniper Woodland, Mountain-foothills Shrub
Black-throated Gray Warbler	Juniper Woodland, Mountain-foothills Shrub
Ovenbird	Plains/Basin Riparian
Lazuli Bunting	Montane Riparian, Plains/Basin Riparian, Mountain-Foothills Shrub
Bullock's Oriole	Montane Riparian, Plains/Basin Riparian
Black Rosy-Finch	Alpine Tundra/Grassland, Specialized (cliffs)
Brown-capped Rosy-Finch	Alpine Tundra/Grassland, Specialized (cliffs)

[a]Classified as a game species in Wyoming.

Table 4.

Level IV (Not Considered Priority). Additional species of concern, but not considered a priority species; species is known to be stable (S) or increasing, or is addressed elsewhere in other management plans; no action is needed; monitoring (M) is not precluded but is not the focus; or species is extirpated (E) and no action is needed.

Species	**Primary Habitat Type(s)**
Wood Duck[a]	Plains/Basin Riparian
Cinnamon Teal [a]	Wetlands
Canvasback[a]	Wetlands
Redhead[a]	Wetlands
Ring-necked Duck[a]	Wetlands
Bufflehead[a]	Wetlands
Barrow's Goldeneye [a]	Wetlands
Hooded Merganser[a]	Aquatic
Northern Bobwhite[b]	Plains/Basin Riparian
Sandhill Crane[a]	Wetlands
California Gull	Aquatic
Chimney Swift	Urban
Warbling Vireo	Plains/Basin Riparian, Mid Elevation Conifer, Aspen
Pinyon Jay Juniper	Woodland
Black-billed Magpie	Generalist
Mountain Chickadee	High Elevation Conifer, Mid Elevation Conifer
Mountain Bluebird	Mountain-foothills Shrub, Shrub-steppe
Western Tanager	Mid Elevation Conifer, High Elevation Conifer
Green-tailed Towhee	Mountain-foothills Shrub, Shrub-steppe
Clay-colored Sparrow	Mountain-foothills Shrub, Shrub-steppe
Rose-breasted Grosbeak	Plains/Basin Riparian, Montane Riparian
Black-headed Grosbeak	Mid Elevation Conifer, Aspen
Cassin's Finch	Mid Elevation Conifer, High Elevation Conifer

[a]Specific management plans already exist for waterfowl and the Rocky Mountain Greater Sandhill Crane.

[b]Classified as a game species in Wyoming

Table 5: Fish and Wildlife Service's Wyoming Ecological Services Field Office's Recommended Spatial and Seasonal Buffers for Breeding Raptors

Raptors of Conservation Concern (see below for more information)

Common Name	Spatial buffer (miles)	Seasonal buffer
Golden Eagle	0.5	January 15 - July 31
Ferruginous Hawk	1	March 15 - July 31
Swainson's Hawk	0.25	April 1 - August 31
Bald Eagle[a]	see instructions below[a]	
Prairie Falcon	0.5	March 1 - August 15
Peregrine Falcon	0.5	March 1 - August 15
Short-eared Owl	0.25	March15- August 1
Burrowing Owl	0.25	April 1 – September 15
Northern Goshawk	0.5	April 1 - August 15

Additional Wyoming Raptors

Common Name	Spatial buffer (miles)	Seasonal buffer
Osprey	0.25	April 1 - August 31
Cooper's Hawk	0.25	March 15 – August 31
Sharp-shinned Hawk	0.25	March 15 – August 31
Red-tailed Hawk	0.25	February 1 – August 15
Rough-legged Hawk	----	(winter resident only)
Northern Harrier	0.25	April 1 - August 15
Merlin	0.5	April 1 - August 15
American Kestrel	0.125	April 1 – August 15
Common Barn Owl	0.125	February 1 – September 15
Northern Saw-whet Owl	0.25	March 1 - August 31
Boreal Owl	0.25	February 1 – July 31
Long-eared Owl	0.25	February 1 – August 15
Great Horned Owl	0.125	December 1 – September 31
Northern Pygmy-Owl	0.25	April 1 – August 1
Eastern Screech -owl	0.125	March 1 – August 15
Western Screech-owl	0.125	March 1 – August 15
Great Gray Owl	0.25	March 15 – August 31

[a]Bald Eagles: When the proposed infrastructure and facilities do not pose an increased risk of direct mortality, we recommend using the following general guidelines for work within Wyoming in order to avoid disturbing eagles and adequately protecting their habitat:

1. Conduct surveys within 0.5 mile of proposed activity for eagle nests and/or roosts during the appropriate time of year. Contact the Service's Ecological Services Wyoming Field Office if your project will occur within 0.5 mile of a known nest or roost to determine the potential impact of your activity to nesting and/or roosting bald eagles.

2. Avoid project-related disturbance and habitat alteration within 0.5-mile of bald eagle nests from the period of early courtship to post-fledging of chicks (January 1 through August 15).

3. Avoid disturbance within 0.5 mile of communal winter roosts from November 1 to April 1.

4. Avoid construction of above-ground structures within 0.5-mile of bald eagle nest sites and communal winter roost sites. Below ground structures (e.g., pipelines, buried power lines, fiber optic lines) may be sited closer as long as construction occurs outside of the active nesting or roosting season and will not result in the loss of alternate nest sites or roost trees.

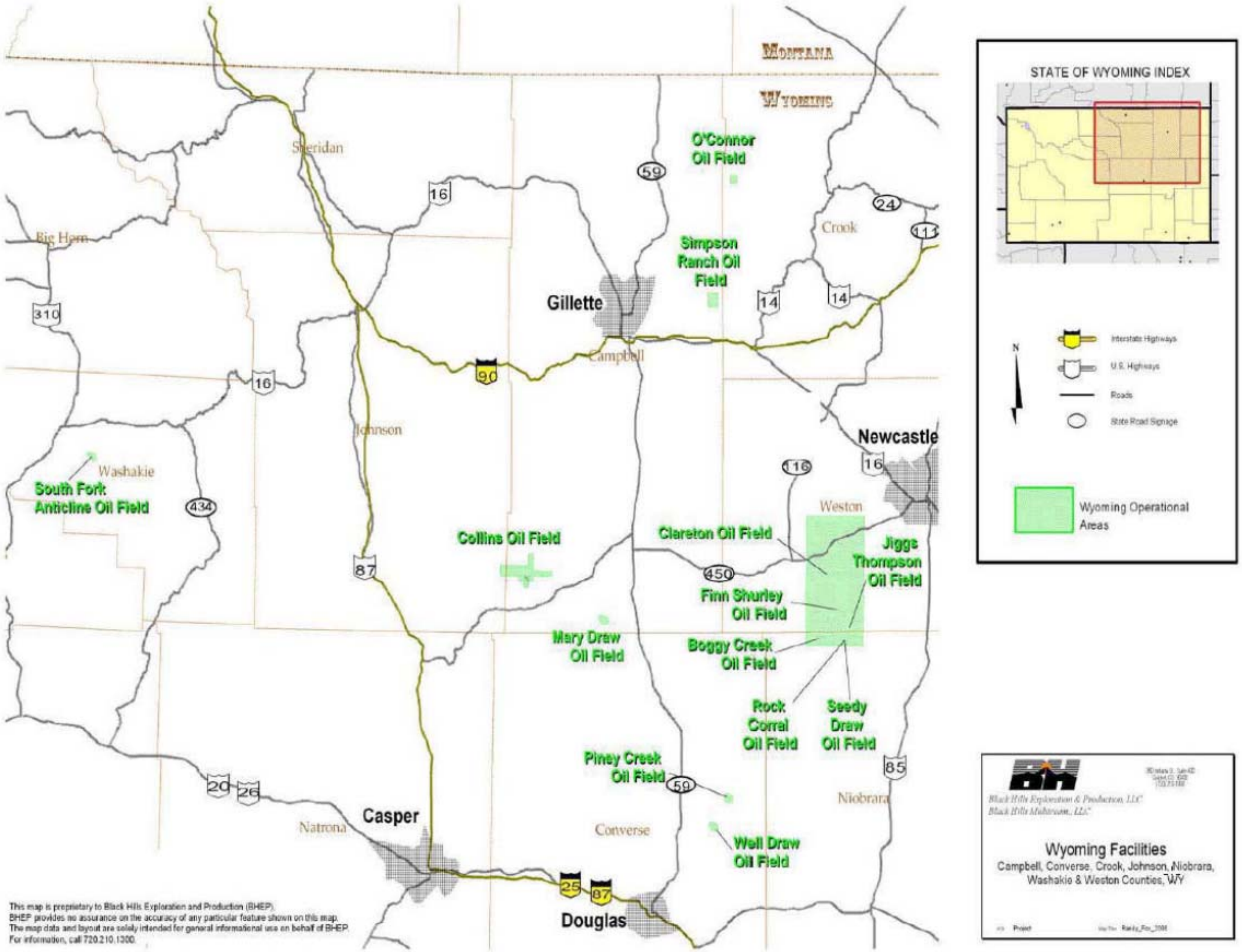
A protective buffer for foraging areas (i.e., a linear length of river) will also be needed if the proposed activity may preclude use of foraging areas (e.g., extensive human activities on or near the water).

In Wyoming, the nesting season occurs from February 1 to August 15 and bald eagle nest buffers should receive full implementation during this time period. For some activities (construction, seismic exploration, blasting, and timber harvest), a larger buffer around the nest may be necessary.

Sensitivity to disturbance by roosting and nesting bald eagles may vary between individual eagles based on topography, density of vegetation, and intensity of activities. Modification of protective buffer recommendations may be considered where biologically supported and developed in coordination with the Service’s Wyoming Ecological Services Field Office.

APPENDIX E: SERVICE TERRITORY MAPS

- **Black Hills Exploration and Production**
- **Black Hills Power / Wyodak Mine**
  - Campbell County, Wyodak, WY – Electric Distribution System and Wyodak Mine
  - Weston County, Upton, WY – Electric Distribution System
  - Weston County, Osage, WY – Electric Distribution System
  - Weston County, New Castle, WY – Electric Distribution System
- **Cheyenne Light Fuel & Power Company**
  - Laramie County, Cheyenne, WY – Electric Distribution System

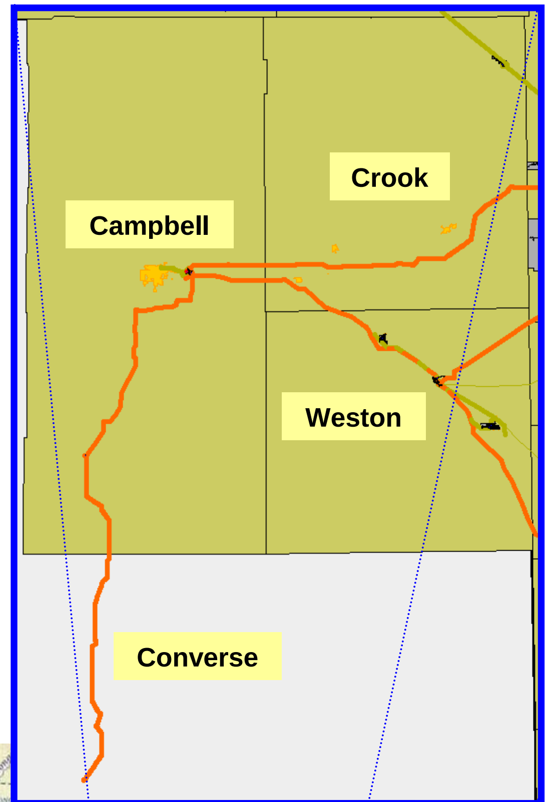


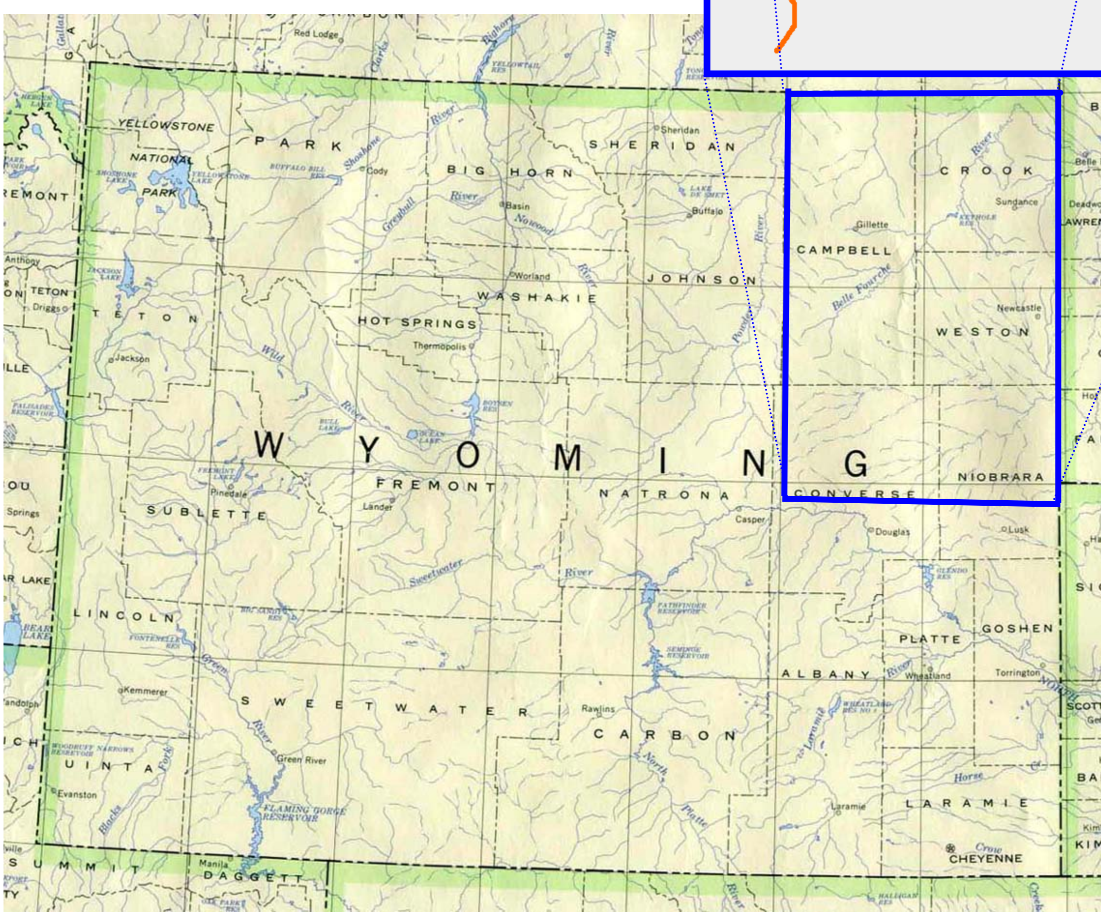
MONTANA
WYOMING
Sheridan
Big Horn
Gillette
Campbell
Johnson
Washakie
Crook
Weston
Newcastle
Natrona
Casper
Converse
Douglas
Niobrara
O'Connor Oil Field
Simpson Ranch Oil Field
South Fork Anticline Oil Field
Collins Oil Field
Clareton Oil Field
Jiggs Thompson Oil Field
Finn Shurley Oil Field
Mary Draw Oil Field
Boggy Creek Oil Field
Rock Corral Oil Field
Seedy Draw Oil Field
Piney Creek Oil Field
Well Draw Oil Field
16
59
24
111
14
310
90
116
434
87
450
85
20
26
25
STATE OF WYOMING INDEX
Wyoming Operational Areas
Wyoming Facilities
Campbell, Converse, Crook, Johnson, Niobrara, Washakie & Weston Counties, WY
This map is proprietary to Black Hills Exploration and Production (BHEP).
BHEP provides no assurance on the accuracy of any particular feature shown on this map.
The map data and layout are solely intended for general informational use on behalf of BHEP.
For information, call 720.210.1300.

BLACK HILLS POWER, WYOMING OPERATIONS

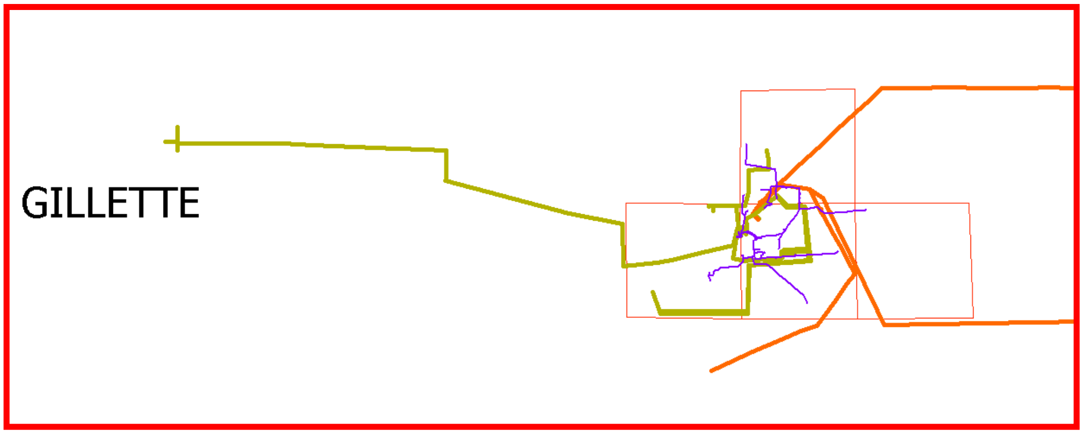
230 kV Transmission

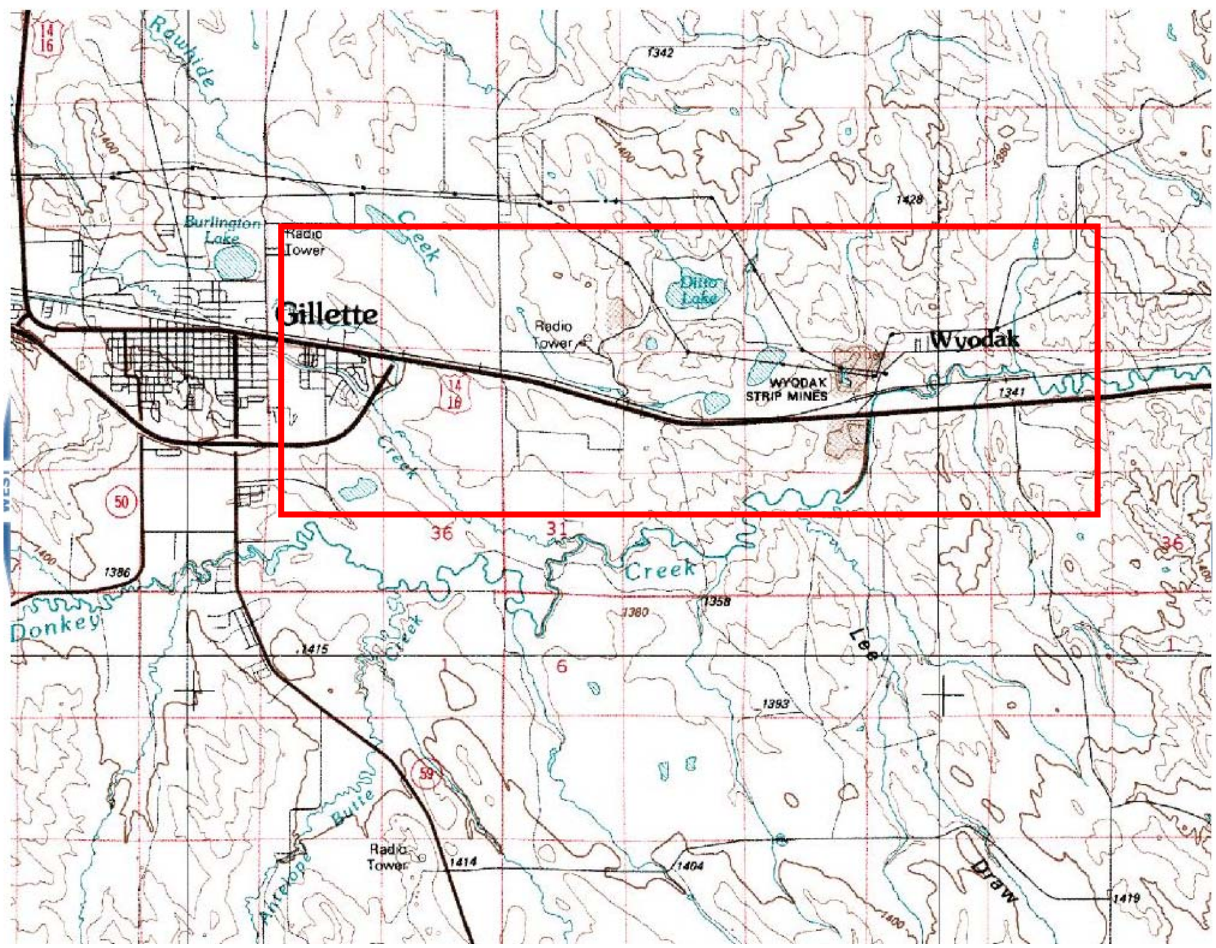
69 kV Transmission



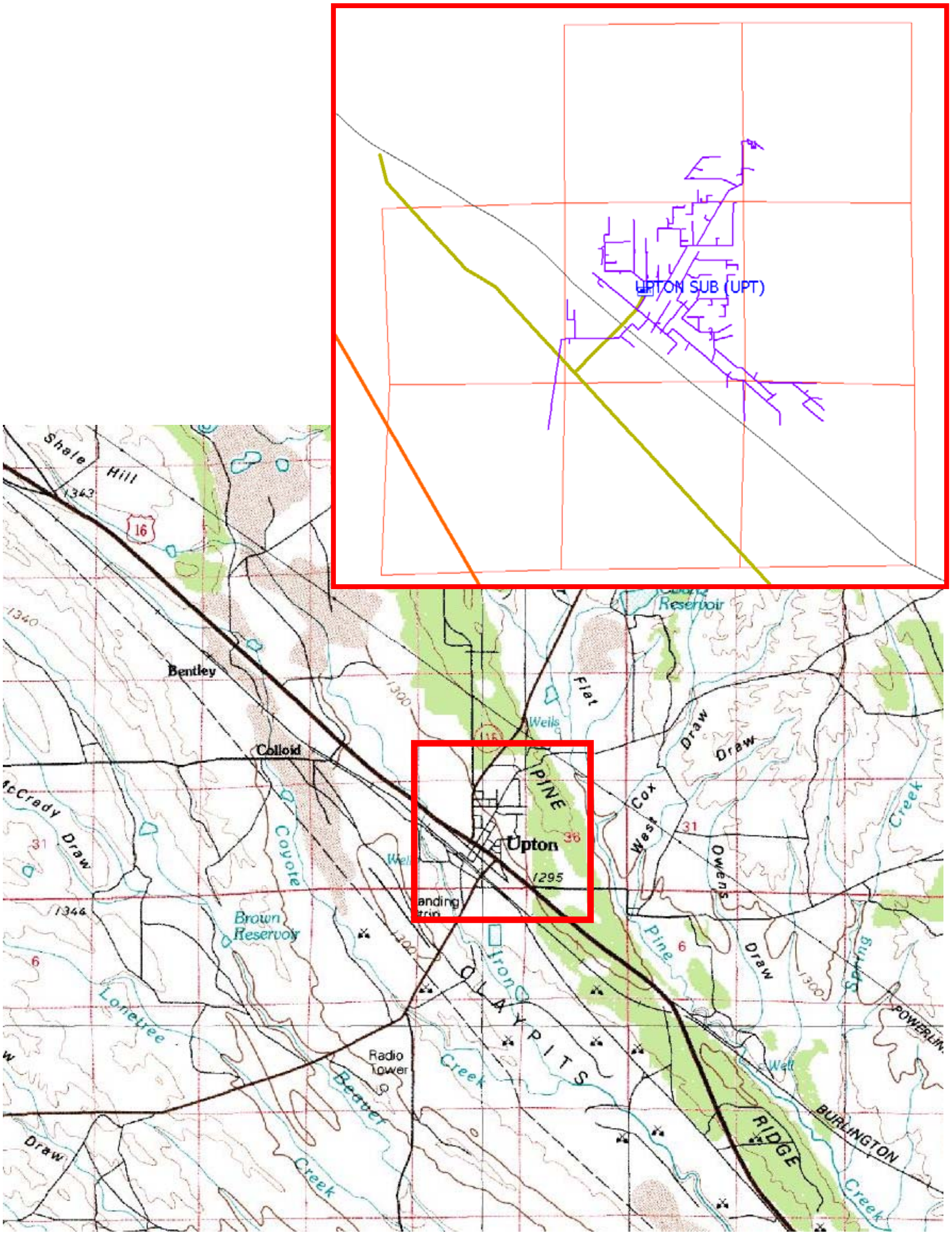


Campbell County, Wyodak, WY,
Electric Distribution System, and Wyodak Mine

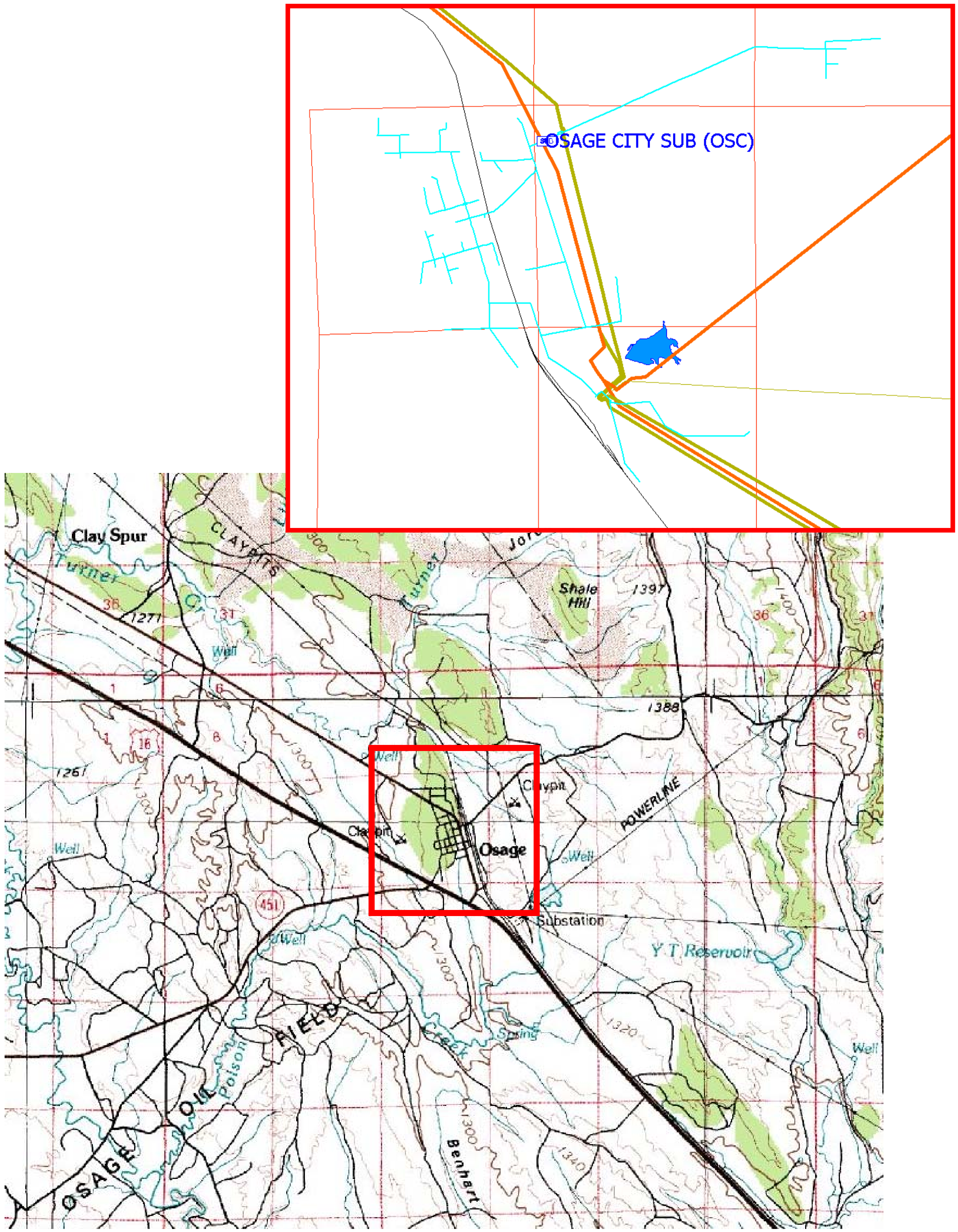




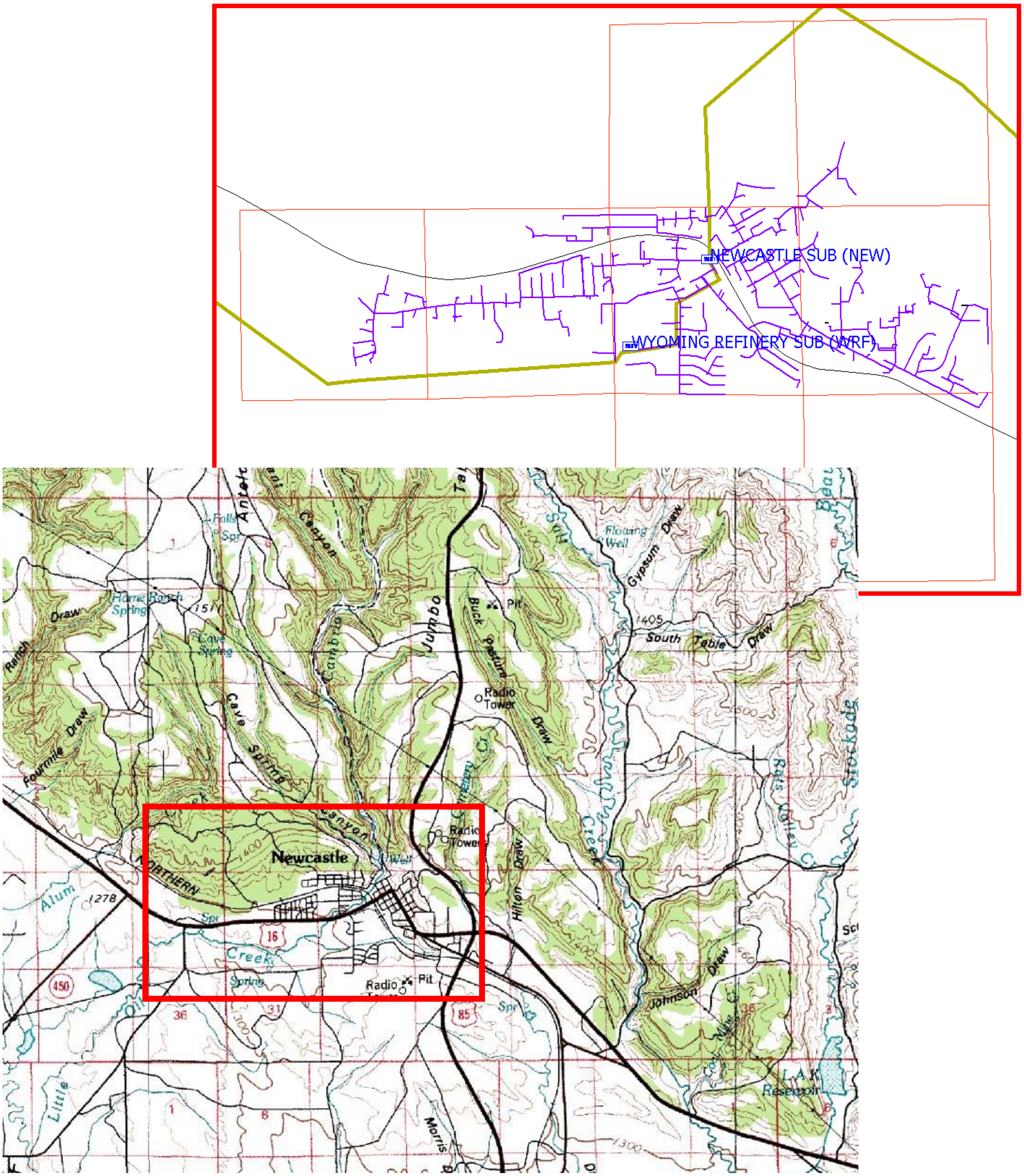
Weston County, Upton, WY Distribution System



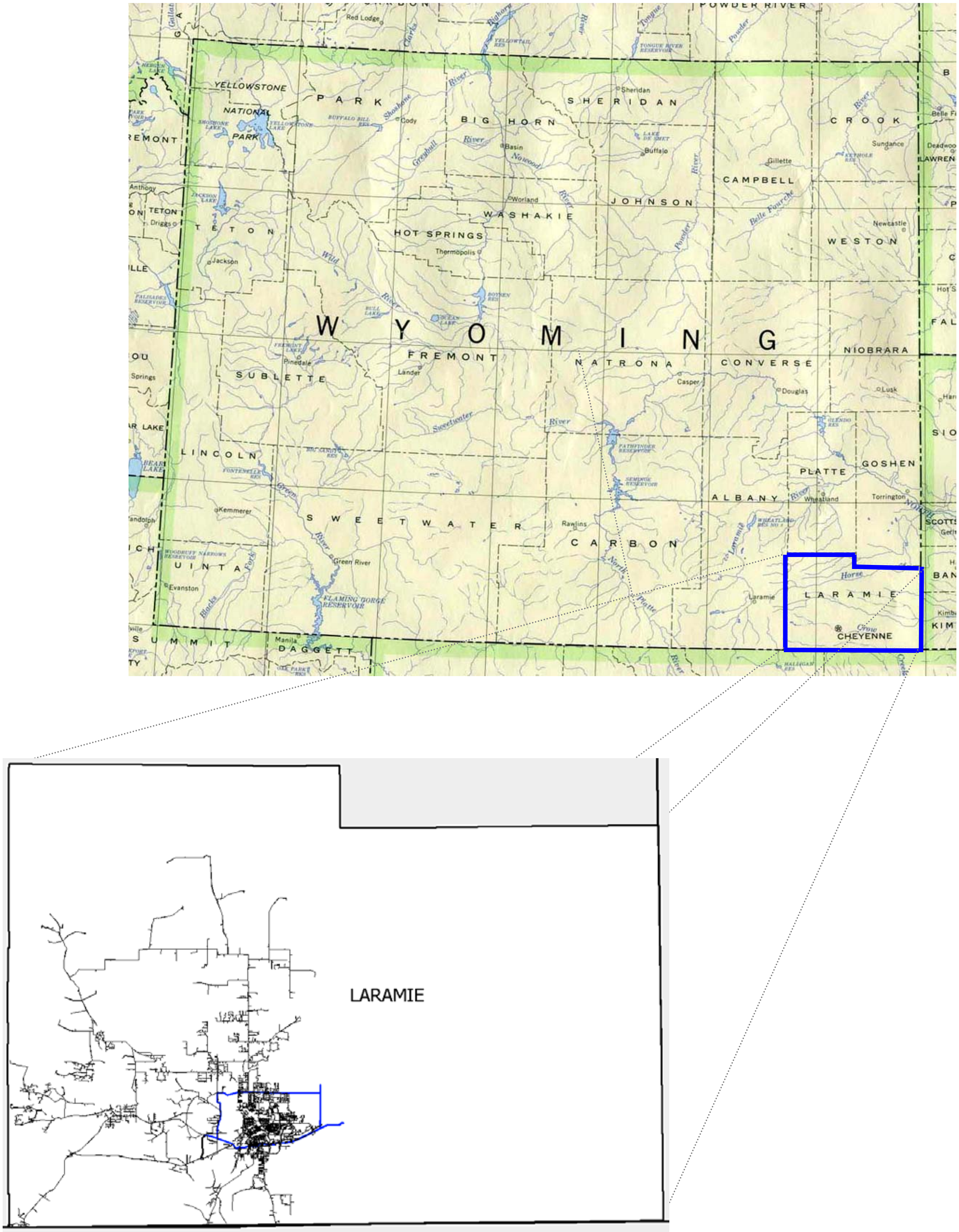
Weston County, Osage, WY Distribution System



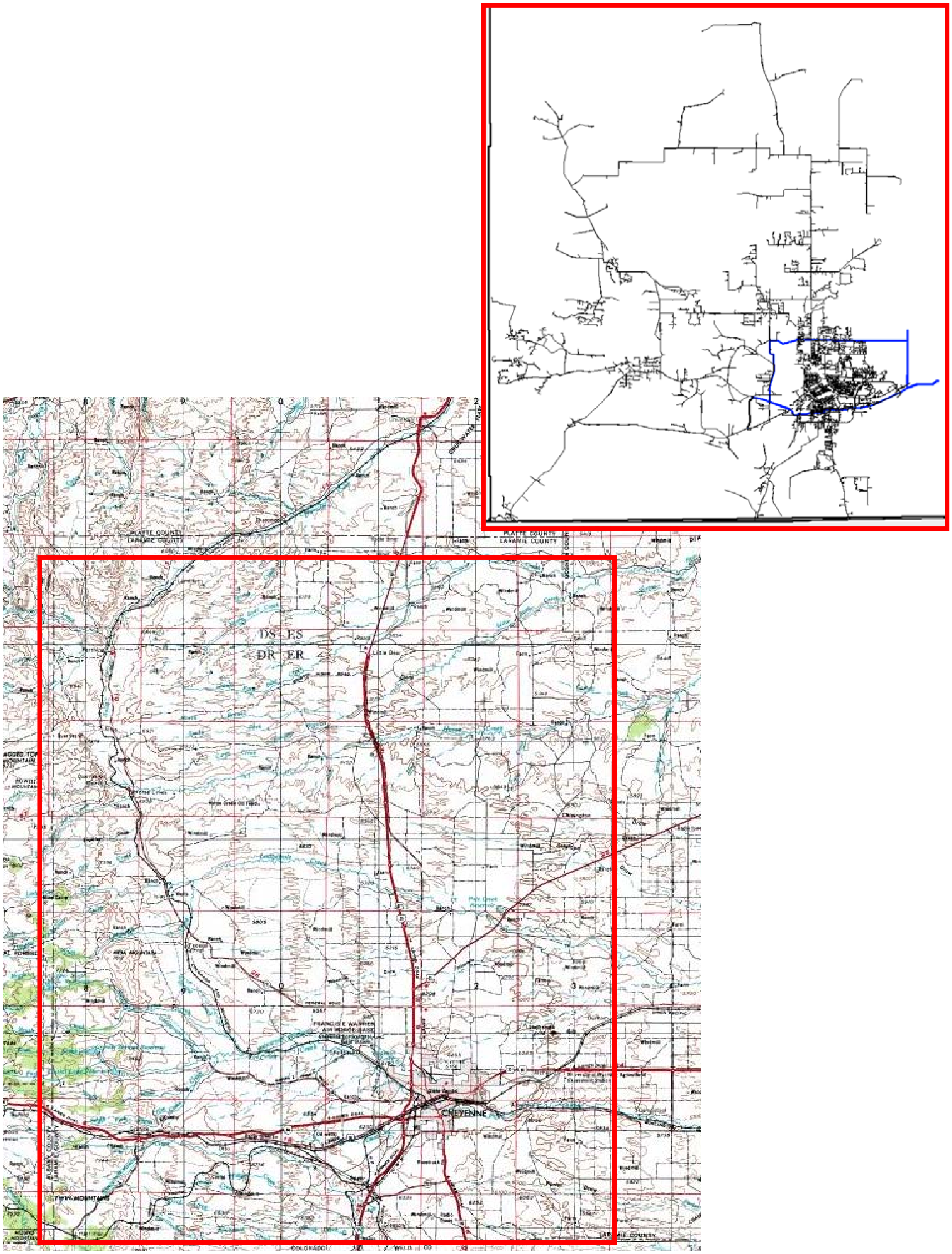
Weston County, New Castle, WY Distribution System



CHEYENNE LIGHT FUEL & POWER



Cheyenne WY, Distribution System



APPENDIX F: BIRD MANAGEMENT POLICY

BLACK HILLS CORPORATION
COMPANY POLICY

Policy Name: AVIAN PROTECTION POLICY				DATE ISSUED 3.15.11	POLICY NO. E-01-02-01
				DATE EFFECTIVE 3.15.11	PAGE NO. Page 1 of 2
SUPERSEDES	(PAGE NO.)	(POLICY NO.)	DATED	Department Environmental Services	APPROVED SH for Senior Management
				Reviewed by	Reviewed Date 3.15.11

1. PURPOSE

The purpose of this Policy is to set forth Black Hills Corporation's policy on managing bird interactions with electric, exploration and production, and mining operations with a commitment to reducing detrimental effects of these interactions.

2. SCOPE

This Policy applies to Black Hills Corporation's electric, exploration and production, and mining operations that own or operate above ground power lines and appurtenances that may cause detrimental interactions.

3. DEFINITIONS

3.1 Company: Black Hills Corporation, its subsidiaries and affiliates.

3.2 Avian Protection Plan (APP): The programs in effect for each subsidiary of the Company to reduce the operational and avian risks that result from avian interactions.

4. POLICY

Bird interactions with Company operations may cause bird injuries and mortalities, which, in turn, may result in violations of bird protection laws, outages, grass and forest fires, or raise concerns by employees, resource agencies and the public.

This Policy is intended to ensure compliance with legal requirements while improving distribution system reliability.

To fulfill this commitment, the Company will:

- Implement and comply with each comprehensive Avian Protection Plan.

- Ensure its actions comply with applicable laws, regulations, permits, and APP procedures.
- Document bird mortalities, problem poles and lines, and problem nests.
- Provide information, resources, and training to improve its employees' knowledge and awareness of the APP.
- Construct all new facilities to avian-safe standards.
- Retrofit or modify power poles where a protected bird has died or been injured. Modifications will be in accordance with APP procedures.
- Participate with public and private organizations in programs and research to reduce detrimental effects of bird interactions with power lines.

5. RESPONSIBILITIES

Company management and employees are responsible for managing bird interactions with power lines and other facilities where such interactions may occur, and are committed to reducing the detrimental effects of these interactions.

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: richard.currit 05/18/2012 11:55 AM
Bcc: Sara Laumann, Deirdre Rothery, Michael Boydston

From:	Christopher Razzazian/R8/USEPA/US
To:	richard.currit@wyo.gov
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA, Michael Boydston/R8/USEPA/US@EPA

Mr. Currit,

Please see attached EPA's public notice, Statement of Basis, and Draft Permit for the proposed new facility.

We will be contacting you under separate letter to satisfy our requirements under the NHPA. These documents have been sent to your office. However, we are not sure whether they will be received prior to the opening of the public comment period on Monday morning. Therefore, we are transmitting the documents electronically at this time as well.

Please do not hesitate to call with any questions or concerns. Thank you

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to SHPO.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: sandra_v_silva 05/18/2012 11:48 AM
Cc: mark_sattelberg, Julie_Proell
Bcc: Sara Laumann, Deirdre Rothery, Kimi Matsumoto

From:	Christopher Razzazian/R8/USEPA/US
To:	sandra_v_silva@fws.gov
Cc:	mark_sattelberg@fws.gov, Julie_Proell@fws.gov
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA, Kimi Matsumoto/R8/USEPA/US@EPA

Ms. Silva,

Per our discussion please see the public notice, Statement of Basis and Draft Permit for the new proposed facility. We are unsure whether the hard copy will be received by your office by Monday morning so we have transmitted the documents electronically in this email. Also, thank you very much Julie, for your help on this project, we'll be in touch over the following months as we finalize this action.

Thank you.

Christopher Razzazian
US EPA Region 8
(303)312-6648

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to US FWS.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

FYI - Fw: Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station
Christopher Razzazian to: dcmiller 05/18/2012 11:44 AM
Bcc: Sara Laumann, Deirdre Rothery

From:	Christopher Razzazian/R8/USEPA/US
To:	dcmiller@fs.fed.us
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Ms. Miller - FYI, please see the documents attached below.

Thank you,

Christopher
----- Forwarded by Christopher Razzazian/R8/USEPA/US on 05/18/2012 11:44 AM -----

From:	Christopher Razzazian/R8/USEPA/US
To:	jasorkin@fs.fed.us
Date:	05/18/2012 11:43 AM
Subject:	Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Hi Jeff,

As discussed, here is our public notice, SOB, and Draft Permit for the proposed new source. The hardcopy is in the mail, but may not arrive by Monday morning. So, here they are electronically as well.

Don't hesitate to call if you have any questions or concerns. Thank you.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to USDA FS.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: jasorkin 05/18/2012 11:43 AM

Bcc: Sara Laumann, Deirdre Rothery

From:	Christopher Razzazian/R8/USEPA/US
To:	jasorkin@fs.fed.us
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Hi Jeff,

As discussed, here is our public notice, SOB, and Draft Permit for the proposed new source. The hardcopy is in the mail, but may not arrive by Monday morning. So, here they are electronically as well.

Don't hesitate to call if you have any questions or concerns. Thank you.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to USDA FS.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: Susan_Johnson, don_shepherd 05/18/2012 11:39 AM

Bcc: Sara Laumann, Deirdre Rothery

From:	Christopher Razzazian/R8/USEPA/US
To:	Susan_Johnson@nps.gov, don_shepherd@nps.gov
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Susan and Don,

Please see attached our public notice, Statement of Basis, and Draft Permit for the proposed new facility. We have sent a hard copy to Susan, but are unsure whether it will arrive by Monday morning at the start of the public comment period. Therefore, we are transmitting the documents electronically in this email.

Don't hesitate to call with any questions you may have. Thank you.

Christopher Razzazian
US EPA Region 8
(303) 312-6648

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to NPS.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: glopez 05/18/2012 11:32 AM

Bcc: Sara Laumann, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US
To: glopez@laramiecounty.com
Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Dear Mr. Lopez,

Please see attached our letter to your office and the enclosed public notice, Statement of Basis, and Draft Permit for the proposed new facility. A hard copy of these documents has been sent to your office. However, it is not clear whether they will be received by Monday morning by the opening of the public comment period. Therefore, we are providing electronic copies of these documents to you in this email.

Please do not hesitate to call with any questions you may have. Thank you,

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to county health.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Fw: Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: Allison.william 05/18/2012 11:27 AM
Cc: r.hancock, roland.hea
Bcc: Sara Laumann, Deirdre Rothery

From:	Christopher Razzazian/R8/USEPA/US
To:	Allison.william@state.co.us
Cc:	r.hancock@state.co.us, roland.hea@state.co.us
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Hi - for some reason the last message to you bounced back to me. I hope this makes it to you, however perhaps Roland or Chip could help me out?

Thank you very much!

Christopher

----- Forwarded by Christopher Razzazian/R8/USEPA/US on 05/18/2012 11:26 AM -----

From:	Christopher Razzazian/R8/USEPA/US
To:	sdietr@wyo.gov, allison.william@state.co.us, clark.smith@nebraska.gov
Cc:	akeyfa@wyo.gov, cander@wyo.gov, roland.hea@state.co.us, r.hancock@state.co.us
Date:	05/18/2012 11:22 AM
Subject:	Greenhouse Gas PSD draft air permit notice for Cheyenne Prairie Generating Station

Hello Gentlemen.

Please see below our letters to your offices regarding the public notice of our draft permit for the proposed Cheyenne Prairie Generating Station. We hope that the hard copies arrive at your offices by the opening of the public comment period on Monday. However, in the event that they do not, please see attached the documents in electronic format.

Please do not hesitate to call with any questions you may have. Thank you.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to WDEQ.pdf

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to CDPHE.pdf

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to NDEQ.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: mayor, vriley 05/18/2012 11:15 AM
Bcc: Sara Laumann, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US
To: mayor@cheyennecity.org, vriley@cheyennecity.org
Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Honorable Mr. Kaysen and Ms. Riley,

Please see attached our letters to you allow with their enclosures including a public notice for this draft pre-construction air permit and the Statement of Basis and Draft Permit.

In the event that the hard copies of these documents do not arrive by mail by Monday morning at the opening of the public comment period we are transmitting the documents electronically via this email.

Please do not hesitate to call with any questions you may have. Thank you very much.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to mayor of cheyenne.pdf

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to city of Cheyenne.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: dlathrop 05/18/2012 11:09 AM
Bcc: Sara Laumann, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US
To: dlathrop@laramiecountyclerk.com
Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Good morning Ms. Lathrop.

Please see attached our letter to you regarding the opening of a public comment period for the proposed Cheyenne Prairie Generating Station, and the enclosed documents including the public notice (to run on Monday in the Wyoming Tribune), SOB, and Draft Permit, two letters, and the GHG PSD permit application. We anticipate that the documents will arrive via fedex by, or near, Monday morning 5/21/2012. Please retain those copies and make them available as requested in our attached letter. Thank you very much for your time and service.

Please don't hesitate to call if there are any questions.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

Cheyenne Light, Fuel & Power - CPGS - 5-16-2012 cover letter to county clerk.pdf

The Public Notice, Statement of Basis, and Draft Permit:

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdfCheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdf

The two letters referenced:

2012-05-03_Letter_EPA GHG PSD Comments on CO2 BACT.pdf2011-11-22_Letter_Response to EPA Inquires.pdf

The GHG PSD Permit Application (original and revised):

2011-09-23_Application_EPA GHG - Revised - Combined.pdf Black_Hills_Final_Draft_Combined_080411.pdf

Greenhouse Gas PSD draft air permit notice for Cheyenn Prairie Generating Station

Christopher Razzazian to: Mark.Lux, Tim.Rogers, Tim.Mordhorst, Fred.Carl, Jason.Hartman, George.Tatar — 05/18/2012 10:57 AM

Bcc: Sara Laumann, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US

To: Mark.Lux@blackhillscorp.com, Tim.Rogers@blackhillscorp.com, Tim.Mordhorst@blackhillscorp.com, Fred.Carl@blackhillscorp.com, Jason.Hartman@blackhillscorp.com, George.Tatar@blackhillscorp.com

Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Gentlemen -

Good morning. Please see attached our letter to Mr. Lux, and the enclosed documents including the public notice (to run on Monday in the Wyoming Tribune), SOB, and Draft Permit.

Cheyenne Light, Fuel & Power - CPGS - 5-17-2012 cover letter to BHC.pdf

Cheyenne Light, Fuel & Power - CGS - public notice for draft PSD permit.pdf

Cheyenne Light, Fuel & Power - CPGS - DRAFT Permit.pdfCheyenne Light, Fuel & Power - CGS - DRAFT SOB.pdf

Don't hesitate to call with any questions or concerns. Hard copy is in the mail to Mr. Lux, however it is unclear whether it will arrive by Monday morning.

Thank you so much for working with us.

Christopher Razzazian
US EPA Region 8
(303)312-6648
razzazian.christopher@epa.gov

RE: Black Hills Corporation information request
Rogers, Tim to: Christopher Razzazian 05/11/2012 09:51 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Alright – let me know if you need anything from our end. Looking forward to seeing a draft. Have a good weekend.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

From: Christopher Razzazian [mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Friday, May 11, 2012 9:37 AM
To: Rogers, Tim
Subject: Re: Black Hills Corporation information request

Thanks Tim,

I thought it was 625, but one of the old emails had 629 so just had to triple check. Almost there!

Chris

Black Hills Corporation information request
Rogers, Tim to: Christopher Razzazian 05/10/2012 06:30 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to.

Chris,

I've been out of town for two days in Gillette – here is the information you requested.

George Tatar
DIRECTOR of GENERATION OPERATIONS II
719-696-3217

Addresses:

Black Hills Corporation
625 9th Street
Rapid City, SD 57701

Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Re: Black Hills Power, Cheyenne Prairie Generating Station
Christopher Razzazian to: Richard Currit 05/09/2012 02:59 PM
Bcc: Sara Laumann, Deirdre Rothery, Mike Owens

From: Christopher Razzazian/R8/USEPA/US
To: Richard Currit <richard.currit@wyo.gov>
Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA

Hello Mr. Currit,

Just left you a voicemail as well. Would like to chat with you prior to all this needing to be transmitted and finalized.

The permit is scheduled to be public noticed on 5/21/2012 for thirty days, however if our letter were to be sent after that date we realize you would still be afforded a 30 day comment period if needed.

Thus far I searched the online registry (produced a list with distances to the plant site) and found nothing that could be affected. The site specific survey identified a ditch and two artifacts. I would like to get your opinion on whether the ditch needs any special treatment. My understanding is that Black Hills Corp., would not be disturbing that area.

Thanks you very much for reaching out to me.

Sincerely,

Christopher Razzazian
(303)312-6648
(303)941-1796

-----Richard Currit <richard.currit@wyo.gov> wrote: -----
To: Christopher Razzazian/R8/USEPA/US@EPA
From: Richard Currit <richard.currit@wyo.gov>
Date: 05/09/2012 12:52PM
Subject: Re: Black Hills Power, Cheyenne Prairie Generating Station

Hi Christopher,

It's been about a month since we last emailed. I've received the industrial siting application, but am unable to review or comment on it until we have completed the Section 106 consultation. When might I expect a letter from your office with EPA's comments on the report and determinations of eligibility and effect?

Sincerely,

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-5497

On Tue, Apr 10, 2012 at 3:29 PM, Christopher Razzazian <Razzazian.Christopher@epamail.epa.gov> wrote:

Great,

I've been trying to get in touch with your office for quite some time. I have completed a search of the registry and Black Hills has conducted a site evaluation. I will be contacting you soon to hammer this out.

Thank you,

Christopher Razzazian

Richard Currit ---04/10/2012 01:00:40 PM---Mr. Razzazian, Our office has received information from Black Hills Power, Inc., regarding

From: Richard Currit <richard.currit@wyo.gov>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 04/10/2012 01:00 PM
Subject: Black Hills Power, Cheyenne Prairie Generating Station

Mr. Razzazian,

Our office has received information from Black Hills Power, Inc., regarding the Cheyenne Light, Fuel & Power Company, Cheyenne Prairie Generating Station. According to the information from Black Hills Power you are the EPA contact for this project. This note is just to inform you that I will be the SHPO reviewer for the EPA's compliance with Section 106 of the National Historic Preservation Act, and that you may address your consultation with our office under that act to me.

I look forward to further consultation with your office concerning this project. If you have any questions, do not hesitate to contact me.

Sincerely,

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-5497

E-Mail to and from me, in connection with the transaction of public business, is subject to the Wyoming Public Records Act and may be disclosed to third parties.

Re: Black Hills Power, Cheyenne Prairie Generating Station
Richard Currit to: Christopher Razzazian 05/09/2012 12:52 PM

From: Richard Currit <richard.currit@wyo.gov>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to.

Hi Christopher,

It's been about a month since we last emailed. I've received the industrial siting application, but am unable to review or comment on it until we have completed the Section 106 consultation. When might I expect a letter from your office with EPA's comments on the report and determinations of eligibility and effect?

Sincerely,

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-5497

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Thank you,

Christopher Razzazian

Richard Currit ---04/10/2012 01:00:40 PM---Mr. Razzazian, Our office has received information from Black Hills Power, Inc., regarding

From: Richard Currit <richard.currit@wyo.gov>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 04/10/2012 01:00 PM
Subject: Black Hills Power, Cheyenne Prairie Generating Station

Mr. Razzazian,

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I look forward to further consultation with your office concerning this project. If you have any questions, do not hesitate to contact me.

Sincerely,

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-5497

E-Mail to and from me, in connection with the transaction of public business, is subject to the Wyoming Public Records Act and may be disclosed to third parties.

FW: CPGS

Rogers, Tim to: Christopher Razzazian 05/07/2012 10:03 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

FYI - no address at the present time. My Plant Engineer is putting all the weight on my shoulders.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

From: Hartman, Jason
Sent: Monday, May 07, 2012 9:58 AM
To: Rogers, Tim; Tatar, George
Subject: RE: CPGS

We will not have an address until we record the final plat, which won't happen until we close on the purchase of the land, which won't happen until we get the air permit...

From: Rogers, Tim
Sent: Monday, May 07, 2012 9:51 AM
To: Tatar, George; Hartman, Jason
Subject: CPGS

Good Morning,

Do we have a plant address for the site? EPA is asking.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

FW: Emailing: SNL (EPA's CO2 Emissions Rule)
Rogers, Tim to: Christopher Razzazian 05/03/2012 03:51 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been forwarded.

Chris – I have not read the entire report yet, but thought I would send your way.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

From: Finley, Steven
Sent: Thursday, May 03, 2012 7:07 AM
To: Rogers, Tim; Mordhorst, Tim; Carl, Fred
Subject: Emailing: SNL (EPA's CO2 Emissions Rule)

SNL

SNLFinancial

Wednesday, May 02, 2012 5:51 PM ET Exclusive
Study: Smaller-than-expected number of gas plants would meet EPA's CO2 emissions rule

By Jonathan Crawford
The U.S. EPA's proposed carbon dioxide emissions standards for new power plants may affect more recently constructed natural gas-fired plants than estimated by the agency, according to a new study by the University of California Center for Energy and Environmental Economics.
While the EPA reported that 95% of combined-cycle gas turbine units that began operations between 2006 and 2010 would meet the 1,000 pounds of CO2 per megawatt-hour standard that the agency proposed, an analysis of actual emissions and self-reported generation shows that 84% of such power plants would meet the standard, the study's authors explained in their report, "How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?"
The study examined three years of CO2 emissions of combined-cycle gas turbine units that began operations between 2006 and 2010 to understand how the standards could affect generating units that are modified and become subject to the standard under the Clean Air Act's New Source Review provisions.
"If you want to know how stringent the rules are based on how power plants are constructed in the next few years, the best way is to look at the ones most recently constructed," said Matthew Kotchen, co-author of the study and an associate professor of environmental economics and policy at Yale University.
The report revealed that 71% of combined-cycle gas turbine units slated for construction through 2017 would meet the emissions target because of a trend toward smaller capacity. The authors predicted that such units with a generating capacity of 226 MW or less would fail to meet the standard. Power plants that fail to meet the standard would potentially need to employ carbon capture and storage, which has not been demonstrated on a large scale and is deemed prohibitively expensive.
The EPA's impact analysis, however, does not appear to reflect such a level of noncompliance. The agency contends that its rule will impose few costs on the power sector as the standard generally reflects the emissions profile of an efficient combined-cycle gas turbine. Combined-cycle gas turbines, which are used for

baseload generation, are generally more efficient than other types of plants as they produce additional electricity through driving a steam turbine from exhaust heat.

Kotchen noted his study's analysis does not account for the possibility that operators will adjust their power plant operations to meet the standard. As natural gas becomes cheaper, it will be more economical to run gas-fired power plants at higher utilization rates, which in turn will make it easier to comply with the proposed standards, he said.

"That 71% level is the worst case scenario. As power plants adjust their operations, I would expect that number to get quite a bit higher," he said.

While the proposed rule exempts such facilities that are used for meeting peak demand, only 10% of simple-cycle gas turbine units that began operations between 2006 and 2010 would be able to comply without additional measures.

Consistent with projections by the EPA and industry, the report found that no coal units would comply with the annual target without use of carbon capture and storage. The report analyzed CO_2 emissions data for 2008, 2009 and 2010. Data was collected from the EPA's Continuous Emissions Monitoring System program as well as data on power plants from the U.S. Energy Information Administration.

The University of California Center for Energy and Environmental Economics is a joint venture of the University of California Energy Institute and the University of California Santa Barbara Bren School of Environmental Science and Management.

Black Hills - Cheyenne Prairie Generating Station - Black Hills ES Summary Report on USFWS ES Concerns

Rogers, Tim to: Christopher Razzazian 05/03/2012 09:46 AM

Cc: "Carl, Fred", "Arfmann, Dennis" , "Joe.Hammond@ch2m.com" , "Matt.Kizlinski@CH2M.com", "Hartman, Jason", "Tatar, George" , "Rogers, Tim"

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

Cc: "Carl, Fred" <Fred.Carl@blackhillscorp.com>, "Arfmann, Dennis" <dennis.arfmann@hoganlovells.com>, "Joe.Hammond@ch2m.com" <Joe.Hammond@ch2m.com>, "Matt.Kizlinski@CH2M.com" <Matt.Kizlinski@CH2M.com>,

History: This message has been replied to and forwarded.

Chris,

Another action item from our April 24, 2012 meeting was for Black Hills to provide a summary of measures taken or planned to address USFWS endangered species concerns. This document is attached – it basically provides an update to our March 2, 2012 letter. I am also taking this opportunity to package all of the associated endangered species documents in one email to assist with your response to USFWS.

- May 3, 2012 - Black Hills summary of measures to address USFWS and EPA concerns related to endangered species.
- April 16, 2012 – CH2MHILL – Raptor and Prairie Dog Survey.
- March 2, 2012 – BHC letter addressing USFWS endangered species concerns.
- February 14, 2012 – WEST, Inc. Evaluation of Endangered Species as it is related to the CPGS.
- Black Hills – Wyoming Avian Protection Plan

If you have question, please call. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2012-05-03_Supp_BHC measures to address USFWS Species List for EPA .pdf

2012-04-19_Report_Raptor Nest and Prairie Dog Survey.pdf

2012-03-02_Letter_ESA BA Study to EPA.pdf

2012-02-14_Final Report_West ESA.pdf

E-01-01-02-WY Avian Protection FINAL 2011-09-06 Revised.pdf

Black Hills: Cheyenne Prairie Generating - Comments on CO2 BACT limits in permit

Rogers, Tim to: Christopher Razzazian 05/03/2012 09:14 AM

Cc: "Carl, Fred", "Arfmann, Dennis" , "Joe.Hammond@ch2m.com" , "Gordon.Schott@CH2M.com", "Doug.Huxley@CH2M.com", "Mordhorst, Tim" , "Finley, Steven" , Deirdre Rothery, Christian

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Carl, Fred" <Fred.Carl@blackhillscorp.com>, "Arfmann, Dennis" <dennis.arfmann@hoganlovells.com>, "Joe.Hammond@ch2m.com" <Joe.Hammond@ch2m.com>, "Gordon.Schott@CH2M.com" <Gordon.Schott@CH2M.com>,
History:	This message has been replied to.

Chris,

One of the action items from our April 24, 2012 meeting was for Black Hills to provide further analysis on our justification for the CO_2 BACT limits (simple and combined cycle) we proposed in the permit application. The analysis also includes discussion on our ability to comply with the EPA's proposed NSPS limit (1000 CO_2 lb/MWh).

Hard copy is in the mail. Please call if you have any questions. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2012-05-03_Letter_EPA GHG PSD Comments on CO2 BACT.pdf

The BACT write-up is taking longer than I wanted - it will be coming as will the other info we discussed Friday - thanks.

Rogers, Tim to: Christopher Razzazian 04/30/2012 10:49 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been replied to.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Accepted: GHG PSD - Black Hills Cheyenne Prairie Generating Station
Tue 04/24/2012 2:00 PM - 4:00 PM

Location: EPA Conf. Center 2nd floor ASPEN ROOM - Call in # 1-866-299-9141 Passcode:

Tim.Rogers@blackhillscorp.com "Rogers, Tim" has accepted this meeting invitation	
Required:	April Nowak/R8/USEPA/US@EPA, Christian Fellner/RTP/USEPA/US@EPA, Dave Svendsgaard/RTP/USEPA/US@EPA, David Painter/RTP/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Sara
Optional:	Carl Daly/R8/USEPA/US@EPA

Portions of this document redacted. Personal privacy.

RE: Agenda for Meeting April 24, 2012
Rogers, Tim
to:
Christopher Razzazian
04/23/2012 11:01 AM
Hide Details
From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been forwarded.

1 Attachment

EPA Pre-PN Meeting April 24, 2012_final.doc

Chris,

Must have been the Friday rush to get out of the Office. Here you go.

303 - 844 – 0154 – is this the call-in number. If it would work better, I could use my call in card and set up a conference call. I could then distribute that number to the group.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Agenda

EPA – State – BHC Meeting
April 24, 2012 (2:00 pm to 4:00 pm)
Bighorn Room, EPA Region VIII – Denver, CO

Planned attendees:
BHC: Tim Rogers, Joe Hammond – CH2MHILL, Dennis Arfmann – Legal
EPA: Chris Razzazian, Deirdre Rothery, Mike Owens, Carl Daly, Sara Laumann, J.D.
State: Andrew Keyfauver, Cole Anderson (tentative), Nancy Vehr, AAG

2:00 pm Introductions
2:10 pm Topics for Discussion

EPA Update on GHG PSD Permit Review Status

GHG BACT Limits
- Two efficiency limits (CO2 lbs/MW-hr and Btu/kW-hr)
- Level of CO2 lbs/MW-hr in permit – BHC proposed 1100 and EPA proposed 1000.

Endangered Species Review
- EPA indicated no need for USFWS Consultation

Historical, Cultural, and Archaeological Assessment.
- EPA to send letter to SHPO providing their assessment and asking for the State's comments.

Environmental Justice – Disadvantaged Areas
- EPA recommended more public notice
- Wyoming vs National Database
- Discussion on Public Notice

3:00 pm

Conference Call State into meeting:

EPA update on GHG PSD Permit Review and Date they will be prepared to PN

State update on PSD Permit Review and Date they will be prepared to PN

Discussion on Coordinated Effort to PN Proposed AQ Permits
- Anticipated PN Date
- Newspapers
- Pre-emptive Hearing Date

Black Hills Power, Cheyenne Prairie Generating Station
Richard Currit to: Christopher Razzazian 04/10/2012 01:00 PM

From: Richard Currit <richard.currit@wyo.gov>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to.

Mr. Razzazian,

Our office has received information from Black Hills Power, Inc., regarding the Cheyenne Light, Fuel & Power Company, Cheyenne Prairie Generating Station. According to the information from Black Hills Power you are the EPA contact for this project. This note is just to inform you that I will be the SHPO reviewer for the EPA's compliance with Section 106 of the National Historic Preservation Act, and that you may address your consultation with our office under that act to me.

I look forward to further consultation with your office concerning this project. If you have any questions, do not hesitate to contact me.

Sincerely,

Richard L. Currit
Senior Archaeologist
Wyoming State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-5497

RE: Black Hills Corporation: Cheyenne Prairie Generating Station - Cultural Resource Survey - January 2012

Rogers, Tim to: Christopher Razzazian 03/28/2012 08:54 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to.

Chris,

My error – 220 MW.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

From: Christopher Razzazian [mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Wednesday, March 28, 2012 8:53 AM
To: Rogers, Tim
Subject: Re: Black Hills Corporation: Cheyenne Prairie Generating Station - Cultural Resource Survey - January 2012

Tim,

Thanks for including me in that email and I will follow up with their office . Much appreciated.

I noticed you said 240 MW. That's a change from the 220 we had before. Can you confirm?

Thanks so much and hope you're having a good day.

Chris

Black Hills Corporation: Cheyenne Prairie Generating Station - Cultural Resource Survey - January 2012
Rogers, Tim to: mary.hopkins@wyo.gov 03/27/2012 05:13 PM
Cc: "Rogers, Tim", Christopher Razzazian

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	"mary.hopkins@wyo.gov" <mary.hopkins@wyo.gov>
Cc:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>, Christopher Razzazian/R8/USEPA/US@EPA
History:	This message has been replied to.

Hi Mary,

Thanks for the insight on the Cultural Resource review process in our phone conversation today. As I discussed on the phone, Black Hills is in the process of permitting the Cheyenne Prairie Generating Station. This will be Natural Gas Combustion Turbine project designed to generate 240 MW of electricity and will be located in the Southeast portion of Cheyenne on the south-side of I-18 close immediately west of the Dry Creek Waste Water Treatment Plant.

As explained, we need to obtain an air quality permit from WDEQ and EPA (Region VIII in Denver). We are required to obtain an Air Quality Greenhouse Gas permit from EPA because the State of Wyoming elected not to regulate Greenhouse Gas emissions. Since we are obtaining a permit from a Federal Agency, we need to conduct a Cultural Resource Review on the site. You have not received requests like this from EPA in the past since the decision not to address Greenhouse Gas emissions was decided last year. It is my understanding that the legislature is reversing this decision this year.

Attached is the Cultural Resource Survey. If you have any questions concerning the report, please feel free to contact me. I will send a hard copy in the mail as well.

EPA will need to conduct the consultation, as you indicated in our phone conversation. The EPA contact is Chris Razzazian and Chris has received a copy of the survey. I have included him on the Email to facilitate the communications. Here is his full contact information. My information is below his. Also – you will be reviewing the same report through the Industrial Siting Permit process with WDEQ. Thanks again – hope to hear from you soon.

Chris Razzazian
USEPA Region 8
1595 Wynkoop Street
Mail Code 8P-AR
Denver, CO 80202-1129

Chris's Phone number (303) 312-6648

Tim Rogers, Environmental Manager
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709

(605) 721-2286 - work
(605) 484-0134 - cell

2012-01-23_Report_CPGS Cultural Resouce Survey.pdf

Re: Also sending word version of letter in the event you want to extract verbiage from it.
Christopher Razzazian to: Rogers, Tim 03/05/2012 09:35 AM

From:	Christopher Razzazian/R8/USEPA/US
To:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

Excellent! Thanks Tim,

Will review and call you. Have a wonderful day.

Chris

"Rogers, Tim" Tim Rogers Environmental Services 03/02/2012 03:40:50 PM

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Date:	03/02/2012 03:40 PM
Subject:	Also sending word version of letter in the event you want to extract verbiage from it.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

[attachment "2012-03-01_Draft_CPGS EPA Cover Letter (final).docx" deleted by Christopher Razzazian/R8/USEPA/US]

Also sending word version of letter in the event you want to extract verbiage from it.

Rogers, Tim to: Christopher Razzazian 03/02/2012 03:40 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been replied to and forwarded.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2012-03-01_Draft_CPGS EPA Cover Letter (final).docx

BHC Cheyenne Prairie Generating Station - ESA Biological Assessment for EPA GHG PSD Permit

Rogers, Tim to: Christopher Razzazian 03/02/2012 03:39 PM

Cc: "Rogers, Tim", "Joe.Hammond@ch2m.com" , "Matt.Kizlinski@CH2M.com", "Tatar, George", "Hartman, Jason"

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>, "Joe.Hammond@ch2m.com" <Joe.Hammond@ch2m.com>, "Matt.Kizlinski@CH2M.com" <Matt.Kizlinski@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason"

History: This message has been forwarded.

Chris,

This is the Biological Assessment for the BHC Cheyenne Prairie Generating Station. The cover letter ties together the ESA BA report, BHC WY Avian Protection Plan, and discussions/resolutions with USFWS. We hope this information is useful in your ESA consultation with the Service. If you have any questions, please call. Thanks.

P.S. The attached information has been sent hard copy.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2012-03-02_Letter_ESA BA Study to EPA.pdf

2012-02-14_Final Report_West ESA.pdf

E-01-01-02-WY Avian Protection FINAL 2011-09-06 Revised.pdf

RE: Black Hills Corporation - Cheyenne Prairie Generating Station - EPA-GHG Permit - SF6 electrical containing equipment

Rogers, Tim to: Christopher Razzazian 02/17/2012 12:11 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Chris,

It was good. Definitely provided a clearer direction on what they are looking for and what they want. The word for the day was "avoidance". I am working with my operations people to see if can make "avoidance" happen. If we can, that is what we will transmit to you with the report.

Have a good weekend as well - don't believe we have President's Day off - need to check.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Christopher Razzazian [mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Friday, February 17, 2012 11:04 AM
To: Rogers, Tim
Subject: Re: Black Hills Corporation - Cheyenne Prairie Generating Station - EPA-GHG Permit - SF6 electrical containing equipment

Thank you very much Tim. How did your meeting go yesterday?

Have a good weekend and Presidents' Day.

Chris

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: "Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason" <Jason.Hartman@blackhillscorp.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Date: 02/17/2012 10:52 AM
Subject: Black Hills Corporation - Cheyenne Prairie Generating Station - EPA-GHG Permit - SF6 electrical containing equipment

Chris,

There will be 9 breakers containing SF6 associated with the switchyard at the Cheyenne Prairie Generating Station. All breakers associated with the generators are vacuum breakers (no SF6). Therefore all SF6 breakers are associated with the switchyard.

Each switchyard breaker will have 60 pounds (9 breakers X 60 lbs) of SF6 for a total of 540 lbs. The manufacturer guaranteed leak rate is 1%. This would correlate to a leakage rate of 5.4 lbs per year.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

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Black Hills Corporation - Cheyenne Prairie Generating Station - EPA-GHG Permit - SF6 electrical containing equipment
Rogers, Tim to: Christopher Razzazian 02/17/2012 10:52 AM
Cc: "Joe.Hammond@CH2M.com", "Tatar, George" , "Hartman, Jason" , "Tatar, George" , "Rogers, Tim"

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason" <Jason.Hartman@blackhillscorp.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>,
History:	This message has been replied to.

Chris,

There will be 9 breakers containing SF6 associated with the switchyard at the Cheyenne Prairie Generating Station. All breakers associated with the generators are vacuum breakers (no SF6). Therefore all SF6 breakers are associated with the switchyard.

Each switchyard breaker will have 60 pounds (9 breakers X 60 lbs) of SF6 for a total of 540 lbs. The manufacturer guaranteed leak rate is 1%. This would correlate to a leakage rate of 5.4 lbs per year.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

RE: Cheyenne Prairie Generating Station - Environmental Justice Study and Cultural Resources Report
Rogers, Tim to: Christopher Razzazian 02/07/2012 04:46 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been replied to.

Chris,

You are welcome. Avian will be addressed in the ESA and transmittal letter with ESA - coming soon.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Christopher Razzazian [mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Tuesday, February 07, 2012 4:39 PM
To: Rogers, Tim
Subject: Re: Cheyenne Prairie Generating Station - Environmental Justice Study and Cultural Resources Report

Thanks Tim,

I will be looking at this as soon as I can. Does this include the avian plan as well?

Thanks so much Tim!

Chris

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: "Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Matt.Kizlinski@CH2M.com" <Matt.Kizlinski@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason" <Jason.Hartman@blackhillscorp.com>, "Carl, Fred" <Fred.Carl@blackhillscorp.com>
Date: 02/07/2012 02:48 PM
Subject: Cheyenne Prairie Generating Station - Environmental Justice Study and Cultural Resources Report

Chris,

Enclosed, you will find the Environmental Justice Study and the Cultural Resources Report (and the transmittal letter) for the Cheyenne Prairie Generating Station in Cheyenne. In the very near future, we will send the ESA report with a transmittal letter discussing how we will address the findings in the report.

FYI - All of the documents in this email have been sent in today's mail.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

[attachment "2012-02-07_Letter_EJ and Cultural Study to EPA.pdf" deleted by Christopher Razzazian/R8/USEPA/US] [attachment "2012-02-01_Memo_CPGS EJ Study.pdf" deleted by Christopher Razzazian/R8/USEPA/US] [attachment "2012-01-23_Report_CPGS Cultural Resouce Survey.pdf" deleted by Christopher Razzazian/R8/USEPA/US]

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Cheyenne Prairie Generating Station - Environmental Justice Study and Cultural Resources Report

Rogers, Tim to: Christopher Razzazian 02/07/2012 02:48 PM

Cc: "Joe.Hammond@CH2M.com", "Matt.Kizlinski@CH2M.com" , "Tatar, George", "Hartman, Jason", "Carl, Fred"

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Matt.Kizlinski@CH2M.com" <Matt.Kizlinski@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason" <Jason.Hartman@blackhillscorp.com>, "Carl, Fred" <Fred.Carl@blackhillscorp.com>
History:	This message has been replied to and forwarded.

Chris,

Enclosed, you will find the Environmental Justice Study and the Cultural Resources Report (and the transmittal letter) for the Cheyenne Prairie Generating Station in Cheyenne. In the very near future, we will send the ESA report with a transmittal letter discussing how we will address the findings in the report.

FYI - All of the documents in this email have been sent in today's mail.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2012-02-07_Letter_EJ and Cultural Study to EPA.pdf 2012-02-01_Memo_CPGS EJ Study.pdf

2012-01-23_Report_CPGS Cultural Resouce Survey.pdf

Re: Black Hills - Cheyenne Prairie Generating Station - Response to inquires on general information
Christopher Razzazian to: Rogers, Tim 01/24/2012 05:47 PM
Bcc: Sara Laumann, Mike Owens

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc: Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA

Thanks Tim, really appreciate. Will get back to you if anything comes up with this info during the data entry. Also Carl touched base with WDEQ about your timing question, but Steve D. wasn't available to chat at the time. Hold tight if you can, I'll let you know as soon as I do.

Thanks again,

Chris

"Rogers, Tim" Chris, Below are the responses to some of the g... 01/24/2012 05:25:18 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Date: 01/24/2012 05:25 PM
Subject: Black Hills - Cheyenne Prairie Generating Station - Response to inquires on general information

Chris,

Below are the responses to some of the general information for the facility you asked for at our January 17, 2012 meeting. There will be a joint ownership of this facility between two subsidiaries of Black Hills Corporation (Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company). We would prefer that the joint ownership be represented. Understanding that the database may not accept this – then Black Hills Corporation should be listed. If you have questions, please call.

Facility ID: Assigned by EPA or State
AFS: Assigned by EPA or State
Facility Name: Cheyenne Prairie Generating Station
NAICS: 221112
SIC: 4911
State: Wyoming
Reservation: NA
Lat Long: 41° 07' 27.83" N, 104° 43' 13.34" W, Center of facility
Section, T, R: T13N, R66W, Section 1, Laramie County, – centroid
Operator: Black Hills Service Company, LLC
Owner: Joint Ownership: Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company
Owner Address: P.O. Box 1400, Rapid City, SD 57709, physical address 629 9th Street, Rapid City, SD 57701
Contact (permit): Tim Rogers, 605-721-2286
Operator (facility): Not known at this time
Responsible Official: Mark Lux, Vice President and General Manager of Power Delivery 303-568-3241
Alternate: George Tater, Director of Generation Operations II

Tim Rogers

Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Black Hills - Cheyenne Prairie Generating Station - Response to inquires on general information
Rogers, Tim
to:
Christopher Razzazian
01/24/2012 05:25 PM
Cc:
"Rogers, Tim"
Hide Details
From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

History: This message has been replied to.

Chris,

Below are the responses to some of the general information for the facility you asked for at our January 17, 2012 meeting. There will be a joint ownership of this facility between two subsidiaries of Black Hills Corporation (Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company). We would prefer that the joint ownership be represented. Understanding that the database may not accept this – then Black Hills Corporation should be listed. If you have questions, please call.

Facility ID:	Assigned by EPA or State
AFS:	Assigned by EPA or State
Facility Name:	Cheyenne Prairie Generating Station
NAICS:	221112
SIC:	4911
State:	Wyoming
Reservation:	NA
Lat Long:	41^{o} 07' 27.83" N, 104^{o} 43' 13.34" W, Center of facility
Section, T, R:	T13N, R66W, Section 1, Laramie County, – centroid
Operator:	Black Hills Service Company, LLC
Owner:	Joint Ownership: Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company
Owner Address:	P.O. Box 1400, Rapid City, SD 57709, physical address 629 9th Street, Rapid City, SD 57701
Contact (permit):	Tim Rogers, 605-721-2286
Operator (facility):	Not known at this time
Responsible Official:	Mark Lux, Vice President and General Manager of Power Delivery 303-568-3241
Alternate:	George Tater, Director of Generation Operations II

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Re: Cheyenne Prairie Generating Station - EPA GHG - Question on Operational Situations
Christopher Razzazian to: Rogers, Tim 01/11/2012 10:17 AM
Bcc: Sara Laumann, Mike Owens, Deirdre Rothery

From:	Christopher Razzazian/R8/USEPA/US
To:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc:	Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Thank you Tim,

I think I can address the scenario. I'm glad the conversation came up earlier rather than later.

Thanks again,

Chris

"Rogers, Tim" Chris, In our last conversation, you asked wheth... 01/11/2012 09:52:00 AM

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>, "Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Hartman, Jason" <Jason.Hartman@blackhillscorp.com>
Date:	01/11/2012 09:52 AM
Subject:	Cheyenne Prairie Generating Station - EPA GHG - Question on Operational Situations

Chris,

In our last conversation, you asked whether we would operate the simple cycle combustion turbine units associated with the combined cycle steam generator in simple cycle mode. The response is yes. If there was a problem with the steam turbine generator, the steam generated by the HRSGs (Heat Recovery Steam Generator), using heat from the gas turbine exhaust, would be diverted to the water-cooled condenser. Thus, there would be no MW generation from the steam turbine generator. This essentially would be equivalent to simple cycle operation.

The question was in reference to our CO_2 (GHG) lb/MWhr proposed efficiency limit. The proposed limit for the combined cycle operation is 1100 lb/MWhr and the proposed limit for the simple cycle units is 1600 lb/MWhr.

Issue: Due to the loss of the megawatts from the steam turbine generator not operating, we may potentially be in violation with a combined cycle limit of 1100 lb/MWhr, in this scenario, due to the loss of megawatts from the steam turbine generator in the denominator of the equation for the CO_2 limit. A smaller denominator will make our emissions higher.

Requested Remedy: Black Hills proposes to incorporate an Alternative Operating Scenario in the permit to specify the combined cycle combustion turbines will be subject to the 1600 lb/MWhr limit when the steam turbine generator is not operational or is not capable of generating megawatts.

Notes

1. We will still be generating the same amount of CO_2 in mass regardless of whether the combined cycle steam turbine is operating or not.
2. It is actually to our disadvantage not to be operating the steam turbine generator due to the loss of

MW generation (something we would want to avoid), but we need to account for this scenario if the steam turbine generator is not operational.

I will follow-up with a call. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Cheyenne Prairie Generating Station - Combined Cycle Question
Rogers, Tim
to:
Christopher Razzazian
12/22/2011 07:08 AM
Cc:
"Rogers, Tim"
Hide Details
From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

History: This message has been replied to.

Chris,

In a conversation we had a week ago, you asked a question about the operation of the combined cycle. If I recall correctly, the question was – can the combined cycle system operate with just one LM6000 turbine operating. This was discussed with our operations staff and the answer is yes. The combined cycle system can operate with just one LM6000 turbine operating. Let me know if that answers the question or if this sparks any other questions.

My plans were to get down to Denver before years end to meet and discuss any further issues and timing of permit actions (your internal review, our review, and PN), but that is not going to happen – just running out of time with end of the year deadlines. I would like to shoot for the first part of January – if that would work for you. I guess I am assuming we will get to review your proposed permit before going out to PN. This process is new to us. Will that be the case?

I will call today to open discussions on the reason I would like to meet on permit actions.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

RE: turbine heat rate
Rogers, Tim to: Christopher Razzazian 12/13/2011 11:14 AM
Cc: "Joe.Hammond@CH2M.com"

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>
History:	This message has been replied to.

Chris,

It should have been 366 MMBtu/hr instead of 366 btu/hr for Heat Input on page 5.3 table 5-2.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Tuesday, December 13, 2011 10:41 AM
To: Rogers, Tim
Subject: turbine heat rate

Hi Tim,

I'm writing limits this morning :)

Do you think the application meant to list the turbines at 366 MBtu/hr or is it really 366 Btu/hr (page 5-3 of the revised version)?

I did a calculation of 9263 Btu/kWh (your requested heat rate limit) and multiplied that by the gen capacity of 37100 kWh/hr to get 343 MBtu/hr, so I would assume you meant million Btu (MBtu).

Also, since your heat rate limit in Btu/kWh results in a lower heat rate in Btu/hr than 366, would it be safe to say that your heat rate limit (of 9263 Btu/kWh or equivalently 343 MBtu/hr) is below the capacity of the turbine at 366 MBtu/hr?

Thanks Tim,

Chris

---

further reading.

RE: Response to Inquires
Rogers, Tim to: Christopher Razzazian 12/01/2011 09:59 AM
Cc: "Carl, Fred", "Joe.Hammond@CH2M.com" , "Doug.Huxley@CH2M.com", "Tatar, George", "Hartman, Jason"

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: "Carl, Fred" <Fred.Carl@blackhillscorp.com>, "Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Doug.Huxley@CH2M.com" <Doug.Huxley@CH2M.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason"

Chris - responses to your questions below.

1. In-let Heater: We need to bring the unit up to zero degrees F, when the ambient temperature is below zero degrees F, in order for GE emission limit guarantees to apply. A unit operator may operate the in-let heater to eliminate suspected icing on the unit at anytime for safety and to protect the integrity unit.

2. The 327 HP unit identified is the size needed for this facility. We don't anticipate the size of this unit changing, but if it does - we understand that we will need to submit an amendment to the permit or application. We appreciate your insight on the impacts with permitting in going with a higher HP unit. This has been brought to our operations awareness and they verified the 327 HP level needs.

We are still plugging away with the ESA and Cultural Assessment. I will keep you posted on progress and will forward final work products as received. We will also make a concerted effort to engage the SHPO with the EPA GHG permit requirements/approvals that we will need to obtain with our Industrial Siting Permit with the State of Wyoming on the cultural piece.

Thanks

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Wednesday, November 23, 2011 9:48 AM
To: Rogers, Tim
Subject: Re: Response to Inquires

Thanks Tim. Hope you have a good Holiday as well.

I appreciate your letter.

I have to say there are two questions that stem from this response letter though:

1. Regarding the use of the air heaters. It sounds like they are used anytime the outside air is less than zero degrees F. Is that what you meant?

2. With regard to the emergency generator, the info I need is more along the lines of - after considering all your options in the size ranges available what would the maximum power be (recall you have 327hp now). If all your options are at or below 327, then no change is necessary, I just need to know that. If any option would be above 327hp then we should quote that hp as a possibility.

Thanks for going through the LCRA permit. I agree with all of your comments.

Do you have any thoughts on the timing of your info responding to the expanded species listing for ESA, or news on contact with the SHPO? I know you mention in your letter that these will be coming.

Sincerely,

Christopher Razzazian
US EPA
(303)312-6648

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 11/22/2011 02:28 PM
Subject: Response to Inquires

Chris,

I have been keeping a cache of questions and discussions that we have had over the past two months. I wanted to follow-up in writing with responses to create a paper trail. The hard copy is in the mail, but I am sending a pdf version with the email.

Happy Thanksgiving - have a good weekend

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

[attachment "2011-11-22_Letter_Response to EPA Inquires.pdf" deleted by Christopher Razzazian/R8/USEPA/US]

Re: Response to Inquires

Christopher Razzazian to: Rogers, Tim 11/23/2011 09:48 AM

Bcc: Sara Laumann, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc: Sara Laumann/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Thanks Tim. Hope you have a good Holiday as well.

I appreciate your letter.

I have to say there are two questions that stem from this response letter though:

1. Regarding the use of the air heaters. It sounds like they are used anytime the outside air is less than zero degrees F. Is that what you meant?

2. With regard to the emergency generator, the info I need is more along the lines of - after considering all your options in the size ranges available what would the maximum power be (recall you have 327hp now). If all your options are at or below 327, then no change is necessary, I just need to know that. If any option would be above 327hp then we should quote that hp as a possibility.

Thanks for going through the LCRA permit. I agree with all of your comments.

Do you have any thoughts on the timing of your info responding to the expanded species listing for ESA, or news on contact with the SHPO? I know you mention in your letter that these will be coming.

Sincerely,

Christopher Razzazian
US EPA
(303)312-6648

"Rogers, Tim" Chris, I have been keeping a cache of questions... 11/22/2011 02:28:16 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 11/22/2011 02:28 PM
Subject: Response to Inquires

Chris,

I have been keeping a cache of questions and discussions that we have had over the past two months. I wanted to follow-up in writing with responses to create a paper trail. The hard copy is in the mail, but I am sending a pdf version with the email.

Happy Thanksgiving – have a good weekend

Tim Rogers
Environmental Services

(605) 721-2286 - work
(605) 484-0134 - cell

[attachment "2011-11-22_Letter_Response to EPA Inquires.pdf" deleted by Christopher Razzazian/R8/USEPA/US]

Response to Inquires
Rogers, Tim to: Christopher Razzazian 11/22/2011 02:28 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to and forwarded.

Chris,

I have been keeping a cache of questions and discussions that we have had over the past two months. I wanted to follow-up in writing with responses to create a paper trail. The hard copy is in the mail, but I am sending a pdf version with the email.

Happy Thanksgiving – have a good weekend

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2011-11-22_Letter_Response to EPA Inquires.pdf

RE: Black Hills Cheyenne Generating Station - EPA-PSD-GHG permit
Rogers, Tim to: Christopher Razzazian 10/12/2011 10:43 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Chris,

Will call tomorrow - Out all day with required supervision training today.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Tuesday, October 11, 2011 8:10 AM
To: Rogers, Tim
Subject: Re: Black Hills Cheyenne Generating Station - EPA-PSD-GHG permit

Sure does - I will remain consistent with your numbering.

Can we talk about fugitive methane sometime? I've been looking at a pre-draft permit that EPA is writing in another Region, and to be consistent I think we might want to say something about fugitive methane.

Is that something you've already thought about as far as piping, connections, etc., etc., - or - is it still a bit early to quantify?

Hope you're doing well.

Chris Razzazian
U.S. EPA
(303)312-6648

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Date: 10/09/2011 09:37 AM
Subject: Black Hills Cheyenne Generating Station - EPA-PSD-GHG permit

Chris,

Sources 12-13-14 are inlet chillers.
Source 17 is the wet cooling tower.

All non-greenhouse gas sources - you are correct that they will show up in the State application since they are PM sources and the GHG application is number the way it is to stay consistent with Criteria Pollutant application. Hope that answered your question, if not - let me know. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

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Black Hills Cheyenne Generating Station - EPA-PSD-GHG permit
Rogers, Tim to: Christopher Razzazian 10/09/2011 09:37 AM
Cc: "Rogers, Tim"

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
History:	This message has been replied to.

Chris,

Sources 12-13-14 are inlet chillers.
Source 17 is the wet cooling tower.

All non-greenhouse gas sources – you are correct that they will show up in the State application since they are PM sources and the GHG application is number the way it is to stay consistent with Criteria Pollutant application. Hope that answered your question, if not – let me know. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

RE: ESA Species List
Rogers, Tim to: Christopher Razzazian 09/26/2011 12:06 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Anytime - give me a call.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Monday, September 26, 2011 11:08 AM
To: Rogers, Tim
Cc: Rothery.Deirdre@epamail.epa.gov; Owens.Mike@epamail.epa.gov;
Laumann.Sara@epamail.epa.gov
Subject: RE: ESA Species List

Thanks Tim,

I'm wondering if there might be a need to have a quick conference call after our meeting tomorrow? I'll be getting back to you shortly.

thanks,

Chris

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Cc: Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA
Date: 09/26/2011 10:49 AM
Subject: RE: ESA Species List

Chris,

Thank you. As we discussed, we plan to have our consultant conduct an informal ESA assessment with intent to identify if we are going to run into any issues. Obviously, we will want to know if there are any issues and what we have to do to mitigate the issue - if possible. The work will be done in a Section 7 format. As this work product is completed, we will forward to you.

We understand EPA is the entity preparing the Section 7 review to Wyoming USFWS. Hopefully, this document will be of some use to you in preparing your analysis for the Wyoming USFWS.

Tim Rogers
Environmental Services
(605) 721-2286 - work

(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Monday, September 26, 2011 10:24 AM
To: Rogers, Tim
Cc: Laumann.Sara@epamail.epa.gov; Owens.Mike@epamail.epa.gov;
Rothery.Deirdre@epamail.epa.gov
Subject: ESA Species List

Hi Tim,

I received this species list from FWS several days ago. We are meeting tomorrow with several programs to discuss procedure.

Let's be in touch over the next few days.

Thanks so much,

Chris

(See attached file: Cheyenne Light, Fuel & Power - CGS - ESA Section 7 SPECIES LIST.pdf) (this is without signature, but the sent version has it, I just haven't pdfed that one as well yet. Let me know if you need the signed version).

This electronic message transmission contains information from Black Hills Corporation, its affiliate or subsidiary, which may be confidential or privileged. The information is intended to be for the use of the individual or entity named above. If you are not the intended recipient, be aware the disclosure, copying, distribution or use of the contents of this information is prohibited. If you received this electronic transmission in error, please reply to sender immediately; then delete this message without copying it or further reading.

RE: ESA Species List

Rogers, Tim to: Christopher Razzazian 09/26/2011 10:49 AM
Cc: Sara Laumann, Mike Owens, Deirdre Rothery

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
Cc:	Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

History: This message has been replied to.

Chris,

Thank you. As we discussed, we plan to have our consultant conduct an informal ESA assessment with intent to identify if we are going to run into any issues. Obviously, we will want to know if there are any issues and what we have to do to mitigate the issue - if possible. The work will be done in a Section 7 format. As this work product is completed, we will forward to you.

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Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Monday, September 26, 2011 10:24 AM
To: Rogers, Tim
Cc: Laumann.Sara@epamail.epa.gov; Owens.Mike@epamail.epa.gov;
Rothery.Deirdre@epamail.epa.gov
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Thanks so much,

Chris

(See attached file: Cheyenne Light, Fuel & Power - CGS - ESA Section 7 SPECIES LIST.pdf) (this is without signature, but the sent version has it, I just haven't pdfed that one as well yet. Let me know if you need the signed version).

ESA Species List
Christopher Razzazian to: Rogers, Tim 09/26/2011 10:24 AM
Cc: Sara Laumann, Mike Owens, Deirdre Rothery

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Cc: Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Deirdre Rothery/R8/USEPA/US@EPA

Hi Tim,

I received this species list from FWS several days ago. We are meeting tomorrow with several programs to discuss procedure.

Let's be in touch over the next few days.

Thanks so much,

Chris

Cheyenne Light, Fuel & Power - CGS - ESA Section 7 SPECIES LIST.pdf (this is without signature, but the sent version has it, I just haven't pdfed that one as well yet. Let me know if you need the signed version).

BHC -Cheyenne Generating Station - Revised EPA-PSD-GHG Application

Rogers, Tim to: Christopher Razzazian 09/26/2011 09:40 AM

Cc: "Carl, Fred", "Joe.Hammond@CH2M.com" , "Lux, Mark", "Tatar, George", "Hartman, Jason" , Carl Daly

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA

Cc: "Carl, Fred" <Fred.Carl@blackhillscorp.com>, "Joe.Hammond@CH2M.com" <Joe.Hammond@CH2M.com>, "Lux, Mark" <Mark.Lux@blackhillscorp.com>, "Tatar, George" <George.Tatar@blackhillscorp.com>, "Hartman, Jason"

History: This message has been replied to and forwarded.

Good morning Chris,

Attached please find the revised BHC Cheyenne Generating Station EPA-PSD-GHG Application. I am also attaching a tracked changes application that shows the changes made to the original application.

Joe Hammond with CH2MHill submitted hard copies via Fedex that should be in your office today. Five copies will be delivered to Carl Daly.

Our goal was to address items discussed in our face-to-face meeting and phone conversations – hopefully, we achieved that goal. Please call if you have questions.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

2011-09-23_Application_EPA GHG - Revised - Combined.pdf

2011-09-23_Application_Comparison between Original and Revised.pdf

Re: CGS ESA

Julie_Proell to: Christopher Razzazian 09/14/2011 08:04 AM

From: Julie_Proell@fws.gov
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been forwarded.

Hi, Chris,

Sorry about the delay. Here is the pdf without a signature. The official letter (with signature) is in the mail. Let me know if you have any questions.

~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Julie M. Proell
Fish and Wildlife Biologist (Energy)
5353 Yellowstone Road, Suite 308A
Cheyenne, WY 82009
(307) 772-2374 x 232
(307) 772-2358 fax
Julie_Proell@fws.gov

~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Razzazian.Christopher@epamail.epa.gov

09/13/2011 04:27 PM

To julie_proell@fws.gov
cc
Subject CGS ESA

Hi Julie,

Just wanted to make sure you had my email correctly. I don't see an email from you, so wanted to check.

Thanks again so much for all your time and effort in preparing this.

Yours,

Chris

WY11SL0365_jpCheyenneGeneratingStationBlackHillsPower.pdf

CGS ESA
Christopher Razzazian to: julie_proell 09/13/2011 04:27 PM

From: Christopher Razzazian/R8/USEPA/US
To: julie_proell@fws.gov

Hi Julie,

Just wanted to make sure you had my email correctly. I don't see an email from you, so wanted to check.

Thanks again so much for all your time and effort in preparing this.

Yours,

Chris

Cheyenne Generating Station - EPA/GHG/PSD CO2 CEM issue - 9:30 am meeting 9-2-2011

Rogers, Tim to: Christopher Razzazian, Mordhorst, Tim , Finley, Steven , Carl, Fred 09/01/2011 02:43 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Christopher Razzazian/R8/USEPA/US@EPA, "Mordhorst, Tim" <Tim.Mordhorst@blackhillscorp.com>, "Finley, Steven" <Steven.Finley@blackhillscorp.com>, "Carl, Fred" <Fred.Carl@blackhillscorp.com>

History: This message has been replied to and forwarded.

All – I sent out a meeting invite, but it came back as undeliverable. Our system may be having issues. Regardless, the meeting is scheduled for 9:30 am tomorrow. The call in number is below.

Call in number: 866-242-5249
Participant Code

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Portions of this document redacted. Personal privacy.

RE: ESA question
Christopher Razzazian to: Rogers, Tim 08/23/2011 02:04 PM
Bcc: julie_proell

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc: julie_proell@fws.gov

Thanks Tim,

I'll get back to you on whether we need anything further. Appreciate your quick response!

Chris

"Rogers, Tim" Chris, There are no existing infrastructure utilitie... 08/23/2011 01:56:01 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 08/23/2011 01:56 PM
Subject: RE: ESA question

Chris,

There are no existing infrastructure utilities powerlines, natural gas pipelines, or wastewater lines. We will be installing electrical transmission lines, natural gas pipeline (underground), and wastewater line (underground) to the wastewater treatment plant adjacent to the plant. We are 90% sure we are going to the wastewater plant at this time. One other option is to obtain a NPDES discharge permit and discharge to Crow Creek. We are investigating the ability to comply with in-stream standards on this one vs wastewater treatment plant standards - as well as cost.

We plan to use either Cit water or Wastewater plant water.

Let me know if you have any further questions. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell
-----Original Message-----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Monday, August 22, 2011 9:33 AM
To: Rogers, Tim
Subject: ESA question

Hi Tim,

US FWS has a question with regard to the ESA consultation, which I can't answer - can you? Thanks so much - Chris

Q: Are there existing electrical lines/gas pipelines or will that infrastructure be constructed with the facility? If you plan on constructing that, would you be able to provide some information on what will go in and where?

Thanks so much!

Chris

Re: ESA question
Rogers, Tim to: Christopher Razzazian 08/22/2011 10:55 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been forwarded.

Chris. I am on it. Tim.

----- Original Message -----
From: Razzazian.Christopher@epamail.epa.gov [
mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Monday, August 22, 2011 09:32 AM
To: Rogers, Tim
Subject: ESA question

Hi Tim,

US FWS has a question with regard to the ESA consultation, which I can't answer - can you? Thanks so much - Chris

Q: Are there existing electrical lines/gas pipelines or will that infrastructure be constructed with the facility? If you plan on constructing that, would you be able to provide some information on what will go in and where?

Thanks so much!

Chris

Re: Black Hills Section 7 ESA - Location from google earth with lat long
Julie_Proell to: Christopher Razzazian 08/22/2011 08:53 AM

From: Julie_Proell@fws.gov
To: Christopher Razzazian/R8/USEPA/US@EPA

Hi, Christopher,

One more thing - As I was reviewing the project site information, I realized that I am unaware of the existing or proposed infrastructure that will connect to and from the proposed facility. Do you know if there are existing electrical transmission lines and natural gas pipelines in the project area that the proposed facility will tie in to? If not, do you know of proposed lines?

Thanks!

~~~~~~~~~~~~~~~~~~
Julie M. Proell
Fish and Wildlife Biologist (Energy)
5353 Yellowstone Road, Suite 308A
Cheyenne, WY 82009
(307) 772-2374 x 232
(307) 772-2358 fax
Julie_Proell@fws.gov
~~~~~~~~~~~~~~~~~~

Razzazian.Christopher@epamail.epa.gov

08/17/2011 09:17 AM

To Julie_Proell@fws.gov
cc
Subject Re: Black Hills Section 7 ESA - Location from google earth with lat long

Thanks so much Julie,

That sounds good to me.

As far as current land use/habitat - I believe it is grassland with highway on one side and creek/river to the south. Keep in mind this source may or may not want to discharge water to the river before the treatment plant (I believe). At this point I don't have enough info to really assess temperature/flow impacts.

Thanks again,

Christopher Razzazian
Mechanical/Environmental Engineer
U.S. EPA, Region 8
Air Program
(303)312-6648

From: Julie_Proell@fws.gov
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 08/17/2011 07:57 AM
Subject: Re: Black Hills Section 7 ESA - Location from google earth with lat long

Hi, Christopher,

Sorry I missed your call - I was pulled into a meeting about a couple of wind development projects in the state. Donna and Jim in my office gave me the information that you gave to them yesterday.

Based on the address that you gave to Jim and the close-up maps that were included with the project description, I was able to determine the exact location of the project. That should be sufficient for me to determine which species might be within the proposed project area and generate a species list for you.

Then, based on the information that I provide to you, you or your biologists should make determinations of effects for each species that might be within the project area, and send that determination, with justification, to me so that I may concur or not concur with your determinations.

I may be pulled into another meeting today, but otherwise, I should be in the office until 3:15 and all day tomorrow. Please let me know if you have any more information to add, such as a description of the current land usage or habitat on-site, or questions regarding consultation under Section 7 of the ESA.

Thanks!

~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Julie M. Proell
Fish and Wildlife Biologist (Energy)
5353 Yellowstone Road, Suite 308A
Cheyenne, WY 82009
(307) 772-2374 x 232
(307) 772-2358 fax
Julie_Proell@fws.gov
~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Razzazian.Christopher@epama
il.epa.gov

08/16/2011 02:10 PM

To
julie_proell@fws.gov
cc

Subject
Black Hills Section 7 ESA - Location from google earth with lat long

Hi Julie,

Got your message - mine was a bit long. Give me a call and I can straighten out the location for you. Here it is below (the white area along the highway). The lat long listed in the window was for the center of the rectangle, but I suggest you verify for yourself. I could almost see the fence line in google earth that Black Hills shows in the application I sent. Anyway - give a call and we'll make sure you have the right location.

Thanks a bunch,

Chris(Embedded image moved to file: pic05000.gif)[attachment "pic05000.gif" deleted by Julie Proell/R6/FWS/DOI]

Wyoming State Historic Preservation Office
Rogers, Tim to: Christopher Razzazian 08/18/2011 12:16 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Mary Hopkins
Wyoming State Historic Preservation Office
Barrett Building - 3rd Floor
2301 Central Avenue
Cheyenne, WY 82002
(307) 777-7697

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Re: Black Hills Section 7 ESA - Location from google earth with lat long
Christopher Razzazian to: Julie_Proell 08/17/2011 09:17 AM

From: Christopher Razzazian/R8/USEPA/US
To: Julie_Proell@fws.gov

Thanks so much Julie,

That sounds good to me.

As far as current land use/habitat - I believe it is grassland with highway on one side and creek/river to the south. Keep in mind this source may or may not want to discharge water to the river before the treatment plant (I believe). At this point I don't have enough info to really assess temperature/flow impacts.

Thanks again,

Christopher Razzazian
Mechanical/Environmental Engineer
U.S. EPA, Region 8
Air Program
(303)312-6648

Julie_Proell | Hi, Christopher, Sorry I missed your call - I was... | 08/17/2011 07:57:20 AM

From: Julie_Proell@fws.gov
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 08/17/2011 07:57 AM
Subject: Re: Black Hills Section 7 ESA - Location from google earth with lat long

Hi, Christopher,

Sorry I missed your call - I was pulled into a meeting about a couple of wind development projects in the state. Donna and Jim in my office gave me the information that you gave to them yesterday.

Based on the address that you gave to Jim and the close-up maps that were included with the project description, I was able to determine the exact location of the project. That should be sufficient for me to determine which species might be within the proposed project area and generate a species list for you.

Then, based on the information that I provide to you, you or your biologists should make determinations of effects for each species that might be within the project area, and send that determination, with justification, to me so that I may concur or not concur with your determinations.

I may be pulled into another meeting today, but otherwise, I should be in the office until 3:15 and all day tomorrow. Please let me know if you have any more information to add, such as a description of the current land usage or habitat on-site, or questions regarding consultation under Section 7 of the ESA.

Thanks!

~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Julie M. Proell
Fish and Wildlife Biologist (Energy)
5353 Yellowstone Road, Suite 308A
Cheyenne, WY 82009
(307) 772-2374 x 232
(307) 772-2358 fax
Julie_Proell@fws.gov
~~~~~~~~~~~~~~~~~

Razzazian.Christopher@epamail.epa.gov
08/16/2011 02:10 PM

To julie_proell@fws.gov
cc
Subject Black Hills Section 7 ESA - Location from google earth with lat long

Hi Julie,

Got your message - mine was a bit long. Give me a call and I can straighten out the location for you. Here it is below (the white area along the highway). The lat long listed in the window was for the center of the rectangle, but I suggest you verify for yourself. I could almost see the fence line in google earth that Black Hills shows in the application I sent. Anyway - give a call and we'll make sure you have the right location.

Thanks a bunch,

Chris(Embedded image moved to file: pic05000.gif)[attachment "pic05000.gif" deleted by Julie Proell/R6/FWS/DOI]
~~~~~~~~~~~~~~~~~

Re: Black Hills Section 7 ESA - Location from google earth with lat long
Julie_Proell to: Christopher Razzazian 08/17/2011 07:57 AM

From: Julie_Proell@fws.gov
To: Christopher Razzazian/R8/USEPA/US@EPA
History: This message has been replied to and forwarded.

Hi, Christopher,

Sorry I missed your call - I was pulled into a meeting about a couple of wind development projects in the state. Donna and Jim in my office gave me the information that you gave to them yesterday.

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5353 Yellowstone Road, Suite 308A
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(307) 772-2358 fax
Julie_Proell@fws.gov
~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Razzazian.Christopher@epamail.epa.gov

08/16/2011 02:10 PM

To julie_proell@fws.gov
cc
Subject Black Hills Section 7 ESA - Location from google earth with lat long

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Thanks a bunch,

Chris(Embedded image moved to file: pic05000.gif)[attachment "pic05000.gif" deleted by Julie Proell/R6/FWS/DOI]

Black Hills Section 7 ESA - Location from google earth with lat long
Christopher Razzazian to: julie_proell 08/16/2011 02:09 PM

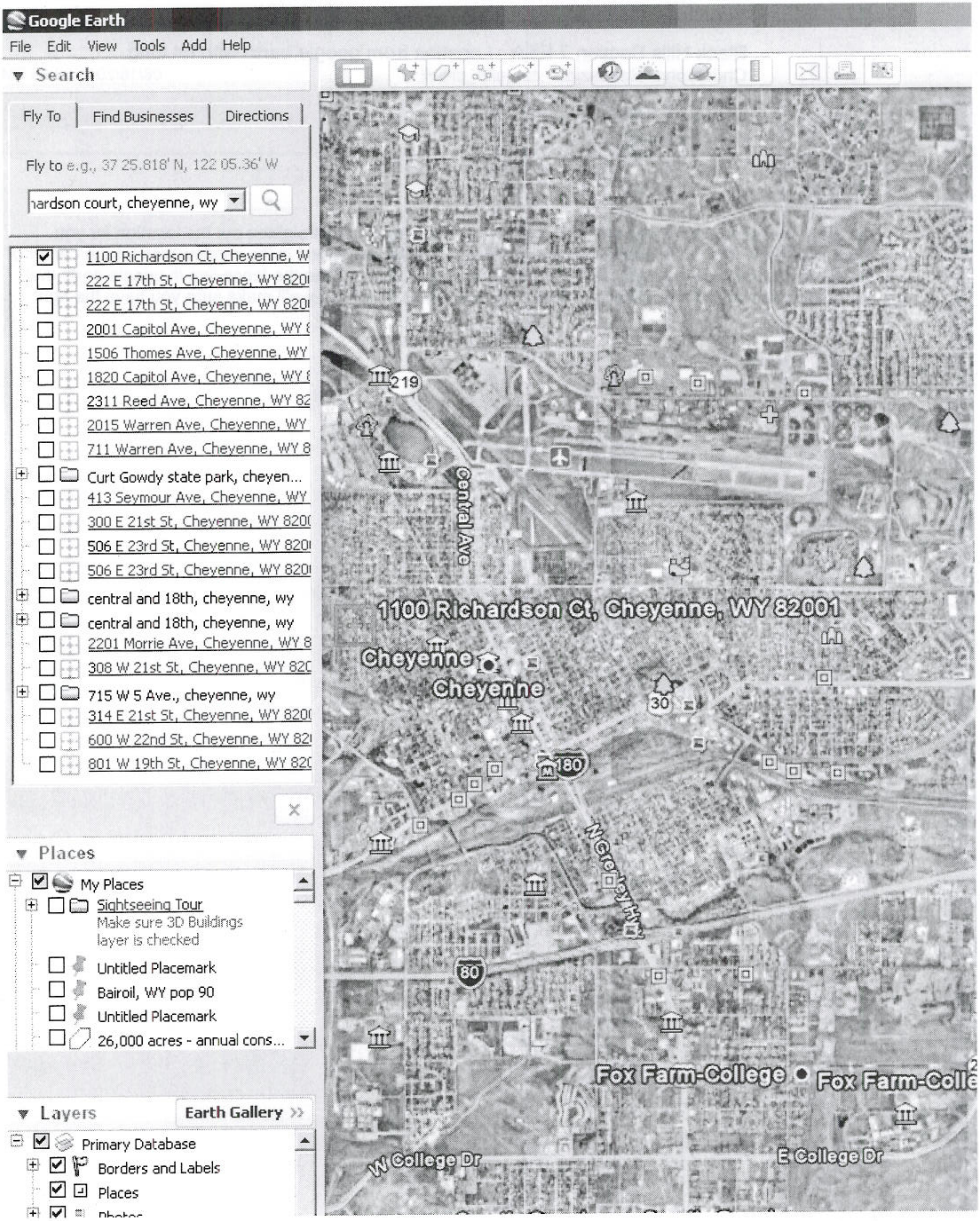
From: Christopher Razzazian/R8/USEPA/US
To: julie_proell@fws.gov

Hi Julie,

Got your message - mine was a bit long. Give me a call and I can straighten out the location for you. Here it is below (the white area along the highway). The lat long listed in the window was for the center of the rectangle, but I suggest you verify for yourself. I could almost see the fence line in google earth that Black Hills shows in the application I sent. Anyway - give a call and we'll make sure you have the right location.

Thanks a bunch,

Chris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1100 Richardson Ct, Cheyenne, W
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2001 Capitol Ave, Cheyenne, WY
1506 Thomes Ave, Cheyenne, WY
1820 Capitol Ave, Cheyenne, WY
2311 Reed Ave, Cheyenne, WY 82
2015 Warren Ave, Cheyenne, WY
711 Warren Ave, Cheyenne, WY 8
Curt Gowdy state park, cheyen...
413 Seymour Ave, Cheyenne, WY
300 E 21st St, Cheyenne, WY 820
506 E 23rd St, Cheyenne, WY 820
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Places
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Fox Farm-College
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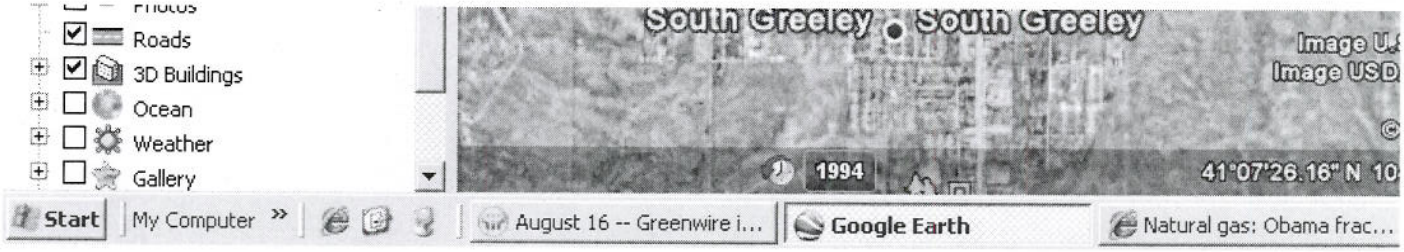
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August 16 -- Greenwire i...
Google Earth
Natural gas: Obama frac...

Re: BH Cheyenne Generating Station - EPA/PSD/GHG application

Christopher Razzazian to: Rogers, Tim 08/16/2011 09:31 AM
Bcc: Sara Laumann, Mike Owens

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc: Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA

Hi Tim,

Here are some answers to your questions.

1. ESA - I have begun the process. You are correct that we will do this. If you already have any information for the area compiled you are free to submit that and we will consider it.

2. EJ - We will conduct an EJ analysis. Again if you have any information, it would be fine to submit that. This could include, but would not be limited to: outreach, translation, community projects, etc...

3. NHPA - I have searched the database for appropriate properties and will likely be the one to conduct any consultations.

Hopefully this answers your questions, let me know.

Have a great day.

Christopher Razzazian
US EPA, Region 8
(303)312-6648

"Rogers, Tim" Chris, At our July 8 meeting in Denver, there wer... 08/16/2011 07:29:03 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 08/16/2011 07:29 AM
Subject: BH Cheyenne Generating Station - EPA/PSD/GHG application

Chris,

At our July 8 meeting in Denver, there were three items that we discussed that we would like to follow-up on.

1. Endangered Species Act;
2. Environmental Justice – disadvantaged areas; and
3. National Historic Preservation Act.

If I recall correctly, EPA was going to determine if these requirements applied with this permit. Here is my understanding on these items.

1. ESA – I was not certain on whether this was something EPA would conduct or whether we would conduct the analysis. If it is our responsibility, we would consider just moving forward with the review to make it a non-issue. We would just need to know what is expected.
2. Environmental Justice - I believe it was stated that EPA would make the call on Environmental Justice in the sense if you would identify any disadvantaged areas near the facility that needed to be taken into

consideration.
3. NHPA – if this applies, we would initiate the process. It is my understanding that this approval goes through the National agency and is then approved at the State level. Again, if this is something we would conduct, we would move forward with it to make it a non-issue.

Could you provide an update on these items? Again, if it appears that it will take a while to obtain an answer, we would like to move forward with the study or review to make them a non-issue in moving forward with the permitting process. Thanks.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Re: I will call in a little bit -
Christopher Razzazian to: Rogers, Tim 08/09/2011 09:45 AM

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

Oh thanks Tim, I see - each.

Thanks

Chris

"Rogers, Tim"	I am taking pto in the afternoons this week - hom...	08/09/2011 08:26:52 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA
Date: 08/09/2011 08:26 AM
Subject: I will call in a little bit -

I am taking pto in the afternoons this week – home project.

With a quick look, it appears the numbers are okay. In section three, it states the CO_2 are for each turbine and section 5 combined all of the emissions – so 6 X 4,117.00 tons.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

I will call in a little bit -
Rogers, Tim to: Christopher Razzazian 08/09/2011 08:26 AM

From:	"Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To:	Christopher Razzazian/R8/USEPA/US@EPA
History:	This message has been replied to.

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With a quick look, it appears the numbers are okay. In section three, it states the CO2 are for each turbine and section 5 combined all of the emissions – so 6 X 4,117.00 tons.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

RE: PSD Permitting timelines

Rogers, Tim to: Christopher Razzazian 07/17/2011 07:42 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Christopher Razzazian/R8/USEPA/US@EPA

Chris - thanks for the clarification.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

-----Original Message-----
From: Christopher Razzazian [mailto:Razzazian.Christopher@epamail.epa.gov]
Sent: Thursday, July 14, 2011 3:29 PM
To: Rogers, Tim
Subject: Re: PSD Permitting timelines

Hi Tim,

Thanks for your time today. As I mentioned on the phone, the completeness review for PSD is actually 30 days.

from 40 CFR 124.3(c):

"The Regional Administrator shall review for completeness every application for an EPA-issued permit. Each application for an EPA-issued permit submitted by a...major PSD stationary source or major PSD modification...should be reviewed for completeness by the Regional Administrator within 30 days of its receipt."

Thanks so much and hope you have safe travels.

Yours,

Christopher Razzazian
U.S. EPA Region 8

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Chad Schlichtemeier <chad.schlichtemeier@wyo.gov>,
Christopher Razzazian/R8/USEPA/US@EPA
Date: 07/13/2011 03:56 PM
Subject: PSD Permitting timelines

Chad and Chris - I excluded the "commence construction" time period after permit issuance. Please let me know if these timeframes are accurate. Thanks.

```
|-------+---------+------------+---------+---------+------------+-----------
--|
|       | Permit  |Completeness|Technical| Public  |  Hearing   |  Commence
|
```

	Process	Review	Review	Notice	Notice (public notice)	Construction permit after issuance
EPA	12 mo	60 days	NA	30 days	30 days	18 mo
WDEQ*	12-18 mo	30 days	60 days	30 days	30 days?	24 mo

*WDEQ does not have specified timelines in their rules Chapter 6, Section 4 for PSD permits. They attempt to following the time-lines in Section 2, but are not legally bound to these timelines.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

This electronic message transmission contains information from Black Hills Corporation, its affiliate or subsidiary, which may be confidential or privileged. The information is intended to be for the use of the individual or entity named above. If you are not the intended recipient, be aware the disclosure, copying, distribution or use of the contents of this information is prohibited. If you received this electronic transmission in error, please reply to sender immediately; then delete this message without copying it or further reading.

Re: PSD Permitting timelines
Christopher Razzazian to: Rogers, Tim 07/14/2011 03:28 PM
Bcc: Sara Laumann, Mike Owens, Alexis North, Carl Daly, "Schlichtemeier, Chad"

From: Christopher Razzazian/R8/USEPA/US
To: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
Bcc: Sara Laumann/R8/USEPA/US@EPA, Mike Owens/R8/USEPA/US@EPA, Alexis North/R8/USEPA/US@EPA, Carl Daly/R8/USEPA/US@EPA, "Schlichtemeier, Chad" <CSchli@wyo.gov>

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Thanks so much and hope you have safe travels.

Yours,

Christopher Razzazian
U.S. EPA Region 8

"Rogers, Tim" Chad and Chris - I excluded the "commence con... 07/13/2011 03:56:18 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Chad Schlichtemeier <chad.schlichtemeier@wyo.gov>, Christopher Razzazian/R8/USEPA/US@EPA
Date: 07/13/2011 03:56 PM
Subject: PSD Permitting timelines

Chad and Chris – I excluded the "commence construction" time period after permit issuance. Please let me know if these timeframes are accurate. Thanks.

	Permit Process	Completeness Review	Technical Review	Public Notice	Hearing Notice (public notice)	Commence Construction after permit issuance
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*WDEQ does not have specified timelines in their rules Chapter 6, Section 4 for PSD permits. They attempt to following the time-lines in Section 2, but are not legally bound to these timelines

Tim Rogers
Environmental Services
(605) 721-2286 - work

(605) 484-0134 - cell

PSD Permitting timelines

Rogers, Tim to: Chad Schlichtemeier, Christopher Razzazian 07/13/2011 03:56 PM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Chad Schlichtemeier <chad.schlichtemeier@wyo.gov>, Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been replied to and forwarded.

Chad and Chris – I excluded the "commence construction" time period after permit issuance. Please let me know if these timeframes are accurate. Thanks.

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Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

BHC Cheyenne CT Project - EPA/WDEQ Permitting timeframes

Rogers, Tim to: Chad Schlichtemeier, Christopher Razzazian 07/13/2011 11:37 AM

From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>
To: Chad Schlichtemeier <chad.schlichtemeier@wyo.gov>, Christopher Razzazian/R8/USEPA/US@EPA

History: This message has been forwarded.

Chad and Chris,

Based upon our discussions last week, does the table below capture the PSD permitting timeframes for both your agencies?

	Permit Process	Completeness Review	Technical Review	Public Notice	Hearing Notice (public notice)
EPA	12 months	60 days	NA	30 days	30 days
WDEQ*	12-18 months	30 days	60 days	30 days	?

*WDEQ does not have specified timelines in Chapter 6, Section 4 for PSD permits. Their practice is to follow the time-lines in Section 2, but they are not legally bound to these timelines.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Black Hills Corporation's - Cheyenne CT Project - Meeting Agenda for Pre-application meeting with EPA on July 8, 2011
Rogers, Tim
to:
Carl Daly, Christopher Razzazian, Chad Schlichtemeier
07/07/2011 01:41 PM
Cc:
"Rogers, Tim"
Hide Details
From: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

To: Carl Daly/R8/USEPA/US@EPA, Christopher Razzazian/R8/USEPA/US@EPA, Chad Schlichtemeier <chad.schlichtemeier@wyo.gov>

Cc: "Rogers, Tim" <Tim.Rogers@blackhillscorp.com>

1 Attachment

EPA Pre-Application Meeting Agenda_July 8 2011_Final.doc

Carl, Chris, and Chad,

Attached please find the meeting agenda for tomorrow. We have a PowerPoint presentation that we will give to kick off the meeting.

Chad has indicated that he will be traveling down for the meeting.

See you tomorrow.

Tim Rogers
Environmental Services
(605) 721-2286 - work
(605) 484-0134 - cell

Cheyenne Combustion Turbine Project

EPA Pre-Application Meeting
9:00 AM – July 8, 2011
2nd Floor Conference Room, EPA Region VIII, Denver, Colorado

Agenda

1. Introductions

2. Cheyenne Gas Generating Station Project Description

- Renewable Following
- Black Hills Business Purpose
- Black Hills Operating Cycle
- Combined Cycle/Simple Cycle CT Project

3. EPA Permitting Process – GHG

4. WDEQ Permitting Process - Criteria Pollutants and HAPs

5. Discussion for EPA - GHG

- No GHG Modeling
- GHG Guidance
- GHG BACT Review (5 Step BACT Review Process)
- Combined public notice and comment, combined hearing, separate application and permits.

6. Other Potential Issues:

7. Establish EPA, WDEQ, BHC, and CH2MHILL Point of Contacts

Contacts

Name	Company	Email	Phone
Black Hills Corporation			
Tim Rogers Environmental Manager	Black Hills Permit Lead	trogers@bh-corp.com	605-721-2286 W 605-484-0134 C
Fred Carl Environmental Director	Black Hills	fcarl@bh-corp.com	605-721-2219 W 605-390-8056 C
Tim Mordhorst Environmental Manager	Black Hills CEM's	tmordhorst@bh-corp.com	605-721-2181 W 605-390-9933 C
George Tatar	Black Hills Operations	George.tatar@blackhillscorp.com	719-696-3217 W 303-945-6619 C
Jason Hartman	Black Hills Operations	Jason.hartman@blackhillscorp.com	303-566-3445 W 720-413-9199 C
CH2MHILL – Permitting Consultants			
Joe Hammond	CH2MHILL Permit Consultant	Joe.hammond@ch2m.com	720-286-5919 W 719-330-1771 C
Bob Pearson	CH2MHILL Permit Consultant	Robert.Pearson@ch2m.com	720-286-5056 W 303-517-9102 C
Gordon Schott	CH2MHILL BACT	Gordon.Schott@ch2m.com	720-286-5134 W 720-560-6116 C
Brad Ryan ME Manager	CH2MHILL Engineering	Bradley.ryan@ch2m.com	720-286-5121 W 303-726-5629 C
Wyoming Department of Environmental Quality			
Chad Schlichtemeier PSD Permit Director	WDEQ	chad.schlichtemeier@wyo.gov	307-777-5924 W
Josh Nall Modeling	WDEQ		
Andy Keyfauver	WDEQ Permit Writer		
Nancy Vering Assistant AG	WDEQ Legal		
EPA – Region VIII			
Carl Daly	EPA AQ Director	daly.carl@epa.gov	(303) 312-6416
Chris Razzazian	EPA Permit Writer	razzazian.christopher@epa.gov	(303) 312-6648
	EPA Legal		

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

May 23, 2012

MEMORANDUM

SUBJECT: Record of Communication - conference call regarding Draft GHG PSD permit for Black Hills Corp./Cheyenne Light Fuel & Power Cheyenn Prairie Generating Station

FROM: Christopher Razzazian

TO: Cheyenne Prairie Generating Station GHG PSD permit docket

This memorandum is to serve as a record of communication for a conference call that occurred on 5/22/2012 from 1:30 p.m. - 2:30 p.m.

Attendees:

EPA
- Christopher Razzazian - Air Program
- Deirdre Rothery - Air Program, Unit Chief
- Sara Laumann - Office of Regional Council

Black Hills Corp.
- Tim Rogers - Black Hills Corp.
- Fred Carl - Black Hills Corp.
- Tim Mordhorst - Black Hills Corp.
- Dennis Arfmann - legal council

Summary of phone call

Environmental Justice (EJ)
Black Hills notes that this is discussed in the Statement of Basis (SOB) and wonders why ESA and NHPA were not touched upon in the SOB. EPA responded that the SOB provides the current EPA policy for EJ in GHG PSD permitting and went on to explain ESA and NHPA requirements (see below).

Endangered Species Act (ESA)
Black Hills would like the public record available for public comment to include the efforts to date submitted to EPA with regard to ESA compliance. EPA responded that efforts are underway to provide the information to the Laramie County Clerk and to include the information on the EPA website with the draft permit documents. However, EPA notes that ESA requirements are not open for public comment at this stage and EPA must fulfill its obligations under the ESA before the issuance of the final GHG PSD permit.

National Historic Preservation Act (NHPA)
Black Hills would like the public record available for public comment to include the efforts to date submitted to EPA with regard to NHPA compliance. EPA responded that efforts are underway to provide the cultural resources report to the Laramie County Clerk and to post that information on the

EPA website with the draft permit documents. However, EPA is still analyzing the requirements of the statute and will comply with any public participation requirements in the NHPA in order to show compliance with those requirements prior to issuance of the final permit.

Permit Questions
Black Hills asked whether EPA Region 8 could provide a full rationale of draft permit Condition III.B.3.b. and noted a typographical error. EPA responded that the correct citation in Condition III.B.3.b. should be to III.B.1.b.ii, not III.B.1.c. EPA also indicated that it would not be able to speak to the intent of Condition III.B.3.b. at this time without further representation from others within the agency.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

MAY 1 7 2012

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Mark L. Lux
Vice President and General Manager, Power Delivery
Black Hills Corporation
P.O. Box 1400
625 Ninth Street
Rapid City, South Dakota 57709

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000001-2011.001

Dear Mr. Lux:

The U.S. Environmental Protection Agency (EPA), Region 8, has completed its initial review of Black Hills Corporation/Cheyenne Light Fuel & Power's permit application dated September 23, 2011, for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit to allow construction and operation of a new 220 MW natural gas fired combustion turbine electric generating utility to be known as the Cheyenne Prairie Generating Station.

Enclosed is the draft PSD permit and corresponding Statement of Basis, along with a copy of the public notice. A copy of these materials (in addition to the PSD application submitted to the EPA) are also being sent to the Laramie County Clerk's office. These documents are also available on the EPA's website at: http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading.

A copy of the administrative record for the draft permit, which consists of the draft permit, the draft Statement of Basis, the permit application and addendums, all data submitted by the permit applicant, and all permit-related correspondence, is available for public inspection through June 21, 2012, at the Region 8 office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

The public notice will be published in the Wyoming Tribune Eagle on Monday, May 21, 2012. The public comment period will end on June 21, 2012, at 8:30 p.m. All written or emailed comments submitted by the close of the public comment period will be considered by the EPA in making its final permit decision. Please refer to the enclosed copy of the public notice for details on the public comment period.

The Wyoming Department of Environmental Quality (WDEQ) will issue a draft PSD permit for PSD pollutants other than GHGs for this facility. The WDEQ will conduct a public comment period concurrent with the EPA's for its draft PSD permit.

The conditions contained in the permit will become effective and enforceable if the permit is issued as a final permit. If you are unable to accept any term or condition of the draft permit, please submit your written comments, along with the reason(s) for non-acceptance, to:

Christopher Razzazian - Permit Contact
U.S. EPA, Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202-1129

If you have any questions concerning the enclosed materials, you may contact Mr. Razzazian at (303) 312-6648.

Sincerely,

Callie A.Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures (3)

Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Pre-Construction Permit
for the Black Hills Corporation/Cheyenne Light Fuel & Power,
Cheyenne Prairie Generating Station

Permit Number: PSD-WY-000001-2011.001

May 21, 2012

This document serves as the Statement of Basis (SOB) required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, and 40 CFR 52.37 (FIP to issue permits under the PSD requirements to sources that emit greenhouse gases), that would apply if the permit is issued. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On September 23, 2011, Black Hills Corporation/Cheyenne Light Fuel & Power (BHC/CLF&P) submitted to the Environmental Protection Agency Region 8 (EPA) a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions associated with the construction and operation of a new power generation facility to be known as the Cheyenne Prairie Generating Station (CPGS). In connection with the same proposed project, BHC/CLF&P submitted a PSD permit application for non-GHG pollutants to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) on October 19, 2011. The new proposed plant would be a 220 megawatt (MW) natural gas fired combustion turbine (CT) electric utility power generating facility including five CTs each rated at 40 MW. Two of the CTs will be operated in a 2-on-1 combined cycle mode with two CTs feeding two heat recovery steam generators (HRSG) and then combining to drive a single 20 MW electric generating steam turbine. After reviewing the application, EPA has prepared the following SOB and draft New Source Review (NSR)/PSD pre-construction air permit to authorize construction of GHG air emission sources at the BHC/CLF&P, CPGS.

This SOB documents the information and analysis EPA used to support decisions made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA concludes that BHC/CLF&P's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD air permit regulations for GHG. EPA's conclusions rely upon information provided in the permit application, supplemental information EPA requested and provided by BHC/CLF&P, and EPA's own technical analysis. EPA is making all of this information available as part of the public record.

II. Applicant

Black Hills Power Corporation/Cheyenne Light, Fuel & Power
P.O. Box 1400
625 Ninth Street
Rapid City, South Dakota 57709

Physical Location:
Cheyenne Prairie Generating Station
Section 1, Township 13 North, Range 66 West
Latitude: 41º 07' 27.83" North
Longitude: 104º 43' 13.34" West
Cheyenne, Laramie County, Wyoming

Operator: Black Hills Service Company, LLC
Owner: Joint Ownership - Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company
Responsible Official: Mark Lux, Vice President and General Manager of Power Delivery, 303-568-3241
Alternate: George Tater, Director of Generation Operations II, 719-696-3217
Permit Contact: Tim Rogers, Environmental Services, 605-721-2286

III. Permitting Authority

On December 30, 2010, EPA published a Federal Implementation Plan (FIP) making EPA the GHG PSD permitting authority for states that do not have the authority to implement GHG PSD permitting. 75 FR 82246 (promulgating 40 CFR 52.37). Wyoming still retains approval of its State Implementation Plan (SIP) and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD permitting authority for the state of Wyoming is:

EPA, Region 8
1595 Wynkoop St.
Denver, CO 80202

Permit Author:
Christopher Razzazian
Air Permitting Monitoring and Modeling Unit (8P-AR)
(303) 312-6648

The non-GHG PSD permitting authority for the state of Wyoming is:

Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

IV. Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD GHG permit will be published on May 21, 2012, in the Wyoming Tribune. The public comment period will begin on May 21, 2012 and close on June 21, 2012, at 8:30 p.m. During the public comment period, the public will be given the opportunity to review a copy of the permit application, the draft permit prepared by EPA, the SOB, and permit-related correspondence. The draft permit, SOB, and Administrative Record for the draft permit will be available for review at EPA Region 8's office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). The permit application, draft permit and SOB will also be available for review on EPA's website at http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading. A hardcopy of these documents will also be available for review at the Laramie County Clerk's Office in Cheyenne, Wyoming, Monday through Friday from 8:00 a.m. to 5:00 p.m. until the close of the public comment period.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person is afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a hearing. A public hearing will be held for this action on June 21, 2012 from 7:00 p.m. to 8:30 p.m. in the Cottonwood Room of the Laramie County Library located at 2200 Pioneer Avenue, Cheyenne, WY 82001. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed generating station. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants there will be a hearing held prior to the EPA GHG permit hearing from 5:30 p.m. to 7:00 p.m. at the aforementioned date and location regarding the WDEQ draft PSD permit. All comments regarding pollutants other than GHGs from the proposed facility must be submitted to the WDEQ, which is running a concurrent public comment period for this facility.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the project is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's decision, by the close of the public comment period.

Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 30-day public comment period may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

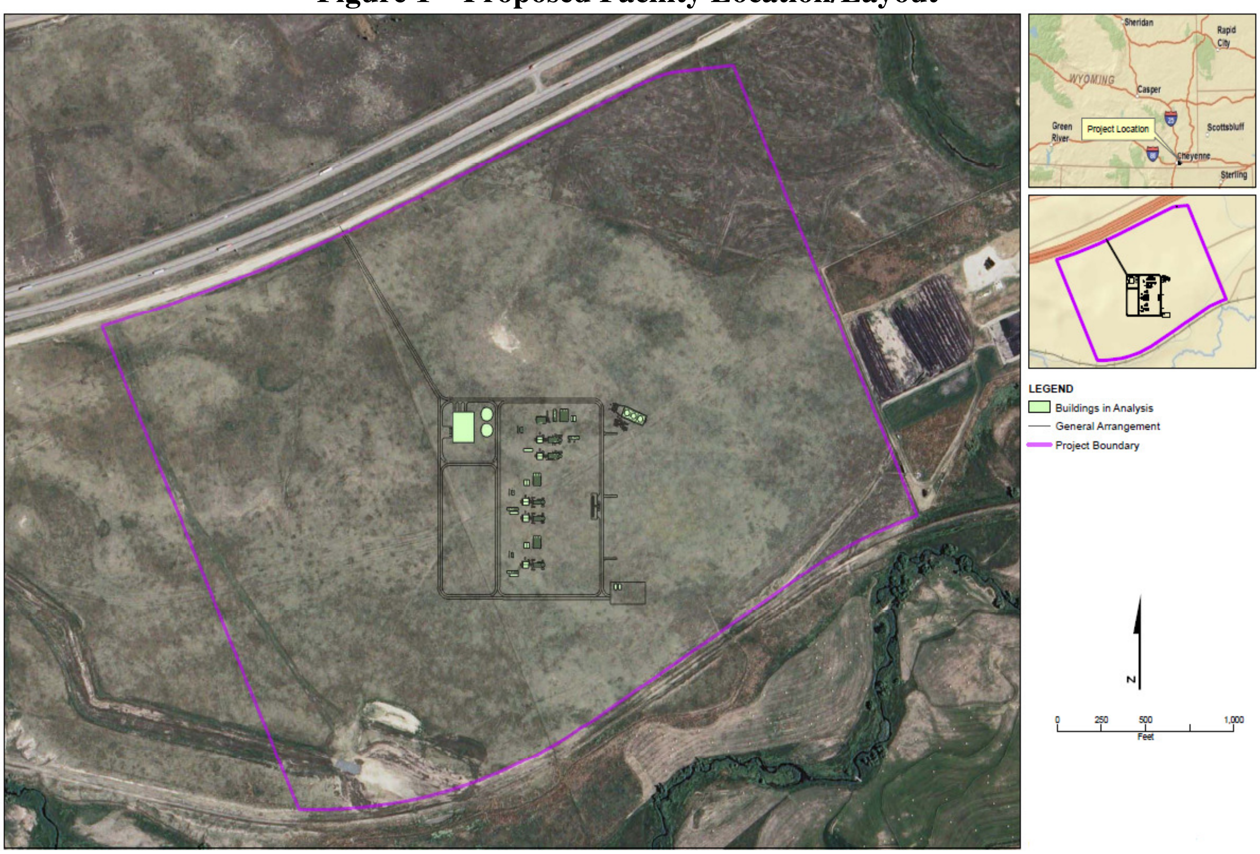
In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only on changes from the draft to the final permit decision.

V. Facility Location

The CPGS is located in Laramie County, Wyoming, which is currently considered to be in attainment for all of the National Ambient Air Quality Standards (NAAQS). The nearest federal Class 1 area is Rocky Mountain National Park, which is located approximately 60 miles southwest from the proposed site. Savage Run Wilderness Area is a Class I area recognized by the state of Wyoming located approximately 83 miles west from the proposed site. The geographic coordinates for this facility are as follows:

Latitude: 41º 07' 27.83" North
Longitude: 104º 43' 13.34" West

Figure 1 – Proposed Facility Location/Layout



VI. Applicability of Prevention of Significant Deterioration (PSD) Regulations

Under EPA's Clean Air Act permitting rules, the term "greenhouse gas" means an air pollutant consisting of the aggregate of six gases with atmospheric warming potential: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHG emissions are determined by multiplying the mass emissions of each of these gases, in tons per year (tpy) by its respective Global Warming Potential (GWP) and summing the result, which is referred to as the "CO_2-equivalent" (CO_{2e}). The GWPs (from 40 CFR 98, Table A-1) are 1.0 for CO_2, 21 for CH_4, 310 for N_2O, and 23,900 for SF_6. No emissions of HFCs or PFCs are expected from this project.

EPA concludes that BHC/CLF&P's application is subject to PSD review for GHG, because the project would lead to a facility GHG emissions increase as described at 40 CFR § 52.21(b)(49)(iv) and (v). The proposed project emissions would result in increased GHG emissions above both of the PSD thresholds, which are 250 tpy on a mass basis and 75,000 tpy on a CO_{2e} basis. BHC/CLF&P has presented CO_{2e} potential emissions of 964,289 tpy. The potential GHG emissions on a mass basis are 962,965 tpy. EPA is the permitting authority responsible for implementing a GHG PSD FIP for Wyoming under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.37.

As the permitting authority for regulated NSR pollutants other than GHGs, WDEQ has determined the proposed new source is subject to PSD review for non-GHG pollutants. Specifically, the PSD application submitted to WDEQ explains the proposed facility will be a new "major stationary source" as defined in PSD rules, which will emit the following pollutants above PSD significant emission rates: nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), and particulate matter less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$). Accordingly, WDEQ is proposing to issue the non-GHG portion of the PSD permit and EPA is proposing to issue the GHG portion.[1]

EPA applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (Guidance), available on EPA website at: www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf. Consistent with the Guidance, we have not required the applicant to model or conduct ambient monitoring for GHG, since there are no ambient air quality standards for GHGs, and we have not required any assessment of impacts of GHG in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed, at present, to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from WDEQ.

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting authorities (April 19, 2011).
Available online at: http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf.

For a description of the five-step process involved in making a PSD BACT determination for GHGs, please refer to the aforementioned Guidance. EPA has followed those steps in making the GHG BACT determination for this project.

VII. Project Description

The proposed GHG PSD permit, if finalized, will allow BHC/CLF&P to construct a new nominal 220 MW gross simple and combined cycle natural gas-fired CT electric utility power plant in Laramie County, Wyoming. The plant, the CPGS, will be located five miles southeast of downtown Cheyenne along Interstate 80. CLF&P is a wholly owned subsidiary of BHC and was acquired from Xcel Energy in 2005. CLF&P provides electric utility service to Laramie County, Wyoming. CPGS will include three simple cycle General Electric (GE) LM6000PF SPRINT natural gas CTs, and two GE LM6000PF SPRINT CTs operated in a 2-on-1 combined cycle configuration (each turbine exhausts to its own HRSG and that steam is routed to a single steam turbine electric generator). In addition to the CTs, the facility will include the following: one wet cooling tower for the combined cycle steam turbine; three electric chiller units, each with cooling towers, for inlet air cooling for the CT inlet air; six natural gas-fired inlet air heaters to heat the CT inlet air; two natural gas-fired fuel gas heaters; one diesel emergency generator; and one diesel fire pump.

Table 1 – Potential to Emit for CPGS Emission Sources

Equipment	Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	SF_6 (tpy)	CO_{2e} (tpy)
EP01 - EP02	CT01A - GE LM6000PF SPRINT Combined Cycle Combustion Turbine (366 MBtu/hr) with HRSG #1, SCR and CatOx	374268 (187,134 each)	7.1 (3.53 each)	0.7 (0.35 each)	0	374,635
EP03 - EP05	CT02A - GE LM6000PF SPRINT Simple Cycle Combustion Turbine (366 MBtu/hr) with SCR and CatOx	561,402 (187,134 each)	10.6 (3.53 each)	1.1 (0.35 each)	0	561,966
EP06 - EP11	Natural Gas-Fired Inlet Air Heaters #1 - #6	24,679 (4,113.13 each)	0.5 (0.08 each)	0.06 (0.01 each)	0	24,708
EP12 - EP14	Inlet Air Chillers	0	0	0	0	0
EP15	Diesel Emergency/Standby Generator	225.01	0.01	0	0	225
EP16	Diesel Fire Pump Engine	50.95	0	0	0	51
EP17	Wet Cooling Tower	0	0	0	0	N/A
EP18 - EP19	Natural Gas-Fired Fuel Gas Heater #1 and #2	2,304 (1,151.92 each)	0.04 (0.02 each)	0	0	2,305
NG-FUG	Fugitive natural gas emissions from valves, flanges, nad on-site compressor	0	16	0	0	336
SF_6-FUG1 through SF_6-FUG9	Nine SF_6 Capacitors in circuit breakers, 60 lbs SF6 each breaker, maximum 1% leak rate assumed	0	0	0	0.0027	64.5
TOTALS		962,929	34.25	1.86	0.0027	964,289

VIII. BACT Analysis

The BACT analysis provided by the applicant included the assumptions described below, which have been considered and adopted and modified by EPA in its own BACT analysis.

1. Table 1 above presents estimated CPGS GHG emissions in terms of CO_{2e} emissions, and only includes emissions of CO_2, CH_4, and N_2O and SF_6 (which was considered due to the potential for leaks from equipment containing SF_6). The CPGS is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents. SF_6 is also a man-made gas that may be used as an insulating gas for high-voltage equipment, such as capacitors, and circuit breakers.

2. From the GHG emissions inventory presented in Table 1 above, CH_4 and N_2O total only approximately 1,296 tpy of CO_{2e} emissions, which is about 0.13% of total CO_{2e} emissions. Due to the small contribution of CH_4 and N_2O emissions to the total, the CPGS GHG BACT analysis includes the full five-step BACT determination process only for CO_2 emissions from combustion sources. With regard to SF_6 emissions, the only emissions included in Table 1 are those that would result from leaks from the nine SF_6 circuit breakers at the CPGS; an abbreviate BACT analysis for those emissions is included near the end of this document.

3. The WDEQ's BACT analysis for criteria pollutants proposes the installation of a selective catalytic reduction (SCR) system for NO_x emissions reduction, and an oxidation catalyst (CatOx) for control of CO and VOCs for each CT.

4. During actual CT operation, the CatOx may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA's Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule or MRR) (40 CFR 98) includes factors for estimating CO_{2e} emissions from the combustion of natural gas and assumes complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the MRR factors and included in the CO_{2e} totals.

5. Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be minimal under proper operating scenarios. From Table 1, above, the estimated N_2O emissions from all combustion sources total only 1.86 tpy on a mass basis, or 576 tpy CO_{2e}. Therefore, even if there were an order of magnitude increase in N_2O as a result of the SCR, the impact to CO_{2e} emissions would be small as compared to facility CO_{2e} emissions.

Use of the SCR and CatOx slightly decreases the project's thermal efficiency due to backpressure on the CTs (these impacts are already included in the emission inventory presented in Table 1) and, as noted above, may create a marginal increase to N_2O emissions. While elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT analysis, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Therefore, in accordance with section III.E., of the Guidance, EPA has concluded that the potential marginal increase in N_2O emissions does not warrant elimination of these controls for other pollutants, which are anticipated to be required by the state as part of its BACT determination for those other pollutants.

A. Natural Gas-Fired Combined Cycle Combustion Turbines

The new power plant will have a generating capacity of approximately 220 MW. This generating capacity is divided between five identical CTs each rated at 40 MW for a total generating capacity from the CTs of 200 MW. The remaining 20 MW will be generated by the combined cycle steam turbine generator, which will be fed by the two CT combined cycle HRSGs. The CTs chosen for the project are GE Energy Aeroderivative LM6000 PF SPRINT CTs.

The GHG permit application from BHC/CLF&P included a 5-step top-down BACT analysis for the CT emission units (EP01-EP05). EPA has considered the information submitted by BHC/CLF&P and presents the following BACT analysis for the CTs.

1. Step 1 - Identify All Control Technologies

The applicant identified two alternatives to limit GHG emissions from the proposed project: (1) carbon capture and storage/sequestration (CCS); and (2) electrical generation efficiency. We describe these below.

> CCS - CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to supercritical temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). Three fundamental types of carbon capture systems are employed throughout different process and energy industries: sorbent adsorption; physical absorption; and chemical absorption.
>
> Electrical generation efficiency - Other than capture and sequestration of GHG emitted by combustion, the only known option for reducing GHG emissions is through maximization of the energy released during the combustion process and then through the maximization of the use or capture of that energy. To minimize GHG emissions, it is desirable to use less fuel to generate a given amount of electrical energy. There are several factors that may be examined that affect the amount of GHG produced per MW-hr of energy produced. These include low carbon fuels (those fuels that inherently produce less GHG, or CO_{2e}, per unit of energy released when combusted), and the thermodynamic and mechanical efficiency of the combustion unit (CT in this case).

The applicant has stated that their Business Plan and Integrated Resource Plan (Plans) have determined that the proposed mix of natural gas combined cycle and simple cycle power generation is the only alternative that meets all of the Plan requirements to generate economically viable and reliable electrical power 8,760 hours per year in all weather conditions. CPGS is intended to provide supplemental and backup electrical generation for solar and wind projects within the region. In order to serve that purpose, any power generation built would need to be capable of generating power during periods when wind or solar energy sources are not available, necessitating fuel-based generation. Additionally, the applicant has stated that as a peaking power plant simple cycle operation is necessary to accommodate short term load fluctuations. However, the applicant has acknowledged that future expansion of the facility could include build-out of the simple cycle CTs into combined cycle systems to provide additional thermal efficiency. The primary energy efficiency option presented by Black Hills focuses on choosing a highly efficient low emitting CT, highly efficient HRSGs, and electric generating steam turbine.

The first aspect to evaluate with regard to an energy efficient process is the source of fuel. To compare the emission factors for GHG from the combustion of various fuels, we have provided Table 2 through Table 4 below (which have been extracted from Tables C-1 (Table 2) and C-2 (Tables 3 and 4) of 40 CFR part 98, subpart C to the MRR). In order to facilitate this analysis, the tables have been reorganized from the order listed in the CFR to show lower emitting fuels at the top of the tables and the higher emitting (less attractive) fuels at the bottom. BHC/CLF&P has proposed to use natural gas as the fuel for the CTs. Natural gas is listed as the third cleanest fuel with respect to CO_2 emissions, the third cleanest fuel with respect to CH_4 emissions, and the cleanest fuel with respect to N_2O emissions. The two cleaner fuels with respect to CO_2 emissions (coke oven gas and biogas) cannot be utilized by a CT. With regard to fuels that can be utilized by a CT, natural gas produces the lowest GHG emissions profile.

Table 2 – Default CO_2 Emission Factors by Fuel Type (extracted from 40 CFR part 98, Subpart C, Table C-1)

Fuel type	**Default CO_2 emission factor (Kg/MMBtu)**
Coke Oven Gas	46.85
Biogas (Captured methane)	52.07
Natural Gas (Weighted U.S. Average)	**53.02**
Fuel Gas	59
Propane	61.46
Propane Gas	61.46
Ethane	62.64
Liquefied petroleum gases (LPG)	62.98
Isobutane	64.91
Butane	65.15
Propylene	65.95
Natural Gasoline	66.83
Ethylene	67.43
Butylene	67.73
Isobutylene	67.74
Naphtha (<401 deg F)	68.02
Ethanol	68.44
Ethanol	68.44
Aviation Gasoline	69.25
Pentanes Plus	70.02

Motor Gasoline	70.22
Petrochemical Feedstocks	70.97
Rendered Animal Fat	71.06
Kerosene-Type Jet Fuel	72.22
Special Naphtha	72.34
Residual Fuel Oil No. 5	72.93
Distillate Fuel Oil No. 1	73.25
Biodiesel	73.84
Biodiesel (100%)	73.84
Distillate Fuel Oil No. 2	73.96
Used Oil	74
Lubricants	74.27
Unfinished Oils	74.49
Crude Oil	74.49
Heavy Gas Oils	74.92
Plastics	75
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 6	75.1
Kerosene	75.2
Asphalt and Road Oil	75.36
Other Oil (>401 deg F)	76.22
Vegetable Oil	81.55
Tires	85.97
Municipal Solid Waste	90.7
Bituminous - Coal	93.4
Mixed (Industrial coking) - Coal and coke	93.65
Wood and Wood Residuals - solid fuel	93.8
Mixed (Industrial sector) - Coal and coke	93.91
Mixed (Electric Power sector) - Coal and coke	94.38
Mixed (Commercial sector) - Coal and coke	95.26
Lignite - Coal	96.36
Subbituminous - Coal	97.02
Coke	102
Petroleum Coke	102.4

Petroleum Coke	102.4
Anthracite Coal	103.5
Biomass Solid Byproducts	105.5
Peat - solid fuel	111.8
Agricultural Byproducts - solid fuel	118.2
Blast Furnace Gas	274.3

Table 3 – Default CH_4 Emission Factors by Fuel Type (extracted from 40 CFR part 98, Subpart C, Table C-2)

Fuel type	**Default CH_4 emission factor (kg CH_4/MMBtu)**
Blast Furnace Gas	2.2E-05
Coke Oven Gas	4.8E-04
Natural Gas	**1.0E-03**
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1E-03
Petroleum (All fuel types in Table C–1)	3.0E-03
Biogas	3.2E-03
Coal and Coke (All fuel types in Table C–1)	1.1E-02
Municipal Solid Waste	3.2E-02
Tires	3.2E-02
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2E-02

Table 4 – Default N_2O Emission Factors by Fuel Type (extracted from 40 CFR part 98, Subpart C, Table C-2)

Fuel type	**Default N_2O emission factor (kg N_2O/MMBtu)**
Natural Gas	**1.0E-04**
Blast Furnace Gas	1.0E-04
Coke Oven Gas	1.0E-04
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1E-04
Petroleum (All fuel types in Table C–1)	6.0E-04
Biogas	6.3E-04
Coal and Coke (All fuel types in Table C–1)	1.6E-03
Municipal Solid Waste	4.2E-03
Tires	4.2E-03
Biomass Fuels—Solid (All fuel types in Table C–1)	4.2E-03

The second aspect of the energy generation process to evaluate with regard to energy efficiency is the mode by which the fuel will be combusted. In this case, the applicant's Business Plan calls for generation of electricity utilizing CTs, which represent the most efficient mode of natural gas combustion to generate mechanical (and thermal) energy. CTs utilize compressed air to maximize the amount of energy that can be released during the expansion of the hot combustion products.

BHC/CLF&P provided the following information in their application with regard to available turbines that would meet plant requirements, including calculations of each turbine's efficiency. BHC/CLF&P has proposed to use the GE Energy Aeroderivative LM6000PF SPRINT CT because it best meets its Business Plan, its system, and operational criteria. Business Plan considerations for turbine selection include: combustion efficiency; exhaust characteristics that impact combined cycle system efficiency; size range; and consistency with other locations. Selection of a fleet of like turbines for different locations provides advantages with knowledge of maintenance and operations, stocking of spare parts, and ability to swap turbines between locations. The CT calculated efficiency for the GE LM6000PF SPRINT is 37.6%. Using a conversion factor of 3,412.14245 Btu = 1 kW-hr, the calculated efficiency would be 37.58%. The only commercially available turbines surpassing this efficiency are the Rolls-Royce Trent 60 DLE and DLE ISI model turbines (37.7% and 38.3%, respectively).

Table 5 - Combustion Turbine Efficiency Comparison

Turbine[1]	Production (kW)	Gross Heat Rate (Btu/kWh) Higher Heating Value (HHV)	Efficiency[2] (%)
Dresser-Rand			
DR-63G PC	35,150	9,095	37.5
GE Energy Aeroderivative			
LM6000PC	39,253	9,487	36.0
LM6000PC Sprint	40,605	9,419	36.2
LM6000PD	34,612	9,103	37.5
LM6000PD Sprint	38,079	9,091	37.5
LM6000PF	34,612	9,103	37.5
LM6000PF Sprint	38,649	9,079	37.6
LM6000PG	42,995	9,556	35.7
GE Energy Oil & Gas			
LM6000PD	33,964	9,283	36.8
IHI Power Systems			
LM6000PC	34,306	9,198	37.1
LM6000PC Sprint	37,129	9,228	37.0
LM6000PD	33,800	9,231	37.0
LM6000PD Sprint	37,236	9,213	37.0

LM6000PG	40,084	9,157	37.3
Pratt & Whitney Power Systems			
FT8 TwinPac	41,267	9,898	34.5
SwiftPac 50 DLN	41,175	9,914	34.4
Rolls-Royce			
Trent 60 DLE	41,537	9,064	37.7
Trent 60 DLE ISI	46,612	8,913	38.3
Siemens Energy			
SGT-800	37,772	10,126	33.7
SGT-900	39,781	11,626	29.4

[1] Specifications for simple-cycle production output at 59ºF, 5,950-Foot Altitude, Gross Output, HHV.
[2] Calculation: Efficiency= [3,413 Btu/kWh divided by Gross Heat Rate] x 100

The information presented in Table 5, above was not adjusted for site specific conditions applicable to the proposed CPGS. In Table 6 below, BHC/CLF&P has provided site-specific CT criteria for the GE LM6000PF SPRINT turbine based upon GE provided information, including consideration for parasitic auxiliary loads at CPGS site conditions. With these considerations in place, the adjusted Gross Heat Rates are as shown in Table 6 below, for simple cycle and combined cycle. The calculated efficiency of the turbine is 36.8% in simple-cycle mode (versus 37.6% in Table 5 above) and 48.3% in combined-cycle mode.

Table 6 - GE LM6000PF SPRINT Combustion Turbine Attributes

Combustion Turbine Criteria	Value[1]
Simple-Cycle Combustion Turbine Gross Output (MW)	37.1
2x1 Combined-Cycle Combustion Gross Turbine Output (MW)	97.4
Simple-Cycle Gross Heat Rate (Btu/KWh) HHV	9,263
Combined-Cycle Gross Heat Rate (Btu/KWh) HHV	7,062
Heat Input (Btu/hr) HHV	366

[1] 60º F at site elevation

2. Step 2 - Eliminate Technically Infeasible Options

CCS - BHC/CLF&P has provided an analysis asserting that post-combustion CCS should be considered technically infeasible for the CPGS project based on a variety of technical and logistical barriers, and thus they argue that CCS should be eliminated from further consideration (Application, pg. 5-7 through 5-11). Given that EPA plans to propose this permit concurrently with the WDEQ non-GHG PSD permit, there is not time to perform an in-depth analysis of the applicant's claims regarding the technical and logistical barriers to implementing CCS for this project. Accordingly, we have assumed, for purposes of this permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for the CPGS project, and have asked the applicant to address economic feasibility issues in Step 4 of the BACT analysis in order to address any arguments that CCS is BACT for this project.

3. Step 3 - Rank Remaining Control Technologies

Both CCS and electrical generation efficiency will be carried forward to Step 4 of the analysis and are ranked below. As part of electrical generation efficiency BHC/CLF&P has proposed to utilize natural gas, which, as explained above, is the cleanest source of fuel available.

1. CCS
2. Electrical Generation Efficiency

4. Step 4 - Energy, Environmental, and Economic Impacts

CCS - Cost of Compliance

EPA requested that BHC/CLF&P provide an evaluation of the economic feasibility of CCS as part of Step 4 of the CT BACT analysis. Control options considered in this step therefore include application of CCS technology, and plant energy efficiency. On Page 42 of the EPA PSD and Title V Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective, where the Guidance explained that, "[w]ith respect to the valuation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system."

The Guidance also acknowledges that construction and utilization of CSS at this time can result in high costs. See Guidance at 42-43. With regard to the CPGS project, the costs of constructing and operating CCS technology are projected to be extraordinarily high based on current technology. Even with the assumption that appropriate EOR opportunities could be identified in order to lower costs as compared to sequestration in deep saline aquifers or depleted coal seams, additional costs to the CPGS would include the following:

- Licensing of scrubber technology and construction of carbon capture systems;
- Significant reduction to plant output due to the high energy consumption of capture and compression systems;
- Identification of oil and gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long term contracts for CO_2 purchases;
- Construction of compression systems and pipelines to deliver CO_2 to EOR locations;
- Labor to operate, maintain, and monitor the capture, compression, and transport systems; and
- Issues regarding current project risk that would jeopardize ability to finance construction and to obtain Public Utility Commission (PUC) approval.

(BHC/CLR&P PSD Application, pg. 5-16)

The August 2010 Report of the Interagency Task Force on Carbon Capture and Storage[2] provides an estimate of capital and operating costs for carbon capture from natural gas systems, "[f]or a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million

[2] Available online at: http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

and an energy penalty of 15% would result from the inclusion of CO_2 capture." (August 2010 Report of the Interagency Task Force on Carbon Capture and Storage, pg. 33) Using the "Capacity Factor Method" for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering (AACE), CO_2 capture system capital cost for the CPGS is estimated to require an additional $196 million. Based on an estimated CPGS plant capital cost of $300 million, the capture system alone would thus be expected to add approximately 65% to the overall plant capital cost.

Actual cost per MW associated with CCS would likely be higher for CPGS than the referenced plant in the Interagency Task Force report due to the inclusion of simple cycle units in the CPGS design, which pose additional challenges. Simple cycle units would require capture systems to handle a much higher temperature gas flow for which there exists little or no pilot test data. Also, modifications to the absorption process may be required, including different materials of construction.

The energy penalty would also be higher for simple cycle systems that will be utilized in the CPGS design than for the combined cycle systems examined in the Interagency Task Force report. This is due to scrubber and compressors sized based on CT output, but overall unit output is lower for simple cycle turbines, causing the fractional energy penalty to be higher than for combined cycle units. BHC/CFL&P stated that whether plant size would remain the same with output reduced, or plant size were to be increased to account for lost output, the energy penalty alone represents at least a 15% increase to the fuel component of the cost of electricity. BHC/CFL&P estimates that at a cost of 8.9¢/kWh residential retail price for electricity, and assuming an annual average of 50% capacity factor for plant operation and 15% energy penalty, the value of lost electricity sales from the project is $12.9 million per year (BHC/CLF&P PSD Application, pg. 5-17).

The effort required to identify and negotiate with oil and gas companies who may be able to utilize the CO_2 in EOR would be substantial according to BHC/CLF&P. BHC/CLF&P is aware that the proposed Greencore pipeline is being substantially oversized, versus what would be required for only the Belle Creek EOR operation, so it is reasonable to assume project developers are planning that there will be a future need for CO_2 in the Powder River Basin or other locations in Wyoming or Montana. The location and timing of those sites, however, is not public information, and due to the patchwork of oil well ownership, many parties could potentially be involved in negotiations over CO_2 value (BHC/CLF&P PSD Application, pg. 5-17).

Due to the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are very specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight stage design. It is unclear whether the Interagency Task Force cost estimate noted above includes the required compression systems, but if not this represents another substantial capital cost. Pipelines must be designed to withstand the very high pressures (over 2000 psig), and the potential for corrosion if any water is introduced to the system. The most realistic scenario for CPGS would be to construct a pipeline from Cheyenne to tie into the proposed Greencore pipeline. At its closest point, the Greencore pipeline would be approximately 175 miles from Cheyenne. Based on engineering analysis done by the designers of that pipeline, costs for an eight inch CO_2 pipeline to connect the Cheyenne project to the Greencore pipeline are estimated at $600,000 per mile, for a total cost of $105 million. Thus, the cost to install the connecting pipeline alone would represent a 35% increase to the project cost, and the pipeline and capture system together would double the project capital cost (BHC/CLF&P PSD Application, pg. 5-17).

BHC/CLF&P believes it is unlikely that financing could be approved for CPGS if it were to combine electrical generation with CCS, given the technical and financial risks listed above. Also, as evidenced with utilities' inability to obtain PUC approval for integrated gasification / combined cycle (IGCC) projects due to unacceptable cost and risk to rate-payers, such as Wisconsin's disapproval of the We Energy project, BHC/CLF&P believes it is reasonable to assume that the same issues would apply in this case before the Wyoming PUC (BHC/CLF&P PSD Application, pg. 5-17, 5-18).

If BHC/CLF&P were to construct or pay for construction of the pipeline to deliver some (or all) captured CO_2 for use in EOR, it is possible that revenue from sale of the CO_2 could be realized. However, current market pricing for CO_2 delivered for EOR is proprietary and confidential, and reliable sources of information could not be identified within the scope of this BACT analysis.

In summary, capital cost for capture system and pipeline construction are estimated at $300 million, and the retail value of lost power sales due to the CCS system energy penalty is estimated at $12.9 million per year, assuming only 50% plant capacity factor. Other costs, such as identification, negotiation, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; less favorable financing terms or inability to finance; and difficulty in obtaining PUC approval would also impact the project. As stated earlier, it is unclear if compression systems are included in the Interagency Task Force estimate of capture system costs, which could pose additional costs. A fraction of these costs could possibly be offset through the sale of CO_2, but BHC/CLF&P has stated that the addition of CCS, with or without EOR opportunity, would make the CPGS project economically unviable. Therefore, for the reasons presented above, CCS is eliminated as an economically unviable control option for the CPGS project and will not be considered further.

Accordingly, the only control option left for the CTs is electrical generation efficiency.

5. Step 5 - Select BACT

The CT proposed by BHC/CLF&P is the third most efficient turbine identified in Table 5 above and Table 7 below. While both Rolls-Royce turbines providing slightly higher efficiencies, they are not chosen as BACT technology for this project, for reasons explained below. As explained in the review of the three evaluation metrics presented below, the heat rate for the CPGS GE LM6000PF SPRINT CT, selected pursuant to the CPGS Business Plan, was found to favorably compare with other CTs and projects.

Turbine Energy Efficiency Comparison

Energy Impacts - The following table, Table 7, provides a direct comparison of the GE and Rolls-Royce CTs, which was also presented in Table 5, above. Although the Rolls-Royce CTs provide better efficiency there are other considerations that resulted in BHC/CLF&P's proposal to use the GE turbine. These were listed above in Step 1 and include the turbine's ability to meet its Business Plan (combustion efficiency, exhaust characteristics, size range, and consistency with other locations allowing for fleet experience, stocking of spare parts and turbine swap-outs), the plant system, and operational criteria.

Table 7 – Comparison of Selected Turbine with Higher Efficiency Turbines of Comparable Electrical Production

Turbine	Production (kW)	Gross Heat Rate (Btu/kWh) HHV	Efficiency (%)
GE LM6000PF Sprint	38,649	9,079	37.6
Rolls-Royce Trent 60 DLE	41,537	9,064	37.7
Rolls-Royce Trent 60 DLE ISI	46,612	8,913	38.3

General Electric Combustion Turbine Design Elements

As demonstrated above, the GE LM6000PF SPRINT CT has high efficiency which is equal to or greater than the majority of other turbines with comparable electrical production capacity. However, the differences in efficiency from offerings of other vendors are in some cases very small. The design elements of those turbines that result in high efficiency undoubtedly vary between vendors, and in many cases are proprietary and confidential. However the issue was discussed by BHC/CLF&P with the selected turbine vendor, GE, and they offered comments on the unique elements of their design. This information is provided in Appendix B-4 of the application submitted to EPA by BHC/CLF&P.

Some of the key elements noted by GE are dual shaft architecture, low shaft speed, modulation of shaft speed and air flow with power, and high operating pressure ratio. It should be noted that the electrical generator is provided as a combined unit with the GE LM6000PF SPRINT CT package, and has been engineered to match CT operating characteristics. Preliminary information gathered by BHC/CLF&P provided in their application indicates that the generator is greater than 98% efficient, so overall system efficiency is driven by the CT characteristics. The CPGS 2-on-1 combined cycle system will also utilize a steam turbine and HRSG. Steam turbines manufactured today for small combined cycle plants have efficiencies limited by the metal design temperatures and pressures. The steam turbine is custom engineered rotating machinery where the efficiency is optimized in the blade path design, which maximizes the energy extracted from the steam. HRSG efficiency is maximized in the design by selecting aggressive approach and pinch points to extract the maximum heat out of the gas turbine exhaust stream. The efficiency is further improved by tube bundle arrangement, finned tubing and back end recirculation and or condensate preheating.

RACT/BACT/LAER Clearinghouse (RBLC) Efficiency Comparison

The RBLC information presented in Table 8 below, provided by BHC/CLF&P, compares efficiencies for projects with CTs in the same nominal 40 MW size range as the CPGS project. The information presented is for CTs operating in simple cycle. No information was found by BHC/CLF&P or EPA for comparable 40 MW combined cycle units without duct burning.

Table 8
RBLC Efficiency Information – Simple Cycle

Facility	State	Description	Heat Capacity MMBtu/hr (HHV)	Net MW	Heat Rate Btu/kWh (HHV)	Calculated Efficiency (%)
Western Farmers Electric	Oklahoma	Simple Cycle Combustion Turbine	462.7	50	9,254	36.9
El Colton, LLC	California	LM6000 (Enhanced Sprint)	456.5	48.7	9,374	36.4
Bayonne Energy Center	New Jersey	Rolls Royce Trent 60WLE	603	64	9,422	36.2
Creole Trail LNG	Louisiana	Simple Cycle Combustion Turbine	290	30	9,667	35.3
Arvah B. Hopkins Generating Station	Florida	GE LM6000PC, Simple Cycle	489.5	50	9,790	35
Indigo Energy Facility	California	LM6000 (Enhanced Sprint)	450	45	10,000	34.1
Lambie Energy Center	California	GE LM6000PC, Simple Cycle	500	49.9	10,020	34.1

Note: 1.108 was used for the HHV/LHV conversion factor.

The CTs compared above are similar in size to those planned for the CPGS project. This analysis and the resulting CPGS proposed permit limits are based on use of a turbine with simple cycle gross heat rate of 9,263 Btu/kWh (HHV). An exact comparison cannot be made between the CPGS CTs and those listed in Table 8 above because each project has unique equipment and site conditions, primarily elevation and temperature. However, the CPGS heat rate compares very favorably with all of the reviewed comparable projects listed above, which demonstrates the high-efficiency attributes of the CPGS project. The only project listed above with a lower heat rate is Western Farmers Electric, which is a slightly larger CT (approximately 10 MW larger). Therefore it is not surprising that this project is slightly more efficient on a CT heat rate basis.

CO_{2e} Emission Rate Comparison

In simple-cycle operation, the CPGS turbines are estimated to produce 1,102 pounds of CO_{2e}/MWh at average ambient conditions and full-load operation. Considering the range of normal operating loads (50% to 100% generator output), and ambient temperatures (0 degrees Fahrenheit to 108 degrees Fahrenheit), GHG emissions for the CPGS simple-cycle CTs range from 1,072 to 1,603 pounds of CO_{2e} for new and clean CT prior to any degradation.

In combined-cycle operation, GHG emissions for the CPGS 2x1 combined-cycle system ranges from 833 to 985 lb CO_{2e}/MWh for a new or clean CT prior to any degradation (again considering the range of normal operating loads, 50% to 100% output, and ambient temperature, 0 degrees Fahrenheit to 108 degrees Fahrenheit).

The information below, in Table 9, was provided by BHC/CLF&P and presents operating information from the EPA Acid Rain database, and was developed using actual comparable operating unit information from 2010.

Table 9
CPGS Comparable Unit GHG Emissions

State	Facility Name	Unit ID	Operating Time (hr)	Net Load (MWh)	CO_2 (Tons)	lb CO_2/MWh
CA	El Cajon Energy Center	1	242	9450	5652	1196
OK	Horseshoe Lake	10	710	29,293	18,142	1,239
OK	Horseshoe Lake	9	174	6,851	4,248	1,240
CA	Orange Grove Project	CTG1	632	25,017	15,734	1,258
CA	Orange Grove Project	CTG2	654	24,954	15,847	1,270
FL	Arvah B Hopkins	HC4	903	27,627	17,623	1,276
FL	Polk*	2	249	27,652	18,500	1,338
FL	Arvah B Hopkins	HC3	662	18,283	12,529	1,371
FL	Polk*	5	476	51,662	36,111	1,398
FL	Polk*	4	563	60,221	42,443	1,410
FL	Polk*	3	204	23,176	16,600	1,432
NJ	Bayonne Plant Holding, LLC	2001	1,055	35,582	28,385	1,595
NJ	Bayonne Plant Holding, LLC	1001	1,208	39,061	32,004	1,639
NJ	Bayonne Plant Holding, LLC	4001	1,134	36,629	30,200	1,649
NE	C W Burdick	GT-3	24	426	399	1,871
NE	C W Burdick	GT-2	33	606	579	1,912
CA	Escondido Energy Center, LLC	CT1A	28	345	466	2,702
CA	Escondido Energy Center, LLC	CT1B	28	345	468	2,718

Notes: *Net load 5% lower than gross load
Data based on EPA Clean Air Markets - Data and Maps
(available online at:http://www.epa.gov/airmarkets)
Based on 2010 data

The proposed CPGS combined cycle CT GHG limit of 1,100 lb/MWh (see Table 10 below) compares favorably with the facilities shown Table 9 above. The proposed simple cycle GHG limit of 1,600 lb/MWh (also in Table 10 below) does not appear to be as favorable when compared to Polk, Arvah B Hopkins, Horseshoe Lake, or El Cajon Energy Center; however, BHC/CLF&P provided the following explanation.

Allowance must be given for load variances, impact of ambient conditions, startup and shutdown, and equipment degradation over time. In reviewing the information from Table 9, a large variance in CO_2 lb/MWh emission can be seen (1,196 to 2,718 lb/MWh). All of the units listed in Table 9 can be considered to be "peaking" units, due to the low number of annual operating hours. The resultant wide variance in pounds of CO_2/MWh may likely be attributed to the significant proportion of time in startup and shutdown and/or reduced load operation.

Based on explanations from BHC/CLF&P described above, EPA proposes the following emission limits:

Table 10 - Proposed CPGS Combustion Turbine CO_{2e} Permit Limits

Emission Unit	Annual CO_{2e} Limit (Pounds/MWhr)	Annual CO_{2e} Limit (Tons/Year)
Combined Cycle Combustion Turbine CT01A	1,100	187,318
Combined Cycle Combustion Turbine CT01B	1,100	187,318
Simple Cycle Combustion Turbine CT02A	1,600	187,318
Simple Cycle Combustion Turbine CT02B	1,600	187,318
Simple Cycle Combustion Turbine CT03A	1,600	187,318

We note that on April 13, 2012, EPA published a Federal Register notice (77 FR 22392) which proposes a GHG emission standard , under a new subpart TTTT of 40 CFR Part 60 (New Source Performance Standards), of 1,000 lb/MWh for combined cycle CTs, on a 12-month annual average basis, at electric utility power plants. Simple cycle CTs are proposed to be exempted from NSPS GHG emission standards. The definition of BACT in PSD rules at 40 CFR 52.21(b)(12) states that "In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61." In light of this relationship between the NSPS and BACT and emissions limits that had been examined for this permit, BHC/CLF&P wrote to EPA on May 3, 2012 to explain that if the combined cycle CTs at this project are operated at less than 75% of maximum load (which is an expected operating scenario for this proposed facility, given the peaking role it is intended to serve), then the proposed NSPS emission limit will be exceeded. However, in that same letter, BHC/CLF&P indicates that they understand they will have to comply with the standards established in the final NSPS rule.

B. Auxiliary Combustion Equipment

In addition to the five CTs planned for the CPGS project, there are several other small combustion sources associated with auxiliary equipment which will operate at the plant. The GHG calculations for these small combustion sources are located in Appendix B-1 to BHC/CLF&P's GHG PSD permit application.

- EP06 - EP11 - (6) Natural gas-fired inlet air heaters (nominal 16-MMBtu/hr air heater with estimated emissions of 4,117 CO_{2e} tpy each), required for safety to prevent icing of air handling systems
- EP18, EP19 - (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_{2e} tpy each)
- EP15 - (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 225 CO_{2e} tpy)
- EP16 - (1) Diesel-fired fire pump (nominal 327-BHP engine with estimated 51 CO_{2e} tpy)

The total GHG emissions from the above small combustion sources are minor as compared to the emissions from the CTs. Therefore, the auxiliary combustion equipment GHG emission sources were evaluated in aggregate below.

1. Step 1 - Identify All Control Technologies

The available control technologies for the CPGS auxiliary combustion equipment GHG sources are identical to those identified for the CTs, with the exception that there is the potential for fugitive emissions of SF_6 and CH_4 at the auxiliary equipment, so fugitive emissions are considered here. These options include:

- CCS;
- Small Combustion Source Efficiency;
- Efficient Use of Energy; and
- Minimization of fugitive emissions (SF_6 and CH_4).

Small Combustion Source Efficiency

EP06 - EP11, Inlet Air Heaters

The inlet air anti-icing heater is similar to a conventional natural gas fired watertube boiler, and is required for safety reasons to prevent icing during winter weather. However, the water does not reach the boiling point in this system and a mixture of water and glycol is used for its thermodynamic advantages over water. The unit is designed for quick load response eliminating the requirement for a stored energy system and associated efficiency losses. Combusted natural gas is used to directly heat the incoming water/glycol mixture. Other technologies available for heating the water/glycol mixture include an indirect fired water bath heater or fire tube boiler. The fire tube boiler has similar efficiency but a much higher capital cost. The indirect fired water bath heater has a lower efficiency resulting in higher operating costs and increased emissions. With both cost and environmental operations considered, these two options are not economical for this application.

EP18 - EP19, Fuel Gas Heaters

Indirect water/glycol bath heaters were selected for heating of high-pressure natural gas.
The natural gas is heated to ensure a measure of superheat before reaching the CT generator. Indirect heaters use a fire tube to transfer heat from the fired natural gas (fuel) to the water/glycol solution. The heat is then transferred from the water/glycol bath to the natural gas coil (product) in a safe manner.

EP15, Diesel Emergency/Standby Generator & EP16, Diesel Fire Pump Engine

While BHC/CLF&P has not made the final selection of CPGS emergency diesel equipment, BHC/CLF&P has informed EPA that the potential choices of diesel equipment comply with relevant NSPS emissions standards for these types of equipment and be will evaluated to ensure that the final selection has a high efficiency design. Regardless of specific equipment selected, the potential GHG emissions from these units would be minimal, and the available control options will be evaluated in light of that fact.

Efficient Use of Energy

The small combustion sources will not be operated continuously, but only during conditions when they are needed. For example, the inlet air heaters and fuel gas heaters will be operated only when required for safety reasons to protect against icing of the turbines or condensation within the fuel lines. Therefore, energy will be utilized in an efficient manner.

2. Step 2 - Eliminate Technically Infeasible Options

CCS - Auxiliary Combustion Equipment

For the same reasons as those presented for the turbines, CCS is considered economically unviable for such small combustion sources at a plant not otherwise equipped to capture and compress CO_2.

Fuel Gas Heater - Direct Heating

Although direct heating of natural gas is more efficient than indirect heat when considering heating technology for the fuel gas heaters, it is extremely dangerous and not recommended. With direct heating, any small manufacturing defect, failure, or leak may result in catastrophic explosions as the product (natural gas) is exposed to an open flame/heat source. Accordingly, indirect heating is considered the only technically feasible option due to the safety reasons with direct heating.

3. Step 3 - Rank Remaining Control Technologies

The remaining technically feasible GHG control technologies for auxiliary combustion equipment at the CPGS project are “Small Combustion Source Efficiency” and “Efficient Use of Energy.”

4. Step 4 - Energy, Environmental, and Economic Impacts and Level of Control

“Small Combustion Source Efficiency” and “Efficient Use of Energy” will both be implemented. Neither option is eliminated at Step 4.

5. Step 5 - Select BACT

GHG BACT for the CPGS auxiliary combustion equipment consists of selecting equipment with consideration for high design efficiency, and operation of that equipment in an energy-efficient manner. To ensure energy-efficient operation, the BACT limits in Table 11 below shall apply. These limits have been calculated based on information provided by BHC/CLF&P and equipment vendors. For detailed information see BHC/CLF&P’s permit application, Appendix B-8 and B-9 for the inlet air heaters; Appendix B-10 and B-11 for the fuel gas heaters; Appendix B-12 for the diesel emergency/standby generator; and Appendix B-13 for the diesel fire pump engine.

The following BACT limits apply to the auxiliary combustion equipment:

Table 11 – Proposed BACT limits for CO_{2e} from Auxiliary Combustion Equipment

Source ID.	Emission Point/Equipment	Limitations (All numeric limits are based on a 365-day rolling average)
EP06 - EP11	Natural Gas-Fired Inlet Air Heaters #1 - #6	4,117 tpy CO_{2e} per heater Fuel: pipeline quality natural gas
EP18 - EP19	Natural Gas-Fired Fuel Gas Heater #1 and #2	1,153 tpy CO_{2e} per heater Fuel: pipeline quality natural gas
EP15	Diesel Emergency/Standby Generator	226 tpy CO_{2e} Not to exceed 500 hours of operation per 12-month period EPA Tier 2 (or Better) Certified Engine Rated at $\leq$ 839 bhp Diesel fuel (#2 grade fuel oil or better)
EP16	Diesel Fire Pump Engine	51 tpy CO_{2e} Not to exceed 250 hours of operation per 12month period EPA Tier 3 (or Better) Certified Engine Rated at $\leq$ 327 bhp Diesel fuel (#2 grade fuel oil or better)

C. Fugitive Emission Sources

EPA has reviewed and concurs with BHC/CLF&P's Fugitive Emission Sources BACT analysis. Based on Black Hills' BACT analysis for fugitive emissions, EPA concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the appropriate BACT control technology option, with a leak rate of 1% or less, which BHC/CLF&P stated is an industry standard leak rate. The proposed GHG PSD permit, if finalized, includes nine new 60 lb SF_6 insulated circuit breakers for a total of 540 lbs of SF_6. Assuming that the leak rate is 1% or less, this equates to 5.4 lbs/year (0.0027 tpy) of SF_6 that will be leaked or emitted to the atmosphere. The global warming potential of SF_6 is 23,900 from 40 CFR Part 98, which equates to 64.5 tpy CO_{2e} from the SF_6 equipment. BHC/CLF&P will monitor the SF_6 emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.

The annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD1 of 40 CFR Part 98, Subpart DD.

Sources of fugitive methane (CH_4) emissions include the emissions from piping, valves, flanges and on site compression totaling 16 tpy CH_4, or 336 tpy CO_{2e} (see November 22, 2011 letter from BHC/CLF&P responding to questions from EPA). The annual CH_4 emissions will be calculated according to the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems.

EPA concurs with and adopts BHC/CLF&P's proposed best work practice standards as BACT for control of CH_4 emissions from fugitive emission sources; and these work practice standards are included in the draft permit at Section III.D.2.

Table 12 – Proposed BACT Limits for CH4 and SF6 from Fugitive Emission Sources

Unit ID. No.	Unit Description	GHG Pollutants (Mass Basis)		GHG CO_{2e}
		Pollutant	TPY	TPY
NG-FUG	Fugitive natural gas emissions from valves, flanges and on site compressor	CH4	16	336
SF6-FUG1 through SF6-FUG9	9 SF_6 circuit breakers 60 lbs SF_6 each breaker 1% SF_6 leak rate or better With leak detection	SF_6	0.0027 (5.4 lbpy)	64.5

IX. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes the federal executive policy on EJ. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA maintains an ongoing commitment to ensure EJ for all people, regardless of race, color, national origin, or income. Ensuring EJ means not only protecting human health and the environment for everyone, but also ensuring that all people are treated fairly and are given the opportunity to participate meaningfully in the development, implementation, and enforcement of environmental laws, regulations, and policies.

Based on the EO, the EPA's Environmental Appeals Board (EAB) has held that EJ issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices. *See, e.g., In re Prairie State Generating Co.,* 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 174-75 (EAB 1999). This permitting action, if finalized, only authorizes emissions of GHGs and does not select environmental controls for any other pollutants. Climate change modeling and evaluations of risks and impacts is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. As a result, quantifying the exact impacts in specific places and points attributable to a specific GHG source obtaining a permit would not be possible (Guidance, pg. 48). Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an EJ analysis is not necessary for this permitting record.

X. Conclusion and Proposed Action

Based on the information supplied by BHC/CLF&P, our review of the analyses contained in the WDEQ PSD Permit Application and in the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHG under the terms contained in the draft permit. Therefore, EPA is proposing to issue BHC/CLF&P, a PSD permit for GHG for the CPGS, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received (if any) during the public comment period.

United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
May 21, 2012

Draft
Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

PSD-WY-000001-2011.001

Permittee:
Cheyenne Light, Fuel & Power / Black Hills Corporation
P.O. Box 1400
625 Ninth Street
Rapid City, South Dakota 57709

Permitted Facility:
Cheyenne Generating Station
Laramie County, Wyoming

Table of Contents

Table of Acronyms

BACT	Best Available Control Technology
bhp	Brake Horse Power
Btu/hr	British Thermal Units per Hour
CatOx	Catalytic Oxidation
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CGS	Cheyenne Generating Station
CH_4	Methane
CLF&P	Cheyenne Light, Fuel & Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
dscf	Dry Standard Cubic Foot
EP	Emission Point
FIP	Federal Implementation Plan
FR	Federal Register
FTIR	Fourier Transform Infra-Red Spectroscopy
GC-FID	Gas Chromatograph-Flame Ionization Detector
GE	General Electric
GHG	Greenhouse Gas
gr	Grains
HHV	High Heating Value
hr	Hour
HRSG	Heat Recovery Steam Generator
kWh	Killowatt-Hour
lb	Pound
lbpy	Pounds Per Year
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatt
MWh	Megawatt-Hour
N_2O	Nitrous Oxide
NSPS	New Source Performance Standards
NO_x	Nitrogen Oxides
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
Scf/hr	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
tpy	Tons Per Year
VOC	Volatile Organic Compounds
%	Percent

I. INTRODUCTION

This Federal PSD permit is being issued under authority of 40 CFR 52.21 (PSD) and 52.37 (FIP to issue permits under the PSD requirements to sources that emit GHG). Cheyenne Light, Fuel & Power (hereinafter the "Permittee") proposes to construct a new nominal 220 MW gross simple and combined cycle natural gas-fired combustion turbine power plant in Laramie County, Wyoming. The plant, the Cheyenne Plains Generating Station, will be located five miles southeast of downtown Cheyenne along Interstate 80. Cheyenne Light, Fuel and Power Company is a wholly owned subsidiary of Black Hills Corporation and was acquired from Xcel Energy in 2005. Cheyenne Light, Fuel and Power Company provides electric utility service to Laramie County, Wyoming. The Cheyenne Prairie Generating Station will include three simple cycle General Electric LM6000 PF SPRINT natural gas turbines, and two General Electric LM6000 PF SPRINT turbines operated in a 2-on-1 combined cycle configuration (each turbine exhausts to its own HRSG and that steam is routed to a single steam turbine electric generator). In addition to the turbines the facility will include one wet cooling tower for the combined cycle steam turbine; three electric chiller units, each with cooling towers, for inlet air cooling for the turbine inlet air; six natural gas-fired inlet air heaters to heat the turbine inlet air, two natural gas-fired fuel gas heaters, one diesel emergency generator, and one diesel fire pump.

II. GENERAL PERMIT CONDITIONS

On the basis of findings set forth in Section III Special Permit Conditions, of this permit, and pursuant to the authority (as delegated by the Administrator) of 52.21(u), EPA hereby conditionally authorizes Black Hills Corporation to construct the Cheyenne Prairie Generating Station. The authorization is expressly conditioned as follows:

A. PERMIT EFFECTIVE DATE AND EXPIRATION

As provided in 40 CFR 124.15(b), this PSD permit shall become effective 30 days after the service of notice of the permit decision, unless:

1. a later effective date is specified in the decision;

2. review is requested on the permit under §124.19; or

3. no comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

As provided in 40 CFR 52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time; and,

4. EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

The Permittee shall notify EPA in writing of:

1. the date construction is commenced, postmarked within 30 days of such date;

2. the actual date of initial startup, postmarked within 15 days of such date. Startup means the setting in operation of an affected facility for any purpose;

3. the date upon which initial performance tests will commence, in accordance with the provisions of Section V., Shakedown Periods, of this permit, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B.; and

4. the date upon which certification tests of the CO_2 CEMS will commence in accordance with 40 CFR § 75.61(a)(1)(i) and 40 CFR Part 60, Appendix B, Performance Specification 3. Additionally, the initial certification or recertification application shall be submitted for the CO_2 CEMS as required by 40 CFR 75.63.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall maintain and operate the facility including associated air pollution control equipment (including SCR and CatOx) in a manner consistent with good air pollution control practice for minimizing GHG emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. The Permittee shall notify EPA by mail within two working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO_{2e} emissions above the allowable emission limits stated in Condition III.A., of this permit.

2. In addition, the Permittee shall notify EPA in writing within 15 days of any such failure described under Section IV Recordkeeping Requirements. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Condition III.A., and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed under this permit, this PSD Permit is binding on all subsequent owners and operators. The Permittee shall notify, by letter, the succeeding owner and operator of the existence of this PSD Permit and its conditions. A copy of the letter shall be provided to EPA within 30-days of the letter signature. Permit transfers shall be made in accordance with 40 CFR Part 122, Subpart D.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

The Permittee shall construct and operate this project in compliance with this PSD Permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This

PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. BINDING APPLICATION

This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Permittee's application to EPA dated September 23, 2011, and subsequent information provided by the Permittee to EPA, as listed in the Administrative Record for issuance of this permit.

The Permittee shall abide by all representations, statements of intent and agreements contained in the permit application and subsequent submittals as listed in the Administrative Record. EPA shall be notified no less than 10 days in advance of any significant deviation from the permit application as well as any plans, specifications or supporting data furnished. The issuance of this PSD Permit to Construct and Operate may be suspended or revoked if EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been, or is to be, made.

J. ENFORCEABILITY OF PERMIT

On the effective date of this permit, the conditions herein become enforceable by EPA pursuant to any remedies it now has or may have in the future, under the Clean Air Act.

K. TREATMENT OF EMISSIONS

Emissions in excess of the limits specified in this permit shall constitute a violation.

III. SPECIAL PERMIT CONDITIONS

A. POINT SOURCE EMISSION LIMITS

At all times, including during startup, shutdown and malfunction, the Permittee shall not allow the discharge of GHG emissions from each unit into the atmosphere, in excess of the following:

Table 1: Emission Limits

Source ID.	Emission Point/Equipment	Limitations (All numeric limits are based on a 365-day rolling average)
EP01 - EP02	CT01A and CT01B - GE LM6000PF SPRINT Combined Cycle Combustion Turbine (366 MMBtu/hr) with HRSG #1, SCR and CatOx	• 1100 lb CO_{2e} /MWh per turbine • 187,318 tpy CO_{2e} per turbine • Fuel: pipeline quality natural gas
EP03 - EP05	CT02A, CT02B, CT03A - GE LM6000PF SPRINT Simple Cycle Combustion Turbine (366 MMBtu/hr) with SCR and CatOx	• 1600 lb CO_{2e}/MWh per turbine • 187,318 tpy per turbine • Fuel: pipeline quality natural gas
EP06 - EP11	Natural Gas-Fired Inlet Air Heaters #1 - #6	• 4,117 tpy CO_{2e} per heater • Fuel: pipeline quality natural gas
EP12 - EP14	Inlet Air Chillers	N/A
EP15	Diesel Emergency/Standby Generator	• 226 tpy CO_{2e} • Not to exceed 500 hours of operation per 12-month period • EPA Tier 2 (or Better) Certified Engine • Rated at $\leq$ 839 bhp • Diesel fuel (#2 grade fuel oil or better)
EP16	Diesel Fire Pump Engine	• 51 tpy CO_{2e} • Not to exceed 250 hours of operation per 12-month period • EPA Tier 3 (or Better) Certified Engine • Rated at $\leq$ 327 bhp • Diesel fuel (#2 grade fuel oil or better)
EP17	Wet Cooling Tower	N/A
EP18 - EP19	Natural Gas-Fired Fuel Gas Heater #1 and #2	• 1,153 tpy CO_{2e} per heater • Fuel: pipeline quality natural gas

B. REQUIREMENTS FOR COMBUSTION TURBINE

1. Compliance with Combustion Turbine Generator (CTG) BACT Emission Limits

a. To demonstrate compliance with the lb CO_{2e}/MWh BACT emission limits (for Units EP01-EP05), the Permittee shall calculate the pounds of CO_{2e} emitted hourly from the equations provided in 40 CFR Part 75 Appendix G or the CO_2 emissions CEMS data, and divide the emissions value by the measured net hourly energy output (MWh (net)). The result shall be expressed on a 365-day rolling average.

b. The Permittee shall determine the hourly stack gas volumetric flow rate using one of the following methods:
   i. Using 40 CFR Part 75, Appendix G, using F_c factors updated monthly from fuel analysis; or
   ii. Installing and operating a volumetric stack gas flow monitor and associated data acquisition and handling system in accordance with the CO_2 CEMS system requirements provided in 40 CFR § 75.10(a)(3) and (a)(5).

2. CO_2 Emission Monitor or CO_2 CEMS

a. The Permittee shall install, calibrate, and operate a CO_2 emission monitor for each emission unit, EP01-EP05, and shall meet the applicable requirements, including certification testing, of 40 CFR Part 60, Appendix B, Performance Specification 3, and 40 CFR Part 75. This monitor shall be used in conjunction with the F_c factor and conversion procedures in 40 CFR Part 75, Appendix F, to calculate the volumetric stack gas flow rate.

b. As an alternative to Condition III.B.2.a., the Permittee may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

c. In accordance with 40 CFR § 75.4(b), the Permittee shall ensure that all required CO_2 monitoring system/equipment are installed, and all certification tests are completed, on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR § 72.2).

d. The Permittee shall comply with the specifications and test procedures for CO_2 CEMS at 40 CFR 75.13 and related requirements in Appendices A, B and G of Part 75.

e. The Permittee shall comply with the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO_2 CEMS.

3. **Combustion Turbine Work Practice and Operational Requirements**

a. The Permittee shall calculate the amount of CO_2 emitted from CTG EP01-EP05 in tons/hr, averaged daily and converted to tpy on a 365-day rolling average, based on equation G-4 of 40 CFR Part 75 and the average net heat rate on an hourly basis based on the heat input calculation procedures contained in 40 CFR Part 75, Appendix F, equation F-20.

b. The Permittee shall compare the calculated CO_2 emissions from Special Condition III.B.3.a. to the measured CO_2 emissions from the CO_2 emission monitor, required in Condition III.B.2.a., and the calculated hourly stack gas volumetric flow rate, required in Condition III.B.1.c., on a daily basis. If the Permittee finds that the mean difference between the calculated and measured CO_2 emission monitor result is greater than 10% of measured CO_2 concentration, the Permittee shall review the operational performance of the emission units and monitoring instrumentation. From this review, any necessary corrective measures to restore the difference to less than 10% shall be identified and recorded by the Permittee, including the reason for the CO_2 emissions difference. The Permittee shall complete corrective measures within 48 hours of identification of a difference of greater than 10%, to restore the difference to less than 10%. If the Permittee chooses to install and operate a CO_2 CEMS equipped with a volumetric stack gas monitoring system, then the CO_2 emission calculation from Condition II.B.3.a and the mean difference comparison shall not be required, and the Permittee shall rely instead on the data from the CO_2 CEMS for compliance purposes.

c. The Permittee shall calculate the CH_4 and N_2O emissions on a 365-day rolling average. The Permittee shall determine compliance with the CO_{2e} emissions limits in Condition III.A., using the default CH_4 and N_2O emission factors contained in Table C-2 of 40 CFR Part 98 and the measured actual hourly heat input (HHV).

d. The Permittee shall calculate the CO_{2e} emissions on a 365-day rolling average, based on the procedures contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A using the Global Warming Potentials (GWP) listed in Table A-1 of 40 CFR Part 98, Subpart A.

e. The Permittee shall determine the gross calorific value of the fuel monthly using the procedures contained in 40 CFR Part 75, Appendix F, § 5.5.2, and shall maintain records of the monthly fuel gross calorific value for a period of five years. Upon request by EPA, the Permittee shall provide a sample and/or analysis of the fuel fired in the Combustion Turbines, or shall allow a sample to be taken by EPA for analysis.

f. The Permittee shall install, maintain and operate a non-resettable elapsed flow meter, to measure the flow rate of the fuel combusted in emission units EP01-EP05.

g. The Permittee shall measure and record the net energy output (MWh_{net}) on an hourly basis.

h. The Permittee shall maintain and operate units EP01 and EP02, each with HRSGs equipped with SCR and CatOx, and EP03-EP05 each equipped with SCR and CatOx, to ensure the GHG emissions are continuously at or below the emissions limits specified in this permit.

C. REQUIREMENTS FOR AUXILIARY COMBUSTION EQUIPMENT

1. The Permittee shall install, maintain and operate a non-resettable elapsed time meter for the Diesel Emergency/Standby Generator (EP15) and the Diesel Fire Pump Engine (EP16).

2. The Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the diesel fired engines, EP15 and EP16. This may include, but is not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of EP15 and/or EP16; for each diesel fuel oil delivery, documents from the fuel supplier certifying the fuel heat input values required to show compliance with the heat rate limitations in Condition III.A., hours of operation; and all other information required by this permit recorded in a permanent form suitable for inspection. The Permittee must retain the file for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. FUGITIVE EMISSION SOURCES

1. **Fugitive Emission Sources Emission Limits**

At all times the Permittee shall not discharge from the source, or cause the discharge, of fugitive emissions from each unit into the atmosphere in excess of the following:

Table 2: Fugitive Emission Sources Emission Limits

Unit ID. No.	Unit Description	GHG Pollutants (Mass Basis)		GHG CO_{2e}
		Pollutant	**TPY**	**TPY**
NG-FUG	Fugitive natural gas emissions from valves, flanges and on site compressor	CH_4	16	336
SF_6-FUG1 through SF_6-FUG9	9 SF_6 circuit breakers 60 lbs SF_6 each breaker 1% SF_6 leak rate or better With leak detection	SF_6	0.0027 (5.4 lbpy)	64.5

2. **Fugitive Emission Sources Work Practice and Operational Requirements**

a. For CH_4 emissions from sources NG-FUG, emissions shall be calculated by the Permittee annually (calendar year). Emissions shall be calculated based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems.

b. For SF_6 emissions from sources SF_6-FUG1 through SF_6-FUG9, emissions shall be calculated by the Permittee annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD.

c. The Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emissions sources (NG-FUG and SF_6-FUG1 through SF_6-FUG9) including, but not limited to, the following: all records or reports pertaining to maintenance performed, equipment replacement, and all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.

IV. RECORDKEEPING REQUIREMENTS

A. Including any recordkeeping requirements specified elsewhere in this permit, the Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the limitation to burn diesel fuel in Condition III.A.; and other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

B. The Permittee shall maintain the following records for at least five years, including:

1. the occurrence and duration of any startup, shutdown, malfunction;
2. duration of any initial shakedown period for the emission units, pollution control units and CEMS;
3. performance testing of emission units for demonstrating compliance with this permit;
4. CEMS emission measurements**;**
5. CEMS testing, maintenance and calibration checks conducted to satisfy quality assurance requirements;
6. the time and duration of any periods that monitoring devices are not operating; and
7. any emission data required by this permit.

C. The Permittee shall maintain records of all GHG emission units and CO_2 emission CEMS certification tests and monitoring and compliance information required by this permit.

D. The Permittee shall maintain records of any exceedance of limitations in this permit and submit a written report of all exceedances to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator of authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

1. time intervals, data and magnitude of the exceedance, the nature and cause (if known), corrective actions taken and preventative measures adopted;

2. applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);

3. if no exceedances of a permit limit occurred during the reporting period or the monitoring equipment has not been inoperative, repaired or adjusted, a statement that no exceedance of that limit occurred, and/or that the monitoring equipment has not been inoperative, repaired or adjusted (as applicable), shall be submitted;

4. any failure to conduct any required source testing, monitoring, or other compliance activities; and

5. any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator of fire pump.

E. Exceedance shall be defined as any period in which the facility emissions or other parameter of operation exceed a maximum limit set forth in this permit.

F. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

G. All records required by this PSD Permit shall be retained for not less than five years following the date of such measurements, maintenance, and reports.

V. <u>SHAKEDOWN PERIODS</u>

The shakedown period is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period between initial startup and the deadline for initial performance testing specified in Condition VI.A.

VI. PERFORMANCE TESTING REQUIREMENTS

A. The Permittee shall conduct a performance test to establish the actual quantities of CO_{2e} being emitted into the atmosphere from one of the five identical combustion turbines and to determine compliance with the annual CO_{2e} emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO_2. The test shall be conducted by the Permittee within one calendar year of initial startup and a written report of the performance testing results shall be furnished by the Permittee to the EPA.

B. The Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted by the Permittee in accordance with the submitted protocol, and any changes required by EPA.

C. Fuel sampling for emission units EP01-EP05 shall be conducted by the Permittee in accordance with 40 CFR Part 75 and Part 98.

D. Each turbine tested by the Permittee shall be at or above 90% of maximum load operations. Tested turbine load shall be identified by the Permittee in the sampling report. The Permittee shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Condition III.A.

E. The Permittee shall conduct performance tests under conditions that are representative of normal operation of the affected facility. The Permittee shall make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

F. The Permittee shall provide the EPA at least 30 days prior notice of any performance test, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the Permittee must provide at least 7 days prior notice of the rescheduled date of the performance test.

G. The Permittee shall provide, or cause to be provided, performance testing facilities as follows:

1. sampling ports adequate for test methods applicable to this facility;
2. safe sampling platform(s);
3. safe access to sampling platform(s); and
4. utilities for sampling and testing equipment.

H. Unless otherwise specified, each performance test conducted by the Permittee shall consist of three separate runs using the applicable test method. Each run shall be conducted by the Permittee for the time, and under the conditions, specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

VII. AGENCY NOTIFICATIONS

The Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Air Program (8P-AR)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

The Permittee shall submit a copy of all compliance and enforcement correspondence as required by this permit to:

Air Technical Enforcement Program (8ENF-AT)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

Authorized By: United States Environmental Protection Agency, Region 8

____
Callie A.Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Date: _______________________________

BLACK HILLS POWER & LIGHT CO.
BLACK HILLS GENERATION
A Black Hills Corporation Enterprise

Tim Rogers
Environmental Manager

605•721•2286

November 22, 2011

Chris Razzazian
USEPA Region 8
1595 Wynkoop Street
Mail Code 8P-AR
Denver, CO 80201-1129

RE: Black Hills Corporation: Cheyenne Generating Station – Response to Questions

Dear Mr. Razzazian:

Over the past couple of months, Black Hills Corporation and EPA exchanged phone conversations and emails discussing specific aspects of our Cheyenne Generating Station Greenhouse Gas PSD application submitted to EPA. This purpose of this correspondence is to respond to questions that were not answered and to provide a paper trail for the responses.

Question 1: In regards to the combustion turbine, can we propose how we will comply with limit?
Response: Black Hills will calculate hourly CO2 emissions using methodologies required by EPA's Clean Air Markets Division under 40CFR75 Appendix G and EPA's Mandatory Greenhouse Gas Reporting rule under 40CFR98 Subpart D.

CO2e Lb/MWhr Limit: To determine compliance with the 365 rolling day CO2e BACT emission limit for each combustion turbine, Black Hills will measure gross hourly energy output (MWh) from the generator and the hourly CO2 mass (tons) calculated using the 40CFR60/40CFR75 onsite continuous emission monitoring system (CEMS). For each operating hour the CO2 ton/hr emission rate will be determined according to 40CFR75 Appendix G, Section 2.3, Eq. G-4. Heat input shall be determined hourly using 40CFR75 Appendix F Section 5. At the end of each unit operating day, a new 365 day rolling average will be calculated by summing all valid hourly CO2 mass ton/hr data, multiplying by 2000 lbs/ton, and then dividing by the sum of all valid hourly gross MWh data generated. All valid CO2 lb/hr data in the 365 day period will be used and all valid gross megawatt hours will be used. Missing heat input (CO2 lb/hr) will be substituted according to the methodologies of 40CFR75 Appendix D Section 2.4. Megawatt substitution will follow a similar approach to 40CFR75 methods. The 365 day data availability will be maintained according to the typical 40CFR60 requirement target of greater than ninety percent. This CEMS 365 day rolling CO2 lb/MWh calculated average would be compared to the permit limit to determine compliance.

CO2e Ton/Year Limit: To determine compliance with the mass CO2e BACT emission limit (tons/year) for each combustion turbine, the limit will be calculated as noted above, except that the annual CO2 mass emission sum would not be multiplied by 2000 and would not be divided by the megawatt production sum, thus yielding tons of CO2 per calendar year.

Question 2: In regards to the inlet heater, Black Hills stated that the heaters will heat combustion air to prevent icing. Is the purpose of this device to maintain the 49 degree F ideal/optimal inlet air temperature for performance purposes?
Response: The inlet air heater is designed to raise the inlet air from -40 degrees F (worse case temperature scenario) to 0 degrees to meet GE emission guarantees. It will also provide the side benefit to prevent icing.

Question 3: In regards to the combustion turbine, inlet air heaters, and gas-line heaters, do these sources have separate stacks?
Response: These sources do have separate stacks.

Question 4: In regards to the diesel emergency generator and diesel fire water pump, has Black Hills locked into specific equipment yet?
Response: No, Black Hills does not plan on locking into specific equipment until the Spring/Summer of 2012. There are several reasons for not locking into equipment at this time such as technology advancements, prices, budgeting, and changes in site requirements.

EPA forwarded Region VI's proposed GHG permit for the Lower Colorado River Authority (LCRA) and were interested in Black Hills thoughts on some of the approaches taken in this permit. Black Hills is providing the following observations on the permit.

Fugitive emission requirements: The estimated fugitive emissions from the valves, flanges and compressor on site appear to be insignificant (16 ton/year – methane and 327 ton/year CO2e). Black Hills suggests that the sources be identified and emissions calculated annually, but there should not be a limitation on the number of devices.

Start-up and Shut-down limits: A lb/hr limitation was set for CO2e emissions for start-up and shut-down on combustion turbines. EPA's PSD and Title V Permitting Guidance for Greenhouse Guidance notes that longer-term averages are more appropriate than short-term averages for emission limits. For a natural-gas fired combustion turbine, the mass emission rate of CO_2 will in all cases be less than or equal to the full load emission rate during normal operation. Furthermore, the permit limits (lb/MWh and tpy) proposed by Black Hills for the CGS incorporate startup and shutdown emissions. A short-term permit limit serves no logical purpose and we suggest that it not be included in the CGS permit.

Auxiliary Combustion Equipment Emission Limits. The LCRA permit includes short-term (lb/hr) and annual (tpy) emission limits for the fire water pump and emergency generator. Again, the short term limit is contrary to the EPA guidance and serves no useful purpose. Such emissions would be calculated from fuel consumption and/or hours of operation. We suggest that the CGS permit include only longer-term emission limits and/or limits on hours of operation for auxiliary equipment.

Sulfur content limit in natural gas: The proposed permit appears to expound outside the Greenhouse Gas arena with establishing sulfur limits in the natural gas used (condition B.3(e) and C.2(a)). These limits will be addressed in the State Criteria Pollutant permit.

On a closing note, we continue to work on the Endangered Species Act and Cultural Heritage Assessments and will provide to you as soon as they are completed. Black Hills appreciates the open dialogue in this permit process and is certain it aid in developing sound and timely permit for this project.

If you have any questions related to our responses or with our observations on the LCRA, please contact me at 605-721-2286.

Sincerely,

Tim Rogers
Environmental Manager

Cc Fred Carl, BHC (email)
Tim Mordhorst, BHC (email)
Joe Hammond, CH2MHill (email)
Dennis Arfmann, Legal Counsel

Black Hills Corporation

Tim Rogers
Environmental Manager

605•721•2286

May 3, 2012

Chris Razzazian
USEPA Region 8
1595 Wynkoop Street
Mail Code 8P-AR
Denver, CO 80202-1129

RE: Cheyenne Prairie Generating Station (CPGS) site – CO2 BACT Limit

Dear Mr. Razzazian,

Black Hills Corporation (Black Hills) submitted a permit to construct application to EPA for a natural gas combustion turbine electrical generating facility to be located in Cheyenne, Wyoming. The facility is designed for five GE LM6000 PF Sprint combustion turbines with two of the turbines in a Combined Cycle Combustion Turbine (CCCT) configuration and three in Simple Cycle Combustion Turbine (SCCT) mode. The facility would nominally generate 220 megawatts.

The facility is being constructed to provide peak electrical demand in the Summer for our Cheyenne Light Fuel Power electrical utility, assist with the regulation of wind energy by supplementing this renewable energy, and to replace generation from three coal-fired power plants being retired in the Black Hills Power, Inc. electrical utility. The planned capacity factor for the units in the first couple of years of operation will fluctuate as we phase in the retirement of the coal generating units. Load fluctuation will also result from increasing renewable generation, commonly called renewable generation load following. As we explain below, and as you can see from the attached spreadsheet, such load fluctuating operation has an influence on the CO2 production per MWh generated for both the simple cycle and the combined cycle turbines.

In the application, Black Hills proposed a BACT limit of 1600 CO2 lb/MWh for the SCCT and 1100 CO2 lb/MWh for the CCCT. Please see the application for a full BACT analysis to support these requested limits. During the permit development process, EPA proposed a CO2 New Source Performance Standard (NSPS) rule for Electrical Generating Utilities (Subpart TTTT) that "EPA is proposing a standard of 1000 CO2 lbs/MWh, but…taking comment on a range from 950 lb CO2/MWh to 1,100 lb CO2/MWh." See 77 Fed. Reg. 22392, at page 22406. The proposed rule excluded SCCT from the limit due to the peaking nature of SCCT units and their inability to comply with this limit.

On April 24, 2012, Black Hills met with EPA Region VIII and EPA Headquarters staff to discuss the BACT CO2 limit as it would apply to this facility. Black Hills explained the business need for the proposed facility and provided more details on the manner in which the facility would be operated. EPA asked for this submittal. The following are the CPGS operating scenarios, more fully described in the attached spreadsheet:

CCCT:

1. Two on One – two combustion turbines operating with the steam turbine generator at various loads;
2. One on One – one combustion turbine operating with the steam turbine generator at various loads; and
3. One or Two on None – Either one or two combustion turbines operating at various loads when the steam turbine generator is malfunctioning and in a planned or unplanned outage.

SCCT:

1. These units would be operated in simple cycle mode, at various loads.

Load:

1. All combustion turbines could be operated from 50 to100 percent load, during normal operation, dependent upon the required electrical dispatch needs (i.e. replacing coal generation, renewable generation load following, etc.).

Black Hills conducted the attached analysis to assist in determining the proper CO2 BACT limits, considering the recently proposed NSPS.

The analysis involved calculating CO2 emissions based upon the operating scenarios described above using the manufacturer's performance runs on the combustion turbines at the following operating loads (50%, 75%, and 100%). The analysis also assessed CO2 emissions with no equipment degradation and a 10% degradation factor. The following are Black Hills observations of the attached analysis:

SCCT: In all of the cases analyzed, the SCCT could not meet the proposed NSPS 1000 lb/MWh limit, however the calculations indicate that the proposed 1,600 lb/MWh permit limit for simple cycle is appropriate on a 12-month rolling average. Compliance is possible with the proposed 12-month rolling average proposed in the NSPS rule. As noted in our application on page 5-13 in table 5-5, there is a wide range of CO2 lb/MWh emission rates for SCCT reviewed (1196 to 2718 CO2 lb/MWh).

CCCT: All of the combined cycle cases at 100% and 75% load points met the proposed NSPS limit of 1,000 lb/MW-hr, however some of the combined cycle cases at 50% load exceeded the limit. The proposed 1,100 lb/MWh on a 12-month rolling average limit would allow compliance for all cases from 50% to 100%. It is also important to note that the 1000 and 1100 lb/MWh limits would be exceeded when the steam turbine generator is malfunctioning or being repaired.

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Rapid City, SD 57709-1400

Conclusion and Requested CO_2 BACT Limits:

SCCT –

- There is a wide range of CO_2 emissions from 1196 to 2718 lb/MWh for SCCT turbines described in the BACT review section of the application. This provides the rationale why SCCT were excluded from the limit in EPA's proposed CO_2 NSPS rule.
- Based upon the manufacturer's performance runs in this analysis, Black Hills believes the proposed BACT limit in the application of 1600 CO_2 lb/MWh with a 12-month rolling average is the proper BACT limit. The averaging period is critical to Black Hills compliance.

CCCT –

- If the CCCT is operated with one or two combustion turbines with the steam turbine generator unit operating at higher operating loads 75-100%, Black Hills could comply with the proposed NSPS limit of 1000 CO_2 lb/MWh. When the CCCT and steam units are operated at 50-75% load, the proposed NSPS limit will be exceeded. Of course, operating below 50% load will result in noncompliance as well.
- There will be times when Black Hills may need to operate the combustion turbines when the steam unit is malfunctioning or in outage. In this mode, the proposed NSPS limit (1000 CO_2 lb/MWh) will be exceeded. The proposed permit limit (1100 lb/MWh) for CCCT would be exceeded during this time as well.
- There will be several SUSD that will result in significantly higher CO_2 lb/MWh limits based upon the lack of power generation during SUSD. These will be short periods, but there will be several hours operating in this mode due to the operating nature of this unit. These emissions will be averaged in the number evaluated against the limit, but nonetheless, the emissions are higher and will increase the recorded value.
- With these observations noted, Black Hills is comfortable with the limit proposed in the application (1100 lb/MWh on a 12-month rolling average) as it will provide the margin needed to deal with the operating scenarios described above. The averaging period is critical to Black Hills compliance.

EPA's Proposed Base-load NSPS Limit based upon Operating Capacity: The proposed NSPS limit was designed for base load operation according to the proposal. As stated above, Black Hills anticipates the generating load for this facility to fluctuate for the first 2-3 years.

The CPGS (both SCCT and CCCT) will be a multi-purpose electrical generating facility.

1. It will replace three coal generating plants in the short term. As such, it will provide intermittent base load demand service,
2. It will provide peaking service during the summer months, and
3. It will chase/supplement/enable renewable (primarily wind) electrical generation year round.

Under all three scenarios, the combustion turbines will also be operated at varying loads (50-100%). As the attached spreadsheet demonstrates, complying with the proposed base load designed NSPS limit will be difficult for this facility. This will be especially true for the CCCT as it will be utilized as much as, if not more than, the SCCT for these scenarios as it will provide a greater efficiency than the SCCT.

Black Hills would propose to set the limits for the CCCT and SCCT at the levels identified in the application with a paragraph stating that the CPGS will comply with the limits in EPA's final NSPS rule. Black Hills plans to comment on the rule. This would include addressing emissions at partial loads and the EGU definition addressing capacity factor.

Black Hills believes the results of the analysis demonstrate that the operating nature of this facility will have difficulty meeting the proposed NSPS CO2 limit. We respectfully request that this information be taken into account in developing the Project's PSD permit CO2 BACT limit and the proposed CO2 EGU NSPS rule. Black Hills understands the facility will have to comply with the limits and requirements of the CO2 NSPS for EGU when it becomes final regardless of the limits established in this permit negotiation.

If you have any questions, please contact me at (605) 721-2286 or Tim.Rogers@blackhillscorp.com.

Sincerely,

Tim Rogers
Environmental Manager

cc: Fred Carl, BHC
Mark Lux, BHC
George Tatar, BHC
Dennis Arfmann, Legal Counsel

Enclosures:

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Rapid City, SD 57709-1400

Black Hills - Cheyenne Priarie Generating Station - Estimated Performance (CO_2 Emissions)
2x1 GE LM6000 Water Cooled CC Plant

Emission Factors

53.02	kg/MMBtu HHV EPA emission factor for pipeline average natural gas (from GHG MRR)
2.205	lb/kg conversion factor
1.1	Btu HHV / Btu L assumed conversion
10%	Degradation

Combined Cycle Plant

	Black Hills	BH-1	BH-2	BH-3	BH-4	BH-5	BH-6	BH-7	BH-8	BH-9
Plant configuration	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1
CTG Load Point	100%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Ambient Temperature, oF	95	108	108	108	60	60	60	0	0	0
Relative Humidity, %	20	10	10	10	60	60	60	60	60	60
Inlet Chilling Tons	885	0	0	0	0	0	0	0	0	0
Fuel Heating Value, Btu/Lb (LHV)	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
CT Generators terminal power, kW	77,640	52,930	39,730	26,510	74,300	55,750	37,180	81,180	60,900	36,460
ST Generator terminal power, kW	23,370	20,842	18,680	17,879	23,140	20,230	18,355	24,330	21,020	18,930
Gross Plant Power, kW	101,010	73,772	58,410	44,389	97,440	75,980	55,535	105,510	81,920	55,390
Gas Turbine Fuel Input, Btu/Hr	643,019,998	474,222,015	395,765,928	322,265,990	621,096,051	492,911,948	385,392,034	659,610,107	528,612,022	409,122,021
Gross Plant Heat Rate, Btu/kWH (LHV)	6,366	6,428	6,776	7,260	6,374	6,487	6,940	6,252	6,453	7,386
Plant Auxiliary Loads, kW	4,155	2,582	2,044	1,554	3,410	2,659	1,944	3,693	2,867	1,939
Net Plant Power, kW	96,855	71,190	56,366	42,835	94,030	73,321	53,591	101,817	79,053	53,451
Net Plant Heat Rate, Btu/kWH (LHV)	6,639	6,661	7,021	7,523	6,605	6,723	7,191	6,478	6,687	7,654

Exhaust Parameters

Flow, Lb/Hr	846,706	658,668	557,107	476,406	822,616	720,003	538,316	875871	723236	609906
Temperature, F	220	204	195	186	218	211	193	214	203	195
	CO_2 Emission Rates, No Turbine Degradation, lb / MWh									
Combined Cycle 2x1	819	827	871	934	820	834	892	804	830	950
Combined Cycle 2x1 (10% Degradation)	910	919	968	1037	911	927	992	893	922	1055

Simple Cycle Gas Turbine

Plant configuration	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
CTG Load Point	100%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Ambient Temperature, oF	95	108	108	108	60	60	60	0	0	0
Relative Humidity, %	20	10	10	10	60	60	60	60	60	60
Inlet Chilling Tons	885	0	0	0	0	0	0	0	0	0
Fuel Heating Value, Btu/Lb (LHV)	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
CT Generators terminal power, kW	38820	26467	19,864	13,256	37,149	27,873	18,590	40,588	30,450	18,229
Total Fuel Input, Btu/Hr	321,507,240	237,091,386	197,865,304	161,126,680	310,565,640	246,453,066	192,703,940	329818088	264306000	204547609
Gross Plant Heat Rate, Btu/kWH (LHV)	8,282	8,958	9,961	12,155	8,360	8,842	10,366	8,126	8,680	11,221
Plant Auxiliary Loads, kW	1,590	662	497	331	929	697	465	1,015	761	456
Net Plant Power, kW	37,230	25,805	19,367	12,925	36,220	27,176	18,125	39,573	29,689	17,773
Net Plant Heat Rate, Btu/kWH (LHV)	8,636	9,188	10,216	12,467	8,574	9,069	10,632	8,334	8,903	11,509

Exhaust Parameters

Flow, Lb/Hr	846,706	658,668	557,107	476,406	822,616	720,000	538,316	875872	723236	609906
Temperature, F	856	912	938	997	864	860	947	842	854	882
	CO_2 Emission Rates, lb / MWh									
Simple Cycle - 1x0 *or* 2x0	1065	1152	1281	1563	1075	1137	1333	1045	1116	1443
Simple Cycle - 1x0 *or* 2x0 (10% Degradation)	1183	1280	1423	1737	1195	1263	1481	1161	1240	1603
Combined Cycle 1x1	819	827	871	934	820	834	892	804	830	950
Combined Cycle 1x1 (10% Degradation)	910	918	968	1037	911	927	992	893	922	1055

All Scenarios Summary Table

	CO_2 Emission Rates, No Turbine Degradation, lb / MWh									
CTG Load Point	100%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Ambient Temperature, oF	95	108	108	108	60	60	60	0	0	0
Combined Cycle 2x1	819	827	871	934	820	834	892	804	830	950
Simple Cycle - 1x0 *or* 2x0	1065	1152	1281	1563	1075	1137	1333	1045	1116	1443
Combined Cycle 1x1	819	827	871	934	820	834	892	804	830	950

	CO_2 Emission Rates, Assume 10% Degradation both CTG and STG, lb / MWh									
CTG Load Point	100%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Ambient Temperature, oF	95	108	108	108	60	60	60	0	0	0
Combined Cycle 2x1	910	919	968	1037	911	927	992	893	922	1055
Simple Cycle - 1x0 *or* 2x0	1183	1280	1423	1737	1195	1263	1481	1161	1240	1603
Combined Cycle 1x1	910	918	968	1037	911	927	992	893	922	1055

NOTE: Combined cycle 2X1 or 1X1 configurations without the steam turbine are equivalent to the simple cycle 2X0 and 1X0 configurations.

Table of Contents

Appendices

Tables

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Acronyms and Abbreviations

BACT	best available control technology
~~Black Hills~~BHC	Black Hills Corporation
BHP	Black Hills Power
CAA	Clean Air Act
CatOx	Catalytic Oxidation
CEM	continuous emissions monitor
CFR	Code of Federal Regulations
CGS	Cheyenne Generating Station
CH_4	~~methane~~Methane
~~Cheyenne Light~~CLFP	Cheyenne Light, Fuel and Power Company
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CTG	combustion turbine generator
°F	degrees Fahrenheit
EPA	U.S. Environmental Protection Agency
FIP	Federal Implementation Plan
FR	Federal Register
GHG	greenhouse gas
GWP	global warming potential
HFC	~~hydrofluorocarbon~~Hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kW	~~kilowatt~~Kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate

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lb	~~pound~~Pound	**Formatted:** Space After: 6 pt
lb/hr	pound per hour	**Formatted:** Space After: 6 pt
LHV	lower heating value	**Formatted:** Space After: 6 pt
MACT	maximum achievable control technology	**Formatted:** Space After: 6 pt
MRR	Final Mandatory Reporting of Greenhouse Gases Rule~~, or Mandatory Reporting Rule~~	**Formatted:** Space After: 6 pt
MMBtu	million British thermal units per hour	**Formatted:** Space After: 6 pt
MW	~~megawatt~~Megawatt	**Formatted:** Space After: 6 pt
N_2O	nitrous oxide	**Formatted:** Space After: 6 pt
NAAQS	National Ambient Air Quality Standards	**Formatted:** Space After: 6 pt
NO_X	nitrogen oxide	**Formatted:** Space After: 6 pt
NSR	New Source Review	**Formatted:** Space After: 6 pt
N_2O	nitrous oxide	**Formatted:** Space After: 6 pt
O_2	~~oxygen~~Oxygen	**Formatted:** Space After: 6 pt
PFC	~~perfluorocarbon~~Perfluorocarbon	**Formatted:** Space After: 6 pt
PM_{10}	particulate matter less than 10 microns in diameter	**Formatted:** Space After: 6 pt
ppm	parts per million	**Formatted:** Space After: 6 pt
PTE	potential to emit	**Formatted:** Space After: 6 pt
PSD	Prevention of Significant Deterioration	**Formatted:** Space After: 6 pt
RACT	Reasonably Available Control Technology	**Formatted:** Space After: 6 pt
RBLC	RACT/BACT/LAER Clearinghouse	**Formatted:** Space After: 6 pt
SCR	Selective Catalytic Reduction	**Formatted:** Space After: 6 pt
SF_6	sulfur hexafluoride	**Formatted:** Space After: 6 pt
SIP	State Implementation Plan	**Formatted:** Space After: 6 pt
SO_2	sulfur dioxide	**Formatted:** Space After: 6 pt
STG	steam turbine generator	**Formatted:** Space After: 6 pt
tpy	tons per year	**Formatted:** Space After: 6 pt
WDEQ	Wyoming Department of Environmental Quality	**Formatted:** Space After: 6 pt
VOC	volatile organic compound	**Formatted:** Space After: 6 pt

Executive Summary

Black Hills Corporation (~~Black Hills~~BHC) plans to construct a new nominal 220-megawatt (MW) gross simple~~-~~-and combined-cycle natural gas-fired combustion turbine power plant in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located within the city limits of the City of Cheyenne, Wyoming, approximately 5 miles southeast of the downtown area.

Cheyenne Light, Fuel and Power Company (~~Cheyenne Light~~CLFP) is a wholly owned subsidiary of ~~Black Hills~~BHC. It was acquired from Xcel Energy on January 1, 2005, and provides electric utility service to Laramie County, Wyoming, including the City of Cheyenne.

Presently, electricity sold by ~~Cheyenne Light~~CLFP is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is currently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The CGS project will include the following:

- Five ~~40-MW~~General Electric (GE) LM6000 PF SPRINT combustion turbine generators (CTGs) fired by ~~clean-burning~~pipeline quality natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, ~~Black Hills~~BHC is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) from the CGS and contains a description of the project, a review of applicable federal regulations, a listing of the emissions, and a best available control technology analysis.

The CGS will have potential emissions of 963,874 tons per year (tpy) of GHGs expressed as carbon dioxide equivalent (CO_2e). This is comprised of 962,929 tpy of carbon dioxide (CO_2~~),~~) or CO2e of 962,929 tpy, 1.8 tpy of nitrous oxide (N_2O~~),~~) or CO2e of 564 tpy, and 18.2 tpy of methane (CH_4~~).~~) or a CO2e of 381 tpy. Because the emissions of CO_2e exceed 100,000 tpy, this plant will be a major new source and will be subject to the Prevention of Significant Deterioration (PSD) rules.

Because the emission rate of GHG exceeds the 100,000-tpy limit specified in the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule), a best available control technology (BACT) analysis was performed. The BACT analysis concludes that the CGS project operating at its design energy conversion efficiency is BACT for GHGs.

SECTION 1.0

Introduction

Black Hills Corporation (Black Hills)BHC plans to construct a new nominal 220-megawatt (MW) gross simple and combined-cycle combustion turbine power plant located in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located in the City of Cheyenne approximately 5 miles southeast of the downtown area.

The facility will produce electrical power for Cheyenne Light, Fuel and Power Company (Cheyenne Light),CLFP, a wholly owned subsidiary of Black Hills. Cheyenne LightBHC. CLFP provides electric service to Laramie County, Wyoming, and the City of Cheyenne, with more than 38,000 customers.

Presently, electricity sold by Cheyenne LightCLFP is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is presently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The power plant will include the following:

- Five 40-MW combustion turbine generators (CTGs) fired by clean-burningpipeline quality natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode. Operating in combined-cycle will provide approximately 20-MW.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, Black HillsBHC is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) and contains a description of the project, a review of applicable regulations, a listing of the emissions, and a best available control technology (BACT) analysis.

Section 1.1 provides project contacts and an overview of the documentation being submitted with the application for a permit to construct the CGS.

1.1 Project Contacts

The following individuals may be contacted for additional information on this project:

Applicant	Tim Rogers Environmental Manager Black Hills Corporation 625 Ninth Street Rapid City, SD 57709 (605) 721-2286 ~~TRogers@bh-corp.com~~TRogers@bh-corp.com
Permitting Consultant	Joe Hammond ~~Senior~~Principal Project Manager CH2M HILL Engineers, Inc. 9193 South Jamaica Street Englewood, CO 80112 (720) 286-5919 ~~joe.hammond@ch2m.com~~joe.hammond@ch2m.com

1.2 Document Overview

The following is an overview of the information included in this permit application.

- **Section 1.0 – Introduction.** This section provides an overview of the project and describes the application organization.
- **Section 2.0 – Project Description.** This section includes a general description of the proposed project including equipment and operations of the project. Information regarding non-emitting processes and equipment is provided for a general understanding of plant operations.
- **Section 3.0 – Greenhouse Gas Emissions Summary.** This section provides a summary of emissions-related information.
- **Section 4.0 – Greenhouse Gas Regulatory Review.** This section contains a detailed regulatory review of federal GHG air regulations that may impact the permitting, construction, or operation of the proposed project.
- **Section 5.0 – BACT Analysis.** This section includes a BACT analysis for GHG pollutants. This analysis follows the EPA-prescribed five-step top-down approach. Requested permit limits are also included in this section.
- **Appendix A – Location Map and Plot Plan.** This appendix includes a location map, plot plan, and general equipment arrangement drawing for the proposed project.
- **Appendix B – Greenhouse Gas Supporting Documentation.** This appendix contains the calculations used to determine the GHG emissions for this permit application~~.~~

- and additional information on the GE combustion turbines and auxiliary equipment.

SECTION 2.0

Project Description

~~Black Hills~~BHC proposes to construct and operate the CGS in Cheyenne, Wyoming. A plot plan of the facility and a map detailing the location of the proposed facility can be found in Appendix A. The facility will be a nominal 220-MW gross output power plant that will produce electrical power for the ~~Black Hills~~BHC-owned ~~Cheyenne Light, Fuel and Power (~~CLFP~~)~~ electric retail service territory in Laramie County, Wyoming, including the City of Cheyenne and Black Hills Power (BHP) service territory in Wyoming and South Dakota. Facility output varies with ambient temperature, with higher output at lower ambient temperatures. A general arrangement of the turbine layout and associated equipment can be found in Appendix A.

The CGS facility configuration was selected based upon the needs identified in the CLFP *Integrated Resource Plan* (IRP).[1] The CLFP Certificate of Public Convenience and Necessity (CPCN) was filed with the Wyoming Public Service Commission (August 1, 2011 – Docket Number 20003-112-EA11) and was based upon CLFP IRP that identified three simple-cycle combustion turbines (nominally 120 MW gross output). The CLFP CPCN further identifies the potential build-out of the site to accommodate future generation needs. ~~Black Hills~~BHC plans to submit a BHP CPCN in fall 2011 and will be based upon the BHP IRP that tentatively (plan has not been finalized) identifies the need for two ~~simple-cycle~~ combustion turbines configured in combined cycle mode (nominally 100 MW gross output). The ~~Black Hills'~~BHC's Integrated Resource Plans will show the public need for increased capacity requirements in the CLFP and BHP service areas, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking with base-load capability and further enable renewable generation (wind, solar, and other renewable resources).

The proposed CGS facility will consist of five combustion turbines. Combustion turbines CT01A and CT01B will operate in a 2 X 1 combined-cycle design consisting of two 40-MW CTGs with one heat recovery steam generator (HRSG) for each CTG with no duct burners. Steam from the HRSGs will be combined to flow to a steam turbine that will produce additional electricity. The total generating capacity of the combined-cycle configuration will be approximately 100 MW. Combustion turbines CT02A, CT02B, and CT03A, will each be high-efficiency 40-MW CTGs, operating in simple-cycle mode.

Inlet air chillers with wet cooling towers will be provided for each CTG to cool the combustion air, which will enhance overall plant output during times of higher ambient temperature. Inlet air heaters will also be provided for each CTG to heat the combustion air, which will prevent icing during times of lower ambient temperature.

The proposed CGS facility will also have fuel gas pre-heaters, an emergency generator, and a fire pump.

[1] The IRP determines the capacity expansion, which takes into consideration the size of the electrical systems' demand, and further defines the size of combustion turbines selected.

2.1 Power Generation

Power will be produced in the plant by a total of six generators, one for each of the five 40-MW CTGs plus one steam turbine generator (STG). All other facility operations ancillary to the primary generation function are described below.

2.2 Emission Sources

2.2.1 Combined-Cycle Combustion Turbine Generators

The CGS will use two 40-MW combustion turbines CT01A and CT01B will be operated in a 2 X 1 combined-cycle design with two CTGs and one steam turbine. The combustion turbines will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines will be equipped with unfired (no duct burner) HRSGs to extract heat from each combustion turbine exhaust to make steam. The steam will be used in an STG to produce more electricity. The combined-cycle configuration will consist of two CTGs, two HRSGs (one for each CTG), and one STG.

2.2.2 Simple-Cycle Combustion Turbine Generators

The CGS will use three 40-MW combustion turbines operated in simple-cycle mode, without heat recovery from the turbine exhaust. These combustion turbines, designated as CT02A, CT02B, and CT03A, will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines have the capability to reach full-load operation quickly after initiation of startup, thereby reducing overall startup emissions.

Each combustion turbine consists of a compressor, combustor, and expansion turbine. After filtration, air passes through the compressor before combining with the fuel and entering the low nitrogen oxide (NO_X) combustor. The combustion products and compressed air pass through the expansion turbine, which drives both the compressor and the generator. Up to approximately 40 MW of gross electrical power are produced by each CTG over and above the work required by the compressor. The exhaust gas from each combustion turbine enters the Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CatOx) catalysts at high temperature (approximately 850 degrees Fahrenheit [°F] at full load).

2.2.3 Wet Cooling Towers

2.2.3.1 Inlet Chiller Cooling Towers

An inlet air chilling system will be installed at the compressor inlet of each CTG, downstream of the inlet air filter. The inlet air chilling system serves to enhance the overall output of the plant by lowering the temperature of the ambient air entering the CTGs during periods of high air temperature. The cooling process takes place at the cooling coils where air is cooled before entering the compressor section of the turbine. At low temperatures, the air becomes denser and, therefore, more air flows though the CTGs. The net increase in airflow results in higher power output for each of the CTGs at high ambient temperatures. Three inlet chiller cooling towers will be used to serve the inlet chilling system at CGS.

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2.2.3.2 Unit 1 Cooling Tower

One wet cooling tower will be installed to provide cooling to condense the steam that is exhausted from the steam turbine on the combined cycle configuration. in order to increase system efficiency. The steam condensers will have circulating cooling water flow through tubes that will absorb the heat from the condensing steam that is exhausted from the steam turbines. The warmed circulating water is then pumped to the cooling tower where it flows down through the tower and is cooled through evaporation, in a manner similar to other cooling towers. The cooled circulating water then flows back to the steam condensers to pick up more heat.

2.2.4 Inlet Air Heaters

An inlet air heating system will be installed at the compressor inlet of each CTG, upstream of the inlet air filter. The inlet air heating system raises the temperature of the ambient air entering the CTGs during periods of low air temperature to prevent icing for safety reasons.

2.2.5 Fuel Gas Heaters

A fuel gas pre-heat system will be utilized on each CTG to raise the temperature of the natural gas above the saturation temperature. for safety reasons. Natural gas fired fuel gas heaters will be used on the five combustion turbines.

2.2.6 Diesel Fire Pump

One diesel fire pump will be used to provide fire protection water for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the fire pump are 250 hours per year or less.

2.2.7 Emergency Generator

One diesel emergency generator will be used to provide emergency power for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the emergency generator are ~~250~~500 hours per year or less.

2.2.8 Storage Tanks

Storage tanks at the site will include diesel tanks for the fire water pump and emergency generator, aqueous ammonia storage tanks for the SCR NO_x emissions control unit, and several water storage tanks. No GHG emissions will result from these tanks.

2.3 Non-Emitting Major Facility Components

2.3.1 Ancillary Facilities

Other facilities used to support power generation at the CGS will include the following:

- Water treatment system to remove solids and hardness from plant makeup water
- Wastewater treatment system to allow recycle of cooling tower blowdown and other plant wastewater

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- Plant and instrument air compressors (electric-driven) and auxiliary equipment
- Plant sumps, sump pumps, and oily water separator
- Miscellaneous fire protection equipment
- ~~Septic system for sanitary waste~~
- Steam and water sampling systems
- Administration and warehouse/maintenance buildings

2.4 Emission Controls

The CGS will include the following emission controls:

- Dry low NO_X burners on the CTGs, and a SCR system to reduce NO_X emissions on all CTGs
- An oxidation catalyst to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions ~~from the~~on all CTGs
- Good combustion design and operation to reduce particulate matter of 10 microns in diameter (PM_{10}) emissions from the CTGs
- Use of pipeline-quality natural gas to minimize sulfur dioxide (SO_2) emissions from the CTGs
- High-efficiency drift eliminators on the steam condenser cooling towers to reduce PM_{10} emissions in the cooling tower drift

2.5 Emissions Monitoring

As required by Title 40 of the Code of Federal Regulations (CFR) Parts 60 and 75, the CGS will use continuous emissions monitors (CEMs) for NO_X, CO, and oxygen (O_2) for all five CTGs. These CEMs will average and record data on frequencies consistent with state and federal acid rain rules. The plant will also monitor and record the natural gas flow rate and will analyze natural gas fuel quality as required by the acid rain rules.

CGS will use these continuous emissions monitors (CEMs) to determine compliance with the CO_2 emission limits established in the PSD permit. CEMS will be installed and operated for each turbine according to 40CFR75 requirements. Accordingly, these CEMS will calculate CO_2 emissions from each source according to the 40CFR75 Appendix F and G methodologies. The calculated CO_2 emissions follow a strict calculation requirement to determine CO_2 emissions for each minute of fuel combustion typically. The minute data is converted to hourly emissions for reporting per 40CFR75 data reduction requirements. All CO_2 emissions are accounted for in the reported values, including startup and shutdown.

The CO_2 emissions data generated from the CEMS, per 40CFR75 requirements, are used to report emissions for 40CFR98 (Mandatory Greenhouse Gas Reporting rule). Specifically, Subpart D – Electricity Generation, guide the CO_2 emissions reporting requirements. Black

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Hill currently uses this methodology for its natural gas fired combustion turbines. The calculation methodology is defined simply as:

"(a)…continue to monitor and report CO_2 mass emissions as required under §75.13 or section 2.3 of appendix G to 40 CFR part 75, and §75.64. Calculate CO_2 emissions as follows: (1) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023."

This calculation, as required by EPA's Greenhouse Gas MMR rule simply uses the 40CFR75 fourth quarter, or end of year, CO_2 emission and coverts the short tons to metric tons (Nitrous Oxide and Methane emissions are calculated from Green House Gas emission factors). Additionally, the CO_2 data will follow quality assurance/control requirements as well as missing data substitution routines according to 40CFR75 rules. Therefore, since EPA's long standing Acid Rain Program regulations (40CFR75) and the recently released Greenhouse Gas MMR rule (40CFR98) both recognize the 40CFR75 methodology as an accurate and complete method to monitor CO_2 emissions, the CGS will use the methodology to determine compliance with CO_2 emission limits identified in this permit.

In a recent permit application with the Bay Area Air Quality Management District (BAAQMD) for the Russell Energy Center in California, the agency made the following determination regarding CEMS versus the Fuel Meter (heat input) method:

> "The Air District has also considered whether to require the facility to use a Continuous Emissions Monitor (CEM) to measure greenhouse gas emissions directly (as CO_2), but has concluded that calculating emissions from heat input is preferable. Unlike some other pollutants such as NO_x or carbon monoxide whose formation is heavily dependent on conditions of combustion and/or performance of add-on emissions controls, greenhouse gases are a direct and unavoidable byproduct of the combustion process. The amount of carbon within the fuel will all ultimately be emitted as greenhouse gases in a manner that is easily determined using well-established emissions factors. One can therefore determine with great accuracy what greenhouse gases are being emitted by measuring the amount of hydrocarbon fuel being burned (measured as heat input). For this reason, the test methods for measuring heat rate and capacity can achieve an accuracy of ±1.5% [55], which is better than the relative accuracy of CEMs which typically ranges as high as ±10%.[56] The Air District is therefore proposing to require surrogate monitoring for greenhouse gas emissions using heat rate instead of a CEM."
>
> [55] American Society of Mechanical Engineers (ASME), Performance Test Code on Overall Plant Performance, (PTC 46-1996), December 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to steam generator").
> [56] See, e.g., 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.")

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2.6 Operating Schedule

The~~ exact~~ annual operating schedule of the CGS will be dependent on the demand for electric power~~ within Cheyenne Light's electric system~~. Thus, the exact operating schedule cannot be accurately predicted at this time.

For this reason, the permit limits requested in this application, and the resulting assumptions used in the ~~ambient impact analysis~~emissions inventory and BACT analysis, are as follows:

- Up to 8,760 hours per turbine per year of CTG operation (both simple and combined cycle) at 100 percent load or at any lesser load rate
- Up to 600 startups for each simple-cycle combustion turbine per year
- Up to 600 startups for each combined-cycle combustion turbine per year
- Up to 5,330 hours per tower per year of inlet chiller cooling tower operation
- Up to 8,760 hours per year of combined-cycle cooling tower operation
- Up to 4,380 hours of operation per year for each inlet air heater
- Up to 4,380 hours of operation per year for each fuel gas heater

These hours could be based on continuous short-term or long-term operation. In other words, the plant could operate up to 8,760 hours per year (counting startup episodes) and could operate 24 hours per day, 7 days per week, and 365 days per year.

2.7 Permitting and Construction Schedule

The planned permitting and construction timeline is shown in Table 2-1.

TABLE 2-1
Permitting and Construction Schedule

Event	Date
~~Air~~GHG PSD Permit Application Filed with EPA	August ~~5,~~ 2011
~~Air~~Revised GHG PSD Permit Application Filed with ~~WDEQ~~EPA	September ~~1,~~ 2011
PSD Air Permit Application Filed with WDEQ	October 2011
Air Permits Issued by EPA and WDEQ	~~Summer~~September 2012
Begin Purchase Major Pieces of Equipment	~~Summer~~September 2012
Start of Construction	~~Summer~~April 2013
Commercial Operation	~~Summer~~June 2014

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SECTION 3.0

GHG Emissions Summary

GHG emission estimates were prepared for all point emissions sources from the CGS, including the combustion turbines and auxiliary equipment. The annual carbon dioxide (CO_2) equivalent (CO_2e) emissions were estimated based on 100 percent capacity factor (full-load operation for 8,760 hours per year) for each of the combustion turbines. ~~More detailed GHG~~Note that instantaneous fuel flow is always lower during turbine startup than normal turbine operations; therefore, unlike for criteria air pollutants, instantaneous GHG emissions are always lower during startup than normal operations, and 8760 hours per year at full load is a conservative assumption for calculating GHG emissions. More detailed emission calculations are provided in Appendix B.

3.1 Combustion Turbines

The CGS project consists of two ~~nominal 40-MW~~GE LM6000PF SPRINT combustion turbines operating in a 2 X 1 combined-cycle configuration, designated as CT01A and CT01B. There will also be three ~~nominal 40-MW~~GE LM6000PF SPRINT combustion turbines operating in simple cycle identified as CT02A, CT02B, and CT03A. ~~Each~~All five combustion ~~turbine has a~~turbines will have separate ~~stack~~stacks, which will be a separate emission ~~point~~points.

3.2 Auxiliary Equipment

In addition to the five GE LM6000PF SPRINT combustion turbines planned for the CGS project, there are several other small GHG combustion sources associated with auxiliary equipment that will operate at the CGS:

- (6) Natural gas-fired inlet air heaters (nominal 16-million-British-thermal-units-per hour [MMBtu/hr] air heater with estimated emissions of 4,117 CO_2e tons/year each)
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year ~~each~~)
- (1) Diesel-fired fire pumps (nominal 327-BHP engine with estimated 51 CO_2e tons/year ~~each~~)

3.3 GHG Emission Summary

The GHG emission sources for the project are shown in Table 3-1, along with estimated annual CO_2e emissions.

TABLE 3-1
GHG Emission Source Summary

Source Number	Emission Point	Estimated Annual CO_2e Emissions
EP01 and EP02	(2) Nominal 40-MWGE LM6000PF SPRINT Combined-Cycle Combustion Turbines CT01A and CT01B	374,635
EP03, EP04, and EP05	(3) Nominal 40-MW CombinedGE LM6000 PF SPRINT Simple-Cycle Combustion TurbinesCT02A, CT02B, and CT03A	561,953
EP06 through EP11	Six (6) Inlet Air Heaters	24,703
EP18 and EP19	Two (2) Fuel Gas Heaters	2,306
EP16	One (1) Diesel Fire Pump	51
EP15	One (1) Diesel Standby Generator	226

SECTION 4.0

Regulatory Review

This section provides a regulatory review of the applicability of federal air quality permitting requirements for GHGs and GHG air pollution control regulations for the CGS project proposed by ~~Black Hills~~BHC. The purpose of this section is to provide appropriate explanation and rationale regarding the applicability of these regulations to the CGS project. The review is limited to federal regulations for GHG because there are no State of Wyoming regulations for GHG that apply to the permitting of CGS.

Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Both agencies have agreed to work together to process these two air permits for CGS.

4.1 Federal Regulations

The proposed project was evaluated to determine compliance with applicable federal GHG air quality regulations. Potentially applicable federal GHG regulations include the following:

- Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) – 40 CFR 51.166, 52.21, as published in the *Federal Register* (FR) June 3, 2010 (75 FR 31514)
- Federal Implementation Plan (FIP) for State of Wyoming GHG – 40 CFR 52.37, as published in the *Federal Register* December 30, 2010 (75 FR 82246)
- New Source Review (NSR) – 40 CFR 51 and 52

On April 2, 2007, the U.S. Supreme Court found that GHGs are air pollutants under Clean Air Act (CAA) section 302(g) (*Massachusetts* v. *EPA,* 549 U.S. 497 [2007]). GHG includes the six gases of CO_2, nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Of these, the first three will be emitted from the CGS. These gases have different potential to affect global warming, termed the global warming potential (GWP). The GWP of the three emitted gases are CO_2 (1), N_2O (310), and CH_4 (21).

Based on the series of legal and regulatory actions that culminated in the Tailoring Rule, regulation of major increases of GHG emissions through the Prevention of Significant Deterioration (PSD) permit program was required. EPA recognized that the major source threshold levels for the criteria pollutants for PSD pollutants of 100 or 250 tons per year (tpy) would make virtually every new project a major source. Accordingly, in June, 2010, EPA adopted the Tailoring Rule to raise the major source thresholds for GHG to 75,000 or 100,000 tons of GHG per year.

The State of Wyoming has an approved State Implementation Plan (SIP) based program for the criteria pollutants for the PSD permitting of new major sources. However, Wyoming has decided to not include GHG in the state PSD permitting program. Accordingly, the GHG PSD program is being implemented by the EPA for major sources of GHG within the State of Wyoming through the federally approved FIP.

4.1.1 Greenhouse Gas Tailoring Rule

On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed the phasing in of the PSD permitting process for new major sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with the potential to emit (PTE) greater than 100,000 tpy of CO_2e (including the statutory threshold of 100 or 250 tons on a mass basis) comply with PSD and Title V requirements. All references to "tons" are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

As shown in Table 4-1, under the Tailoring Rule, the CGS will be a major source subject to PSD permitting because the total emissions of CO_2e exceed 100,000 tpy. The CGS project will result in an increase in CO_2e emissions of 963,874 tpy, and more than 100 tpy ~~in~~of certain criteria pollutants. Therefore, the project is classified as a major source for PSD applicability determination.

TABLE 4-1
GHG Pollutants Expected to be Emitted, Annual Emission Rates, Global Warming Potential, and Annual Emissions Rates Adjusted for Global Warming Potential

Pollutant	Proposed Facility GHG Emissions (TPY)	Global Warming Potential (GWP)	GHG Emissions Adjusted for GWP (TPY)
Carbon Dioxide (CO_2)	962,929	1	962,929
Nitrous Oxide (N_2O)	1.82	310	564
Methane (CH_4)	18.17	21	381
Total GHG as CO_2e	----	----	963,874

4.1.2 Federal Implementation Plan for Wyoming

EPA has determined that the Wyoming SIP is deficient for purposes of the PSD permitting of GHG. Accordingly, EPA adopted a FIP in which it retains the authority to issue a PSD permit for GHG. Thus, this application is being filed with EPA Region 8 for the sole purpose of obtaining a PSD permit for the emissions of GHG from the CGS. The permit for the emissions of the criteria and hazardous pollutants from CGS will be obtained from the State of Wyoming.

EPA has not adopted ambient air quality standards or new source performance standards for GHG. Accordingly, this application only contains a BACT analysis for GHG.

4.1.3 New Source Review

PSD is the portion of NSR that applies to pollutants that are in attainment of National Ambient Air Quality Standards (NAAQS). Because there are no ambient air quality standards for GHG, all portions of the United States are in attainment for GHG. Major new or modified air emission sources locating in Laramie County are, therefore, potentially subject to PSD review for these GHG pollutants.

The first step in PSD review is determining whether the proposed facility is a major PSD source. As noted above, the CGS will be a major source. Therefore, CGS is subject to PSD review for GHG. The primary elements of PSD requirements ~~are as follows:~~ is application of BACT to emissions of GHG

- ~~Application of BACT to emissions of GHG~~

SECTION 5.0

Greenhouse Gas BACT Analysis

5.1 Background

Black HillsAs described above, BHC plans to build a natural gas-fired combustion turbine generating facility in the southeast section of the City of Cheyenne in Laramie County, Wyoming, pursuant to its approved CLFP *Integrated Resource Plan* filed before the Wyoming Public Service Commission (described in Section 2.0, Project Description). The proposed site is immediately west of the Dry Creek Water Reclamation Facility, which is located approximately 5 miles southeast of the downtown area.

The CGS will consist of a total of five natural gas-fired CTGs sized at a nominalapproximately 40-MW capacity each. Two CTGs will be configured for combined-cycle operation and will each be equipped with dry-low NO_x combustors and a HRSG without duct burners, with steam flowing from the two HRSGs to one condensing STG with condenser in a "2x1" configuration. The combined-cycle generation capacity is nominally 100 MW. All of the CTGs will be equipped with SCR for NO_X control and Catalytic Oxidation for CO and VOC control. Three CTGs will operate in simple cycle. CGS auxiliary equipment includes one mechanical draft condenser wet cooling tower, three electric inlet air chiller units with mechanical draft cooling towers, six natural gas-fired inlet air heaters, two natural gas-fired fuel heaters, one diesel-fired fire pump, and one diesel-fired emergency generator.

5.1.1 CGS Business Plan and Combustion Turbine Selection

The Cheyenne LightCLFP CPCN and associated IRP (Docket Number 20003-112-EA11), were filed August 1, 2011, with the Wyoming Public Service Commission, and present the business plan in detail. The Black Hills PowerBHP CPCN and associated IRP will be submitted to the Commission in fall 2011. Generally, Black Hills'BHC's CPCN and associated IRP show the public need for increased capacity requirements, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking for CLFP, with baseload capabilitycapabilities for BHP, and will further enable renewable generation (wind, solar, and other renewable resources). Black HillsBHC identified natural gas simple-/combined-cycle gas turbines to be the best-suited generation source to meet this CGS business plan.

While Black HillsBHC has determinedselected the nominal output of eachGeneral Electric LM 6000PF SPRINT combustion turbine to be 40 MW,for the combustion turbine manufacturer has not been selected.CGS project. Table 5-1 lists potentialcomparable combustion turbine manufacturers and a comparison of estimated performance efficiency at the CGS site conditions.- This information was compiled from published data from Gas Turbine World magazine, and is presented only for comparative purposes. Gross heat rate and efficiencies are based on power output at the combustion turbine generator terminals, and does not include consideration of parasitic unit auxiliary loads.

TABLE 5-1
Combustion Turbine Comparison

Turbine[1]	Production (kW)	Gross Heat Rate (Btu/kWh) HHV	~~Efficiency~~Efficiency[2]
Dresser-Rand			
DR-63G PC	35,150	9,095	37.5%
GE Energy ~~Aeorderivative~~Aeroderivative			
LM6000PC	39,253	9,487	36.0%
LM6000PC Sprint	40,605	9,419	36.2%
LM6000PD	34,612	9,103	37.5%
LM6000PD Sprint	38,079	9,091	37.5%
LM6000PF	34,612	9,103	37.5%
LM6000PF Sprint	38,649	9,079	37.6%
LM6000PG	42,995	9,556	35.7%
GE Energy Oil & Gas			
LM6000PD	33,964	9,283	36.8%
IHI Power Systems			
LM6000PC	34,306	9,198	37.1%
LM6000PC Sprint	37,129	9,228	37.0%
LM6000PD	33,800	9,231	37.0%
LM6000PD Sprint	37,236	9,213	37.0%
LM6000PG	40,084	9,157	37.3%
Pratt & Whitney Power Systems			
FT8 TwinPac	41,267	9,898	34.5%
SwiftPac 50 DLN	41,175	9,914	34.4%
Rolls-Royce			
Trent 60 DLE	41,537	9,064	37.7%
Trent 60 DLE ISI	46,612	8,913	38.3%
Siemens Energy			
SGT-800	37,772	10,126	33.7%
SGT-900	39,781	11,626	29.4%

[1] Specifications for production output at 59ºF, 5,950-Foot Altitude, Gross Output, HHV.

[2] Calculation: Efficiency= 3,413 Btu/kWh/Gross Heat Rate

Black Hills will select a combustion turbine that best meets its business plan, its system, and operational criteria, with possible selection of any combustion turbine from Table 5.1. A key consideration is that installation of combustion turbines from only one manufacturer is desired, and both simple-cycle and combined-cycle operational considerations must be evaluated. Due to differences in exhaust temperatures and other factors, turbines with lower efficiency than others in simple-cycle operation may actually have higher efficiency than those others in combined-cycle operation. As will be demonstrated below, Black Hills proposes to establish annual GHG mass and output-based limits assuming use of a turbine from the top of the possible efficiency range, and will agree to comply with those limits regardless of actual turbine selection. Black Hills will perform a complete competitive bidding process to select the combustion turbine for the CGS project, and the selected combustion turbine will be subject to the GHG BACT permit limits established by EPA as part of this permitting process.

Therefore, BHC selected the GE LM6000PF SPRINT combustion turbine because it best meets its business plan, its system, and operational criteria. Business plan considerations for turbine selection include combustion efficiency, exhaust characteristics that impact combined cycle system efficiency, size range, and consistency with other locations. Selection of a "fleet" of like turbines for different locations provides advantages with knowledge of maintenance and operations, stocking of spare parts, and ability to "swap" turbines between locations. The combustion turbine calculated efficiency for this turbine (37.6%) compares favorably with other combustion turbines listed in Table 5.1.

Table 5-2 below lists the assumedGE LM6000PF SPRINT combustion turbine attributes to be used within the GHG BACT analysis, and represents high-efficiency operation in both simple- and combined-cycle operation. The information included in Table 5-2 is based upon GE provided information, and summarizes the estimated combustion turbine performance at site conditions including consideration for parasitic auxiliary loads. Therefore, since Table 5-1 does not consider unit auxiliary loads in the efficiency calculation, and Table 5-2 includes allowance for auxiliary loads, the values are slightly different between the two tables.

TABLE 5-2
EfficientGE LM6000PF SPRINT Combustion Turbine DefinitionAttributes

Combustion Turbine Criteria	Assumed Value[1]
Simple-Cycle Combustion Turbine Gross Output (MW)	37.1
2x1 Combined-Cycle Combustion Gross Turbine Output (MW)	97.4
Simple-Cycle Gross Heat Rate (Btu/KWh) HHV	9,300263
Combined-Cycle Gross Heat Rate (Btu/KWh) HHV	7,200062
Heat Input (Btu/hr) HHV	366

[1] 60^0 F at site elevation.

5.2 Regulatory Basis

GHGs have become subject to emission permitting through PSD and Title V programs. On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed phasing in the PSD permitting process for new sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with PTE greater than 100,000 tpy of GHGs on a CO_2e basis, and with a GHG PTE of 100 or 250 tpy, depending on source type, on a mass basis will become subject to PSD and Title V requirements. All references to tons within the table and in this BACT analysis are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

The CGS project will be a new source with a GHG PTE of greater than 100,000 tpy CO_2e and greater than the 100-tpy mass basis for listed sources, and will also have a PTE of greater than 100 tpy for certain criteria pollutants. Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Therefore, this GHG BACT analysis was prepared for presentation to EPA Region 8 as part of the CGS permit application process.

5.3 Emissions Summary

Per EPA Tailoring Rule definitions, GHGs consist of the following gases:

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)

To determine CO_2e emissions, mass flows of each individual gas are multiplied by the appropriate GWP as referenced to the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report, and the results are summed.

The combustion turbines, inlet air heaters, and fuel gas heaters will be fired with pipeline-quality natural gas, and complete combustion will result primarily in water and CO_2 byproducts. However, incomplete combustion will result in some unburned natural gas or CH_4 emissions. Additionally, due to the presence of nitrogen in the combustion air, some small quantities of N_2O will also be emitted. The standby generator and fire pump engines will be fired with diesel fuel, again resulting in CO_2 emissions from oxidation of the fuel and with minor quantities of CH_4 emissions resulting from incomplete combustion and N_2O emissions from conversion of nitrogen from the atmosphere and fuel.

Table 5-3 represents potential sources and estimated quantities of GHG emissions from CGS project equipment.

TABLE 5-3
CGS Estimated GHG Emissions by Equipment Category

Equipment	Description	Total CO_2e Emissions (t/yr)
Two (2) Combustion Turbines in Combined-Cycle Operation with no HRSG Duct Burner	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	374,635
Three (3) Simple-Cycle Combustion Turbines	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	561,953
Two (2) Fuel Gas Heaters	Maximum Heat Input 4.5 MMBtu/hr each	2,306
One (1) Diesel Fire Pump	Maximum Heat Input 2.5 MMBtu/hr	51
One (1) Diesel Standby Generator	Maximum Heat Input 5.52 MMBtu/hr	226
Six (6) Inlet Air Heaters	Maximum Heat Input 16.07 MMBtu/hr each	24,703
Total		**963,874**

5.3.1 GHG BACT Analysis Assumptions

During the completion of GHG BACT analysis, the following assumptions were made:

1. Table 5-3 above presents estimated CGS GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, and N_2O. The CGS is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents. SF_6 is also a man-made gas that may be used as an insulating gas for high-voltage equipment and circuit breakers; however, ~~Black Hills~~BHC does not plan to install electrical equipment containing SF_6 at the CGS. Therefore, only CO_2, CH_4, and N_2O will be included in CO_2e totals.

2. From the GHG emissions inventory presented in Appendix ~~A~~B-1, the relative quantities of CH_4 and N_2O total only approximately ~~20~~945 tpy of CO_2e emissions, or less than 0.~~00~~21 percent of total CO_2e emissions. Due to the extremely small contribution of CH_4 and N_2O emissions to the total, the CGS GHG BACT analysis only ~~included~~includes the five-step process for CO_2 emissions.

3. Completion of the BACT analysis for criteria pollutants will result in the installation of an SCR system for NO_x emissions reduction, and an oxidation catalyst for control of CO and VOCs for each turbine.

4. During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule or MRR) (40 CFR 98) factors for estimating CO_2e emissions from the combustion of natural gas assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the MRR factors and included in the CO_2e totals.

5. Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or

negligible. From the GHG emissions inventory, the estimated N_2O emissions from all combustion turbines total only 1.5 tpy. Therefore, even if there were an order–of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. The combustion turbine SCR systems will be designed to reduce NO_x from the combustion turbine low-NO_x burners (LNBs) from 25 parts per million (ppm) to 3 ppm. Similarly, the oxidation catalyst systems have the benefits of reducing both CO and VOCs. The oxidation catalyst reduces CO and VOC emissions from 70 ppm to 6 ppm, and from 8.4 ppm to 3 ppm, respectively.

While elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Thus, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 due to other environmental impacts. Therefore, we have not considered omission of these controls within the BACT analysis.

5.4 Top-Down BACT Process

The EPA has developed a recommended process for conducting BACT analyses, referred to as the "top-down" method. The following steps to conducting a top-down analysis are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, has been conducted for GHG emissions for the CGS project. The following top-down BACT analysis for CO_2e has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990). A top-down BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology.

5.5 Combustion Turbine BACT for GHGs

Step 1: Identify All Control Technologies

The combustion turbines will be nominal 40 MW machinesGE LM6000PF SPRINT combustion turbines that utilize the latest emissions control technology. There are two basic alternatives identified to limit the GHG emissions of this project. These options include

- Carbon Capture and Storage (CCS)
- Electrical Generation Efficiency

~~Black Hills'~~BHC's CGS Business Plan and IRP have determined that the proposed mix of natural gas combined-cycle and simple-cycle power generation is the only alternative that meets all of the CGS requirements for economic and reliable power 24 hours per day and in all weather conditions. As such, other generation technologies such as coal, wind, and solar were not evaluated in this BACT analysis. This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26) Nonetheless, it should be noted that the CGS is intended to provide supplemental and backup generation for solar and wind projects, and renewable generation is not an adequate supplement and backup for other renewable generation; a fuel-based alternative is required.

The only identified ~~alternatives~~GHG emission "control" options are post-combustion CCS and energy efficiency of the proposed generation facility.

Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

CCS systems involve use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery.

~~The concentration of CO_2 is required because injection of exhaust streams containing high levels of nitrogen, oxygen and dilute CO_2 is not technically feasible. Research into technically and economically feasible capture systems is ongoing and is the focus of many large-scale grants from the U.S. Department of Energy (DOE). Adequate techniques for compression of CO_2 exist, but such compression systems require large amounts of energy. Furthermore, the capture process is energy intensive. It is estimated that a significant portion of power plant output would be required for CO_2 capture and subsequent compression. As stated in the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*, "For a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture."~~

~~Research into geologic storage requirements is also ongoing. DOE research programs are investigating the reliability, permanence, risks, required monitoring, verification, and other issues to be addressed before geologic storage can proceed on a large commercial scale. Many regulatory issues remain to be resolved, such as pore space ownership, financial responsibility requirements, long-term risk following closure of the sequestration site, and issues regarding CO_2 purity and potential contamination of aquifers.~~

CCS systems are not currently available on a commercial basis. Large-scale demonstration projects are currently being planned or are in early stages of development, but no company or vendor currently offers a commercially available turn-key, integrated CCS system.While many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the CGS:

- No full scale systems are currently in operation for capture of CO_2 from dilute exhaust steams such as that from natural gas fired electrical generation systems,
- Lack of pilot scale experience with capture systems for high-temperature streams such as simple cycle combustion turbine exhaust currently exists,
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however identification of suitable oil reservoirs with willing and able owners and operators is beyond the capability for most electric utilities. Owners of oil fields generally closely guard information regarding production volumes and reservoir status,
- Little experience exists with other types of storage systems such as deep saline aquifers or depleted coal seams,
- Because of the developmental nature of CCS technology, vendors and contractors do not offer turn-key offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring,
- Significant legal uncertainties still exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, etc, and
- Potential for frequent startup and shutdown of generation units at the CGS make CCS impractical for two reasons – inability of capture systems to startup in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. The simple cycle units at the CGS are designed for peaking operation and as such the ability to rapidly startup the units and to operate them for short durations is critical. While the combined cycle units are being designed for baseload operation, under many operational scenarios rapid response may also be needed for these units.

These issues are discussed in more detail below.

As suggested in the 1990 Draft EPA New Source Review Workshop Manual, control technologies should be demonstrated in practice on full scale operations in order to be considered available within a BACT analysis. "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." As will be discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice, but the technology used for these processes cannot be applied to power plants.

Three fundamental types of carbon capture systems are employed throughout different process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial scale systems currently in operation, due in large part to concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam methane reforming process which contains primarily hydrogen (H_2), unreacted methane (CH_4) and CO_2. Based on the stoichiometry of the reforming process the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds per square inch, gauge (psig). Because of the high concentration and high pressure a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-H_2 components including CO_2 and CH_4 are adsorbed onto the solid media under high pressure. After the sorbent becomes saturated the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; but where the CO_2 is to be sold offset an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 "DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update", NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. From Section 4.B, "When the fluid component has a high concentration in the feed stream (e.g., 10 percent or more), a pressure swing adsorption (PSA) mechanism is more appropriate."

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant (GPSP) in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily hydrogen (H_2), methane (CH_4), and 30 to 35 percent CO_2 and a physical absorption process (Rectisol) is used. In contrast, as shown in the GE Guarantee in Appendix B-3, and as noted on Page 29 of the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*, CO_2 concentrations for natural-gas fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced Technology Update, NETL notes this difference between pre-combustion CO_2 capture such as that from the GPSP versus the post-combustion capture such as that required from a natural-gas fired power plant, "Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas."

The Interagency Task Force on Carbon Capture and Storage consists of 14 executive departments and federal agencies, co-chaired by the DOE and EPA. In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where

CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is a key player in the nation's efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html). Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems), which are shown as "active" with "injection ongoing" or "plant in operation", yields four projects. Three projects, one of which is a pilot-scale process noted in the Interagency Task Force report as described above, are listed at a capacity of 274 tons per day (100,000 tons per year) and the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of even the modestly-sized CGS facility, which could produce up to 964,000 tons per year or 2,600 tons per day. Furthermore, scale-up involving a 10x increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

As detailed in ~~its~~the August 2010 report, one goal of the ~~task force~~Task Force is to bring five to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available.~~-~~ It is notable that several projects, including those with DOE funding or loan guarantees, have been cancelled in recent months, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, at the AEP Mountaineer site noted above, the commercial scale project was to expand capture capacity to 100,000 tpy, but to date only the "Project Validation Facility" was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front end engineering design due to uncertain economic and policy conditions.

The Interagency Task Force report notes the lack of demonstration in practice: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

One of the many technical challenges with carbon capture systems is the temperature of the exhaust steams. For coal-based plants, where most of the post-combustion capture technology research has been accomplished, typical exhaust temperatures are in the range of 300 degrees F. For the three simple cycle systems planned for the CGS, exhaust temperature will be up to 900 degrees F. To our knowledge, CCS pilot tests have not been accomplished on a simple cycle gas turbine system anywhere in the world. This would represent another major technical uncertainty associated with CCS implementation at the CGS. Chemical absorption of CO_2, such as that accomplished by most amine-based carbon capture processes, is an exothermic reaction, meaning that heat is released during absorption; high temperature of the exhaust and solvent would therefore inhibit the carbon capture.

Furthermore, the regeneration of the sorbent to release the CO_2 for compression requires heating of the sorbent, so high temperature of the solution would clearly inhibit the chemical reaction required for absorption.

BHC is aware of the planned construction of a CO_2 pipeline, intended to transport byproduct CO_2 from oil and gas operations to an EOR location in Montana. This project will be used as a CCS large-scale demonstration project by the DOE-funded Plains CO_2 Reduction Partnership. From review of publicly available documentation, the pipeline is being designed with excess capacity, presumably to provide future capability to transport CO_2 from other sources to EOR locations in the region. At its closest point the pipeline is estimated to be 175 miles away from the power plant location. However the location, time frame, and needed flowrates for those future EOR operations are closely guarded trade secrets. Thus BHC, as developer of this power generation facilities, has no way of knowing when and if those future needs will be realized. At the current time, the only known CO_2-based tertiary oil recovery system operating in the region is the Salt Creek Field (also approximately 175 miles from the power plant location),for which current CO_2 needs are being served from current separation systems in the Shute Creek Field of southwest Wyoming, with CO_2 being transported by existing pipeline.

Ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. While it is believed that saline aquifers are a viable opportunity, many uncertainties exist. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post injection site care, long term stewardship, property rights, and other issues. In regards to CO_2 storage security, the CCS Task Force Report notes such uncertainties, "The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, IPCC concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, hence, risk profiles (e.g., IPCC, 2005)."

CCS technology development is dominated by vendors who are attempting to commercialize carbon capture technologies and academia-lead teams (largely funded by DOE) who are leading research into the geologic systems. Ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. While capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations which exceed the turbine startup time. The simple cycle generation systems are designed to be able to produce electricity at full load within 10 minutes of cold start, and the combined cycle systems designed to be able to produce electricity at full load with SCR and oxidation catalysts controlling criteria air pollutants within 40 minutes of startup. Durations of plant operation may be short, depending on needs to serve peak power loads. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to startup and shutdown in the time frames required to effectively serve this type of operation, meaning that significant portions of at least the simple cycle operations would run without CO_2 capture even with implementation of a CCS system.

Finally, the potential to sell CO_2 to industrial or oil & gas operations is infeasible for an operation such as this, where daily operation of both simple cycle and combined cycle systems may depend on grid dispatch needs. Even if a potential EOR opportunity could be identified by the power plant developers, such an operation would typically need a steady supply of CO_2 year-round. Intermittent CO_2 supply from potentially short-duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited on applications which have low variability in operating conditions.

In the EPA PSD and Title V GHG permitting guidance, ~~it is acknowledged that~~the issues noted above are summarized, "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (italics added). From Page 36 of this guidance, "While CCS is a promising technology~~,~~; EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases~~."~~. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard~~.~~."

~~The Interagency Task Force report notes the lack of demonstration in practice: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."~~

Therefore, the CCS alternative is not considered technically feasible for the CGS project, and is eliminated from further consideration. While it is being eliminated based on technical feasibility in Step 2, ~~it should be acknowledged that even if carried forward for further analysis, it would undoubtedly be eliminated in Step 4 based on cost effectiveness. The technical risks associated with the technologies would make the project un-financeable. The energy requirements for the capture and compression systems alone would dramatically~~

~~increase the overall cost of generation for the project, and the cost of capture and compression systems, pipelines, development of storage reservoirs, and monitoring systems is very high as well.~~at the suggestion of USEPA team members, economic feasibility issues will be covered in Step 4.

Electrical Generation Efficiency

EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA, 2011) identifies three categories of control technologies (p. 25):

1. Inherently lower-emitting processes/practices/designs
2. Add-on controls, and
3. Combinations of lower-emitting process/practices/designs and add-on controls

Because there are no demonstrated add-on controls, only those processes, practices, and designs that result in lower GHG emissions are applicable for this BACT analysis. As noted above, the project includes both simple-cycle and combined-cycle generation in this phase of the project, and possible, but unplanned future expansion of the facility could include build-out of the simple-cycle combustion turbines into combined-cycle systems~~.~~ providing added thermal efficiencies. The CGS project as proposed will utilize a high-efficiency, state-of-the-art, combustion turbine, generator, and HRSG design. ~~Operation~~Operations will use good combustion practices and result in energy efficient operation to provide steam to a new steam turbine generator.

~~In addition, installation of two combustion turbines in a combined-cycle configuration results in a lower resultant plant heat rate as compared to only simple-cycle combustion turbines. In some cases, the turbine which is most efficient in simple-cycle mode will result in a less efficient turbine for combined-cycle operations.~~

Furthermore, inlet air chillers will be used to prevent loss of turbine efficiency that results during hot weather~~.~~, and a wet cooling tower will be used to improve the thermal efficiency of the combined cycle system.

The following analysis will demonstrate that the overall generation efficiency meets or exceeds that of other recently implemented projects.

The permit limits proposed in this application are based on ~~assumed use of a~~a GE LM 6000PF SPRINT combustion turbine of 37.1 MW gross output and a gross heat rate of 9,~~300~~263 Btu/kWh (HHV) for simple-cycle operation. This results in an estimated net output of approximately 97.4 MW at a ~~net~~gross heat rate of 7,~~200~~062 Btu/kWh (HHV) for the 2x1 combined-cycle system, which results in an efficiency of 36.8% and 48.3% for simple cycle and combined cycle operation respectively. These efficiencies include consideration of parasitic auxiliary loads. The combined-cycle system will not have duct firing. All noted performance information is based upon CGS site conditions at 60ºF; the high altitude of the area results in marginal decreases to turbine efficiency compared to other locations. The CGS project will utilize all new equipment.

Combustion Turbine Generator Comparable Permitted Emissions

A search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) was performed for simple- and combined-cycle projects with combustion turbines similar to those proposed for the CGS project. No GHG permit ~~information was~~ limits were found in searching the RBLC for comparable units. Information from other recent combustion turbine projects was researched for this BACT analysis, even though this information has not yet been posted to the RBLC, thermal efficiency data was available.

Efficiency Review

An efficiency review of the proposed CGS project was completed with two metrics: 1) RBLC comparable unit heat rates and 2) comparison of CO_2e emission rates.

RBLC Efficiency Comparison

The RBLC information presented in Table 5-4 below provides a comparison of efficiencies for projects with combustion turbines in the same nominal 40-MW size range as the CGS project. The information presented is for combustion turbines operating in simple cycle. No information was found for comparable 40-MW combined-cycle units without duct burning.

TABLE 5-4
RBLC Efficiency Information – Simple Cycle

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Facility	State	Description	Heat Capacity MMBtu/hr (HHV)	Net MW	Heat Rate Btu/kWh (HHV)	Calculated Efficiency (%)
~~Arvah B. Hopkins Generating Station~~Western Farmers Electric	~~Florida~~Oklahoma	~~GE LM6000PC~~Combustion Turbine Simple Cycle	~~489.5~~462.7	50	9,~~790~~254	36.9
~~Lambie Energy Center~~El Colton, LLC	California	~~GE LM6000PC Simple Cycle~~ LM6000 (Enhanced Sprint)	~~500~~456.5	~~49.9~~48.7	~~10,020~~9,374	36.4
~~Creole Trail LNG~~Bayonne Energy Center	~~Louisiana~~New Jersey	~~Combustion Turbine Simple Cycle~~Rolls Royce Trent 60WLE	~~290~~603	~~30~~64	9,~~667~~422	36.2
~~Western Farmers Electric~~Creole Trail LNG	~~Oklahoma~~ Louisiana	Combustion Turbine Simple Cycle	~~462.7~~290	~~50~~30	9,~~254~~667	35.3
~~El Colton, LLC~~Arvah B. Hopkins Generating Station	~~California~~Florida	~~LM6000 (Enhanced Sprint)~~GE LM6000PC Simple Cycle	~~456~~489.5	~~48.7~~50	9,~~374~~790	35.0
Indigo Energy Facility	California	LM6000 (Enhanced Sprint)	450	45	10,000	34.1
~~Bayonne~~Lambie Energy Center	~~New Jersey~~California	~~Rolls Royce Trent 60WLE~~GE LM6000PC Simple Cycle	~~603~~500	~~64~~49.9	~~9,422~~10,020	34.1

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Notes: Used 1.108 for HHV/LHV conversion factor.

The combustion turbines compared above are similar in size to those planned for the CGS project. As noted above, this analysis and resulting CGS proposed permit limits are based on use of a turbine with simple-cycle gross heat rate of 9,~~300~~263 Btu/kWh (HHV). An exact comparison cannot be made between the CGS combustion turbines and those listed in Table 5-~~1~~4 above because each project has unique equipment and site conditions, primarily elevation and temperature. However, the CGS heat rate compares very favorably with all of the reviewed comparable projects listed above, which demonstrates the high-efficiency attributes of the CGS project.

CO_2e Emission Rate Comparison

In simple-cycle operation, the CGS turbines are estimated to produce 1,102 pounds of CO_2e/MWh at average ambient conditions and full-load operation. Considering the range of normal operating loads (50 to 100 percent generator output), and ambient temperature (0°F to 108°F), GHG output for the CGS simple-cycle combustion turbines range from 1,072 to 1,603 pounds of CO_2e for new and clean combustion turbine prior to any degradation.

Table 5-5 below presents operating information from the EPA Acid Rain database, and was developed using actual comparable operating unit information from 2010.

TABLE 5-5
CGS Comparable Unit GHG Emissions

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State	Facility Name	Unit ID	Operating Time (Hr)	Net Load (MWh)	CO_2 Tons	lb CO_2/MWh
CA	El Cajon Energy Center	1	242	9450	5652	1196
OK	Horseshoe Lake	10	710	29293	18142	1239
OK	Horseshoe Lake	9	174	6851	4248	1240
CA	Orange Grove Project	CTG1	632	25017	15734	1258
CA	Orange Grove Project	CTG2	654	24954	15847	1270
FL	Arvah B Hopkins	HC4	903	27627	17623	1276
FL	Polk	**2	249	27652	18500	1338
FL	Arvah B Hopkins	HC3	662	18283	12529	1371
FL	Polk	**5	476	51662	36111	1398
FL	Polk	**4	563	60221	42443	1410
FL	Polk	**3	204	23176	16600	1432
NJ	Bayonne Plant Holding, LLC	2001	1055	35582	28385	1595
NJ	Bayonne Plant Holding, LLC	1001	1208	39061	32004	1639
NJ	Bayonne Plant Holding, LLC	4001	1134	36629	30200	1649
NE	C W Burdick	GT-3	24	426	399	1871
NE	C W Burdick	GT-2	33	606	579	1912
CA	Escondido Energy Center, LLC	CT1A	28	345	466	2702
CA	Escondido Energy Center, LLC	CT1B	28	345	468	2718

Notes:

Net load 5% lower than gross load.
Data as per EPA Clean Air Markets – Data and Maps.
Based on 2010 data.

The CGS combustion turbine GHG output compares favorably with the facilities shown Table 5-5 above. It is recognized that in establishing any permit limit, allowance must be given for load variances, impact of ambient conditions, startup and shutdown, and equipment degradation over time. This is exemplified by reviewing the information from Table 5-5, because all of these units can be considered as "peaking" due to the low number of annual operating hours. The resultant wide variance in pounds of CO_2e/MWh may likely be attributed to the significant proportion of time in startup and shutdown and/or reduced load operation, as well as lower thermal efficiency for older units.

Note that, ~~based on the combustion turbine defined above, and~~ considering the range of normal operating loads (50 to 100 percent output~~),~~) and ambient temperature (0°F to 108°F), GHG output for the CGS 2x1 combined-cycle system ranges from 833 to 985 pounds of CO_2e for a new or clean combustion turbine prior to any degradation.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible GHG control technology for the CGS project is the electrical generation efficiency.Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible GHG control technology for the CGS project is the electrical generation efficiency. This option is presented in Table 5-6 based on their energy efficiencies expressed in terms of heat rate.

TABLE 5-6
CGS Project GHG Control Technology Ranking

TABLE 5-6
CGS Project GHG Control Technology Ranking

Configuration	Gross Plant Heat Rate (HHV) (Btu/kWh)[1]
~~Electrical Generation Combined-Cycle Efficiency (without duct firing)~~	~~7,200~~
~~Electrical Generation Simple-Cycle Efficiency~~	~~9,300~~
Electrical Generation Combined-Cycle Efficiency	7,062
Electrical Generation Simple-Cycle Efficiency	9,263

Note: [1]At CGS site conditions.

Combustion Turbine Design Elements

As demonstrated above, the GE LM6000PF SPRINT combustion turbine has high efficiency which is equal or greater the majority of other turbines of the same nominal capacity. However the differences in efficiency from offerings of other vendors are in some cases trivial. The design elements of those turbines that result in high efficiency undoubtedly vary between vendors, and in many cases are proprietary and confidential. Thus an extensive analysis of what design considerations are needed to have an efficient turbine design is beyond the scope of this permit application.

However the issue was discussed with the selected turbine vendor, GE, and they offered comments on the unique elements of their design. This information is provided in Appendix B-4. Some of the key elements noted by GE are dual shaft architecture, low shaft speed, modulation of shaft speed and air flow with power, and high operating pressure ratio.

It should be noted that the electrical generator is provided as a combined unit with the GE LM6000PF SPRINT combustion turbine package, and has been engineered to match combustion turbine operating characteristics. Preliminary information indicates that the generator is 98%+ efficient, so overall system efficiency is driven by the combustion turbine characteristics.

The CGS 2x1 combined cycle system will also utilize a steam turbine and Heat Recovery Steam Generators (HRSG). Steam turbines manufactured today for small combined cycle plants have efficiencies limited by the metal design temperatures and pressures. The steam turbine is custom engineered rotating machinery where the efficiency is optimized in the blade path design, which maximizes the energy extracted from the steam. HRSG efficiency is maximized in the design by selecting aggressive approach and pinch points to extract the maximum heat out of the gas turbine exhaust stream. The efficiency is further improved by tube bundle arrangement, finned tubing and back end recirculation and or condensate preheating.

Step 4: Evaluate Most Effective Controls and Document Results

~~The~~As demonstrated in Step 2 above, CCS is not a technically feasible alternative for the CGS project. Nonetheless, at the suggestion of USEPA team members, economic feasibility of CCS technology is reviewed in this Step 4. Control options considered in this step therefore include application of CCS technology, and plant energy efficiency. As demonstrated below, CCS is clearly not economically feasible for the CGS.

On Page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective: "With respect to the valuation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system."

The guidance document also acknowledges the high costs of CCS technology at the current time: "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."

The costs of constructing and operating CCS technology are indeed extraordinarily high based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs as compared to "pure" sequestration in deep saline aquifers or depleted coal seams, additional costs to the CGS would include the following:

- Licensing of scrubber technology and construction of carbon capture systems,
- Significant reduction to plant output due to the high energy consumption of capture and compression systems,
- Identification of oil & gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long term contracts for CO_2 purchases,
- Construction of compression systems and pipelines to deliver CO_2 to EOR locations,
- Labor to operate, maintain, and monitor the capture, compression, and transport systems, and
- Issues regarding project risk that would jeopardize ability to finance construction and to obtain PUC approval.

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: "For a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture." Using the

"Capacity Factor Method" for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering (AACE) and other organizations, CO_2 capture system capital cost for the CGS is estimated as at least $196 million. Based on an estimated CGS plant capital cost of $300 million, the capture system alone would thus be expected to add approximately 65 percent to the overall plant capital cost.

Actual cost per megawatt would likely be higher for CGS than the reference plant in the Task Force report due to the inclusion of simple cycle units; this would require capture systems to handle a much higher temperature gas flow; little or no pilot test data is available for this situation, different materials of construction may be required, and modifications to the absorption process may be required.

Similarly, the energy penalty would be higher for simple cycle systems than for combined cycle; since scrubber and compressors are sized based on combustion turbine output, but overall unit output is lower for simple cycle, the fractional penalty would be higher. Whether plant size would remain the same with output reduced, or plant size increased to account for lost output, the energy penalty alone represents at least a 15% increase to the fuel component of the cost of electricity. At an estimated 8.9¢/kWh residential retail price for electricity, and assuming an annual average of 50% capacity factor for plant operation and 15% energy penalty, the value of lost electricity sales from the project is $12.9 million per year.

As noted above, the effort required to identify and negotiate with oil & gas companies who may be able to utilize the CO_2 would be substantial. BHC is aware that the proposed Greencore pipeline is being substantially oversized, versus what would be required for only the Belle Creek EOR operation, so it is reasonable to assume project developers are planning that there will be a future need for CO_2 in the Powder River Basin or other locations in Wyoming or Montana. The location and timing of those sites, however, is not public information, and due to the patchwork of oil well ownership many parties could potentially be involved in negotiations over CO_2 value.

Due to the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are very specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight stage design. It is unclear whether the Task Force NGCC cost estimate noted above includes the required compression systems, but if not this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2000 pounds per square inch, gauge) and potential for corrosion if any water is introduced to the system. As noted above, if CCS were otherwise technically and economically feasible for the CGS, the most realistic scenario could be to construct a pipeline from Cheyenne to tie into the proposed Greencore pipeline. At its closest point, the Greencore pipeline would be approximately 175 miles from Cheyenne. Based on engineering analysis done by the designers of that pipeline, costs for an 8" CO_2 pipeline to connect the Cheyenne project to the Greencore pipeline are estimated at $600,000 per mile, for a total cost of $105 million. Thus the pipeline alone would represent a 35 percent increase to the project cost, and the pipeline and capture system together would double the project capital cost.

It is unlikely that financing could be approved for a project which combines CCS in conjunction with generation, given the technical and financial risks. Also, as evidenced with utilities' inability to obtain PUC approval for integrated gasification / combined cycle (IGCC) projects due to unacceptable cost and risk to ratepayers, such as Wisconsin's disapproval of the We Energy project, it is reasonable to assume that the same issues would apply in this case before the Wyoming PUC.

Sale of the CO_2 for EOR could be the one positive direct economic impact of CCS. If BHC were to construct or pay for construction of the pipeline to deliver captured CO_2, it is possible that revenue from sale of the CO_2 could be realized. Current market pricing for CO_2 delivered for EOR is however proprietary and confidential, and reliable sources of information could not be identified within this scope of this BACT analysis.

In summary, capital cost for capture system and pipeline construction are estimated at $300 million, and retail value of lost power sales due to the CCS system energy penalty is estimated at $12.9 million per year assuming only 50% plant capacity factor. Other costs such as identification, negotiation, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; less favorable financing terms or inability to finance; and difficulty in obtaining PSC approval would also impact the project, and it is unclear if compression systems are included in the Task Force estimate of capture system costs. A fraction of these impacts could possibly be offset through sale of the CO_2, but overall addition of CCS with or without EOR opportunity would make the project unviable.

CCS is clearly not economically feasible for natural gas fired power plants at the current time. Since CCS is not considered technically or economically feasible, the proposed CGS electrical generation efficiency is determined to be the most effective GHG control technology.

From a review of the three evaluation metrics presented above, the ~~CGS combustion turbine net~~ heat rate for the CGS GE LM6000 PF Sprint combustion turbine, selected pursuant to the CGS business plan, was found to favorably compare with other combustion turbines and projects.

Step 5: Select BACT

The only remaining option is the "Electrical Generation Efficiency" option, which, therefore, is selected as BACT. This option determined to consist of the CGS project as proposed with new state-of-the-art combustion turbines. Consistent with the review criteria presented above, the CGS project evaluated combustion turbine exhibits comparable efficiency with most of the evaluated alternative combustion turbines, and superior efficiency over ~~the Pratt & Whitney and Siemens~~other comparable machines. Therefore, ~~Black Hills~~BHC proposes that CGS GHG BACT consist of installation of GE LM6000PF SPRINT combustion turbines ~~from any manufacturer with a rating of nominal 40 MW. However,~~, and the annual CO_2 emissions limit for the five new combustion turbines will be based upon the BACT emission limits proposed below~~, which are based upon a combustion turbine from the top of the efficiency range shown. The proposed permit limit of annual total tons of CO_2e and lb/MWh would remain fixed regardless of the combustion turbine selected.~~

. The estimated total annual CO_2e emissions from the combustion turbines are 936,588 tpy, and this value is proposed to be the annual CO_2e permit limit for the five combustion turbines.

EPA's PSD permitting guidance for GHGs suggests use of output-based BACT emission limits and longer-term averaging periods for GHGs. Based on Black Hills' BHC analysis of conservative scenarios for number of turbine startups and shutdowns, partial load operation, and ambient temperature during operations, and considering the range of normalized GHG emissions noted above and eventual turbine degradation, proposed BACT permit limits are 1,100 lb/MWh for each combined-cycle combustion turbine and 1,600 lb/MWh for each simple-cycle combustion turbine on an annual average basis. If the averaging time is less than 1 year, these permit limits should be increased accordingly.

5.6 Small Combustion Sources BACT for GHGs

In addition to the five combustion turbines planned for the CGS project, there are several other small combustion sources associated with auxiliary equipment which will operate at the plant. The GHG calculations for these small combustion sources are located in Appendix B-1.

- (6) Natural gas-fired inlet air heaters (nominal 16-MMBtu/hr air heater with estimated emissions of 4,117 CO_2e tons/year each)), required for safety to prevent icing of air handling systems
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year each)
- (1) Diesel-fired fire pumpspump (nominal 327-BHP engine with estimated 51 CO_2e tons/year each)

The total GHG emissions from the above small combustion sources are very minor as compared to the emissions from the combustion turbines. However, for completeness, these minor GHG emission sources were evaluated in aggregate below.

Step 1: Identify All Control Technologies

The available control technologies for the CGS minor GHG sources are identical to those identified for the combustion turbines. These options include

- Carbon Capture and Storage Systems (CCS
- Small Combustion Source Efficiency
- Efficient Use of Energy

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Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

As discussed above, CCS for GHG control is not considered a technically feasible control option for the combustion turbines. Stand-alone capture systems for the small sources would be even further from technical feasibility. Therefore, CCS is eliminated from further consideration for ~~auxiliary boiler~~small combustion source GHG reduction.

Small Combustion Source Efficiency

~~This~~The small combustion sources for the CGS project will incorporate a high-efficiency design.

Efficiency Background Information

In support of small combustion source design, additional background information is assembled in Appendix B-8 through B-14 regarding efficiency attributes of the auxiliary equipment; i.e., inlet air heater, inlet chiller units, fuel gas heaters, diesel fire pump, and diesel emergency generator.

Inlet Air Heater

The inlet air anti-icing heater is similar to a conventional natural gas fired watertube boiler, and is required for safety reasons to prevent icing during winter weather. However, the water does not reach the boiling point in this system and a mixture of water and glycol is used for its thermodynamic advantages over water. The unit is designed for quick load response eliminating the requirement for a stored energy system and associated efficiency losses. Combusted natural gas is used to directly heat the incoming water/glycol mixture.

Other technologies available for heating the water/glycol mixture include an indirect fired water bath heater or fire tube boiler. The fire tube boiler has similar efficiency but a much higher capital cost. The indirect fired water bath heater has a lower efficiency resulting in higher operating costs and increased emissions. With both cost and environmental operations considered, these two options are not economical for this application.

Fuel Gas Heater

Indirect water/glycol bath heaters were selected for heating of high-pressure natural gas. The natural gas is heated to ensure a measure of superheat before reaching the combustion turbine generator. Indirect heaters use a fire tube to transfer heat from the fired natural gas (fuel) to the water/glycol solution. The heat is then transferred from the water/glycol bath to the natural gas coil (product) in a safe manner. Although this heating technology is not as efficient as direct heating, it is considered the only acceptable option due to safety reasons as noted below.

Direct heating of natural gas would result in a slightly more efficient process; however, direct heating of natural gas is extremely dangerous and not recommended. Any small manufacturing defect, failure, or leak may result in catastrophic explosions as the product (natural gas) is exposed to an open heat source.

Diesel Fire Pump & Standby Generator

While preliminary review of the CGS emergency diesel equipment has been initiated, the final equipment selection has not been completed. However, the diesel equipment will be evaluated to ensure a high efficiency design.

Efficient Use of Energy

The small combustion sources will not be operated continuously, but only during conditions when they are needed. For example, the inlet air heaters and fuel gas heaters will be operated only when required for safety reasons to protect against icing of the turbines or condensation within the fuel lines. Therefore, energy will be utilized in an efficient manner.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies are equally important toward minimizing GHG emissions.

Step 4: Evaluate most effective controls and document results

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies will be implemented for the CGS project.

Step 5: Select BACT

GHG BACT for the CGS small equipment are "Small Combustion Source Efficiency "and "Efficient Use of Energy." All auxiliary equipment will be selected with consideration for high design efficiency, and will be operated in an efficient manner. Due to the ~~estimated~~ minor CO_2e emissions contribution from these small combustion sources, no efficiency or output-based GHG permit ~~limit is~~limits are recommended for the CGS auxiliary equipment.

5.7 Requested Permit Limits

The following Tables 5-7 and Table 5-8 list the recommended permit limits for the combustion turbines and auxiliary equipment respectively:

TABLE 5-7
CGS Combustion Turbine Recommended CO_2e Permit Limits

Emission Unit	**Annual CO_2e Limit (Pounds/MWhr)**	**Annual CO_2e Limit (Tons/Year)**
Combined Cycle Combustion Turbine CT01A	1,100	187,318
Combined Cycle Combustion Turbine CT01B	1,100	187,318
Simple Cycle Combustion Turbine CT02A	1,600	187,318
Simple Cycle Combustion Turbine CT02B	1,600	187,318
Simple Cycle Combustion Turbine CT03A	1,600	187,318

TABLE 5-8
CGS Auxiliary Equipment Recommended CO_2e Permit Limits

Emission Unit	**Annual CO_2e Limit (Tons/Year)**
Six (6) Inlet Air Heaters	24,703
Two (2) Fuel Gas Heaters	2,306
One (1) Diesel Fire Pump	51
One (1) Diesel Standby Generator	226

Black Hills Corporation

Fred Carl
Director of Environmental Services

PO Box 1400. 625 Ninth Street
Rapid City, South Dakota 57709

September 23, 2011

Mr. Carl Daly
Director of Air Programs
EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Black Hills Corporation - Cheyenne Generating Station
Submittal of Greenhouse Gas PSD Construction Air Permit Application **Revision 1 – Sept. 2011**

Dear Mr. Daly,

Black Hills Corporation (BHC) is submitting a revised Greenhouse Gas PSD Construction Permit Application for the Cheyenne Generating Station in the City of Cheyenne in Laramie County, Wyoming. Revisions have been made to the original application submitted on August 5, 2011 to respond to comments made during several telephone conversations and meetings between EPA and BHC staff. For your convenience, we have enclosed five (5) copies of the complete revised application including divider tabs that can be inserted in the original 3-ring binders. As we discussed in the pre-application meeting for this project held in your offices on July 8, 2011, the application for the PSD permit for the criteria pollutant emissions will be submitted to the Wyoming Department of Environmental Quality.

The Cheyenne Generating Station (CGS) will be a nominal 220 MW gross electric generating facility that includes five (5) 40 MW combustion turbines. Two of the turbines will operate in combined cycle mode and three will operate in simple cycle mode. The planned start of construction is summer 2012.

Please contact Tim Rogers, Black Hills Corporation at (605) 721-2286 or Joe Hammond, CH2M HILL at (720) 286-5919 on any questions that EPA may have during the application review. We appreciate your assistance on this important project.

Sincerely,

Fred Carl
Director, Environmental Services
Black Hills Corporation

C: Chris Razzazian, Deirdre Rothery; EPA Region 8
Mark Lux, Tim Rogers; BHC
Chad Schlichtemeier, Wyoming DEQ

Black Hills Corporation

Signature of Responsible Official

I have reviewed this application and based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this application are true, accurate and complete.

Printed or Typed Name	Title
Mark L. Lux	Vice President and General Manager Power Delivery
Signature	Date Signed
	09/23/2011

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Appendices

Tables

Acronyms and Abbreviations

BACT	best available control technology
BHC	Black Hills Corporation
BHP	Black Hills Power
CAA	Clean Air Act
CatOx	Catalytic Oxidation
CEM	continuous emissions monitor
CFR	Code of Federal Regulations
CGS	Cheyenne Generating Station
CH_4	Methane
CLFP	Cheyenne Light, Fuel and Power Company
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CTG	combustion turbine generator
°F	degrees Fahrenheit
EPA	U.S. Environmental Protection Agency
FIP	Federal Implementation Plan
FR	Federal Register
GHG	greenhouse gas
GWP	global warming potential
HFC	Hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound

lb/hr	pound per hour
LHV	lower heating value
MACT	maximum achievable control technology
MRR	Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu	million British thermal units per hour
MW	Megawatt
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NO_X	nitrogen oxide
NSR	New Source Review
N_2O	nitrous oxide
O_2	Oxygen
PFC	Perfluorocarbon
PM_{10}	particulate matter less than 10 microns in diameter
ppm	parts per million
PTE	potential to emit
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SF_6	sulfur hexafluoride
SIP	State Implementation Plan
SO_2	sulfur dioxide
STG	steam turbine generator
tpy	tons per year
WDEQ	Wyoming Department of Environmental Quality
VOC	volatile organic compound

Executive Summary

Black Hills Corporation (BHC) plans to construct a new nominal 220-megawatt (MW) gross simple-and combined-cycle natural gas-fired combustion turbine power plant in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located within the city limits of the City of Cheyenne, Wyoming, approximately 5 miles southeast of the downtown area.

Cheyenne Light, Fuel and Power Company (CLFP) is a wholly owned subsidiary of BHC. It was acquired from Xcel Energy on January 1, 2005, and provides electric utility service to Laramie County, Wyoming, including the City of Cheyenne.

Presently, electricity sold by CLFP is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is currently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The CGS project will include the following:

- Five General Electric (GE) LM6000 PF SPRINT combustion turbine generators (CTGs) fired by pipeline quality natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, BHC is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) from the CGS and contains a description of the project, a review of applicable federal regulations, a listing of the emissions, and a best available control technology analysis.

The CGS will have potential emissions of 963,874 tons per year (tpy) of GHGs expressed as carbon dioxide equivalent (CO_2e). This is comprised of 962,929 tpy of carbon dioxide (CO_2) or CO2e of 962,929 tpy, 1.8 tpy of nitrous oxide (N_2O) or CO2e of 564 tpy, and 18.2 tpy of methane (CH_4) or a CO2e of 381 tpy. Because the emissions of CO_2e exceed 100,000 tpy, this plant will be a major new source and will be subject to the Prevention of Significant Deterioration (PSD) rules.

Because the emission rate of GHG exceeds the 100,000-tpy limit specified in the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule), a best available control technology (BACT) analysis was performed. The BACT analysis concludes that the CGS project operating at its design energy conversion efficiency is BACT for GHGs.

SECTION 1.0

Introduction

BHC plans to construct a new nominal 220-megawatt (MW) gross simple and combined-cycle combustion turbine power plant located in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located in the City of Cheyenne approximately 5 miles southeast of the downtown area.

The facility will produce electrical power for CLFP, a wholly owned subsidiary of Black BHC. CLFP provides electric service to Laramie County, Wyoming, and the City of Cheyenne, with more than 38,000 customers.

Presently, electricity sold by CLFP is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is presently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The power plant will include the following:

- Five 40-MW combustion turbine generators (CTGs) fired by pipeline quality natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode. Operating in combined-cycle will provide approximately 20-MW.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, BHC is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) and contains a description of the project, a review of applicable regulations, a listing of the emissions, and a best available control technology (BACT) analysis.

Section 1.1 provides project contacts and an overview of the documentation being submitted with the application for a permit to construct the CGS.

1.1 Project Contacts

The following individuals may be contacted for additional information on this project:

Applicant	Tim Rogers Environmental Manager Black Hills Corporation 625 Ninth Street Rapid City, SD 57709 (605) 721-2286 TRogers@bh-corp.com
Permitting Consultant	Joe Hammond Principal Project Manager CH2M HILL Engineers, Inc. 9193 South Jamaica Street Englewood, CO 80112 (720) 286-5919 joe.hammond@ch2m.com

1.2 Document Overview

The following is an overview of the information included in this permit application.

- **Section 1.0 – Introduction.** This section provides an overview of the project and describes the application organization.
- **Section 2.0 – Project Description.** This section includes a general description of the proposed project including equipment and operations of the project. Information regarding non-emitting processes and equipment is provided for a general understanding of plant operations.
- **Section 3.0 – Greenhouse Gas Emissions Summary.** This section provides a summary of emissions-related information.
- **Section 4.0 – Greenhouse Gas Regulatory Review.** This section contains a detailed regulatory review of federal GHG air regulations that may impact the permitting, construction, or operation of the proposed project.
- **Section 5.0 – BACT Analysis.** This section includes a BACT analysis for GHG pollutants. This analysis follows the EPA-prescribed five-step top-down approach. Requested permit limits are also included in this section.
- **Appendix A – Location Map and Plot Plan.** This appendix includes a location map, plot plan, and general equipment arrangement drawing for the proposed project.
- **Appendix B – Greenhouse Gas Supporting Documentation.** This appendix contains the calculations used to determine the GHG emissions for this permit application and additional information on the GE combustion turbines and auxiliary equipment.

SECTION 2.0

Project Description

BHC proposes to construct and operate the CGS in Cheyenne, Wyoming. A plot plan of the facility and a map detailing the location of the proposed facility can be found in Appendix A. The facility will be a nominal 220-MW gross output power plant that will produce electrical power for the BHC-owned CLFP electric retail service territory in Laramie County, Wyoming, including the City of Cheyenne and Black Hills Power (BHP) service territory in Wyoming and South Dakota. Facility output varies with ambient temperature, with higher output at lower ambient temperatures. A general arrangement of the turbine layout and associated equipment can be found in Appendix A.

The CGS facility configuration was selected based upon the needs identified in the CLFP *Integrated Resource Plan* (IRP).[1] The CLFP Certificate of Public Convenience and Necessity (CPCN) was filed with the Wyoming Public Service Commission (August 1, 2011 – Docket Number 20003-112-EA11) and was based upon CLFP IRP that identified three simple-cycle combustion turbines (nominally 120 MW gross output). The CLFP CPCN further identifies the potential build-out of the site to accommodate future generation needs. BHC plans to submit a BHP CPCN in fall 2011 and will be based upon the BHP IRP that tentatively (plan has not been finalized) identifies the need for two combustion turbines configured in combined cycle mode (nominally 100 MW gross output). The BHC's Integrated Resource Plans will show the public need for increased capacity requirements in the CLFP and BHP service areas, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking with base-load capability and further enable renewable generation (wind, solar, and other renewable resources).

The proposed CGS facility will consist of five combustion turbines. Combustion turbines CT01A and CT01B will operate in a 2 X 1 combined-cycle design consisting of two 40-MW CTGs with one heat recovery steam generator (HRSG) for each CTG with no duct burners. Steam from the HRSGs will be combined to flow to a steam turbine that will produce additional electricity. The total generating capacity of the combined-cycle configuration will be approximately 100 MW. Combustion turbines CT02A, CT02B, and CT03A, will each be high-efficiency 40-MW CTGs, operating in simple-cycle mode.

Inlet air chillers with wet cooling towers will be provided for each CTG to cool the combustion air, which will enhance overall plant output during times of higher ambient temperature. Inlet air heaters will also be provided for each CTG to heat the combustion air, which will prevent icing during times of lower ambient temperature.

The proposed CGS facility will also have fuel gas pre-heaters, an emergency generator, and a fire pump.

[1] The IRP determines the capacity expansion, which takes into consideration the size of the electrical systems' demand, and further defines the size of combustion turbines selected.

2.1 Power Generation

Power will be produced in the plant by a total of six generators, one for each of the five 40-MW CTGs plus one steam turbine generator (STG). All other facility operations ancillary to the primary generation function are described below.

2.2 Emission Sources

2.2.1 Combined-Cycle Combustion Turbine Generators

The CGS will use two 40-MW combustion turbines CT01A and CT01B operated in a 2 X 1 combined-cycle design with two CTGs and one steam turbine. The combustion turbines will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines will be equipped with unfired (no duct burner) HRSGs to extract heat from each combustion turbine exhaust to make steam. The steam will be used in an STG to produce more electricity. The combined-cycle configuration will consist of two CTGs, two HRSGs (one for each CTG), and one STG.

2.2.2 Simple-Cycle Combustion Turbine Generators

The CGS will use three 40-MW combustion turbines operated in simple-cycle mode, without heat recovery from the turbine exhaust. These combustion turbines, designated as CT02A, CT02B, and CT03A, will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines have the capability to reach full-load operation quickly after initiation of startup, thereby reducing overall startup emissions.

Each combustion turbine consists of a compressor, combustor, and expansion turbine. After filtration, air passes through the compressor before combining with the fuel and entering the low nitrogen oxide (NO_X) combustor. The combustion products and compressed air pass through the expansion turbine, which drives both the compressor and the generator. Up to approximately 40 MW of gross electrical power are produced by each CTG over and above the work required by the compressor. The exhaust gas from each combustion turbine enters the Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CatOx) catalysts at high temperature (approximately 850 degrees Fahrenheit [°F] at full load).

2.2.3 Wet Cooling Towers

2.2.3.1 Inlet Chiller Cooling Towers

An inlet air chilling system will be installed at the compressor inlet of each CTG, downstream of the inlet air filter. The inlet air chilling system serves to enhance the overall output of the plant by lowering the temperature of the ambient air entering the CTGs during periods of high air temperature. The cooling process takes place at the cooling coils where air is cooled before entering the compressor section of the turbine. At low temperatures, the air becomes denser and, therefore, more air flows though the CTGs. The net increase in airflow results in higher power output for each of the CTGs at high ambient temperatures. Three inlet chiller cooling towers will be used to serve the inlet chilling system at CGS.

2.2.3.2 Unit 1 Cooling Tower

One wet cooling tower will be installed to provide cooling to condense the steam that is exhausted from the steam turbine on the combined cycle configuration in order to increase system efficiency. The steam condensers will have circulating cooling water flow through tubes that will absorb the heat from the condensing steam that is exhausted from the steam turbines. The warmed circulating water is then pumped to the cooling tower where it flows down through the tower and is cooled through evaporation, in a manner similar to other cooling towers. The cooled circulating water then flows back to the steam condensers to pick up more heat.

2.2.4 Inlet Air Heaters

An inlet air heating system will be installed at the compressor inlet of each CTG, upstream of the inlet air filter. The inlet air heating system raises the temperature of the ambient air entering the CTGs during periods of low air temperature to prevent icing for safety reasons.

2.2.5 Fuel Gas Heaters

A fuel gas pre-heat system will be utilized on each CTG to raise the temperature of the natural gas above the saturation temperature for safety reasons. Natural gas fired fuel gas heaters will be used on the five combustion turbines.

2.2.6 Diesel Fire Pump

One diesel fire pump will be used to provide fire protection water for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the fire pump are 250 hours per year or less.

2.2.7 Emergency Generator

One diesel emergency generator will be used to provide emergency power for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the emergency generator are 500 hours per year or less.

2.2.8 Storage Tanks

Storage tanks at the site will include diesel tanks for the fire water pump and emergency generator, aqueous ammonia storage tanks for the SCR NO_x emissions control unit, and several water storage tanks. No GHG emissions will result from these tanks.

2.3 Non-Emitting Major Facility Components

2.3.1 Ancillary Facilities

Other facilities used to support power generation at the CGS will include the following:

- Water treatment system to remove solids and hardness from plant makeup water
- Wastewater treatment system to allow recycle of cooling tower blowdown and other plant wastewater

- Plant and instrument air compressors (electric-driven) and auxiliary equipment
- Plant sumps, sump pumps, and oily water separator
- Miscellaneous fire protection equipment
- Steam and water sampling systems
- Administration and warehouse/maintenance buildings

2.4 Emission Controls

The CGS will include the following emission controls:

- Dry low NO_X burners on the CTGs, and a SCR system to reduce NO_X emissions on all CTGs
- An oxidation catalyst to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions on all CTGs
- Good combustion design and operation to reduce particulate matter of 10 microns in diameter (PM_{10}) emissions from the CTGs
- Use of pipeline-quality natural gas to minimize sulfur dioxide (SO_2) emissions from the CTGs
- High-efficiency drift eliminators on the steam condenser cooling towers to reduce PM_{10} emissions in the cooling tower drift

2.5 Emissions Monitoring

As required by Title 40 of the Code of Federal Regulations (CFR) Parts 60 and 75, the CGS will use continuous emissions monitors (CEMs) for NO_X, CO, and oxygen (O_2) for all five CTGs. These CEMs will average and record data on frequencies consistent with state and federal acid rain rules. The plant will also monitor and record the natural gas flow rate and will analyze natural gas fuel quality as required by the acid rain rules.

CGS will use these continuous emissions monitors (CEMs) to determine compliance with the CO_2 emission limits established in the PSD permit. CEMS will be installed and operated for each turbine according to 40CFR75 requirements. Accordingly, these CEMS will calculate CO_2 emissions from each source according to the 40CFR75 Appendix F and G methodologies. The calculated CO_2 emissions follow a strict calculation requirement to determine CO_2 emissions for each minute of fuel combustion typically. The minute data is converted to hourly emissions for reporting per 40CFR75 data reduction requirements. All CO_2 emissions are accounted for in the reported values, including startup and shutdown.

The CO_2 emissions data generated from the CEMS, per 40CFR75 requirements, are used to report emissions for 40CFR98 (Mandatory Greenhouse Gas Reporting rule). Specifically, Subpart D – Electricity Generation, guide the CO_2 emissions reporting requirements. Black Hill currently uses this methodology for its natural gas fired combustion turbines. The calculation methodology is defined simply as:

"(a)…continue to monitor and report CO_2 mass emissions as required under §75.13 or section 2.3 of appendix G to 40 CFR part 75, and §75.64. Calculate CO_2 emissions as follows: (1) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023."

This calculation, as required by EPA's Greenhouse Gas MMR rule simply uses the 40CFR75 fourth quarter, or end of year, CO_2 emission and coverts the short tons to metric tons (Nitrous Oxide and Methane emissions are calculated from Green House Gas emission factors). Additionally, the CO_2 data will follow quality assurance/control requirements as well as missing data substitution routines according to 40CFR75 rules. Therefore, since EPA's long standing Acid Rain Program regulations (40CFR75) and the recently released Greenhouse Gas MMR rule (40CFR98) both recognize the 40CFR75 methodology as an accurate and complete method to monitor CO_2 emissions, the CGS will use the methodology to determine compliance with CO_2 emission limits identified in this permit.

In a recent permit application with the Bay Area Air Quality Management District (BAAQMD) for the Russell Energy Center in California, the agency made the following determination regarding CEMS versus the Fuel Meter (heat input) method:

> "The Air District has also considered whether to require the facility to use a Continuous Emissions Monitor (CEM) to measure greenhouse gas emissions directly (as CO_2), but has concluded that calculating emissions from heat input is preferable. Unlike some other pollutants such as NO_x or carbon monoxide whose formation is heavily dependent on conditions of combustion and/or performance of add-on emissions controls, greenhouse gases are a direct and unavoidable byproduct of the combustion process. The amount of carbon within the fuel will all ultimately be emitted as greenhouse gases in a manner that is easily determined using well-established emissions factors. One can therefore determine with great accuracy what greenhouse gases are being emitted by measuring the amount of hydrocarbon fuel being burned (measured as heat input). For this reason, the test methods for measuring heat rate and capacity can achieve an accuracy of ±1.5% [55], which is better than the relative accuracy of CEMs which typically ranges as high as ±10%.[56] The Air District is therefore proposing to require surrogate monitoring for greenhouse gas emissions using heat rate instead of a CEM."
>
> [55] American Society of Mechanical Engineers (ASME), Performance Test Code on Overall Plant Performance, (PTC 46-1996), December 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to steam generator").
> [56] See, e.g., 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.")

2.6 Operating Schedule

The annual operating schedule of the CGS will be dependent on the demand for electric power. Thus, the exact operating schedule cannot be accurately predicted at this time.

For this reason, the permit limits requested in this application, and the resulting assumptions used in the emissions inventory and BACT analysis, are as follows:

- Up to 8,760 hours per turbine per year of CTG operation (both simple and combined cycle) at 100 percent load or at any lesser load rate
- Up to 600 startups for each simple-cycle combustion turbine per year
- Up to 600 startups for each combined-cycle combustion turbine per year
- Up to 5,330 hours per tower per year of inlet chiller cooling tower operation
- Up to 8,760 hours per year of combined-cycle cooling tower operation
- Up to 4,380 hours of operation per year for each inlet air heater
- Up to 4,380 hours of operation per year for each fuel gas heater

These hours could be based on continuous short-term or long-term operation. In other words, the plant could operate up to 8,760 hours per year (counting startup episodes) and could operate 24 hours per day, 7 days per week, and 365 days per year.

2.7 Permitting and Construction Schedule

The planned permitting and construction timeline is shown in Table 2-1.

TABLE 2-1
Permitting and Construction Schedule

Event	Date
GHG PSD Permit Application Filed with EPA	August 2011
Revised GHG PSD Permit Application Filed with EPA	September 2011
PSD Air Permit Application Filed with WDEQ	October 2011
Air Permits Issued by EPA and WDEQ	September 2012
Begin Purchase Major Pieces of Equipment	September 2012
Start of Construction	April 2013
Commercial Operation	June 2014

SECTION 3.0

GHG Emissions Summary

GHG emission estimates were prepared for all point emissions sources from the CGS, including the combustion turbines and auxiliary equipment. The annual carbon dioxide (CO_2) equivalent (CO_2e) emissions were estimated based on 100 percent capacity factor (full-load operation for 8,760 hours per year) for each of the combustion turbines. Note that instantaneous fuel flow is always lower during turbine startup than normal turbine operations; therefore, unlike for criteria air pollutants, instantaneous GHG emissions are always lower during startup than normal operations, and 8760 hours per year at full load is a conservative assumption for calculating GHG emissions. More detailed emission calculations are provided in Appendix B.

3.1 Combustion Turbines

The CGS project consists of two GE LM6000PF SPRINT combustion turbines operating in a 2 X 1 combined-cycle configuration, designated as CT01A and CT01B. There will also be three GE LM6000PF SPRINT combustion turbines operating in simple cycle identified as CT02A, CT02B, and CT03A. All five combustion turbines will have separate stacks, which will be a separate emission points.

3.2 Auxiliary Equipment

In addition to the five GE LM6000PF SPRINT combustion turbines planned for the CGS project, there are several other small GHG combustion sources associated with auxiliary equipment that will operate at the CGS:

- (6) Natural gas-fired inlet air heaters (nominal 16-million-British-thermal-units-per hour [MMBtu/hr] air heater with estimated emissions of 4,117 CO_2e tons/year each)
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year)
- (1) Diesel-fired fire pumps (nominal 327-BHP engine with estimated 51 CO_2e tons/year)

3.3 GHG Emission Summary

The GHG emission sources for the project are shown in Table 3-1, along with estimated annual CO_2e emissions.

TABLE 3-1
GHG Emission Source Summary

Source Number	Emission Point	Estimated Annual CO_2e Emissions
EP01 and EP02	(2) GE LM6000PF SPRINT Combined-Cycle Combustion Turbines CT01A and CT01B	374,635
EP03, EP04, and EP05	(3) GE LM6000 PF SPRINT Simple-Cycle Combustion TurbinesCT02A, CT02B, and CT03A	561,953
EP06 through EP11	Six (6) Inlet Air Heaters	24,703
EP18 and EP19	Two (2) Fuel Gas Heaters	2,306
EP16	One (1) Diesel Fire Pump	51
EP15	One (1) Diesel Standby Generator	226

SECTION 4.0

Regulatory Review

This section provides a regulatory review of the applicability of federal air quality permitting requirements for GHGs and GHG air pollution control regulations for the CGS project proposed by BHC. The purpose of this section is to provide appropriate explanation and rationale regarding the applicability of these regulations to the CGS project. The review is limited to federal regulations for GHG because there are no State of Wyoming regulations for GHG that apply to the permitting of CGS.

Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Both agencies have agreed to work together to process these two air permits for CGS.

4.1 Federal Regulations

The proposed project was evaluated to determine compliance with applicable federal GHG air quality regulations. Potentially applicable federal GHG regulations include the following:

- Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) – 40 CFR 51.166, 52.21, as published in the *Federal Register* (FR) June 3, 2010 (75 FR 31514)
- Federal Implementation Plan (FIP) for State of Wyoming GHG – 40 CFR 52.37, as published in the *Federal Register* December 30, 2010 (75 FR 82246)
- New Source Review (NSR) – 40 CFR 51 and 52

On April 2, 2007, the U.S. Supreme Court found that GHGs are air pollutants under Clean Air Act (CAA) section 302(g) (*Massachusetts* v. *EPA,* 549 U.S. 497 [2007]). GHG includes the six gases of CO_2, nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Of these, the first three will be emitted from the CGS. These gases have different potential to affect global warming, termed the global warming potential (GWP). The GWP of the three emitted gases are CO_2 (1), N_2O (310), and CH_4 (21).

Based on the series of legal and regulatory actions that culminated in the Tailoring Rule, regulation of major increases of GHG emissions through the Prevention of Significant Deterioration (PSD) permit program was required. EPA recognized that the major source threshold levels for the criteria pollutants for PSD pollutants of 100 or 250 tons per year (tpy) would make virtually every new project a major source. Accordingly, in June, 2010, EPA adopted the Tailoring Rule to raise the major source thresholds for GHG to 75,000 or 100,000 tons of GHG per year.

The State of Wyoming has an approved State Implementation Plan (SIP) based program for the criteria pollutants for the PSD permitting of new major sources. However, Wyoming has decided to not include GHG in the state PSD permitting program. Accordingly, the GHG PSD program is being implemented by the EPA for major sources of GHG within the State of Wyoming through the federally approved FIP.

4.1.1 Greenhouse Gas Tailoring Rule

On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed the phasing in of the PSD permitting process for new major sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with the potential to emit (PTE) greater than 100,000 tpy of CO_2e (including the statutory threshold of 100 or 250 tons on a mass basis) comply with PSD and Title V requirements. All references to "tons" are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

As shown in Table 4-1, under the Tailoring Rule, the CGS will be a major source subject to PSD permitting because the total emissions of CO_2e exceed 100,000 tpy. The CGS project will result in an increase in CO_2e emissions of 963,874 tpy, and more than 100 tpy of certain criteria pollutants. Therefore, the project is classified as a major source for PSD applicability determination.

TABLE 4-1
GHG Pollutants Expected to be Emitted, Annual Emission Rates, Global Warming Potential, and Annual Emissions Rates Adjusted for Global Warming Potential

Pollutant	Proposed Facility GHG Emissions (TPY)	Global Warming Potential (GWP)	GHG Emissions Adjusted for GWP (TPY)
Carbon Dioxide (CO_2)	962,929	1	962,929
Nitrous Oxide (N_2O)	1.82	310	564
Methane (CH_4)	18.17	21	381
Total GHG as CO_2e	----	----	963,874

4.1.2 Federal Implementation Plan for Wyoming

EPA has determined that the Wyoming SIP is deficient for purposes of the PSD permitting of GHG. Accordingly, EPA adopted a FIP in which it retains the authority to issue a PSD permit for GHG. Thus, this application is being filed with EPA Region 8 for the sole purpose of obtaining a PSD permit for the emissions of GHG from the CGS. The permit for the emissions of the criteria and hazardous pollutants from CGS will be obtained from the State of Wyoming.

EPA has not adopted ambient air quality standards or new source performance standards for GHG. Accordingly, this application only contains a BACT analysis for GHG.

4.1.3 New Source Review

PSD is the portion of NSR that applies to pollutants that are in attainment of National Ambient Air Quality Standards (NAAQS). Because there are no ambient air quality standards for GHG, all portions of the United States are in attainment for GHG. Major new or modified air emission sources locating in Laramie County are, therefore, potentially subject to PSD review for these GHG pollutants.

The first step in PSD review is determining whether the proposed facility is a major PSD source. As noted above, the CGS will be a major source. Therefore, CGS is subject to PSD review for GHG. The primary elements of PSD requirements is application of BACT to emissions of GHG

SECTION 5.0

Greenhouse Gas BACT Analysis

5.1 Background

As described above, BHC plans to build a natural gas-fired combustion turbine generating facility in the southeast section of the City of Cheyenne in Laramie County, Wyoming, pursuant to its approved CLFP *Integrated Resource Plan* filed before the Wyoming Public Service Commission (described in Section 2.0, Project Description). The proposed site is immediately west of the Dry Creek Water Reclamation Facility, which is located approximately 5 miles southeast of the downtown area.

The CGS will consist of a total of five natural gas-fired CTGs sized at approximately 40-MW capacity each. Two CTGs will be configured for combined-cycle operation and will each be equipped with dry-low NO_x combustors and a HRSG without duct burners, with steam flowing from the two HRSGs to one condensing STG with condenser in a "2x1" configuration. The combined-cycle generation capacity is nominally 100 MW. All of the CTGs will be equipped with SCR for NO_X control and Catalytic Oxidation for CO and VOC control. Three CTGs will operate in simple cycle. CGS auxiliary equipment includes one mechanical draft condenser wet cooling tower, three electric inlet air chiller units with mechanical draft cooling towers, six natural gas-fired inlet air heaters, two natural gas-fired fuel heaters, one diesel-fired fire pump, and one diesel-fired emergency generator.

5.1.1 CGS Business Plan and Combustion Turbine Selection

The CLFP CPCN and associated IRP (Docket Number 20003-112-EA11), were filed August 1, 2011, with the Wyoming Public Service Commission, and present the business plan in detail. The BHP CPCN and associated IRP will be submitted to the Commission in fall 2011. Generally, BHC's CPCN and associated IRP show the public need for increased capacity requirements, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking for CLFP, with baseload capabilities for BHP, and will further enable renewable generation (wind, solar, and other renewable resources). BHC identified natural gas simple/combined-cycle gas turbines to be the best-suited generation source to meet this CGS business plan.

BHC has selected the General Electric LM 6000PF SPRINT combustion turbine for the CGS project. Table 5-1 lists comparable combustion turbine manufacturers and a comparison of estimated performance efficiency at the CGS site conditions. This information was compiled from published data from Gas Turbine World magazine, and is presented only for comparative purposes. Gross heat rate and efficiencies are based on power output at the combustion turbine generator terminals, and does not include consideration of parasitic unit auxiliary loads.

TABLE 5-1
Combustion Turbine Comparison

Turbine[1]	Production (kW)	Gross Heat Rate (Btu/kWh) HHV	Efficiency[2]
Dresser-Rand			
DR-63G PC	35,150	9,095	37.5%
GE Energy Aeroderivative			
LM6000PC	39,253	9,487	36.0%
LM6000PC Sprint	40,605	9,419	36.2%
LM6000PD	34,612	9,103	37.5%
LM6000PD Sprint	38,079	9,091	37.5%
LM6000PF	34,612	9,103	37.5%
LM6000PF Sprint	38,649	9,079	37.6%
LM6000PG	42,995	9,556	35.7%
GE Energy Oil & Gas			
LM6000PD	33,964	9,283	36.8%
IHI Power Systems			
LM6000PC	34,306	9,198	37.1%
LM6000PC Sprint	37,129	9,228	37.0%
LM6000PD	33,800	9,231	37.0%
LM6000PD Sprint	37,236	9,213	37.0%
LM6000PG	40,084	9,157	37.3%
Pratt & Whitney Power Systems			
FT8 TwinPac	41,267	9,898	34.5%
SwiftPac 50 DLN	41,175	9,914	34.4%
Rolls-Royce			
Trent 60 DLE	41,537	9,064	37.7%
Trent 60 DLE ISI	46,612	8,913	38.3%
Siemens Energy			
SGT-800	37,772	10,126	33.7%
SGT-900	39,781	11,626	29.4%

[1] Specifications for production output at 59ºF, 5,950-Foot Altitude, Gross Output, HHV.

[2] Calculation: Efficiency= 3,413 Btu/kWh/Gross Heat Rate

BHC selected the GE LM6000PF SPRINT combustion turbine because it best meets its business plan, its system, and operational criteria. Business plan considerations for turbine selection include combustion efficiency, exhaust characteristics that impact combined cycle system efficiency, size range, and consistency with other locations. Selection of a "fleet" of like turbines for different locations provides advantages with knowledge of maintenance and operations, stocking of spare parts, and ability to "swap" turbines between locations. The combustion turbine calculated efficiency for this turbine (37.6%) compares favorably with other combustion turbines listed in Table 5.1.

Table 5-2 below lists the GE LM6000PF SPRINT combustion turbine attributes to be used within the GHG BACT analysis, and represents high-efficiency operation in both simple- and combined-cycle operation. The information included in Table 5-2 is based upon GE provided information, and summarizes the estimated combustion turbine performance at site conditions including consideration for parasitic auxiliary loads. Therefore, since Table 5-1 does not consider unit auxiliary loads in the efficiency calculation, and Table 5-2 includes allowance for auxiliary loads, the values are slightly different between the two tables.

TABLE 5-2
GE LM6000PF SPRINT Combustion Turbine Attributes

Combustion Turbine Criteria	Value[1]
Simple-Cycle Combustion Turbine Gross Output (MW)	37.1
2x1 Combined-Cycle Combustion Gross Turbine Output (MW)	97.4
Simple-Cycle Gross Heat Rate (Btu/KWh) HHV	9,263
Combined-Cycle Gross Heat Rate (Btu/KWh) HHV	7,062
Heat Input (Btu/hr) HHV	366

[1] 60^0 F at site elevation.

5.2 Regulatory Basis

GHGs have become subject to emission permitting through PSD and Title V programs. On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed phasing in the PSD permitting process for new sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with PTE greater than 100,000 tpy of GHGs on a CO_2e basis, and with a GHG PTE of 100 or 250 tpy, depending on source type, on a mass basis will become subject to PSD and Title V requirements. All references to tons within the table and in this BACT analysis are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

The CGS project will be a new source with a GHG PTE of greater than 100,000 tpy CO_2e and greater than the 100-tpy mass basis for listed sources, and will also have a PTE of greater than 100 tpy for certain criteria pollutants. Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Therefore, this GHG BACT analysis was prepared for presentation to EPA Region 8 as part of the CGS permit application process.

5.3 Emissions Summary

Per EPA Tailoring Rule definitions, GHGs consist of the following gases:

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)

To determine CO_2e emissions, mass flows of each individual gas are multiplied by the appropriate GWP as referenced to the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report, and the results are summed.

The combustion turbines, inlet air heaters, and fuel gas heaters will be fired with pipeline-quality natural gas, and complete combustion will result primarily in water and CO_2 byproducts. However, incomplete combustion will result in some unburned natural gas or CH_4 emissions. Additionally, due to the presence of nitrogen in the combustion air, some small quantities of N_2O will also be emitted. The standby generator and fire pump engines will be fired with diesel fuel, again resulting in CO_2 emissions from oxidation of the fuel and with minor quantities of CH_4 emissions resulting from incomplete combustion and N_2O emissions from conversion of nitrogen from the atmosphere and fuel.

Table 5-3 represents potential sources and estimated quantities of GHG emissions from CGS project equipment.

TABLE 5-3
CGS Estimated GHG Emissions by Equipment Category

Equipment	Description	Total CO_2e Emissions (t/yr)
Two (2) Combustion Turbines in Combined-Cycle Operation with no HRSG Duct Burner	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	374,635
Three (3) Simple-Cycle Combustion Turbines	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	561,953
Two (2) Fuel Gas Heaters	Maximum Heat Input 4.5 MMBtu/hr each	2,306
One (1) Diesel Fire Pump	Maximum Heat Input 2.5 MMBtu/hr	51
One (1) Diesel Standby Generator	Maximum Heat Input 5.52 MMBtu/hr	226
Six (6) Inlet Air Heaters	Maximum Heat Input 16.07 MMBtu/hr each	24,703
Total		**963,874**

5.3.1 GHG BACT Analysis Assumptions

During the completion of GHG BACT analysis, the following assumptions were made:

1. Table 5-3 above presents estimated CGS GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, and N_2O. The CGS is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents. SF_6 is also a man-made gas that may be used as an insulating gas for high-voltage equipment and circuit breakers; however, BHC does not plan to install electrical equipment containing SF_6 at the CGS. Therefore, only CO_2, CH_4, and N_2O will be included in CO_2e totals.
2. From the GHG emissions inventory presented in Appendix B-1, the relative quantities of CH_4 and N_2O total only approximately 945 tpy of CO_2e emissions, or less than 0.1 percent of total CO_2e emissions. Due to the extremely small contribution of CH_4 and N_2O emissions to the total, the CGS GHG BACT analysis only includes the five-step process for CO_2 emissions.
3. Completion of the BACT analysis for criteria pollutants will result in the installation of an SCR system for NO_x emissions reduction, and an oxidation catalyst for control of CO and VOCs for each turbine.
4. During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule or MRR) (40 CFR 98) factors for estimating CO_2e emissions from the combustion of natural gas assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the MRR factors and included in the CO_2e totals.
5. Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the GHG emissions inventory, the estimated N_2O emissions from all combustion turbines total only 1.5 tpy. Therefore, even if there were an order–of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. While elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Thus, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 due to other environmental impacts. Therefore, we have not considered omission of these controls within the BACT analysis.

5.4 Top-Down BACT Process

The EPA has developed a recommended process for conducting BACT analyses, referred to as the "top-down" method. The following steps to conducting a top-down analysis are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, has been conducted for GHG emissions for the CGS project. The following top-down BACT analysis for CO_2e has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990). A top-down BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology.

5.5 Combustion Turbine BACT for GHGs

Step 1: Identify All Control Technologies

The combustion turbines will be GE LM6000PF SPRINT combustion turbines that utilize the latest emissions control technology. There are two basic alternatives identified to limit the GHG emissions of this project. These options include

- Carbon Capture and Storage (CCS)
- Electrical Generation Efficiency

BHC's CGS Business Plan and IRP have determined that the proposed mix of natural gas combined-cycle and simple-cycle power generation is the only alternative that meets all of the CGS requirements for economic and reliable power 24 hours per day and in all weather conditions. As such, other generation technologies such as coal, wind, and solar were not evaluated in this BACT analysis. This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26) Nonetheless, it should be noted that the CGS is intended to provide supplemental and backup generation for solar and wind projects, and renewable generation is not an adequate supplement and backup for other renewable generation; a fuel-based alternative is required.

The only identified GHG emission "control" options are post-combustion CCS and energy efficiency of the proposed generation facility.

Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

CCS systems involve use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery.

While many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the CGS:

- No full scale systems are currently in operation for capture of CO_2 from dilute exhaust steams such as that from natural gas fired electrical generation systems,
- Lack of pilot scale experience with capture systems for high-temperature streams such as simple cycle combustion turbine exhaust currently exists,
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however identification of suitable oil reservoirs with willing and able owners and operators is beyond the capability for most electric utilities. Owners of oil fields generally closely guard information regarding production volumes and reservoir status,
- Little experience exists with other types of storage systems such as deep saline aquifers or depleted coal seams,
- Because of the developmental nature of CCS technology, vendors and contractors do not offer turn-key offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring,
- Significant legal uncertainties still exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, etc, and
- Potential for frequent startup and shutdown of generation units at the CGS make CCS impractical for two reasons – inability of capture systems to startup in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. The simple cycle units at the CGS are designed for peaking operation and as such the ability to rapidly startup the units and to operate them for short durations is critical. While the combined cycle units are being designed for baseload operation, under many operational scenarios rapid response may also be needed for these units.

These issues are discussed in more detail below.

As suggested in the 1990 Draft EPA New Source Review Workshop Manual, control technologies should be demonstrated in practice on full scale operations in order to be considered available within a BACT analysis. "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." As will be discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice, but the technology used for these processes cannot be applied to power plants.

Three fundamental types of carbon capture systems are employed throughout different process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial scale systems currently in operation, due in large part to concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam methane reforming process which contains primarily hydrogen (H_2), unreacted methane (CH_4) and CO_2. Based on the stoichiometry of the reforming process the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds per square inch, gauge (psig). Because of the high concentration and high pressure a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-H_2 components including CO_2 and CH_4 are adsorbed onto the solid media under high pressure. After the sorbent becomes saturated the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; but where the CO_2 is to be sold offset an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 "DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update", NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. From Section 4.B, "When the fluid component has a high concentration in the feed stream (e.g., 10 percent or more), a pressure swing adsorption (PSA) mechanism is more appropriate."

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant (GPSP) in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily hydrogen (H_2), methane (CH_4), and 30 to 35 percent CO_2 and a physical absorption process (Rectisol) is used. In contrast, as shown in the GE Guarantee in Appendix B-3, and as noted on Page 29 of the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*, CO_2 concentrations for natural-gas fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced Technology Update, NETL notes this difference between pre-combustion CO_2 capture such as that from the GPSP versus the post-combustion capture such as that required from a natural-gas fired power plant, "Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas."

The Interagency Task Force on Carbon Capture and Storage consists of 14 executive departments and federal agencies, co-chaired by the DOE and EPA. In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is a key player in the nation's efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html). Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems), which are shown as "active" with "injection ongoing" or "plant in operation", yields four projects. Three projects, one of which is a pilot-scale process noted in the Interagency Task Force report as described above, are listed at a capacity of 274 tons per day (100,000 tons per year) and the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of even the modestly-sized CGS facility, which could produce up to 964,000 tons per year or 2,600 tons per day. Furthermore, scale-up involving a 10x increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

As detailed in the August 2010 report, one goal of the Task Force is to bring five to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available. It is notable that several projects, including those with DOE funding or loan guarantees, have been cancelled in recent months, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, at the AEP Mountaineer site noted above, the commercial scale project was to expand capture capacity to 100,000 tpy, but to date only the "Project Validation Facility" was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front end engineering design due to uncertain economic and policy conditions.

The Interagency Task Force report notes the lack of demonstration in practice: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

One of the many technical challenges with carbon capture systems is the temperature of the exhaust steams. For coal-based plants, where most of the post-combustion capture technology research has been accomplished, typical exhaust temperatures are in the range of

300 degrees F. For the three simple cycle systems planned for the CGS, exhaust temperature will be up to 900 degrees F. To our knowledge, CCS pilot tests have not been accomplished on a simple cycle gas turbine system anywhere in the world. This would represent another major technical uncertainty associated with CCS implementation at the CGS. Chemical absorption of CO_2, such as that accomplished by most amine-based carbon capture processes, is an exothermic reaction, meaning that heat is released during absorption; high temperature of the exhaust and solvent would therefore inhibit the carbon capture. Furthermore, the regeneration of the sorbent to release the CO_2 for compression requires heating of the sorbent, so high temperature of the solution would clearly inhibit the chemical reaction required for absorption.

BHC is aware of the planned construction of a CO_2 pipeline, intended to transport byproduct CO_2 from oil and gas operations to an EOR location in Montana. This project will be used as a CCS large-scale demonstration project by the DOE-funded Plains CO_2 Reduction Partnership. From review of publicly available documentation, the pipeline is being designed with excess capacity, presumably to provide future capability to transport CO_2 from other sources to EOR locations in the region. At its closest point the pipeline is estimated to be 175 miles away from the power plant location. However the location, time frame, and needed flowrates for those future EOR operations are closely guarded trade secrets. Thus BHC, as developer of this power generation facilities, has no way of knowing when and if those future needs will be realized. At the current time, the only known CO_2-based tertiary oil recovery system operating in the region is the Salt Creek Field (also approximately 175 miles from the power plant location),for which current CO_2 needs are being served from current separation systems in the Shute Creek Field of southwest Wyoming, with CO_2 being transported by existing pipeline.

Ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. While it is believed that saline aquifers are a viable opportunity, many uncertainties exist. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post injection site care, long term stewardship, property rights, and other issues. In regards to CO_2 storage security, the CCS Task Force Report notes such uncertainties, "The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, IPCC concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, hence, risk profiles (e.g., IPCC, 2005)."

CCS technology development is dominated by vendors who are attempting to commercialize carbon capture technologies and academia-lead teams (largely funded by DOE) who are leading research into the geologic systems. Ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. While capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations which exceed the turbine startup time. The simple cycle generation systems are designed to be able to produce electricity at full load within 10 minutes of cold start, and the combined cycle systems designed to be able to produce electricity at full load with SCR and oxidation catalysts controlling criteria air pollutants within 40 minutes of startup. Durations of plant operation may be short, depending on needs to serve peak power loads. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to startup and shutdown in the time frames required to effectively serve this type of operation, meaning that significant portions of at least the simple cycle operations would run without CO_2 capture even with implementation of a CCS system.

Finally, the potential to sell CO_2 to industrial or oil & gas operations is infeasible for an operation such as this, where daily operation of both simple cycle and combined cycle systems may depend on grid dispatch needs. Even if a potential EOR opportunity could be identified by the power plant developers, such an operation would typically need a steady supply of CO_2 year-round. Intermittent CO_2 supply from potentially short-duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited on applications which have low variability in operating conditions.

In the EPA PSD and Title V GHG permitting guidance, the issues noted above are summarized, "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (italics added). From Page 36 of this guidance, "While CCS is a promising technology; EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard."

Therefore, the CCS alternative is not considered technically feasible for the CGS project, and is eliminated from further consideration. While it is being eliminated based on technical feasibility in Step 2, at the suggestion of USEPA team members, economic feasibility issues will be covered in Step 4.

Electrical Generation Efficiency

EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA, 2011) identifies three categories of control technologies (p. 25):

1. Inherently lower-emitting processes/practices/designs
2. Add-on controls, and
3. Combinations of lower-emitting process/practices/designs and add-on controls

Because there are no demonstrated add-on controls, only those processes, practices, and designs that result in lower GHG emissions are applicable for this BACT analysis. As noted above, the project includes both simple-cycle and combined-cycle generation in this phase of the project, and possible, but unplanned future expansion of the facility could include build-out of the simple-cycle combustion turbines into combined-cycle systems providing added thermal efficiencies. The CGS project as proposed will utilize a high-efficiency, state-of-the-art, combustion turbine, generator, and HRSG design. Operations will use good combustion practices and result in energy efficient operation to provide steam to a new steam turbine generator. Furthermore, inlet air chillers will be used to prevent loss of turbine efficiency that results during hot weather, and a wet cooling tower will be used to improve the thermal efficiency of the combined cycle system.

The following analysis will demonstrate that the overall generation efficiency meets or exceeds that of other recently implemented projects.

The permit limits proposed in this application are based on a GE LM 6000PF SPRINT combustion turbine of 37.1 MW gross output and a gross heat rate of 9,263 Btu/kWh (HHV) for simple-cycle operation. This results in an estimated net output of approximately 97.4 MW at a gross heat rate of 7,062 Btu/kWh (HHV) for the 2x1 combined-cycle system, which results in an efficiency of 36.8% and 48.3% for simple cycle and combined cycle operation respectively. These efficiencies include consideration of parasitic auxiliary loads. The combined-cycle system will not have duct firing. All noted performance information is based upon CGS site conditions at 60ºF; the high altitude of the area results in marginal decreases to turbine efficiency compared to other locations. The CGS project will utilize all new equipment.

Combustion Turbine Generator Comparable Permitted Emissions

A search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) was performed for simple- and combined-cycle projects with combustion turbines similar to those proposed for the CGS project. No GHG permit limits were found in searching the RBLC for comparable units, thermal efficiency data was available.

Efficiency Review

An efficiency review of the proposed CGS project was completed with two metrics: 1) RBLC comparable unit heat rates and 2) comparison of CO_2e emission rates.

RBLC Efficiency Comparison

The RBLC information presented in Table 5-4 below provides a comparison of efficiencies for projects with combustion turbines in the same nominal 40-MW size range as the CGS project. The information presented is for combustion turbines operating in simple cycle. No information was found for comparable 40-MW combined-cycle units without duct burning.

TABLE 5-4
RBLC Efficiency Information – Simple Cycle

Facility	State	Description	Heat Capacity MMBtu/hr (HHV)	Net MW	Heat Rate Btu/kWh (HHV)	Calculated Efficiency (%)
Western Farmers Electric	Oklahoma	Combustion Turbine Simple Cycle	462.7	50	9,254	36.9
El Colton, LLC	California	LM6000 (Enhanced Sprint)	456.5	48.7	9,374	36.4
Bayonne Energy Center	New Jersey	Rolls Royce Trent 60WLE	603	64	9,422	36.2
Creole Trail LNG	Louisiana	Combustion Turbine Simple Cycle	290	30	9,667	35.3
Arvah B. Hopkins Generating Station	Florida	GE LM6000PC Simple Cycle	489.5	50	9,790	35.0
Indigo Energy Facility	California	LM6000 (Enhanced Sprint)	450	45	10,000	34.1
Lambie Energy Center	California	GE LM6000PC Simple Cycle	500	49.9	10,020	34.1

Notes: Used 1.108 for HHV/LHV conversion factor.

The combustion turbines compared above are similar in size to those planned for the CGS project. As noted above, this analysis and resulting CGS proposed permit limits are based on use of a turbine with simple-cycle gross heat rate of 9,263 Btu/kWh (HHV). An exact comparison cannot be made between the CGS combustion turbines and those listed in Table 5-4 above because each project has unique equipment and site conditions, primarily elevation and temperature. However, the CGS heat rate compares very favorably with all of the reviewed comparable projects listed above, which demonstrates the high-efficiency attributes of the CGS project.

CO_2e Emission Rate Comparison

In simple-cycle operation, the CGS turbines are estimated to produce 1,102 pounds of CO_2e/MWh at average ambient conditions and full-load operation. Considering the range of normal operating loads (50 to 100 percent generator output), and ambient temperature (0ºF to 108ºF), GHG output for the CGS simple-cycle combustion turbines range from 1,072 to 1,603 pounds of CO_2e for new and clean combustion turbine prior to any degradation.

Table 5-5 below presents operating information from the EPA Acid Rain database, and was developed using actual comparable operating unit information from 2010.

TABLE 5-5
CGS Comparable Unit GHG Emissions

State	Facility Name	Unit ID	Operating Time (Hr)	Net Load (MWh)	CO_2 Tons	lb CO_2/MWh
CA	El Cajon Energy Center	1	242	9450	5652	1196
OK	Horseshoe Lake	10	710	29293	18142	1239
OK	Horseshoe Lake	9	174	6851	4248	1240
CA	Orange Grove Project	CTG1	632	25017	15734	1258

TABLE 5-5
CGS Comparable Unit GHG Emissions

State	Facility Name	Unit ID	Operating Time (Hr)	Net Load (MWh)	CO_2 Tons	lb CO_2/MWh
CA	Orange Grove Project	CTG2	654	24954	15847	1270
FL	Arvah B Hopkins	HC4	903	27627	17623	1276
FL	Polk	**2	249	27652	18500	1338
FL	Arvah B Hopkins	HC3	662	18283	12529	1371
FL	Polk	**5	476	51662	36111	1398
FL	Polk	**4	563	60221	42443	1410
FL	Polk	**3	204	23176	16600	1432
NJ	Bayonne Plant Holding, LLC	2001	1055	35582	28385	1595
NJ	Bayonne Plant Holding, LLC	1001	1208	39061	32004	1639
NJ	Bayonne Plant Holding, LLC	4001	1134	36629	30200	1649
NE	C W Burdick	GT-3	24	426	399	1871
NE	C W Burdick	GT-2	33	606	579	1912
CA	Escondido Energy Center, LLC	CT1A	28	345	466	2702
CA	Escondido Energy Center, LLC	CT1B	28	345	468	2718

Notes:

Net load 5% lower than gross load.
Data as per EPA Clean Air Markets – Data and Maps.
Based on 2010 data.

The CGS combustion turbine GHG output compares favorably with the facilities shown Table 5-5 above. It is recognized that in establishing any permit limit, allowance must be given for load variances, impact of ambient conditions, startup and shutdown, and equipment degradation over time. This is exemplified by reviewing the information from Table 5-5, because all of these units can be considered as “peaking” due to the low number of annual operating hours. The resultant wide variance in pounds of CO_2e/MWh may likely be attributed to the significant proportion of time in startup and shutdown and/or reduced load operation, as well as lower thermal efficiency for older units.

Note that, considering the range of normal operating loads (50 to 100 percent output) and ambient temperature (0ºF to 108ºF), GHG output for the CGS 2x1 combined-cycle system ranges from 833 to 985 pounds of CO_2e for a new or clean combustion turbine prior to any degradation.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible GHG control technology for the CGS project is the electrical generation efficiency. This option is presented in Table 5-6 based on their energy efficiencies expressed in terms of heat rate.

TABLE 5-6
CGS Project GHG Control Technology Ranking

Configuration	Gross Plant Heat Rate (HHV) (Btu/kWh)[1]
Electrical Generation Combined-Cycle Efficiency	7,062
Electrical Generation Simple-Cycle Efficiency	9,263

Note: [1]At CGS site conditions.

Combustion Turbine Design Elements

As demonstrated above, the GE LM6000PF SPRINT combustion turbine has high efficiency which is equal or greater the majority of other turbines of the same nominal capacity. However the differences in efficiency from offerings of other vendors are in some cases trivial. The design elements of those turbines that result in high efficiency undoubtedly vary between vendors, and in many cases are proprietary and confidential. Thus an extensive analysis of what design considerations are needed to have an efficient turbine design is beyond the scope of this permit application.

However the issue was discussed with the selected turbine vendor, GE, and they offered comments on the unique elements of their design. This information is provided in Appendix B-4. Some of the key elements noted by GE are dual shaft architecture, low shaft speed, modulation of shaft speed and air flow with power, and high operating pressure ratio.

It should be noted that the electrical generator is provided as a combined unit with the GE LM6000PF SPRINT combustion turbine package, and has been engineered to match combustion turbine operating characteristics. Preliminary information indicates that the generator is 98%+ efficient, so overall system efficiency is driven by the combustion turbine characteristics.

The CGS 2x1 combined cycle system will also utilize a steam turbine and Heat Recovery Steam Generators (HRSG). Steam turbines manufactured today for small combined cycle plants have efficiencies limited by the metal design temperatures and pressures. The steam turbine is custom engineered rotating machinery where the efficiency is optimized in the blade path design, which maximizes the energy extracted from the steam. HRSG efficiency is maximized in the design by selecting aggressive approach and pinch points to extract the maximum heat out of the gas turbine exhaust stream. The efficiency is further improved by tube bundle arrangement, finned tubing and back end recirculation and or condensate preheating.

Step 4: Evaluate Most Effective Controls and Document Results

As demonstrated in Step 2 above, CCS is not a technically feasible alternative for the CGS project. Nonetheless, at the suggestion of USEPA team members, economic feasibility of CCS technology is reviewed in this Step 4. Control options considered in this step therefore include application of CCS technology, and plant energy efficiency. As demonstrated below, CCS is clearly not economically feasible for the CGS.

On Page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective: "With respect to the valuation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system."

The guidance document also acknowledges the high costs of CCS technology at the current time: "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."

The costs of constructing and operating CCS technology are indeed extraordinarily high based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs as compared to "pure" sequestration in deep saline aquifers or depleted coal seams, additional costs to the CGS would include the following:

- Licensing of scrubber technology and construction of carbon capture systems,
- Significant reduction to plant output due to the high energy consumption of capture and compression systems,
- Identification of oil & gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long term contracts for CO_2 purchases,
- Construction of compression systems and pipelines to deliver CO_2 to EOR locations,
- Labor to operate, maintain, and monitor the capture, compression, and transport systems, and
- Issues regarding project risk that would jeopardize ability to finance construction and to obtain PUC approval.

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: "For a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture." Using the "Capacity Factor Method" for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering (AACE) and other organizations, CO_2 capture system capital cost for the CGS is estimated as at least $196 million. Based on an estimated CGS plant capital cost of $300 million, the capture system alone would thus be expected to add approximately 65 percent to the overall plant capital cost.

Actual cost per megawatt would likely be higher for CGS than the reference plant in the Task Force report due to the inclusion of simple cycle units; this would require capture systems to handle a much higher temperature gas flow; little or no pilot test data is available for this situation, different materials of construction may be required, and modifications to the absorption process may be required.

Similarly, the energy penalty would be higher for simple cycle systems than for combined cycle; since scrubber and compressors are sized based on combustion turbine output, but overall unit output is lower for simple cycle, the fractional penalty would be higher. Whether plant size would remain the same with output reduced, or plant size increased to account for lost output, the energy penalty alone represents at least a 15% increase to the fuel component of the cost of electricity. At an estimated 8.9¢/kWh residential retail price for electricity, and assuming an annual average of 50% capacity factor for plant operation and 15% energy penalty, the value of lost electricity sales from the project is $12.9 million per year.

As noted above, the effort required to identify and negotiate with oil & gas companies who may be able to utilize the CO_2 would be substantial. BHC is aware that the proposed Greencore pipeline is being substantially oversized, versus what would be required for only the Belle Creek EOR operation, so it is reasonable to assume project developers are planning that there will be a future need for CO_2 in the Powder River Basin or other locations in Wyoming or Montana. The location and timing of those sites, however, is not public information, and due to the patchwork of oil well ownership many parties could potentially be involved in negotiations over CO_2 value.

Due to the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are very specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight stage design. It is unclear whether the Task Force NGCC cost estimate noted above includes the required compression systems, but if not this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2000 pounds per square inch, gauge) and potential for corrosion if any water is introduced to the system. As noted above, if CCS were otherwise technically and economically feasible for the CGS, the most realistic scenario could be to construct a pipeline from Cheyenne to tie into the proposed Greencore pipeline. At its closest point, the Greencore pipeline would be approximately 175 miles from Cheyenne. Based on engineering analysis done by the designers of that pipeline, costs for an 8″ CO_2 pipeline to connect the Cheyenne project to the Greencore pipeline are estimated at $600,000 per mile, for a total cost of $105 million. Thus the pipeline alone would represent a 35 percent increase to the project cost, and the pipeline and capture system together would double the project capital cost.

It is unlikely that financing could be approved for a project which combines CCS in conjunction with generation, given the technical and financial risks. Also, as evidenced with utilities' inability to obtain PUC approval for integrated gasification / combined cycle (IGCC) projects due to unacceptable cost and risk to ratepayers, such as Wisconsin's disapproval of the We Energy project, it is reasonable to assume that the same issues would apply in this case before the Wyoming PUC.

Sale of the CO_2 for EOR could be the one positive direct economic impact of CCS. If BHC were to construct or pay for construction of the pipeline to deliver captured CO_2, it is possible that revenue from sale of the CO_2 could be realized. Current market pricing for CO_2 delivered for EOR is however proprietary and confidential, and reliable sources of information could not be identified within this scope of this BACT analysis.

In summary, capital cost for capture system and pipeline construction are estimated at $300 million, and retail value of lost power sales due to the CCS system energy penalty is estimated at $12.9 million per year assuming only 50% plant capacity factor. Other costs such as identification, negotiation, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; less favorable financing terms or inability to finance; and difficulty in obtaining PSC approval would also impact the project, and it is unclear if compression systems are included in the Task Force estimate of capture system costs. A fraction of these impacts could possibly be offset through sale of the CO_2, but overall addition of CCS with or without EOR opportunity would make the project unviable.

CCS is clearly not economically feasible for natural gas fired power plants at the current time. Since CCS is not considered technically or economically feasible, the proposed CGS electrical generation efficiency is determined to be the most effective GHG control technology.

From a review of the three evaluation metrics presented above, the heat rate for the CGS GE LM6000 PF Sprint combustion turbine, selected pursuant to the CGS business plan, was found to favorably compare with other combustion turbines and projects.

Step 5: Select BACT

The only remaining option is the "Electrical Generation Efficiency" option, which, therefore, is selected as BACT. This option determined to consist of the CGS project as proposed with new state-of-the-art combustion turbines. Consistent with the review criteria presented above, the CGS project evaluated combustion turbine exhibits comparable efficiency with most of the evaluated alternative combustion turbines, and superior efficiency over other comparable machines. Therefore, BHC proposes that CGS GHG BACT consist of installation of GE LM6000PF SPRINT combustion turbines, and the annual CO_2 emissions limit for the five new combustion turbines will be based upon the BACT emission limits proposed below. The estimated total annual CO_2e emissions from the combustion turbines are 936,588 tpy, and this value is proposed to be the annual CO_2e permit limit for the five combustion turbines.

EPA's PSD permitting guidance for GHGs suggests use of output-based BACT emission limits and longer-term averaging periods for GHGs. Based on BHC analysis of conservative scenarios for number of turbine startups and shutdowns, partial load operation, and ambient temperature during operations, and considering the range of normalized GHG emissions noted above and eventual turbine degradation, proposed BACT permit limits are 1,100 lb/MWh for each combined-cycle combustion turbine and 1,600 lb/MWh for each simple-cycle combustion turbine on an annual average basis.

5.6 Small Combustion Sources BACT for GHGs

In addition to the five combustion turbines planned for the CGS project, there are several other small combustion sources associated with auxiliary equipment which will operate at the plant. The GHG calculations for these small combustion sources are located in Appendix B-1.

- (6) Natural gas-fired inlet air heaters (nominal 16-MMBtu/hr air heater with estimated emissions of 4,117 CO_2e tons/year each), required for safety to prevent icing of air handling systems
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year)
- (1) Diesel-fired fire pump (nominal 327-BHP engine with estimated 51 CO_2e tons/year)

The total GHG emissions from the above small combustion sources are very minor as compared to the emissions from the combustion turbines. However, for completeness, these minor GHG emission sources were evaluated in aggregate below.

Step 1: Identify All Control Technologies

The available control technologies for the CGS minor GHG sources are identical to those identified for the combustion turbines. These options include

- Carbon Capture and Storage Systems (CCS
- Small Combustion Source Efficiency
- Efficient Use of Energy

Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

As discussed above, CCS for GHG control is not considered a technically feasible control option for the combustion turbines. Stand-alone capture systems for the small sources would be even further from technical feasibility. Therefore, CCS is eliminated from further consideration for small combustion source GHG reduction.

Small Combustion Source Efficiency

The small combustion sources for the CGS project will incorporate a high-efficiency design.

Efficiency Background Information

In support of small combustion source design, additional background information is assembled in Appendix B-8 through B-14 regarding efficiency attributes of the auxiliary equipment; i.e., inlet air heater, inlet chiller units, fuel gas heaters, diesel fire pump, and diesel emergency generator.

Inlet Air Heater

The inlet air anti-icing heater is similar to a conventional natural gas fired watertube boiler, and is required for safety reasons to prevent icing during winter weather. However, the water does not reach the boiling point in this system and a mixture of water and glycol is used for its thermodynamic advantages over water. The unit is designed for quick load response eliminating the requirement for a stored energy system and associated efficiency losses. Combusted natural gas is used to directly heat the incoming water/glycol mixture.

Other technologies available for heating the water/glycol mixture include an indirect fired water bath heater or fire tube boiler. The fire tube boiler has similar efficiency but a much higher capital cost. The indirect fired water bath heater has a lower efficiency resulting in higher operating costs and increased emissions. With both cost and environmental operations considered, these two options are not economical for this application.

Fuel Gas Heater

Indirect water/glycol bath heaters were selected for heating of high-pressure natural gas. The natural gas is heated to ensure a measure of superheat before reaching the combustion turbine generator. Indirect heaters use a fire tube to transfer heat from the fired natural gas (fuel) to the water/glycol solution. The heat is then transferred from the water/glycol bath to the natural gas coil (product) in a safe manner. Although this heating technology is not as efficient as direct heating, it is considered the only acceptable option due to safety reasons as noted below.

Direct heating of natural gas would result in a slightly more efficient process; however, direct heating of natural gas is extremely dangerous and not recommended. Any small manufacturing defect, failure, or leak may result in catastrophic explosions as the product (natural gas) is exposed to an open heat source.

Diesel Fire Pump & Standby Generator

While preliminary review of the CGS emergency diesel equipment has been initiated, the final equipment selection has not been completed. However, the diesel equipment will be evaluated to ensure a high efficiency design.

Efficient Use of Energy

The small combustion sources will not be operated continuously, but only during conditions when they are needed. For example, the inlet air heaters and fuel gas heaters will be operated only when required for safety reasons to protect against icing of the turbines or condensation within the fuel lines. Therefore, energy will be utilized in an efficient manner.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies are equally important toward minimizing GHG emissions.

Step 4: Evaluate most effective controls and document results

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies will be implemented for the CGS project.

Step 5: Select BACT

GHG BACT for the CGS small equipment are "Small Combustion Source Efficiency "and "Efficient Use of Energy." All auxiliary equipment will be selected with consideration for high design efficiency, and will be operated in an efficient manner. Due to the minor CO_2e emissions contribution from these small combustion sources, no efficiency or output-based GHG permit limits are recommended for the CGS auxiliary equipment.

5.7 Requested Permit Limits

The following Tables 5-7 and Table 5-8 list the recommended permit limits for the combustion turbines and auxiliary equipment respectively:

TABLE 5-7
CGS Combustion Turbine Recommended CO_2e Permit Limits

Emission Unit	Annual CO_2e Limit (Pounds/MWhr)	Annual CO_2e Limit (Tons/Year)
Combined Cycle Combustion Turbine CT01A	1,100	187,318
Combined Cycle Combustion Turbine CT01B	1,100	187,318
Simple Cycle Combustion Turbine CT02A	1,600	187,318
Simple Cycle Combustion Turbine CT02B	1,600	187,318
Simple Cycle Combustion Turbine CT03A	1,600	187,318

TABLE 5-8
CGS Auxiliary Equipment Recommended CO_2e Permit Limits

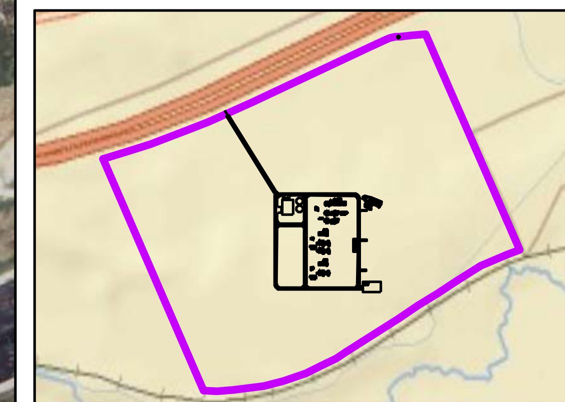
Emission Unit	Annual CO_2e Limit (Tons/Year)
Six (6) Inlet Air Heaters	24,703
Two (2) Fuel Gas Heaters	2,306
One (1) Diesel Fire Pump	51
One (1) Diesel Standby Generator	226

APPENDIX A

Location Map and Plot Plans

APPENDIX A-1

CGS Site Location and Fenceline Map



LEGEND

- Buildings in Analysis
- General Arrangement
- Project Boundary

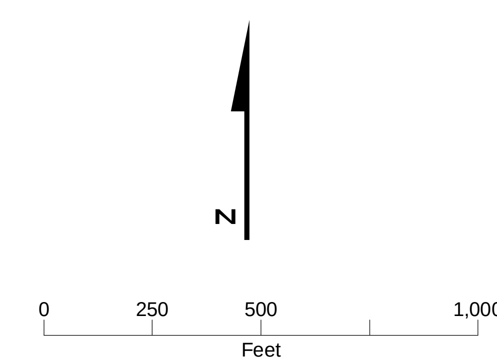
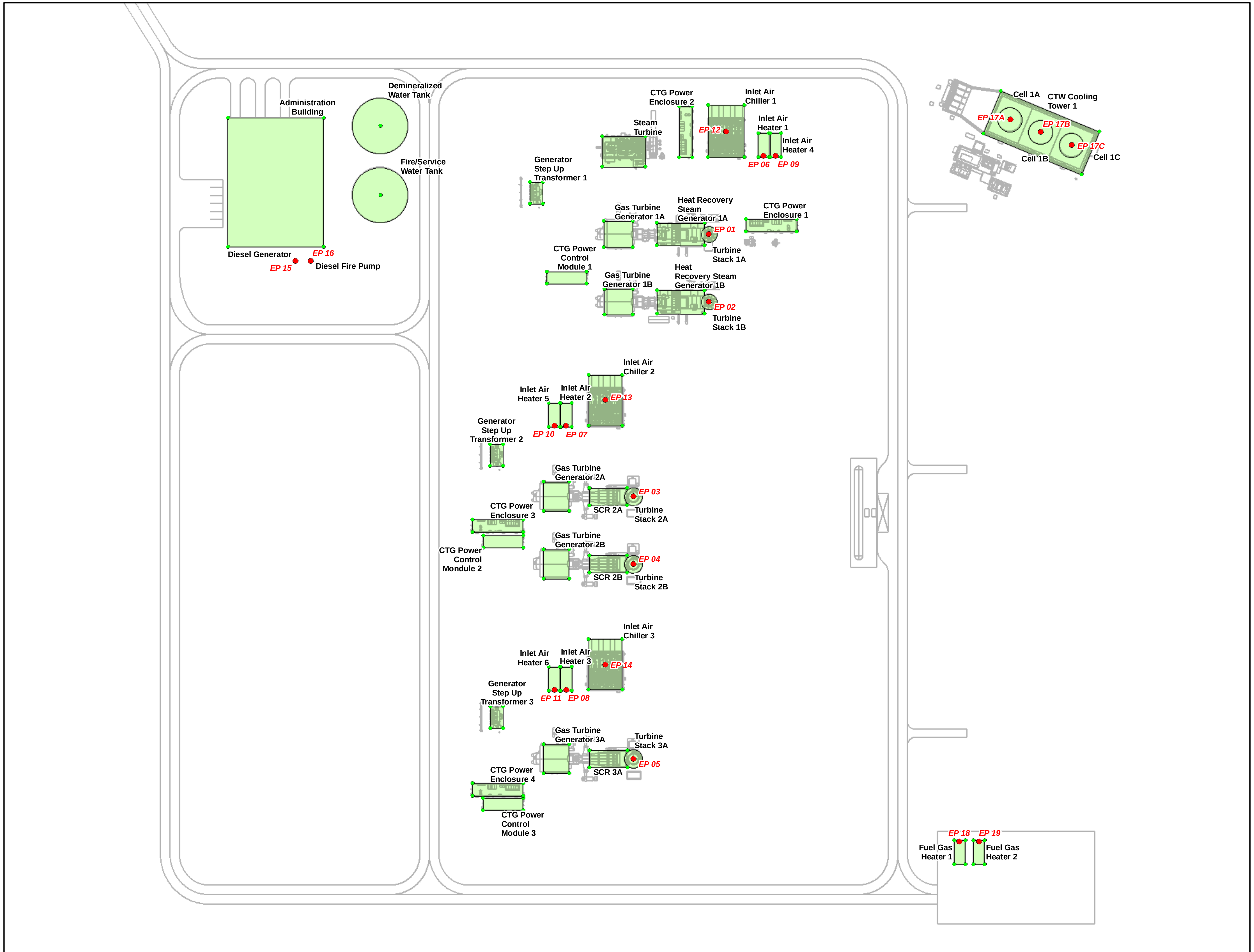
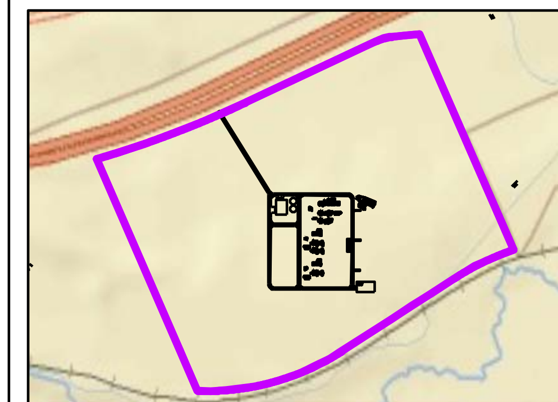


FIGURE A-1
Cheyenne Generating Station
Fenceline and Power Block

APPENDIX A-2

CGS Structures and Emission Points





LEGEND

- Structure Corner
- Emission Point
- Buildings in Analysis

Emission Point	Description
EP01	Combined Cycle Combustion Turbine CT01A
EP02	Combined Cycle Combustion Turbine CT01B
EP03	Simple Cycle Combustion Turbine CT02A
EP04	Simple Cycle Combustion Turbine CT02B
EP05	Simple Cycle Combustion Turbine CT03A
EP06	Inlet Air Heater 01
EP07	Inlet Air Heater 02
EP08	Inlet Air Heater 03
EP09	Inlet Air Heater 04
EP10	Inlet Air Heater 05
EP11	Inlet Air Heater 06
EP12	Inlet Air Chiller 01
EP13	Inlet Air Chiller 02
EP14	Inlet Air Chiller 03
EP15	Diesel Generator
EP16	Diesel Fire Pump
EP17	Combined Cycle Wet Cooling Tower
EP18	Fuel Gas Heater 01
EP19	Fuel Gas Heater 02

0 50 100 200
Feet

N

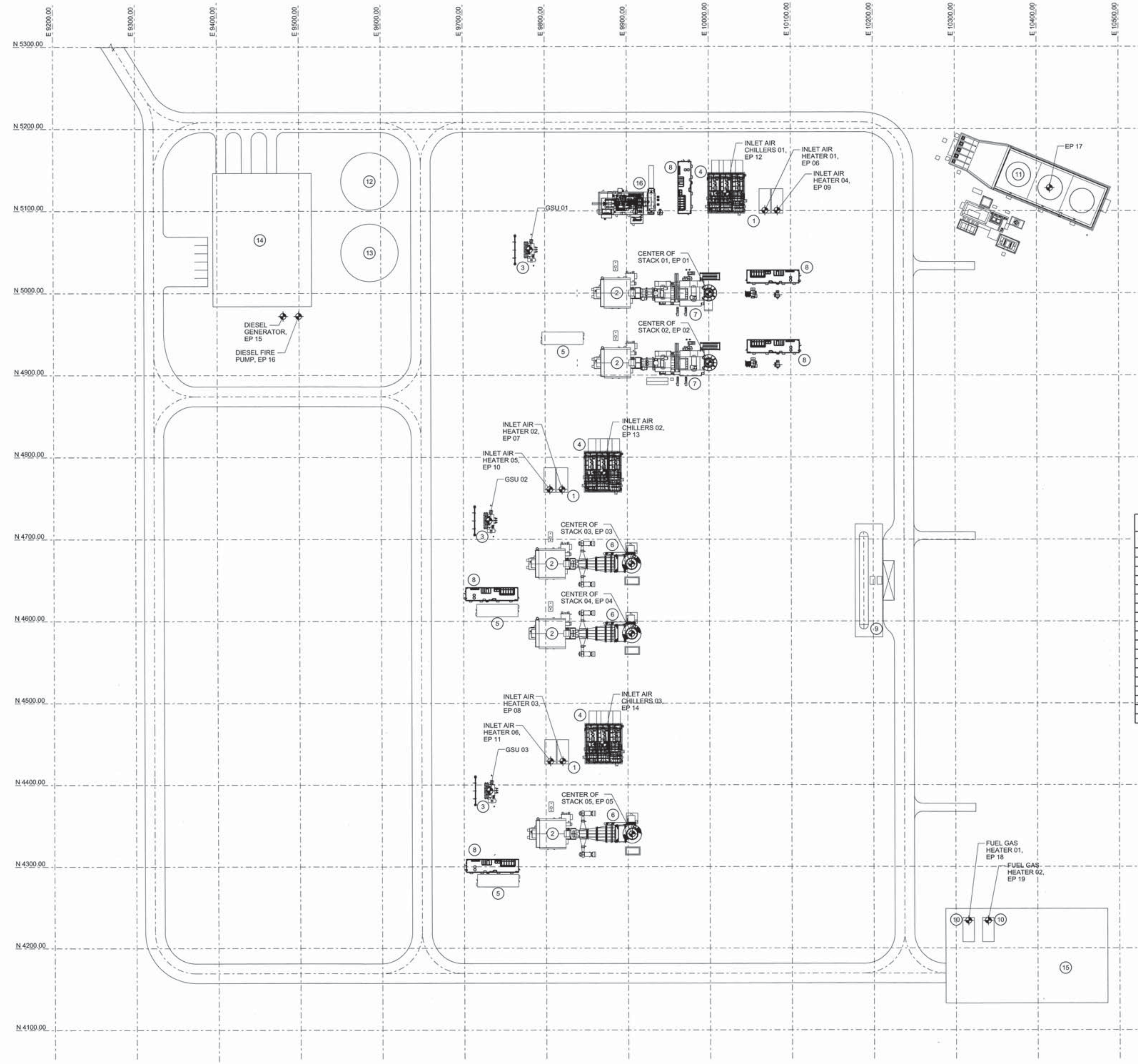
FIGURE A-2
Cheyenne Generating Station General Arrangement

\\COBRA\PROJ\BLACKHILLS_PUC_WY\GIS\MAPFILES\AIR\GENERALARRANGEMENT.MXD ZVALCHAR 8/1/2011 09:55:26

CH2MHILL

APPENDIX A-3

CGS Site General Arrangement



SCALE
IN FEET

GENERAL NOTES

1. HORIZONTAL CONTROL WILL BE BASED ON THE MODIFIED WYOMING STATE PLANE COORDINATE - WYOMING (NAD 1983) SYSTEM.
2. PLANT COORDINATES N 5000.00, E 10000.00 = MODIFIED WYOMING STATE PLANE (NAD1983) COORDINATE N 779204.00, E 227517.00.

EQUIPMENT LEGEND

1. INLET AIR HEATER
2. GAS TURBINE GENERATOR & AUXILIARIES
3. GENERATOR STEP UP TRANSFORMER (GSU)
4. INLET AIR CHILLERS
5. CTG POWER CONTROL MODULE
6. SELECTIVE CATYLIST REDUCTION
7. HEAT RECOVERY STEAM GENERATOR
8. CTG AUXILIARY POWER ENCLOSURE
9. AMMONIA TANK
10. FUEL GAS HEATER
11. CTW COOLING TOWER
12. DEMINERALIZED WATER TANK
13. FIRE/SERVICE WATER TANK
14. ADMINISTRATION BLDG
15. GAS YARD
16. STEAM TURBINE & AUXILIARIES

LEGEND

EMISSION POINT (EP), SEE SURVEY CONTROL CHART FOR LOCATION.

EMISSION POINT SURVEY CONTROL

EMISSION POINT	LOCATION	PLANT COORDINATES (FEET)		MODIFIED STATE PLANE COORDINATES (FEET)		STATE PLANE COORDINATES (FEET)	
01	CENTER OF STACK 01	N 5000.00	E 10000.00	N 227517.00	E 779204.00	N 227442.34	E 778949.97
02	CENTER OF STACK 02	N 4915.00	E 10000.00	N 227432.00	E 779204.00	N 227357.34	E 778949.97
03	CENTER OF STACK 03	N 4670.00	E 9905.00	N 227187.00	E 779109.00	N 227112.34	E 778854.97
04	CENTER OF STACK 04	N 4585.00	E 9905.00	N 227102.00	E 779109.00	N 227027.34	E 778854.97
05	CENTER OF STACK 05	N 4340.00	E 9905.00	N 226857.00	E 779109.00	N 226782.34	E 778854.97
06	INLET AIR HEATER 01	N 5100.50	E 10068.75	N 227617.50	E 779272.75	N 227542.84	E 779018.72
07	INLET AIR HEATER 02	N 4761.00	E 9820.50	N 227278.00	E 779024.50	N 227203.34	E 778770.47
08	INLET AIR HEATER 03	N 4429.00	E 9820.50	N 226946.00	E 779024.50	N 226871.34	E 778770.47
09	INLET AIR HEATER 04	N 5100.50	E 10083.75	N 227617.50	E 779287.75	N 227542.84	E 779033.72
10	INLET AIR HEATER 05	N 4761.00	E 9805.50	N 227278.00	E 779009.50	N 227203.34	E 778755.47
11	INLET AIR HEATER 06	N 4429.00	E 9805.50	N 226946.00	E 779009.50	N 226871.34	E 778755.47
12	INLET AIR CHILLERS 01	N 5122.00	E 10021.50	N 227639.00	E 779225.50	N 227564.34	E 778971.47
13	INLET AIR CHILLERS 02	N 4782.50	E 9870.25	N 227299.50	E 779074.25	N 227224.84	E 778820.22
14	INLET AIR CHILLERS 03	N 4450.50	E 9870.25	N 226967.50	E 779074.25	N 226892.84	E 778820.22
15	DIESEL GENERATOR	N 4972.00	E 9480.50	N 227489.00	E 778684.50	N 227414.34	E 778430.47
16	DIESEL FIRE PUMP	N 4972.00	E 9499.50	N 227489.00	E 778703.50	N 227414.34	E 778449.47
17	COOLING TOWER	N 5128.00	E 10416.00	N 227645.00	E 779620.00	N 227570.34	E 779365.97
18	FUEL GAS HEATER 01	N 4234.00	E 10315.50	N 226751.00	E 779519.50	N 226676.34	E 779265.47
19	FUEL GAS HEATER 02	N 4234.00	E 10339.50	N 226751.00	E 779543.50	N 226676.34	E 779289.47

GSU SURVEY CONTROL

LOCATION	PLANT COORDINATES (FEET)		MODIFIED STATE PLANE COORDINATES (FEET)		STATE PLANE COORDINATES (FEET)	
GSU 01	N 5053.00	E 9781.50	N 227570.00	E 778985.50	N 227495.34	E 778731.47
GSU 02	N 4723.00	E 9731.50	N 227240.00	E 778935.50	N 227165.34	E 778681.47
GSU 03	N 4393.00	E 9731.50	N 223910.00	E 778935.50	N 226835.34	E 778681.47

NO.	REVISION	DATE	DRWN	DSND	CHKD	CHKD
A	ISSUE FOR PERMITTING					

Black Hills Corporation

ZACHRY

BHC CHEYENNE GENERATING STATION
SITE RELATED WORK
GENERAL ARRANGEMENT
2x1 COMBINED CYCLE & 3 UNIT SIMPLE CYCLE

DRAWN: S. LUNA 06-30-11 · DESIGNED · CHECKED: M. DAVIS 06-30-11

D014255-SRWL00005 | SHEET 01 | REV A

APPENDIX B

GHG Support Documentation

APPENDIX B-1

CGS GHG Emission Calculations

Black Hills Corporation
Cheyenne Generating Station
Potential to Emit Facility Wide Greenhouse Gas
Revision 07-28-11

Emission Point	Description	Consumption (MMBtu/hr)	Emission Factors (kg/MMBtu)			Emissions (tons/year)			
			CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2-equivalent
EP01	Combined Cycle Combustion Turbine CT01A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP02	Combined Cycle Combustion Turbine CT01B	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP03	Simple Cycle Combustion Turbine CT02A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP04	Simple Cycle Combustion Turbine CT02B	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP05	Simple Cycle Combustion Turbine CT03A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP06	Inlet Air Heater 01	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP07	Inlet Air Heater 02	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP08	Inlet Air Heater 03	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP09	Inlet Air Heater 04	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP10	Inlet Air Heater 05	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP11	Inlet Air Heater 06	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP15	Diesel Generator	5.52	73.96	0.003	0.0006	225.01	0.01	0.00	225.77
EP16	Diesel Fire Pump	2.5	73.96	0.003	0.0006	50.95	0.00	0.00	51.13
EP18	Fuel Gas Heater 01	4.5	53.02	0.001	0.0001	1,151.92	0.02	0.00	1,153.05
EP19	Fuel Gas Heater 02	4.5	53.02	0.001	0.0001	1,151.92	0.02	0.00	1,153.05
Total PTE for Facility						**962,928.74**	**18.17**	**1.82**	**963,873.80**

Notes:

(1) CO_2 Emission Factors from Table C-1 of the EPA's Mandatory Reporting Rule.
(2) CH_4 and N_2O Emission Factors from Table C-2 of the EPA's Mandatory Reporting Rule.
(3) Global Warming Potentials are:

CO_2	1
CH_4	21
N_2O	310

(4) Combustion Turbines (hr/yr operation per turbine)	8760
(5) Inlet Air Heaters (hr/yr operation per turbine)	4380
(6) Diesel Emergency Generator (hr/yr operation per turbine)	500
(7) Diesel Fire Pump (hr/yr operation per turbine)	250
(8) Fuel Gas Heaters (hr/yr operation per turbine)	4380

APPENDIX B-2

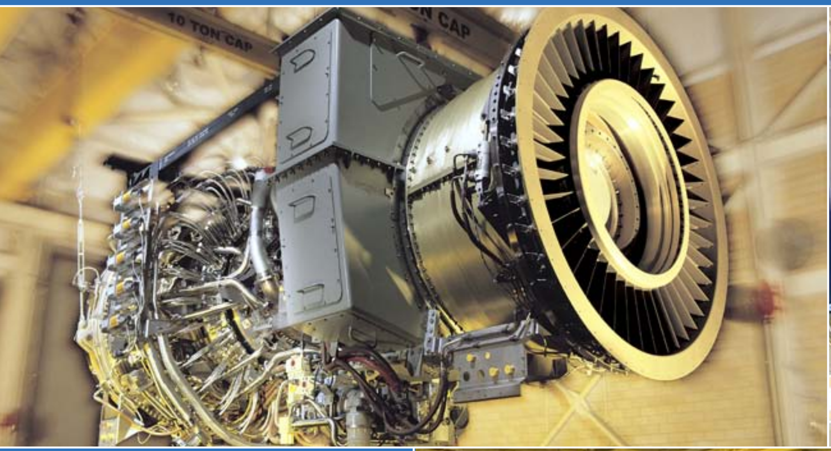
GE LM6000 Sprint Combustion Turbine Series General Information

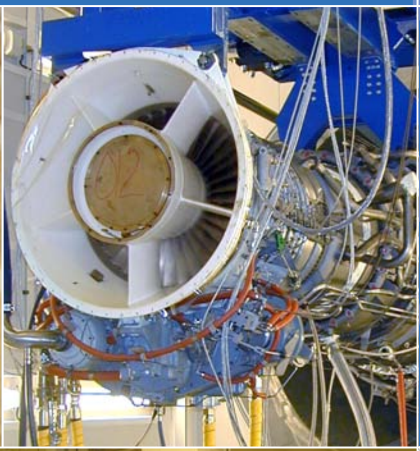
GE Power & Water

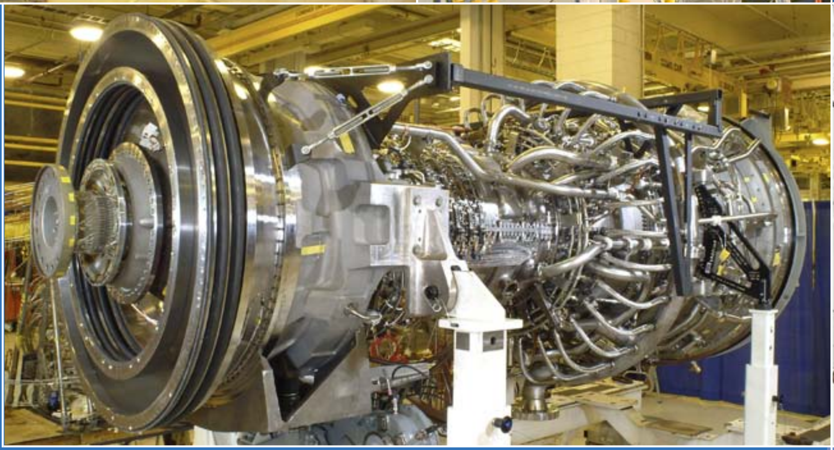
Aeroderivative Gas Turbines

Fast, Flexible Power

Aeroderivative Product and Service Solutions







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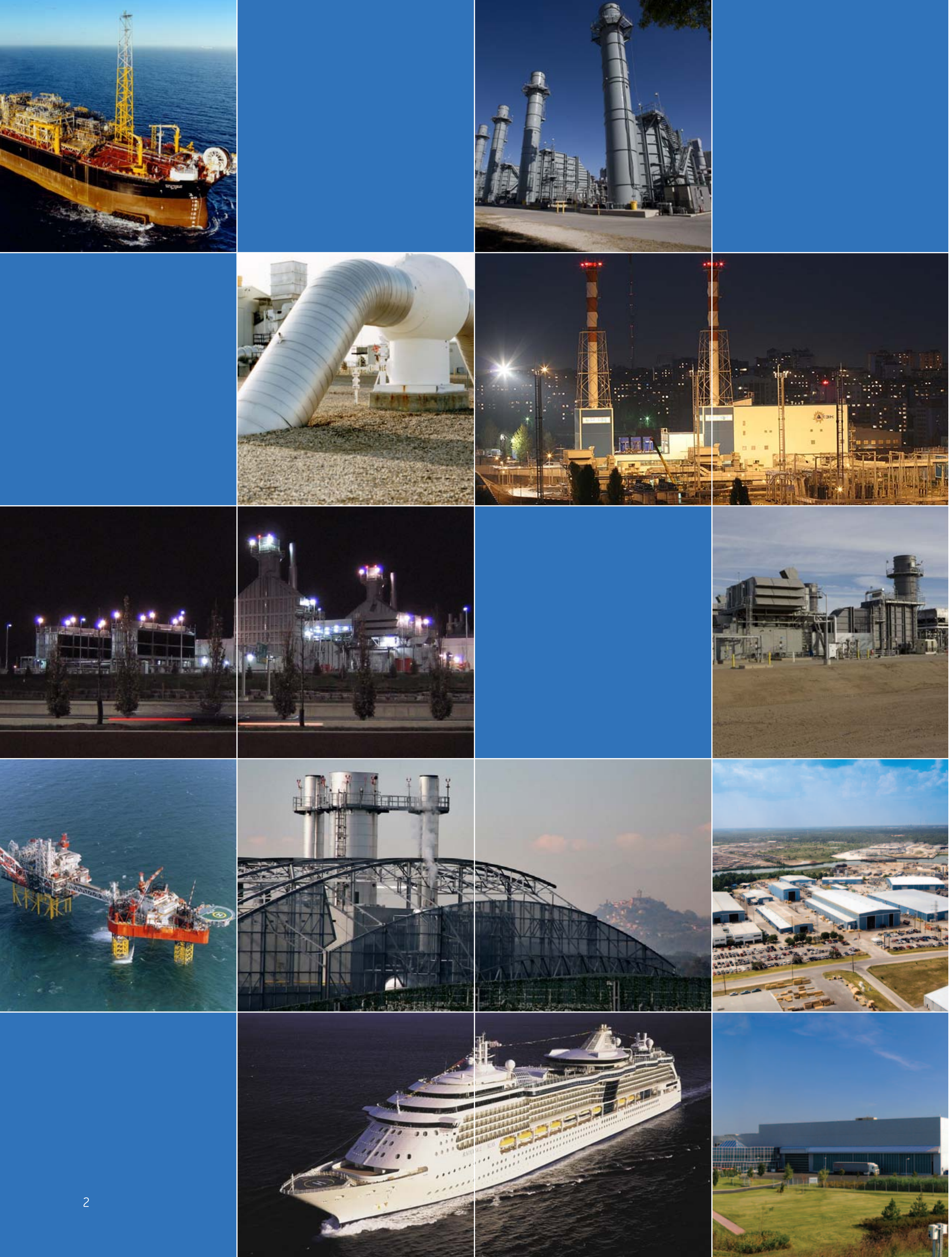


GE Power & Water's Aeroderivative Gas Turbines business is a leading supplier of aeroderivative gas turbines and packaged generator sets for industrial and marine applications. Our products and services help power the potential of customers across a wide range of operational profiles and industries by increasing efficiency while reducing environmental impact.

GE's continued investment in research and development of aircraft engine technology enables the LM series of gas turbines to maintain a leadership position in technology, performance, operational flexibility and value to the customer. With power output from 18 to 100 MW and the ability to operate with a variety of fuels and emission control technologies, GE's aeroderivative gas turbines have gained wide acceptance in the industry, with total operating experience surpassing 100 million hours.

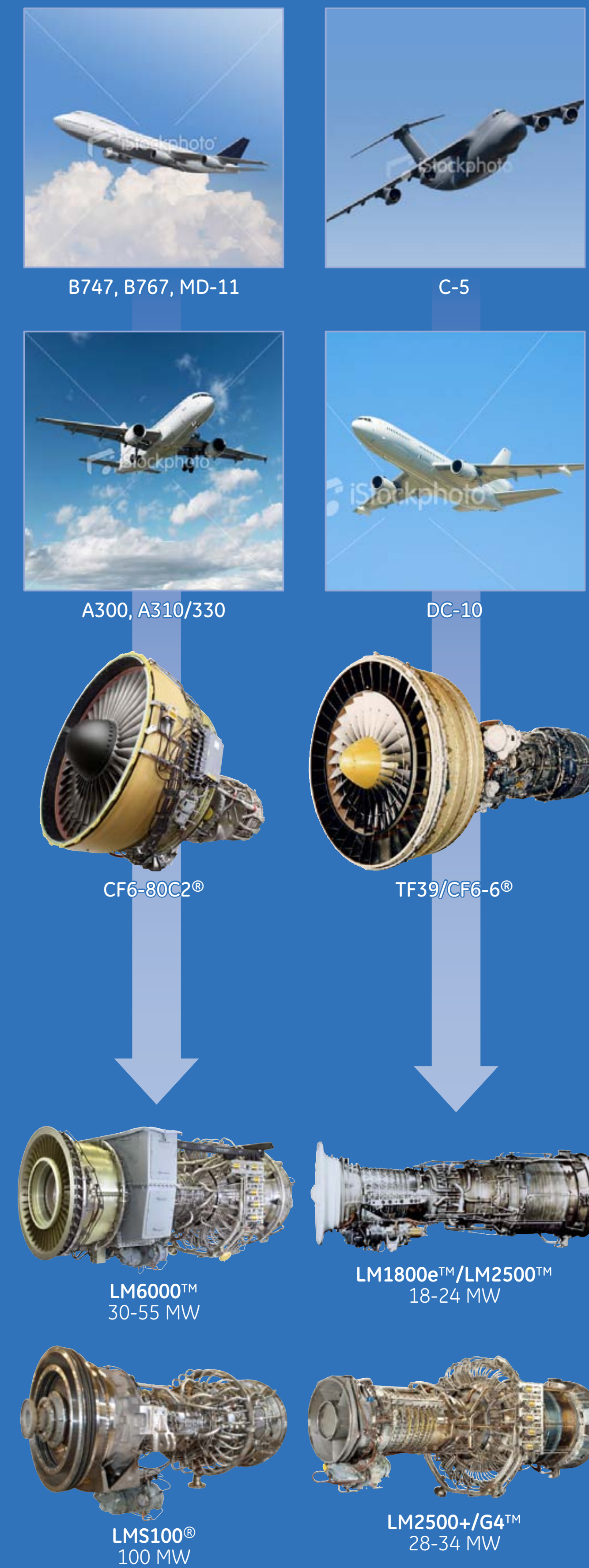
Products known for...

- *Operational flexibility*
- *High efficiency*
- *Superb reliability*
- *Fast installations*

Providing diverse solutions for...

- *FPSO*
- *Grid Stability*
- *Utilities*
- *Oil and Gas*
- *Industrial*
- *Pipeline*
- *Temp Power*
- *Marine*

Aeroderivative Heritage



Fast, Flexible Power

At GE, we recognize the individual operating schemes of our customers are vast and varied. That is why we are committed to providing a flexible portfolio of products to support a full spectrum of operating needs: from fast starts and load following to get peak customers on the grid quickly, to high availability and reliability to keep base load customers online for the long haul. Whatever your scenario, we can tailor a solution to meet your needs.

Operational flexibility is inherent to GE's portfolio of aeroderivative gas turbines and a critical component of our customers' success. We understand the importance of speed and flexibility when it comes to responding to power demands. Our gas turbines are designed to meet these challenges with efficiency and cost effectiveness.

Fast Installation with Less Interruption

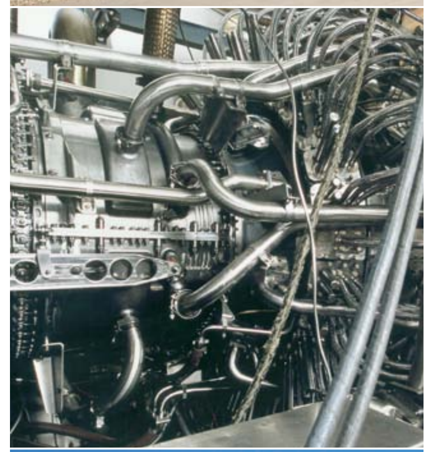
GE is committed to maintaining short manufacturing cycles supported by dependable, predictable delivery times and a robust supply chain. Our modular package designs and on-going interconnect innovation allow for shorter manufacturing cycles and faster installation times with less installed and operational costs than field erected units. All of our units undergo rigorous factory testing after assembly and are ready for operation soon after arriving on site—translating into lower installation costs, shorter project schedules, and reduced financial risk for our customers.

The integration of skid-mounted support systems requires less installation work, time and expense. Fewer materials are shipped directly to the site, reducing the amount of civil works, utilizing package support systems and less foundation work than alternate generation. Our compact, lightweight package design allows for installation flexibility and less process interruption.

Products known for operational flexibility, high efficiency, superb reliability and fast installations

Providing diverse solutions for various industries

- Utilities – peak power, combined cycle, distributed generation, grid stability
- Oil & Gas – mechanical drive, power generation
- FPSO – offshore power with our compact 538 and 538e packages
- Industrial – combined heat and power
- Mobile power – emergency power, peak demand, mining and O&G applications
- Marine – power and propulsion


Fast Starts and Cycling Capability

The ability to go from cold iron to full power in just 10 minutes and the ability to start and stop in short, 15-minute cycles (several times per day if necessary) without impacting maintenance intervals make GE's aeroderivative gas turbines exceptionally adept at accommodating fluctuating demand with increasing efficiency across multiple industry segments. GE's aeroderivative gas turbines can be the first to respond to a peak power demand opportunity, without the costs of a spinning reserve.

Load Following

Thanks to a two-rotor design, GE's aeroderivative portfolio provides higher part power efficiency and faster response to load changes than other similar gas turbines in the industry. This load matching allows for greater grid stability of voltage and frequency, and provides greater starting torque for mechanical drive applications.

High Availability/Reliability

By utilizing aircraft experience and design, our aeroderivative design approach incorporates features such as split casings, modular construction, individual replacement of internal and external parts, and GE's "lease pool" engine program. Our extensive use of high quality components common with parent aircraft engines validates engine reliability and offers reduced parts cost.

Various inspections and hot section repairs can be performed on the gas turbine at site within the turbine enclosure. The "Hot Section," HPT and combustor can be removed/replaced in the field within 72 hours, allowing for greater availability during planned maintenance. Greater availability is achieved by the on-condition maintenance program, which inspects and repairs only as necessary to desired operational condition.

Wide Fuel Range

At GE, we understand flexibility in fuel choices is a high priority. Our Alternate Fuels Center of Excellence is leading the industry in identifying, designing, and delivering fuel flexibility options—all with the high reliability, availability, and maintainability standards you expect from GE.

Our experience on liquid biofuels is proven and growing. In addition to conventional turbine fuels such as #2 diesel, jet fuel, and kerosene, aeroderivative gas turbines are designed to run on a range of alternates—from light distillates like naphtha, to greener fuels such as biodiesels and ethanol derived from various feedstocks. Our package and engine systems have over 450,000 hours of successful operations on naphtha fuel, and over 23,000 hours of operation using biodiesel.

Examples of fuel versatility for our gas turbine and package products include:

Gaseous fuel

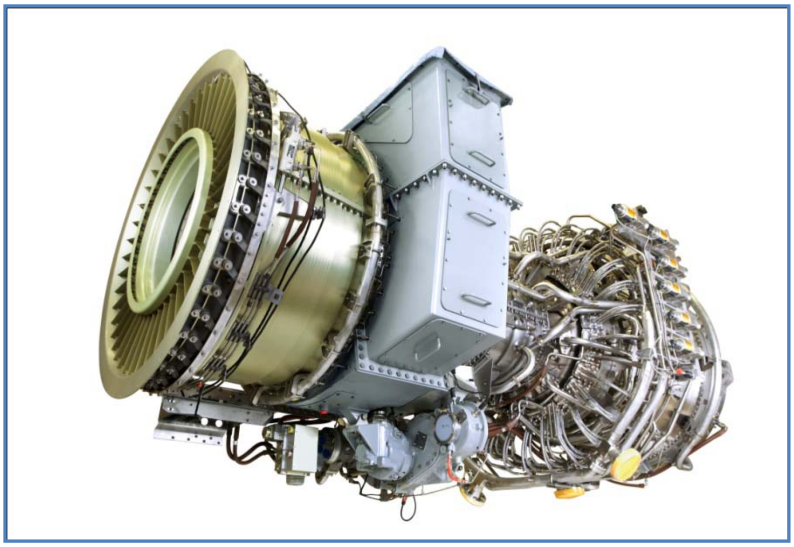
- Pipeline and liquefied natural gas (LNG)
- Syngas (low and medium BTU)
- Propane, high hydrocarbon gas
- Wellhead, associated gas
- Coal bed methane (CBM)
- Landfill gas (LFG)
- Coke oven gas (COG)
- Refinery/process flare gas
- LNG for marine propulsion

Liquid fuel

- #2 Diesel
- Jet fuel, kerosene
- Naphtha
- Biodiesel
- Ethanol
- Liquid blends
- Butane

GE Energy
LM6000 Sprint Aeroderivative Gas Turbines

Unlike most gas turbines, the LM6000® is primarily controlled by the compressor discharge temperature in lieu of the turbine inlet temperature. Some of the compressor discharge air is then used to cool high-pressure turbine components. Sprint — which stands for "Spray Inter-cooled Turbine" — reduces compressor discharge temperature, thereby allowing advancement of the throttle to significantly enhance power and improve thermal efficiency.

- 

Features & Benefits

- Output increased by 12 percent @ ISO condition and over 30 percent at 90 °F (32 °C) ambient temperature
- Enhanced heat rate across the ambient range
- Exhaust conditions are also improved for combined cycle applications
- Full power in ten minutes
- Baseload, cycling, or peaking
- Dual fuel capability (distillate or gas)
- Easy on-site maintenance

Design

The LM6000 Sprint system is composed of atomized water injection at both low-pressure compressor (LPC) and high-pressure compressor (HPC) inlet plenums. This is accomplished by using a high-pressure compressor, eighth-stage bleed air to feed two air manifolds, water-injection manifolds and sets of spray nozzles, where the water droplets are sufficiently atomized before injection at both LPC and HPC inlet plenums.

APPENDIX B-3

GE LM6000 CGS Performance Guarantee

GE ENERGY

GUARANTEE
PROJECT: BLACK HILLS WYOMING
LOCATION: WY, USA

KW AT GEN TERMS	38820
BTU/KW-HR, LHV	8451
(KJ/KW-HR, LHV)	8916

Adesoji Dairo
Performance Engineer
Date: 06/30/11

EMISSIONS ARE VALID FOR T2 WITHIN 0F-120F AND A GTG LOAD DOWN TO 50% AS DEFINED IN STEADY STATE CONDITIONS

NOX:	25 PPMVD AT 15% O2 (51 mg/Nm3)
CO:	70 PPMVD AT 15% O2 (88 mg/Nm3)
VOC:	8.4 PPMVD AT 15% O2 (6 mg/Nm3)
PM10:	4 LB/HR (2 kg/hr)

NOT VALID WITHOUT SIGNATURE

VALID UNTIL 09/28/11

BASIS OF GUARANTEE:	BASE LOAD, GAS FUEL NOZZLE SYSTEM NO BLEED OR EXTRACTED POWER
ENGINE:	(1) GE LM6000PF-SPRINT-25 DLE GAS TURBINE
FUEL:	21000Btu/lb / (48846 kJ/kg) LHV, GAS FUEL (#900-3029)
FUEL SPEC:	MID-TD-0000-1 LATEST REVISION
FUEL TEMP:	SITE FUEL TEMPERATURE OF 76.9°F(25.0°C)
GENERATOR:	BDAX 7-290ERJT
GENERATOR OUTPUT	13.8kV, 60 Hz
POWER FACTOR:	≥ 1
AMBIENT TEMP:	95.0°F / (35.0°C)
AMBIENT RH:	20.0%
INLET CONDITIONING:	CHILL TO 47.0°F / (8.3°C) AT 95.0% RH
ALTITUDE:	5950.0ft / (1813.6m)
INLET FILTER LOSS:	≤ 5.00 inH_2O / (127.0 mmH_2O)
EXHAUST LOSS:	≤ 12.00 inH_2O / (304.8 mmH_2O)
NOX CONTROL:	DLE
ENGINE CONDITION:	NEW AND CLEAN ≤ 200 SITE FIRED HOURS
FIELD TEST METHODS	
PERFORMANCE:	GE ENERGY SGTGPTM
NOX:	EPA METHOD 20
CO:	EPA METHOD 10
VOC:	EPA METHOD 25A/18
PM10:	EPA METHOD 5 / 202

BASIS OF GUARANTEE IS NOT FOR DESIGN, REFER TO PROJECT DRAWINGS FOR DESIGN REQUIREMENTS.
SI VALUES ARE FOR REFERENCE PURPOSES ONLY.

THIS GUARANTEE SUPERSEDES ANY
PREVIOUS GUARANTEES PRESENTED

Conditions for VOC Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.
2. The timing of test to coincide with lowest site ambient VOCs levels.
3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Gas turbine inlet and exhaust system must be free of any dirt,sand,mud,rust,oil or any other contaminates.
5. Re-testing (at purchaser's expense) must be allowed, if required.
6. GE receives a copy of the final test results.
7. A compressor wash prior to testing is highly recommended.

GE ENERGY

Conditions for PM10 Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.
2. The timing of test to coincide with lowest site ambient particulate levels.
3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Combustion turbine must be run for a minimum of 300 total fired hours prior to any particulate testing; combustion turbine must be operating a minimum of 3 - 4 hours at base load prior to PM / PM10 test run.
5. Gas turbine inlet and exhaust system must be free of any dirt,sand,mud,rust,oil or any other contaminates.
6. Sampling probe internal surfaces must be made of chemically inert and non-catalytic material such as quartz.
7. The filter material shall be quartz.
8. Probe wash shall be high purity acetone per EPA Method 5.
9. Re-testing (at purchaser's expense) must be allowed, if required.
10. GE receives a copy of the final test results.
11. A compressor wash prior to testing is highly recommended.
12. The area around the turbine is to be treated (e.g.sprayed down with water) to minimize airborne dust.

Conditions for Steady State Guarantee

1.	Power Output (electrical)	±10.0% / Min
2.	T2 Compressor Inlet air temperature	± 2.5°F / 5.0 Min
3.	Heat Value - gaseous fuel per unit volume	±0.25% / Min
4.	Pressure - gaseous fuel as supplied to engine	± 10 PSIG / 5.0 Min

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo**
Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **12:59:23 PM**
Version: **3.9.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °F	95.0
Wet Bulb, °F	63.9
RH, %	20.0
Altitude, ft	5950.0
Ambient Pressure, psia	11.799
Engine Inlet	
Comp Inlet Temp, °F	47.0
RH, %	95.0
Conditioning	CHILL
Tons or kBtu/hr	885
Pressure Losses	
Inlet Loss, inH20	5.00
Volute Loss, inH20	4.00
Exhaust Loss, inH20	12.00
Partload %	**100**
kW, Gen Terms	**38820**
Est. Btu/kW-hr, LHV	**8282**
Guar. Btu/kW-hr, LHV	**8451**
Fuel Flow	
MMBtu/hr, LHV	321.5
lb/hr	15310
NOx Control	**DLE**
SPRINT	**LPC**
lb/hr	7069
Control Parameters	
HP Speed, RPM	10354
LP Speed, RPM	3600
PS3 - CDP, psia	369.5
T25 - HPC Inlet Temp, °F	193.0
T3CRF - CDT, °F	945
T48IN, °R	2046
T48IN, °F	1587
Exhaust Parameters	
Temperature, °F	856.3
lb/sec	235.2
lb/hr	846706
Energy, Btu/s- Ref 0 °R	79113
Energy, Btu/s- Ref T2 °F	49517
Cp, Btu/lb-R	0.2733
Emissions (ESTIMATED, NOT FOR GUARANTEE)	
NOx ppmvd Ref 15% O2	25
NOx as NO2, lb/hr	32
CO ppmvd Ref 15% O2	25
CO, lb/hr	19.63
CO2, lb/hr	41943.27
HC ppmvd Ref 15% O2	15
HC, lb/hr	6.73
SOX as SO2, lb/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo**
Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **12:59:23 PM**
Version: **3.9.0**

Case #	**100**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2435
N2	72.9173
O2	15.3205
CO2	4.9537
H20	5.5593
SO2	0.0000
CO	0.0023
HC	0.0008
NOX	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.9650
N2	80.6950
O2	14.8437
CO2	3.4896
H20	0.0000
SO2	0.0000
CO	0.0026
HC	0.0015
NOX	0.0026
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.8808
N2	73.6490
O2	13.5476
CO2	3.1849
H20	8.7317
SO2	0.0000
CO	0.0023
HC	0.0014
NOX	0.0023

Aero Energy Fuel Number	**900-3029 (Black Hills Wyoming)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	95.5018	90.7897
Ethane	3.0123	5.3675
Ethylene	0.0000	0.0000
Propane	0.4638	1.2119
Propylene	0.0000	0.0000
Butane	0.1190	0.4099
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0240	0.1026
Cyclopentane	0.0000	0.0000
Hexane	0.0135	0.0689
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.6458	1.6843
Nitrogen	0.2200	0.3652
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

Btu/lb, LHV	21000
Btu/scf, LHV	936.2
Btu/scf, HHV	1037.6
Btu/lb, HHV	23274
Fuel Temp, °F	76.9
NOx Scalar	1.011
Specific Gravity	0.58

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo**
Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **1:05:44 PM**
Version: **3.9.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °C	35.0
Wet Bulb, °C	17.7
RH, %	20.0
Altitude, m	1813.6
Ambient Pressure, kPa	81.353
Engine Inlet	
Comp Inlet Temp, °C	8.3
RH, %	95.0
Conditioning	CHILL
Tons or kBtu/hr	885
Pressure Losses	
Inlet Loss, mmH2O	127.00
Volute Loss, mmH2O	101.60
Exhaust Loss, mmH2O	304.80
Partload %	**100**
kW, Gen Terms	**38820**
Est. kJ/kWh, LHV	**8738**
Guar. kJ/kWh, LHV	**8916**
Fuel Flow	
GJ/hr, LHV	339.2
kg/hr	6944
NOx Control	**DLE**
SPRINT	**LPC**
kg/hr	3206
Control Parameters	
HP Speed, RPM	10354
LP Speed, RPM	3600
PS3 - CDP, kPa	2547.7
T25 - HPC Inlet Temp, °C	89.4
T3CRF - CDT, °C	507
T48IN, °K	1137
T48IN, °C	864
Exhaust Parameters	
Temperature, °C	457.9
kg/sec	106.7
kg/hr	384063
Energy, KJ/s- Ref 0 °K	83469
Energy, KJ/s- Ref T2 °C	52243
Kj/kg-R	1.1440
Emissions (ESTIMATED, NOT FOR GUARANTEE)	
NOx mg/Nm3 Ref 15% O2	51
NOx as NO2, kg/hr	15
CO mg/Nm3 Ref 15% O2	31
CO, kg/hr	8.90
CO2, kg/hr	19025.34
HC mg/Nm3 Ref 15% O2	11
HC, kg/hr	3.05
SOX as SO2, kg/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo**
Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **1:05:44 PM**
Version: **3.9.0**

Case #	**100**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2435
N2	72.9173
O2	15.3205
CO2	4.9537
H20	5.5593
SO2	0.0000
CO	0.0023
HC	0.0008
NOX	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.9650
N2	80.6950
O2	14.8437
CO2	3.4896
H20	0.0000
SO2	0.0000
CO	0.0026
HC	0.0015
NOX	0.0026
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	0.8808
N2	73.6490
O2	13.5476
CO2	3.1849
H20	8.7317
SO2	0.0000
CO	0.0023
HC	0.0014
NOX	0.0023

Aero Energy Fuel Number	**900-3029 (Black Hills Wyoming)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	95.5018	90.7897
Ethane	3.0123	5.3675
Ethylene	0.0000	0.0000
Propane	0.4638	1.2119
Propylene	0.0000	0.0000
Butane	0.1190	0.4099
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0240	0.1026
Cyclopentane	0.0000	0.0000
Hexane	0.0135	0.0689
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.6458	1.6843
Nitrogen	0.2200	0.3652
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

kJ/kg, LHV	48846
kJ/Nm3, LHV	36774.2
kJ/Nm3, HHV	40754.8
kJ/kg, HHV	54134
Fuel Temp, °C	25.0
NOx Scalar	1.011
Specific Gravity	0.58

APPENDIX B-4

GE LM6000 PF Sprint Technology Attributes

GE Infrastructure - Energy

Balachandar Naidu PhD
Senior Product Marketing Manager
One Neumann Way, MD S155
T 513-552-6863
varathar@ge.com

LM6 PF SPRINT® – State of the Art Gas turbine

The LM6000PF is a gas turbine engine derived from GE's proven CF6-80C2 aircraft engine. Aero-derivative engines such as the LM6000 have several distinguishing features. The LM6000 has a dual shaft architecture. The low-speed shaft rotates at 3600 rpm to permit direct connection to a 2-pole electric generator while the air-flow and the high-speed shaft speed modulate with power. This engine also has a high operating pressure ratio (OPR 32), which in a simple-cycle configuration leads to high thermal efficiencies and low CO_2 emissions.

The gas turbine was first introduced in the early 1990's. Since then, GE has sold about a 1000 LM6 gas turbines with fleet hours exceeding 20 million hours. The LM6 gas turbine has achieved best-in-class reliability and availability with fleet averages approaching 99% and 98% respectively.

Since the introduction, GE has continuously invested in improving the gas turbine with state-of-the-art aviation technologies. Some of the critical technologies that make the LM6 a state-of-the art gas turbine are listed below.

Compressor Technologies

- LPC and HPC SPRINT® system (Spray Intercooling system) to improve compressor efficiency
- VIGV and 5-stage VSV to achieve better compressor operability
- Electrostatic suppression bushings

Combustor Technologies

- High temperature Thermal Barrier Coatings
- Full range premixed combustion for low NOx at startup
- Best in class aeroderivative Dry Low Emissions technology
- Single crystal heat shields in combustor with proven life
- Adaptive flame temperature trim to avoid exposure to high combustion dynamics
- Flame temperature control which accounts for fuel property variations

Turbine Technologies

- Single Crystal alloys for HPT
- High Temperature TBC coatings
- State-of-the art cooling

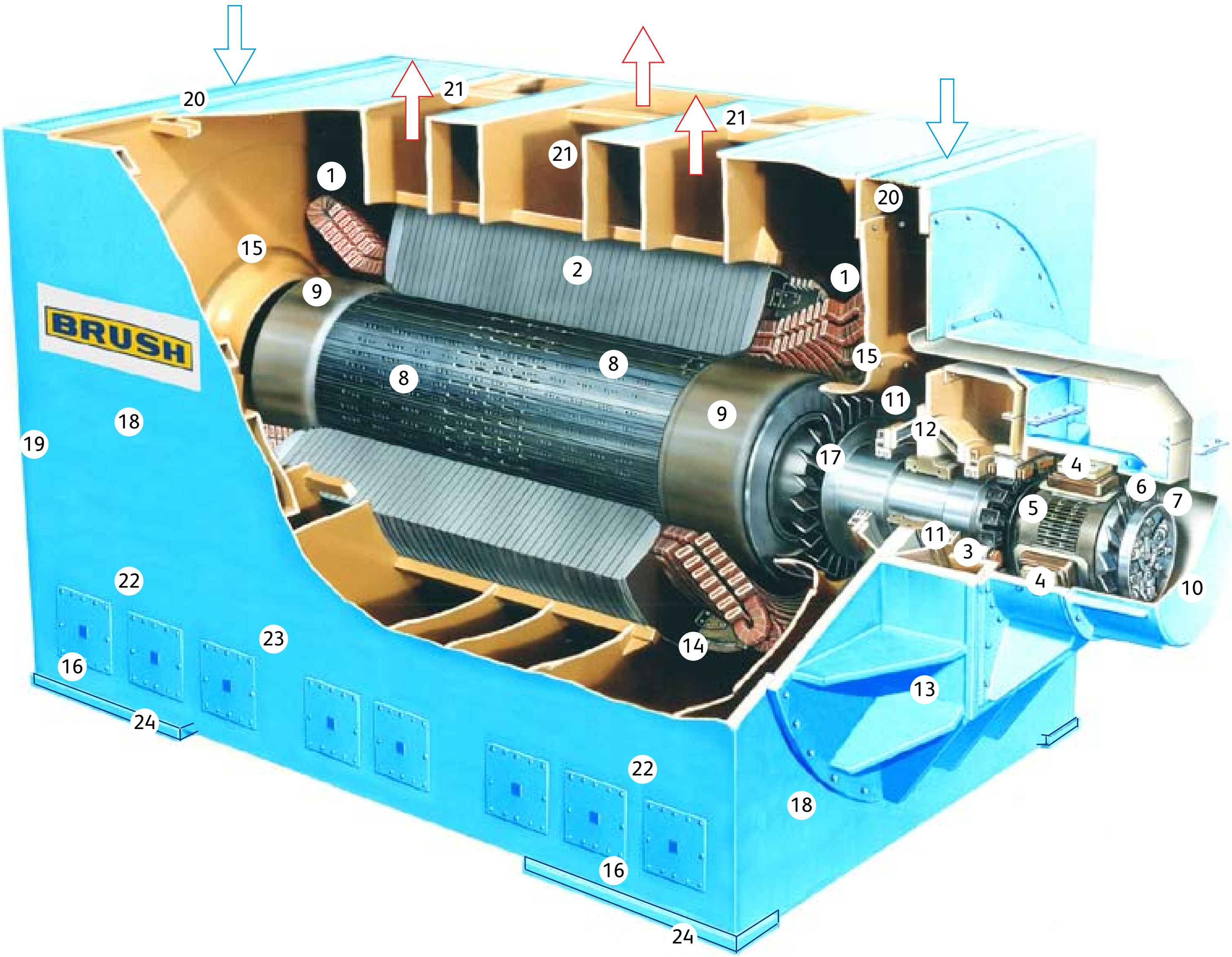
Package Technologies

- SPRINT® system to enable efficient operation at high ambient temperatures
- State of the art fuel system and NOx mitigation system.
- Control system modulation of Sprint® flow to maximize part power efficiency

APPENDIX B-5

Brush Turbine Generator Cross Section

TYPICAL DAX GENERATOR CROSS-SECTION



1. Stator (armature) winding
2. Stator core
3. Permanent magnet pilot exciter (PMG)
4. Exciter field
5. Exciter armature
6. Exciter fan
7. Rotating rectifier (diode wheel)
8. Rotor
9. Endcap (retaining ring)
10. Non drive (exciter) end
11. Oil seals
12. Main bearing (one at each end)
13. Endframe
14. Winding supports
15. Fan shroud
16. Mounting feet
17. Shaft mounted cooling fan (one at each end)
18. Stator frame
19. Drive (coupling) end
20. Cooling air inlets
21. Cooling air exhausts
22. Access to holding down bolts
23. Access to anti-condensation heaters
24. Soleplates

Contact:
BRUSH Turbogenerators Inc.
15110 Northwest Freeway - #150
Houston TX 77040

T: 281-580-1314
e: serviceus@brush.eu
Web site: www.brush.eu

APPENDIX B-6

Brush Turbine Generator Data Curves

ELECTRICAL DATA SHEET

P O Box 18, Falcon Works, Loughborough, Leics. LE11 1HJ, England
Telephone: +44 (0) 1509 611511 Fax: +44 (0) 1509 612345 E-mail: Sales@bem.fki-et.com

1. RATING DETAILS

1.1	Frame size	BDAX 7-290ERJT
1.2	Terminal voltage	13.80 kV
1.3	Frequency	60 Hz
1.4	Speed	3600 rev/min
1.5	Power factor	0.850
1.6	Applicable national standard	IEEE C50.13
1.7	Rated air inlet temperature	15.0 °C
1.8	Rated output	65.400 MW, 76.941 MVA

2. PERFORMANCE CURVES

2.1	Output vs air inlet temperature	H.E.P. 24155
2.2	Generator capability diagram	H.E.P. 24156
2.3	Efficiency vs output	H.E.P. 24157
2.4	Open and short circuit curves	H.E.P. 24158
2.5	V-curves	H.E.P. 24159
2.6	Permitted duration of negative sequence current	H.E.P. 1216

3. REACTANCES

3.1	Direct axis synchronous reactance, $X_{d(i)}$	254%
3.2	Direct axis saturated transient reactance, $X'_{d(v)}$	21.6 % ±15 %
3.3	Direct axis saturated sub transient reactance, $X''_{d(v)}$	15.6 % ± 15 %
3.4	Unsaturated negative sequence reactance, $X_{2(i)}$	19.1 %
3.5	Unsaturated zero sequence reactance, $X_{o(i)}$	10.3 %
3.6	Quadrature axis synchronous reactance, $X_{q(i)}$	233%
3.7	Quadrature axis saturated transient reactance, $X'_{q(v)}$	26%
3.8	Quadrature axis saturated sub transient reactance, $X''_{q(v)}$	19%
3.9	Short circuit ratio	0.44

Notes:

1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.

Date: 04-Dec-2007

Ref: 120404/16/296S/120R

ELECTRICAL DATA SHEET - CONTINUATION

BDAX 7-290ERJT, 65.400 MW, 0.850 pf, 13.80 kV, 60 Hz

4. RESISTANCES AT 20°C

4.1	Rotor resistance	0.138 ohms
4.2	Stator resistance per phase	0.0033 ohms

5. TIME CONSTANTS AT 20°C

5.1	Transient O.C. time constant, T'_{do}	9.7 seconds
5.2	Transient S.C. time constant, T'_{d}	0.66 seconds
5.3	Sub transient O.C. time constant T''_{do}	0.05 seconds
5.4	Sub transient S.C. time constant, T''_{d}	0.04 seconds

6. INERTIA

6.1	Moment of inertia, WR^2 (See note 2)	990 $Kg.m^2$
6.2	Inertia constant, H	0.91 kW.secs/kVA

7. CAPACITANCE

7.1	Capacitance per phase of stator winding to earth	0.19 microfarad

8. EXCITATION

8.1	Excitation current at no load, rated voltage	325 amps
8.2	Excitation voltage at no load, rated voltage	45 volts
8.3	Excitation current at rated load and P.F.	1013 amps
8.4	Excitation voltage at rated load and P.F.	185 volts
8.5	Inherent voltage regulation, F.L. to N.L.	37 %

Notes:

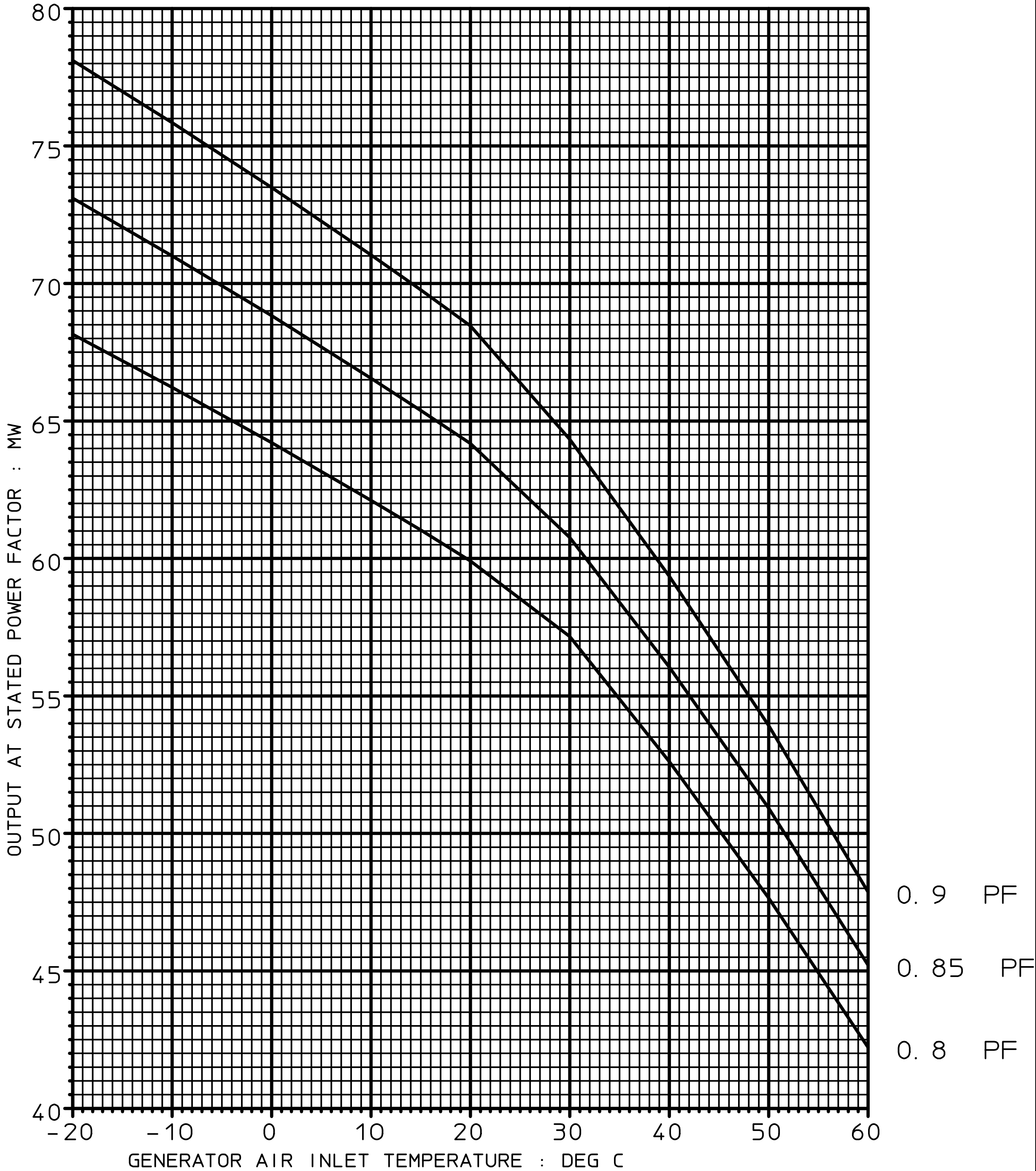
1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.

2. The rotor inertia value may vary slightly with generator / turbine interface. In the event of conflict, the figure quoted on the rotor geometry drawing takes precedence.

Date: 04-Dec-2007

Ref: 120404/16/296S/120R

VARIATION OF GENERATOR OUTPUT WITH AIR INLET TEMP



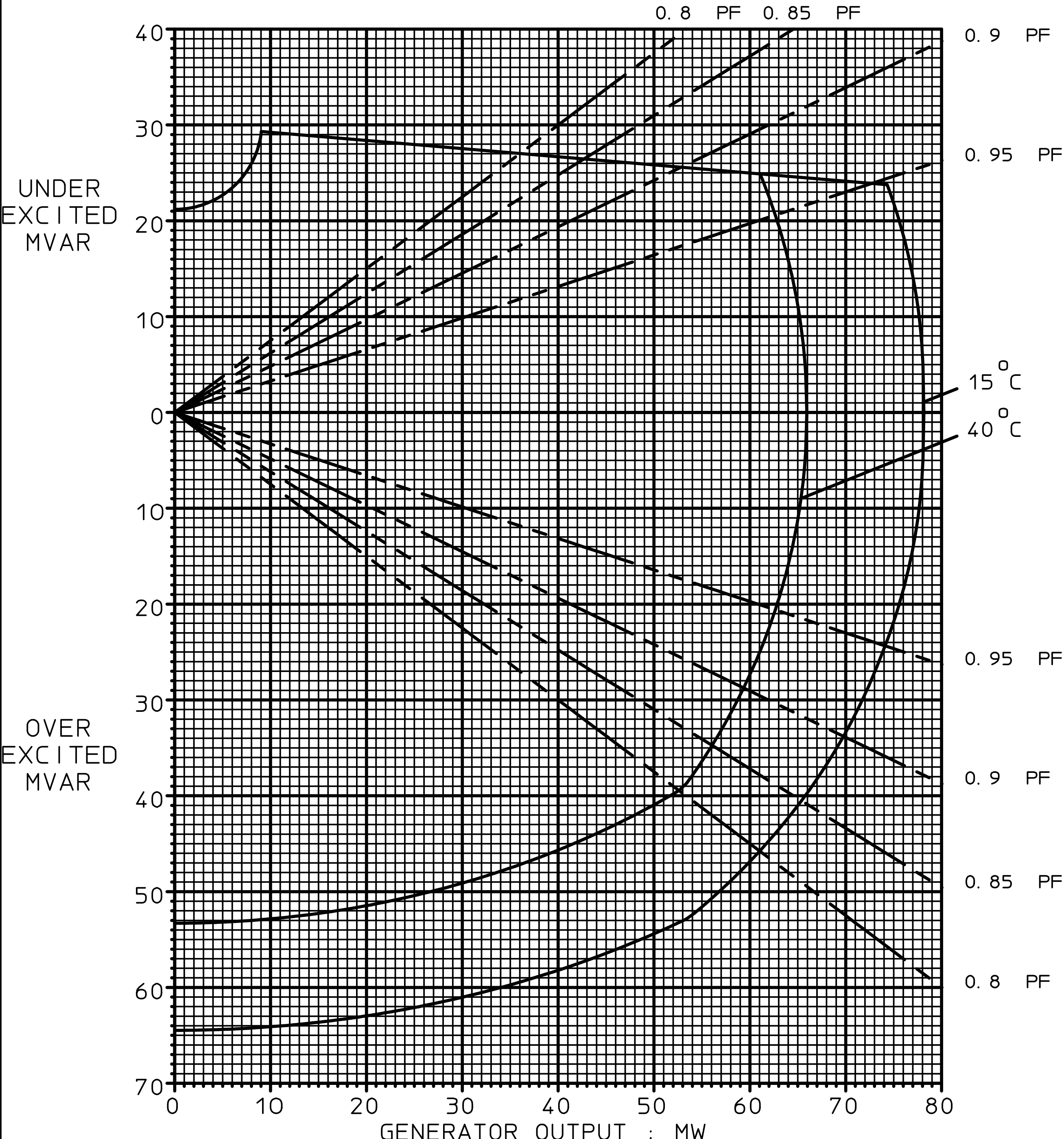
BDAX 7-290ERJT
13. 80KV, 3 Ph, 60Hz.
Up to 1000 meters ASL

IN ACCORDANCE WITH
IEEE C50. 13
Class B temperatures.
Total temperatures Stator 123 Deg C
Rotor 125 Deg C

Issue No. 1 : 04-Dec-2007

BRUSH ELECTRICAL MACHINES LTD. H.E.P 24156

GENERATOR CAPABILITY DIAGRAM



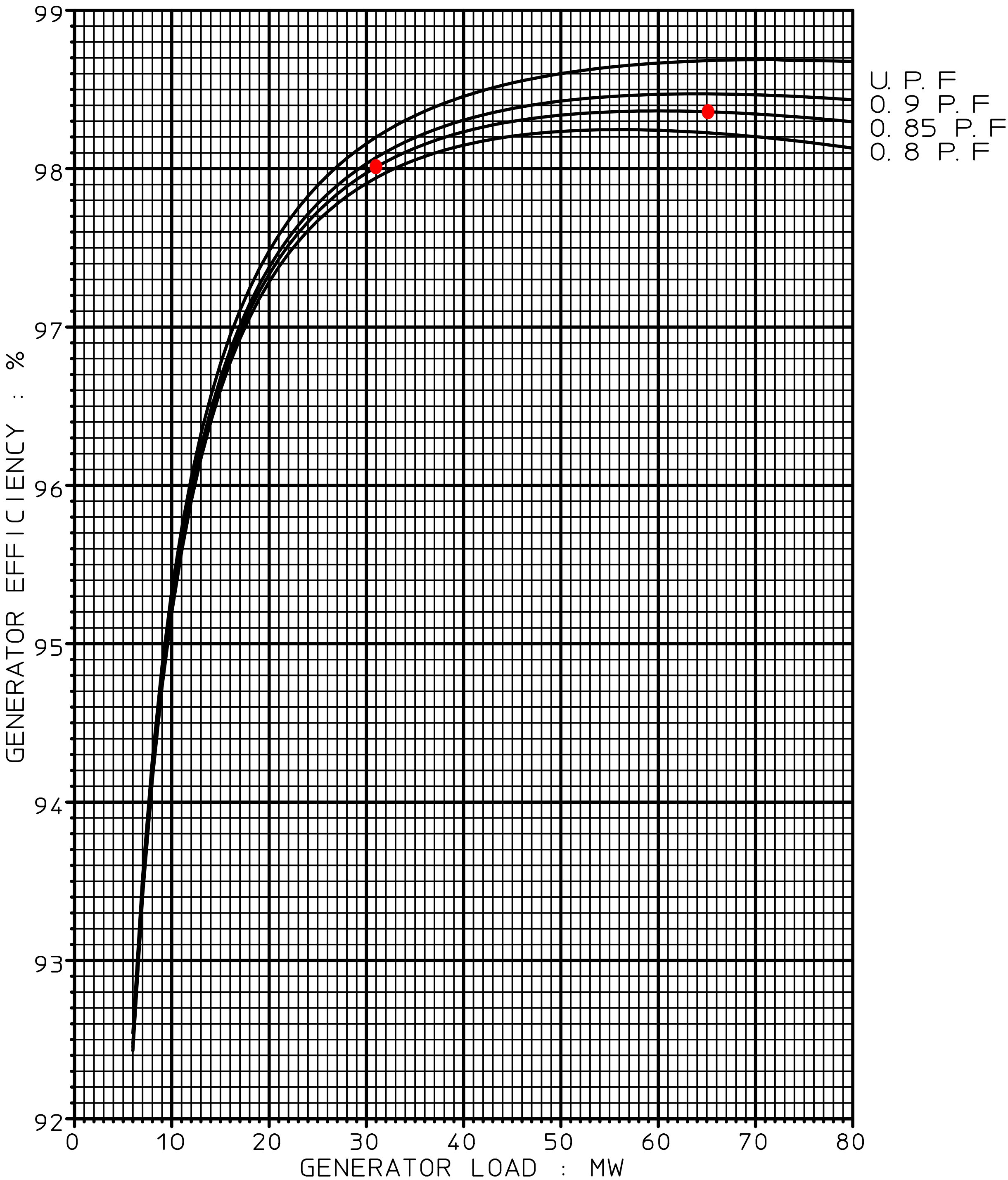
BDAX 7-290ERJT
13.80KV, 3 Ph, 60Hz.

Up to 1000 meters ASL

IN ACCORDANCE WITH
IEEE C50.13
Class B temperatures.
Total temperatures Stator 123 Deg C
Rotor 125 Deg C

Issue No. 1 : 04-Dec-2007

VARIATION OF GENERATOR EFFICIENCY WITH LOAD



BDAX 7-290ERJT
13.8 KV, 3 Ph, 60 Hz.

Efficiencies shown are guaranteed subject to the tolerance specified in IEC 60034-1.

Issue No. 1:04-Dec-2007

APPENDIX B-7

Brush Turbine Generator Efficiency Information

Generators convert the mechanical driver power to electrical output.

Robust original Brush design and modern manufacturing techniques provide our customers with one of the higher efficient mechanical to electrical conversions in the industry. The input power is defined in units of horsepower (HP) or shaft kilowatt (SKW) and the generator output as KW or MW (where MW is a 1000Kw).

Taking the popular General Electric LM6000PF Gas Turbine Package as our example for this explanation, the BDAX7-290 generator is nominally rated at 65MW at an ambient air inlet temperature of 15 deg C at sea level. This open air cooled generator selection has been fine tuned by Brush design to be the most effective technical solution for a variety of project conditions. Investment in modeling and development programs which are physically verified by test measurement have enabled continuous improvement and improved utilization of the construction materials.

TEWAC coolers and alternate utility conditions are all available as options to the same physical build without compromising the expected life and performance.

As the generator converts the mechanical energy shaft energy to electrical voltage and current (KW) the internal materials create heat due to the physical properties of the materials used in construction. These losses occur in the following principal components:

- Bearing friction – lubricating oil is heated.
- Windage losses – ambient cooling air is forced through the internal components. Shaft mounted fans push air around restricted spaces inside the generator, to carry heat away and out of the generator casing.
- The main rotating body (rotor) in the center of the generator contains a winding which creates a very strong magnetic field. The continuous copper strip is fed with a power supply from a brushless exciter which is also rotor mounted. The copper windings get hot as a result of the circulating electrical current.
- The stationary component of the generator is the magnetic stator core which captures the rotating magnetic energy and an electrical winding that converts it to volts and amperes(KW) which is connected to the power utility. Energy is lost in both the magnetic material and the winding copper all creating heat.
- All these active electrical conductors are wrapped in electrical insulation which must transfer the heat to a place where the cooling air can move the heat into the cooling air circuit.
- The heat exits the generator mostly as an increase in the cooling air temperature. A small amount of heat enters the lubricating oil, and a very small amount is radiated from the generator casing surface.

All these losses add up to approximately 1½ % of the output of the machine – so most Brush generators are around 98.5% efficient. The losses comprise fixed portions which relate to the rotating speed of the generator (in this case 3600rpm) and the terminal output voltage – and a variable portion which relate to the output power, so at half capacity the variable losses are halved.

In general, Brush find that in this class of generator (rated from 25 to 150MW capacity), our efficient conversion of the driver horsepower (HP) mechanical energy to electrical KW power output leads many competitors. Brush have modeled and validated numerous design improvements over the product design life, to ensure that the most effective design is provided for the broadest range of operating conditions. Alternate components and material selections are available to provide the customer with the best efficiencies for their many different applications.

Data is provided in the attachment for this BDAX7-290 example. Observe that the efficiency remains above 98% from 30 to 65MW which is a very broad operating range. Even when the driver and electrical load are only used at half capacity the generator losses are only 2%.

In addition to best in class efficiency, Brush generators are renown for their reliability in operations, durability in service and at world competitive first cost.

Derek E. King

General Sales Manager

BRUSH Turbogenerators Inc.
Houston - Texas - USA

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E derek.king@brush.eu
W www.brush.eu

APPENDIX B-8

AQT Watertube Heater Brochure (Inlet Heater)

LE GROUPE GROUP
SIMONEAU INC.

Solution builder
in energy management

Heater

AQT Watertube Heater

Glycol/Water, Thermal Fluid

The Simoneau AQT Watertube Heater is an O-type construction with gas-tight, welded steel intercasing, water cooled rear wall, staggered bent tube convection section, ceramic wool front wall. Simoneau's AQT Watertube Heater applications glycol/water mixture and thermal fluid heating.

Typical industries include manufacturing & processing facilities, pulp & paper, petrochemical, pharmaceuticals, hospitals, universities and many others.

Simoneau's AQT Watertube Heater Design Features:

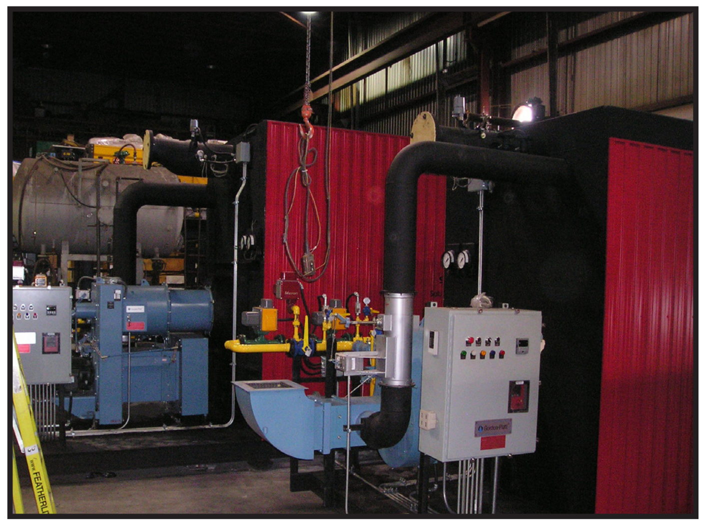
- Capacities: up to 75 MMBTU/HR.
- Design pressures: up to 500 psig.
- Temperature up to 550 °F.
- Two pass flue gas contact with staggered tube arrangement for maximum heat transfer.
- Balanced heat transfer prevents thermal shock.
- Operates with natural gas, #2 oil and alternative gases.
- Meets or exceeds NOx Emission Standards while providing high turndown ratio.

P-AQTH-1_1291110

AQT Watertube Heater | Glycol/Water, Thermal Fluid

Benefits of Simoneau's AQT Watertube Heater Design:

- High efficiency provides significant fuel savings.
- Minimizes installation and maintenance costs.
- Extensive capacity range and excellent long-term reliability to meet commercial, industrial and institutional applications.
- Provides quick load response, low operating and reduced maintenance costs.
- Heater system components (burner, controls and emissions options) designed specifically to provide ease of operation.



Why Simoneau:

As a Solution Builder in Energy Management, Simoneau utilizes its technical expertise (most qualified engineering team in the industry) and quality manufacturing to provide custom solutions for your specific boiler applications. Reliability, efficiency and the safety of its boiler systems are key results of the Simoneau designs. Our integration of technical expertise, quality manufacturing, on-time delivery and field support makes Simoneau your partner of choice.

To learn more about Simoneau and its products, please contact:

LE GROUPE GROUP SIMONEAU INC.

LE GROUPE SIMONEAU INC.
1541 De Coulomb Street
Boucherville (Québec) J4B 8C5
P. 450 641.9140 • 1 800 748.3783 • F. 450 641.9141
info@groupesimoneau.com

Represented by:

P-AQTH-2_291110

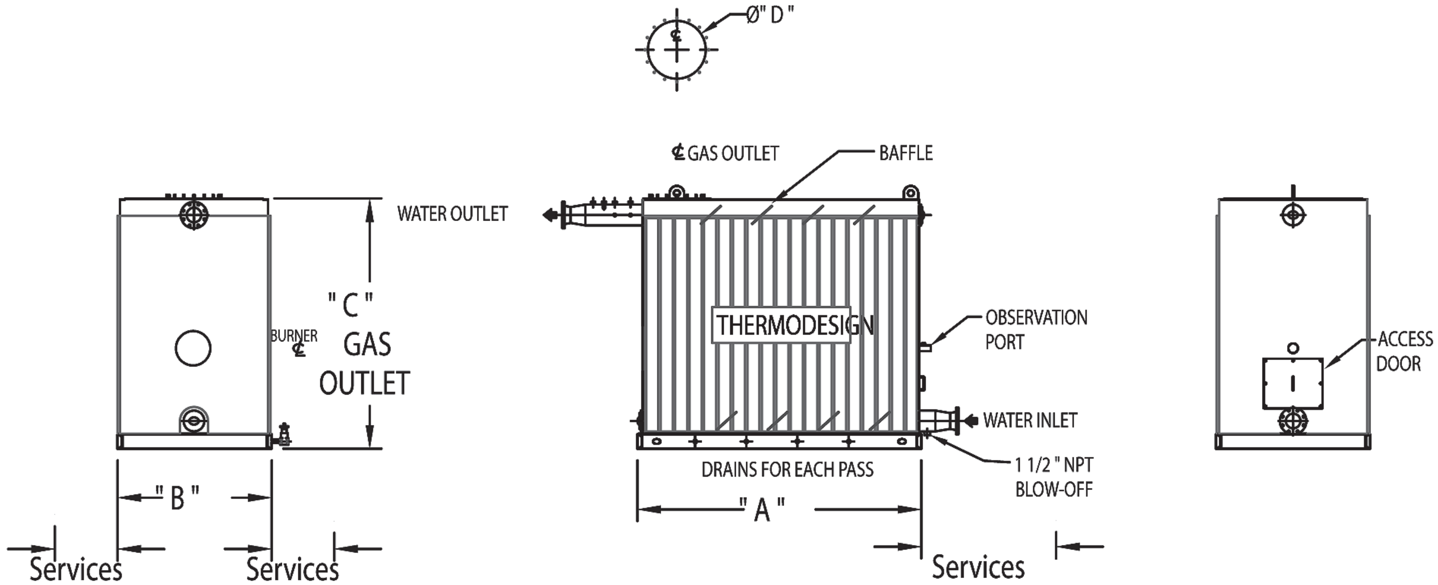
APPENDIX B-9

AQT Watertube Heater Data Sheet (Inlet Heater)

Physical data sheet

AQT Type
Heater Glycol / Thermal Fluid

AQT Heaters are registred under ASME Code Section I.



Boiler Model Number	Capacity MMBTU / hr	A Length	B Width	C Height	D Gas Outlet	WEIGHTS (in Pounds)	
						Dry	Flooded
A1-100	2,678	82 5/8”	54”	97 11/16”	12” dia.	7,200	8,250
A1-125	3,347	88 3/4”	54”	97 11/16”	16” dia.	7,750	9,000
A1-150	4,017	100 7/8”	54	97 11/16”	16” dia.	8,750	10,000
A1-175	4,686	110”	54”	97 11/16”	18” dia.	9,250	10,750
A1-200	5,356	121 1/4”	54”	97 11/16”	18” dia.	10,250	12,000
A1-250	6,695	118”	64”	109 3/16”	20” dia.	12,250	14,500
A1-300	8,034	127 1/4”	64”	109 3/16”	20” dia.	13,250	15,500
A1-350	9,373	139”	64”	109 3/16”	20” dia.	14,250	16,750
A1-400	10,712	171 5/16”	78”	120 15/16”	24” dia.	17,250	20,500
A1-450	12,051	177 3/8”	78”	120 15/16”	24” dia.	18,000	21,250
A1-500	13,390	189 1/2”	78”	120 15/16”	24” dia.	19,250	23,000
A1-600	16,068	196 1/4”	90”	131 3/8”	30” dia.	23,500	28,250
A1-700	18,746	214 1/2”	90”	131 3/8”	32” dia.	25,750	31,250
A1-800	21,424	241 1/2”	90”	131 3/8”	32” dia.	28,040	29,750
A1-900	24,102	253 5/8”	90”	131 3/8”	32” dia.	29,750	36,000
A1-1000	26,780	202 1/2”	108”	144 1/4”	36” dia.	35,000	43,250
A1-1100	29,458	211 1/2”	108”	144 1/4”	36” dia.	36,500	45,000
A1-1200	41,400	220 5/8”	108”	144 1/4”	36” dia.	37,500	46,850

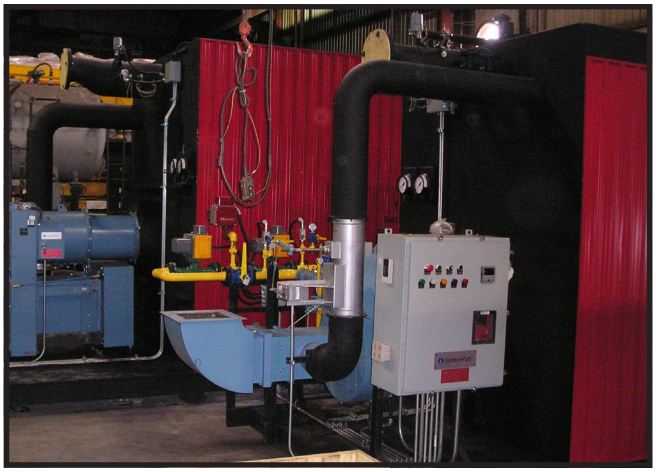
Capacities up to 2000 HP available upon request. All dimensions are imperial.
Sizing and dimension may vary depending on temperature and pressure design and are available upon request.

DS-AQTGH-1_101210

Physical data sheet

AQT Type
Heater Glycol / Thermal Fluid

Typical AQT Heater Glycol / Thermal Fluid



LE GROUPE GROUP SIMONEAU INC.
DESIGNED BY OUR ENGINEERING TEAM:
THERMO DESIGN
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APPENDIX B-10

Fuel Gas Heater Brochure

T.E.R.I.

Total Energy Resources, Inc.

"ENGINEERED SOLUTIONS"

Indirect Fired Water Bath Heaters

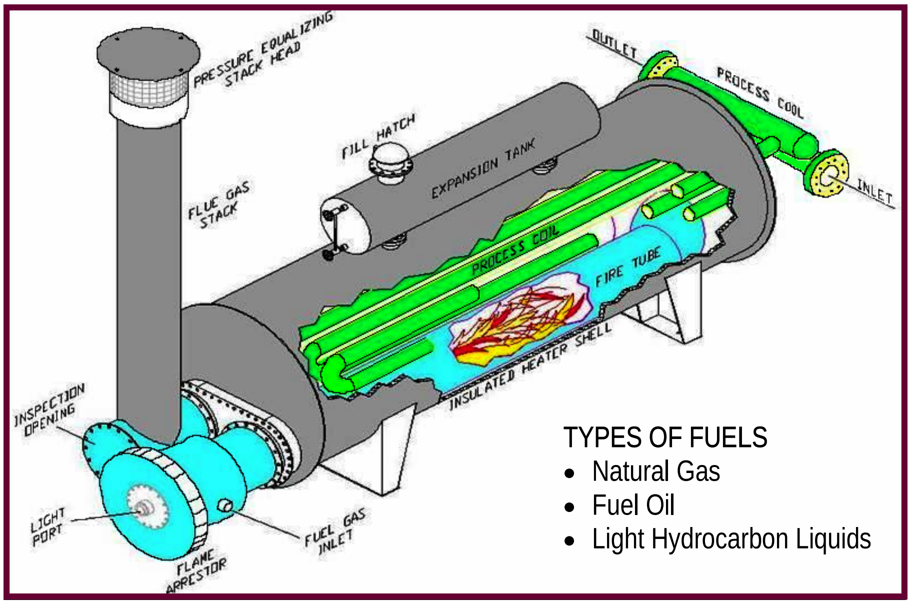
OVERVIEW

Indirect fired water bath heaters are used successfully in hundreds of utility, processing, and upstream oil and gas industry applications.

Water bath heaters are commonly used in applications where process temperatures do not exceed 170°F.

Typical uses include:

- Heating natural gas prior to pressure reduction to eliminate frost formation downstream of expansion valving.
- Preventing hydrate formation in well stream fluids.
- Heating well stream fluids prior to phase separation.
- Heating process streams to maintain fluid viscosity at a minimum to reduce HP pumping requirements.
- Heating critical feed stocks that require tightly controlled film to bulk temperature differentials.
- Heating turbine fuel gases to maintain a given dew point temperature.



TYPES OF FUELS

- Natural Gas
- Fuel Oil
- Light Hydrocarbon Liquids

HEATER OPERATION

The process to be heated flows through a serpentine configured coil that is mounted in the upper reaches of the heater shell. A controlled amount of heat is liberated into the firetube (combustion chamber) which is located in the lower reaches of the heater shell where heat is efficiently transferred form the firetube in the bath media. The heat contained in the bath media is then transferred by natural convection into the process stream which flows through the process coil.

HEATER COMPONENTS

The indirect fired water bath heater consists of the following components each designed to meet specific design criteria:

The heater shell is an atmospheric vessel designed in accordance with API 12 K requirements. The shell contains the process coil, firetube (combustion chamber), and heat media.

The firetube is commonly of the U-tube configuration. The tube is removable & designed to efficiently transfer heat into the surrounding heat media and to minimize flue gas friction losses.

The process coil is a pressure containing part commonly designed in accordance with API—12K or ASME Section VIII Division 1 code requirements.

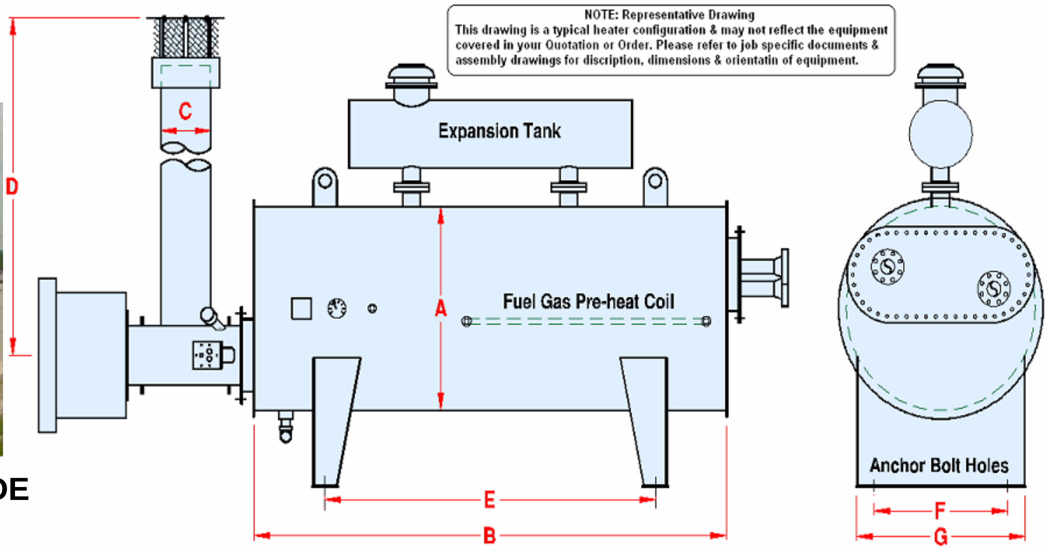
The flue gas stack is designed to provide positive flue gas flow (draft) by overcoming the friction losses in the complete combustion system.

The heat media is commonly a mixture of inhibited ethylene or propylene glycol and water which is blended to a consistency to provide the proper freeze protection for a given application.

The expansion tank is designed to reduce internal corrosion within the heater shell by keeping the heater shell liquid packed & moving the wet dry interface of the expanding bath media from the heater shell into the expansion tank. The expansion tank is designed to contain 100% of the expanded bath media from a temperature of 40° to the maximum operating temperature.

Accessories Items: TERI designs & manufactures heaters with a wide variety of accessories to meet customer specified mechanical & operation requirements. Including simple pneumatic controls to sophisticated remotely controlled & monitored equipment.

"ENGINEERED SOLUTIONS"



STANDARD FEATURES INCLUDE

- Laser cut shop fabricated components
- Individually removable firetubes
- 304 SS Flue gas stack or stacks
- Stack clean out tee
- Flue gas stack anti reverse-draft diverters w/rain cap & bird screens
- "Pilot In A Drawer" assemblies for easy maintenance & inspection
- Basic electric & pneumatic in addition to PLC control systems
- Multi mitered firetube bends (no single miter cut to greater than 22.5°)
- Positive seal flange designs
- Bath media expansion reservoir designed to hold 6% of the total bath media
- Heat media level gauge
- Heat media temperature Indicator
- Shell designed in accordance with API 12K
- Coil designed and stamped in accordance with ASME-8-1
- 100% Radiography on process coil welds
- Process coil, National Board Stamped

Optional Control Enhanced Designs

- Pneumatic controlled equipment operation
- Electrical controlled equipment operation
- Combination pneumatic & electrical controlled equipment operation
- Flame-Safeguard assemblies including, Pneumatic, 120VAC & 12VDC or Solar Power
- Manual OR Automatic pilot ignition designs

Optional Fabricated Enhanced Components

- Cushioned (Electrically Insulated) process coil supports & Tube Sheets
- Shell internally grit or sandblasting w/water soluble rust preventive coating
- Customized heater supports to meet existing pier locations
- Hot dipped galvanized heater skids, ladders & platforms

www.terisales.com
8939 West 21st St., Sand Springs, OK 74063
(918) 447-0844 • Fax (918) 447-0877

MM Btu/Hr	A	B	C	D	E	F	G
0.10	20"	6'	6.63"	10'0"	5'8"	1'2"	1'7"
0.25	24"	7'5"	8.63"	10'0"	7'2"	1'2"	1'7"
0.50	30"	10'0"	10.75"	12'0"	7'0"	1'8"	2'3"
0.75	36"	12'0"	10.75"	12'0"	9'0"	2'0"	2'8"
1.00	42"	15'0"	12.75"	14'0"	10'0"	2'2"	3'1"
1.25	42"	15'0"	12.75"	14'0"	10'0"	2'2"	3'1"
1.50	48"	17'5"	14"	15'0"	12'6"	2'10"	3'7"
1.75	48"	20'0"	16"	15'0"	16'0"	2'10"	3'7"
2.00	54"	20'0"	18"	15'0"	15'0"	3'0"	3'11"
2.50	54"	22'5"	18"	16'0"	17'6"	3'0"	3'11"
3.00	60"	22'5"	20"	16'0"	18'6"	3'0"	4'4"
3.50	72"	27'7"	22"	17'5"	22'6"	4'0"	5'3"
4.00	72"	30'0"	24"	17'5"	25'0"	4'0"	5'3"
4.50	84"	32'0"	24"	17'5"	27'0"	4'6"	6'2"
5.00	84"	32'0"	26"	17'5"	27'0"	4'6"	6'2"
6.00	84"	32'0"	28"	17'5"	27'0"	4'6"	6'2"
7.00	96"	30'0"	2@22"	17'5"	25'0"	5'6"	6'11"
8.00	96"	32'0"	2@22"	17'5"	27'0"	5'6"	6'11"
10.00	102"	32'0"	2@26"	20'0"	27'0"	6'0"	7'6"

(OTHER SIZES ARE AVAILABLE . . . "ENGINEERED SOLUTIONS")

	Units	Ethylene	Propylene
Freezing Point	**Temp (°F)**	**-32**	**-24**
Boiling Point (1 Atm)	**Temp (°F)**	**225**	**222**
Specific Gravity	**60 / 60**	**1.064**	**1.043**
Viscosity @ 200°F	**Centipoises**	**0.75**	**0.75**
Specific Heat @ 200°F	**Btu / Lb / °F**	**0.83**	**0.91**
Thermal Conductivity	**Btu / Hr, Sq Ft, °F / Ft**	**0.28**	**0.022**

*Properties are representative of 50% Glycol / 50% Water

Heater Type	Process Temp (F)
Water/Glycol	160°
LP Steam (<15 Psig)	220°
Heat Transfer Oil	400°
Eutectic Salt	600°
Flue Gas Recirculation	625°

APPENDIX B-11

Fuel Gas Heater Data Sheet

T.E.R.I.
Total Energy Resources, Inc.

INDIRECT FIRED HEATER SPECIFICATION SHEET

Customer	CH2M Hill	Date:	22-Aug-11
Address	9189 South Jamaica Street	Customer Reference	
City/State/Zip	Englewood, CO 80112	Customer Project No	
Location	TBD	Quotation Item Number:	Q00322 BE
Station	TBD	Operating Data	Data: 800Psig/27°F To 795Psig/77°F
Engineer:	David Chamberlain		
Purchasing Agent	David Chamberlain		

BASIC HEATER DATA				REMARKS
Outside Diameter (Inches)	48.00	Bath Media Volume (Gal)	1,114	50/50 Ethylene Glycol
Length (Ft)	18.00	Heater Weight (Dry Lbs)	8,400	
Nominal Rating (MM Btu/Hr)	1.600	Heater Weight (Wet Lbs)	17,680	

PROCESS CONDITIONS		INLET	OUTLET	REMARKS	
Type of Fluid		Natural Gas	Natural Gas		
Total fluid Entering	SCFH	1,000,000	---------		
Vapor	lb/hr	45,692	45,692		
Liquid	lb/hr				
Steam	lb/hr				
Non-condensable	lb/hr				
Fluid Vaporized or Cond	lb/hr				
Liquid Density (In/Out)	lb/ft3	N.A.	N.A.		
Liquid Viscosity	Cp	N.A.	N.A.		
Liquid Specific Heat	Btu/lb-F	N.A.	N.A.		
Liquid Thermal Cond	Btu/hr-ft-F	N.A.	N.A.		
Vapor Molecular Wt	lbs/lbs Mol	17.340		Fluid Specific Gravity	0.600
Vapor Density	lbs/ft3	3.175	2.715		
Vapor Viscosity	Cp	0.011	0.012		
Vapor Specific Heat	Btu/lb-F	0.683	0.642		
Vapor Thermal Cond.	Btu/hr-ft-F	0.020	0.022		
Temperature (In/Out)	**F**	**27**	**77.00**	**After Regulation:**	**77**
Operating Pressure	**Psig**	**800**	**789**	**After Regulation:**	**795**
Velocity	ft/sec	------	52.88		
Pressure Drop (Allow/Calc)	**Psid**	**------**	**11.13**		
Fouling Resistance	hr-ft2-F/Btu		------		

THERMAL DATA			REMARKS	
Heat Transferred	**Btu/hr**	**1,521,417**	**Operating Bath Temperature**	**171 F**
Transfer Rate (Fouled/Clean)	Btu/hr-ft2-F	79.29		
Temperature Diff (LMTD)		116.88		

PROCESS COIL DATA					
Design Pressure	Psig	900	Fabrication Code		ASME Sec 8 Div 1
Test Pressure	Psig	1350	Radiography (Percent)	100	
Design Temperature	F	-20 to 250°F	National Board Stamped	Yes	
Number of Pass/Path	Units	8			
Number of Paths	Units	1	Connections (Size/Rating)		Nominal
Total Number of Tubes	Units	8	Inlet		4in ANSI 600# RFWN
Straight Tube Length	Ft	16.5	Outlet		4in ANSI 600# RFWN
Heat Flux	Btu/hr-ft2	9,269	Inlet and Outlet header Thk		0.237 In
Tube Size	Inches **OD**	4.500	Header Velocity		52.88 ft/sec
Tube Wall Thickness	Inches	0.237	Surface Area Actual		164 Ft2
Corrosion Allowance	Inches	None	Return Bend Type		SR

HEATER DATA			Remarks and/or Other Data	
Design Code		API 12K		
Shell Diameter	Inches	48	Treq per 49 CFR, Part 192	0.145
Shell Length	ft	18	Treq per ASME	0.111 in
Shell (Thk)	Inches	1/4		
Firetube Diameter	Inches **OD**	18		
Number of Firetubes		1	Tube Wall Thickness	0.237 in
Firetube Length	ft	17.75	Selected Pipe Tmin (12.5% mill Tol)	0.207 in
Firetube (Material/Thk)	Inches	1/4" - SA53-B		
Firetube Heat Density	Btu/hr-in2	9,302		
Firetube Flux Rate	Btu/hr-ft2	9,440		
Stack Diameter	In	18		
Stack Height	Ft	16		
Expansion Tank Diameter	in	18.00		
Expansion Tank Length	ft	6.5		
Percent of Net Shell Vol.	%	7.3%		

APPENDIX B-12

Diesel Emergency Generator Data Sheet

DIESEL GENERATOR SET


Image shown may not reflect actual package.

STANDBY

600 ekW 750 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

FUEL/EMISSIONS STRATEGY
- EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 listed packages available. Certain restrictions may apply. Consult with your Cat® Dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Cat dealers provide extensive post sale support including maintenance and repair agreements
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT ® C18 ATAAC DIESEL ENGINE
- Utilizes ACERT™ Technology
- Reliable, rugged, durable design
- Field-proven in thousands of applications worldwide
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight
- Electronic controlled governor

CAT GENERATOR
- Matched to the performance and output characteristics of Cat engines
- Load adjustment module provides engine relief upon load impact and improves load acceptance and recovery time
- UL 1446 Recognized Class H insulation

CAT EMCP 4 CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Light Duty Air Filter • Service indicator	[ ] Single element air filter [ ] Dual element air filter [ ] Heavy-duty dual element air filter with precleaner [ ] Air inlet shut-off
Cooling	• Radiator package mounted • Coolant level sight gauge • Coolant drain line with valve • Fan and belt guards • Cat® Extended Life Coolant*	[ ] Radiator duct flange [ ] Low coolant level sensor
Exhaust	• Dry exhaust manifold • Stainless steel exhaust flex fittings with split-cuff • Exhaust flange outlets	[ ] Industrial [ ] Residential [ ] Critical Mufflers [ ] Manifold and turbocharger guards [ ] Elbows and through-wall kits
Fuel	• Primary fuel filter with integral water separator • Secondary fuel filters • Fuel priming pump • Flexible fuel lines • Fuel cooler* *Not inlcuded with packages without radiators	[ ] Integral single wall fuel tank base [ ] Integral dual wall UL fuel tankbase [ ] Sub-base dual wall UL listed fuel tank base [ ] Manual transfer pump [ ] Fuel level switch
Generator	• Class H insulation • Class H temperature rise • VR6 voltage regulator with 3-phase sensing with load adjustment • IP23 Protection	[ ] Oversize generators [ ] Internal excited (IE) [ ] Permanent magnet excitation(PMG) [ ] Cat digital voltage regulator (CDVR) with kVAR/PF control [ ] Anti-condensation space heaters [ ] Coastal Insulation Protection (CIP) [ ] Reactive droop
Power Termination	• Power Center houses EMCP controller and power/control terminations (rear mounted) • Power terminal strips (NEMA or IEC mechanical lug holes) • Segregated low voltage wiring termination panel • IP22 protection • Bottom cable entry	[ ] Power Center mounting option (right side) [ ] Circuit breakers, UL listed, 3 pole (80% & 100% Rated) [ ] Circuit breakers, IEC compliant, 3-4 pole(100% Rated) [ ] Multiple circuit breaker options [ ] C.B. Shunt trips [ ] C.B. Auxiliary contacts
Governor	• ADEM™ A4	[ ] Load Share Module
Control Panels	• EMCP 4.1 (mounted in Power Center) • Speed adjustment • Voltage adjustment • Emergency stop pushbutton	[ ] EMCP 4.2 [ ] Local annunciator module (NFPA 99/110) [ ] Remote annunciator module (NFPA 99/110) [ ] Digital I/O module
Lube	• Lubricating oil • Oil drain line with valves • Oil filter and dipstick • Fumes disposal • Lube oil level indicator • Oil cooler	[ ] Oil temperature sensor [ ] Manual sump pump
Mounting	• Formed steel narrow base frame • Linear vibration isolation-seismic zone 4	[ ] Oil skid base [ ] Formed steel wide base frame
Starting/Charging	• 24 volt starting motor • 24 volt, 45 amp charging alternator	[ ] Jacket water heater with shut-off valves [ ] Engine block heater [ ] Ether starting aid [ ] Battery disconnect switch [ ] Battery chargers (5 or 10 amp) [ ] Oversize batteries [ ] Batteries with rack and cables
General	• Paint - Caterpillar Yellow except rails and radiators gloss black • Flywheel housing - SAE No. 0	[ ] UL 2200 package [ ] CSA Certification [ ] EU or CE Certificate of Conformance [ ] Weather protective enclosure [ ] Sound attenuated protective enclosure

SPECIFICATIONS

CAT GENERATOR

Frame size...LC7024F
Excitation...Internal Excitation
Pitch...0.6667
Number of poles...4
Number of bearings..................................... Single bearing
Number of Leads...012
Insulation....................... UL 1446 Recognized Class H with tropicalization and antiabrasion
- Consult your Caterpillar dealer for available voltages
IP Rating..Drip Proof IP23
Alignment...Pilot Shaft
Overspeed capability..125
Wave form Deviation (Line to Line)...............................2%
Voltage regulator...............................Three phase sensing
Voltage regulation............Less than +/- 1/2% (steady state)
Less than +/- ½% (w/ 3% speed change)
Telephone influence factor..............................Less than 50
Harmonic Distortion..Less than 5%

CAT DIESEL ENGINE

C18 ATAAC, I-6, 4-Stroke Water-cooled Diesel
Bore.. 145.00 mm (5.71 in)
Stroke... 183.00 mm (7.2 in)
Displacement..18.13 L (1106.36 in^3)
Compression Ratio... 14.5:1
Aspiration.. Air-to-Air Aftercooled
Fuel System...MEUI
Governor Type................ Caterpillar ADEM control system

CAT EMCP 4 SERIES CONTROLS

EMCP 4 controls including:
- Run / Auto / Stop Control
- Speed and Voltage Adjust
- Engine Cycle Crank
- 24-volt DC operation
- Environmental sealed front face
- Text alarm/event descriptions

Digital indication for:
- RPM
- DC volts
- Operating hours
- Oil pressure (psi, kPa or bar)
- Coolant temperature
- Volts (L-L & L-N), frequency (Hz)
- Amps (per phase & average)
- ekW, kVA, kVAR, kW-hr, %kW, PF (4.2 only)

Warning/shutdown with common LED indication of:
- Low oil pressure
- High coolant temperature
- Overspeed
- Emergency stop
- Failure to start (overcrank)
- Low coolant temperature
- Low coolant level

Programmable protective relaying functions:
- Generator phase sequence
- Over/Under voltage (27/59)
- Over/Under Frequency (81 o/u)
- Reverse Power (kW) (32) (4.2 only)
- Reverse reactive power (kVAr) (32RV)
- Overcurrent (50/51)

Communications:
- Four digital inputs (4.1)
- Six digital inputs (4.2 only)
- Four relay outputs (Form A)
- Two relay outputs (Form C)
- Two digital outputs
- Customer data link (Modbus RTU) (4.2 only)
- Accessory module data link (4.2 only)
- Serial annunciator module data link (4.2 only)
- Emergency stop pushbutton

Compatible with the following:
- Digital I/O module
- Local Annunciator
- Remote CAN annunciator
- Remote serial annunciator

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8518	
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	750 kVA	
Genset Power rating with fan	600 ekW	
Coolant to aftercooler		
Coolant to aftercooler temp max	49 ° C	120 ° F
Fuel Consumption		
100% load with fan	161.6 L/hr	42.7 Gal/hr
75% load with fan	129.8 L/hr	34.3 Gal/hr
50% load with fan	91.7 L/hr	24.2 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	804 m^3/min	28393 cfm
Engine Coolant capacity with radiator/exp. tank	81.8 L	21.6 gal
Engine coolant capacity	20.8 L	5.5 gal
Radiator coolant capacity	61.0 L	16.1 gal
Inlet Air		
Combustion air inlet flow rate	47.8 m^3/min	1688.0 cfm
Exhaust System		
Exhaust stack gas temperature	534.6 ° C	994.3 ° F
Exhaust gas flow rate	135.5 m^3/min	4785.1 cfm
Exhaust flange size (internal diameter)	203 mm	8 in
Exhaust system backpressure (maximum allowable)	10.0 kPa	40.2 in. water
Heat Rejection		
Heat rejection to coolant (total)	189 kW	10748 Btu/min
Heat rejection to exhaust (total)	634 kW	36056 Btu/min
Heat rejection to aftercooler	153 kW	8701 Btu/min
Heat rejection to atmosphere from engine	86 kW	4891 Btu/min
Heat rejection to atmosphere from generator	41.0 kW	2331.7 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	1633 skVA	
Frame	LC7024F	
Temperature Rise	150 ° C	270 ° F
Lube System		
Sump refill with filter	64.0 L	16.9 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.84 g/hp-hr	
CO g/hp-hr	.48 g/hp-hr	
HC g/hp-hr	.01 g/hp-hr	
PM g/hp-hr	.035 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] Generator temperature rise is based on a 40° C (104° F) ambient per NEMA MG1-32. Some packages may have oversized generators with a different temperature rise and motor starting characteristics.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, CSA, IEC60034-1, ISO3046, ISO8528, NEMA MG 1-22, NEMA MG 1-33, UL508A, 72/23/EEC, 98/37/EC, 2004/108/EC

Standby - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

Ratings are based on SAE J1349 standard conditions. These ratings also apply at ISO3046 standard conditions.

Fuel rates are based on fuel oil of 35º API [16º C (60º F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29º C (85º F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Cat representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Cat dealer.

DIMENSIONS

Package Dimensions		
Length	3933.4 mm	154.86 in
Width	1536.0 mm	60.47 in
Height	2165.8 mm	85.27 in
Weight	4306 kg	9,493 lb

NOTE: For reference only - do not use for installation design. Please contact your local dealer for exact weight and dimensions. (General Dimension Drawing #2859356).

APPENDIX B-13

Diesel Fire Pump Data Sheet

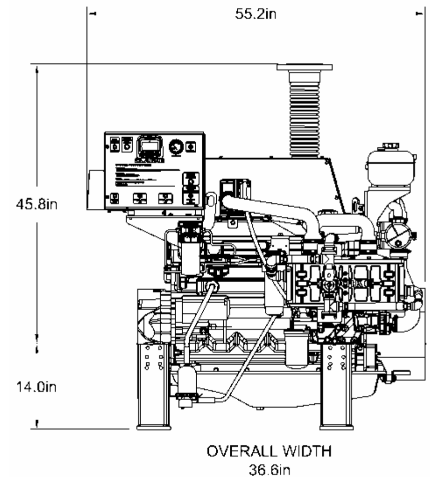
MODELS

JU6H-UFAD58 JU6H-UFADP0 JU6H-UFAD88 JU6H-UFADS8 JU6H-UFADW8
JU6H-UFADM8 JU6H-UFADNG JU6H-UFADP8 JU6H-UFADR0 JU6H-UFADS0 JU6H-UFADX8
JU6H-UFADMG JU6H-UFADN0 JU6H-UFADQ0 JU6H-UFADR8 JU6H-UFADT0 JU6H-UFAD98

USA Purchased - EPA Tier 3 Emissions Certified[1]

FM-UL-cUL APPROVED RATINGS BHP/*KW*

JU6H MODEL	RATED SPEED 1760		2100		2350		2400	
UFADM8	175	*131*						
UFADMG			175	*131*	175	*131*		
UFAD58	183	*137*						
UFADNG	190	*142*	181	*135*	183	*137*	183	*137*
UFADN0	197	*147*	197	*147*	200	*149*	200	*149*
UFADP0	220	*164*	209	*156*	211	*157*	211	*157*
UFADP8	220	*164*						
UFADQ0			224	*167*	226	*169*	226	*169*
UFAD88	237	*177*						
UFADR0			238	*177.5*	240	*179*	240	*179*
UFADR8	250	*187*						
UFADS8	260	*194*						
UFADS0			260	*194*	268	*200*	268	*200*
UFADT0	229	*171*	274	*204*	275	*205*	275	*205*
UFADW8	282	*211*						
UFADX8	305	*227.5*						
UFAD98	315	*235*						



Engines are:
EPA Tier 3 Emissions Certified Off-Road (40 CFR Part 89) and NSPS Stationary (40 CFR Part 60 Sub Part IIII);
CARB Approved Off-Road (Title 13 CCR Section 2423) and ATCM Stationary (Title 17 CCR Section 93115.6 (a) (4)) for 2010 engines manufactured by John Deere Power Systems.

SPECIFICATIONS

<table>
<tr><th rowspan="2">ITEM</th><th colspan="17">JU6H-UFAD MODELS</th></tr>
<tr><th>M8</th><th>MG</th><th>58</th><th>NG</th><th>N0</th><th>P8</th><th>88</th><th>P0</th><th>Q0</th><th>R0</th><th>R8</th><th>S8</th><th>S0</th><th>T0</th><th>W8</th><th>X8</th><th>98</th></tr>
<tr><td>Number of Cylinders</td><td colspan="17">6</td></tr>
<tr><td>Aspiration</td><td colspan="17">TRWA</td></tr>
<tr><td>Rotation*</td><td colspan="17">Clockwise (CW)</td></tr>
<tr><td>Weight – lb (kg)</td><td colspan="17">1747 (791)</td></tr>
<tr><td>Compression Ratio</td><td colspan="7">19.0:1</td><td colspan="10">17.0:1</td></tr>
<tr><td>Displacement – cu. in. (l)</td><td colspan="17">415 (6.8)</td></tr>
<tr><td>Engine Type</td><td colspan="17">4 Stroke Cycle – Inline Construction</td></tr>
<tr><td>Bore & Stroke – in. (mm)</td><td colspan="17">4.19 x 5.00 (106 x 127)</td></tr>
<tr><td>Installation Drawing</td><td colspan="17">D628</td></tr>
<tr><td>Wiring Diagram AC</td><td colspan="17">C07591</td></tr>
<tr><td>Wiring Diagram DC</td><td colspan="7">C071367, C071360, C071361</td><td colspan="10">C071368, C071360, C071761</td></tr>
<tr><td>Engine Series</td><td colspan="7">John Deere 6068 Series Power Tech E</td><td colspan="10">John Deere 6068 Series Power Tech Plus</td></tr>
<tr><td>Speed Interpolation</td><td colspan="7">N/A</td><td colspan="4">Opt.</td><td colspan="2">N/A</td><td>Opt.</td><td colspan="3">N/A</td></tr>
</table>

Abbreviations: CW – Clockwise TRWA – Turbocharged with Raw Water Aftercooling N/A – Not Available

*Rotation viewed from Heat Exchanger / Front of engine

CERTIFIED POWER RATING

- Each engine is factory tested to verify power and performance.
- FM-UL power ratings are shown at specific speeds, Clarke engines can be applied at a single rated RPM setting ± 50 RPM.

ENGINE RATINGS BASELINES

- Engines are to be used for stationary emergency standby fire pump service only. Engines are to be tested in accordance with NFPA 25.
- Engines are rated at standard SAE conditions of 29.61 in. (752.1 mm) Hg barometer and 77°F (25°C) inlet air temperature [approximates 300 ft. (91.4 m) above sea level] by the testing laboratory (see SAE Standard J 1349).
- A deduction of 3 percent from engine horsepower rating at standard SAE conditions shall be made for diesel engines for each 1000 ft. (305 m) altitude above 300 ft. (91.4 m)
- A deduction of 1 percent from engine horsepower rating as corrected to standard SAE conditions shall be made for diesel engines for every 10°F (5.6°C) above 77°F (25°C) ambient temperature.

c UL us   Meets NFPA 20 Requirements   FM c us APPROVED

ENGINE EQUIPMENT

EQUIPMENT	STANDARD	OPTIONAL
Air Cleaner	Direct Mounted, Washable, Indoor Service with Drip Shield	Disposable, Drip Proof, Indoor Service Outdoor Type
Alternator	12V-DC, 42 Amps with Poly-Vee Belt and Guard	24V-DC, 40 Amps with Poly-Vee Belt and Guard
Exhaust Protection	Metal Guards on Manifolds and Turbocharger	
Coupling	Bare Flywheel	UL Listed Driveshaft and Guard, JU6H-UFADMG/58/NG/N0/Q0/R0-CDS30-S1; JU6H-UFADM8/P8/P0/T0/88/R8/S8/S0/W8/X8/98-CDS50-SC at 1760/2100 RPM only
Electronic Control Module	12V-DC, Energized to Stop, Primary ECM always Powered on	24V-DC, Energized to Stop, Primary ECM always Powered on
Exhaust Flex Connection*	Stainless Steel Flex, 150# ANSI Flanged Connection, 5" for JU6H-UFADM8/MG/58/NG/N0/P8/88; Stainless Steel Flex, 150# ANSI Flanged Connection, 6" for JU6H-UFADP0/Q0/R0/R8/S8/S0/T0/W8/X8/98	Stainless Steel Flex, 150# ANSI Flanged Connection, 6" for JU6H-UFADM8/MG/58/NG/N0/P8/88; Stainless Steel Flex, 150# ANSI Flanged Connection, 8" for JU6H-UFADP0/Q0/R0/R8/S8/S0/T0/W8/X8/98
Flywheel Housing	SAE #3	
Flywheel Power Take Off	11.5" SAE Industrial Flywheel Connection	
Fuel Connections	Fire Resistant, Flexible, USA Coast Guard Approved, Supply and Return Lines	Stainless Steel, Braided, cUL Listed, Supply and Return Lines
Fuel Filter	Primary Filter with Priming Pump	
Fuel Injection System	High Pressure Common Rail	
Engine Heater	120V-AC, 1500 Watt	240V-AC, 1500 Watt
Governor, Speed	Dual Electronic Control Modules	
Heat Exchanger	Tube and Shell Type, 60 PSI (4 BAR), NPT(F) Connections	
Instrument Panel	Multimeter to Display English and Metric, Tachometer, Hourmeter, Water Temperature, Oil Pressure and One (1) Voltmeter with Toggle Switch, Front Opening	
Junction Box	Integral with Instrument Panel; For DC Wiring Interconnection to Engine Controller	
Lube Oil Cooler	Engine Water Cooled, Plate Type	
Lube Oil Filter	Full Flow with By-Pass Valve	
Lube Oil Pump	Gear Driven, Gear Type	
Manual Start Control	On Instrument Panel with Control Position Warning Light	
Overspeed Control	Electronic, Factory Set, Not Field Adjustable	
Raw Water Solenoid Operation	Automatic from Fire Pump Controller and from Engine Instrument Panel	
Run – Stop Control	On Instrument Panel with Control Position Warning Light	
Starters	Two (2) 12V-DC	Two (2) 24V-DC
Throttle Control	Adjustable Speed Control by Increase/Decrease Button, Tamper Proof in Instrument Panel	
Water Pump	Centrifugal Type, Poly-Vee Belt Drive with Guard	

Abbreviations : DC – Direct Current, AC – Alternating Current, SAE – Society of Automotive Engineers, NPT(F) – National Pipe Tapered Thread (Female), NPT(M) – National Pipe Tapered Thread (Male), ANSI – American National Standards Institute

*JU6H-UFADP8/R8/S8/W8/X8/98 – All provided with orifice plate mounted in flex exhaust.

Note: Engine Controller needs 2 additional signals: Injector Failure, Alternate ECM Selected

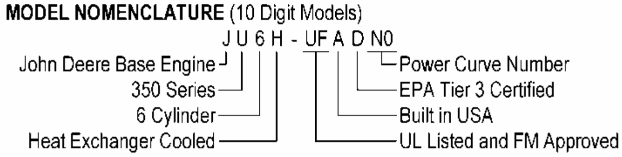
CLARKE

Project and Contract Identification
Project Name: Mariposa Energy Project
PO Number: 415059-2200-011
Client: Diamond Generating Corp.
Location: Mariposa, CA
Equip. Desc.: Firewater Pump House
Contractor: Patterson Pumps
Tag Number: EN-FP-0-01
Tag Number: Diesel Pump - P-FP-0-01

Date Engineer Received

Engineer's Action
(See Contract Documents)
Initials & Date
CODE 1
CODE 2
CODE 3
CODE 4

MODEL NOMENCLATURE (10 Digit Models)



CLARKE Fire Protection Products, Inc.
3133 E. Kemper Rd., Cincinnati, Ohio 45241
United States of America
Tel +1-513-475-FIRE(3473) Fax +1-513-771-0726
www.clarkefire.com

CLARKE UK, Ltd.
Grange Works, Lomond Rd., Coatbridge, ML5-2NN
United Kingdom
Tel +44-1236-429946 Fax +44-1236-427274
www.clarkefire.com

CLARKE
Fire Protection Products, Inc.

JU6H-UFADM8
INSTALLATION & OPERATION DATA (I&O Data)
USA Produced

Basic Engine Description

Engine Manufacturer	John Deere Co.
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in (mm)	4.19 (106) X 5 (127)
Displacement - in³ (L)	415 (6.8)
Compression Ratio	19.0:1
Valves per cylinder	
Intake	1
Exhaust	1
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Fuel Management Control	Electronic, High Pressure Common Rail
Firing Order (CW Rotation)	1-5-3-6-2-4
Aspiration	Turbocharged
Charge Air Cooling Type	Raw Water
Rotation, viewed from front of engine, Clockwise (CW)	Standard
Engine Crankcase Vent System	Open
Installation Drawing	D628
Weight - lb (kg)	1747 (792)

Power Rating	**1760**
Nameplate Power - HP (kW)	175 (131)

Cooling System - [C051386]	**1760**
Engine Coolant Heat - Btu/sec (kW)	90 (95)
Engine Radiated Heat - Btu/sec (kW)	40 (42.2)
Heat Exchanger Minimum Flow	
60°F (15°C) Raw H_20 - gal/min (L/min)	13 (49.2)
95°F (35°C) Raw H_20 - gal/min (L/min)	20 (75.7)
Heat Exchanger Maximum Cooling Raw Water	
Inlet Pressure - psi (bar)	60 (4.1)
Flow - gal/min (L/min)	40 (151)
Typical Engine H_20 Operating Temp - °F (°C)[1]	180 (82.2) - 195 (90.6)
Thermostat	
Start to Open - °F (°C)	180 (82.2)
Fully Opened - °F (°C)	203 (95)
Engine Coolant Capacity - qt (L)	20.5 (19.4)
Coolant Pressure Cap - lb/in² (kPa)	15 (103)
Maximum Engine Coolant Temperature - °F (°C)	230 (110)
Minimum Engine Coolant Temperature - °F (°C)	160 (71.1)
High Coolant Temp Alarm Switch - °F (°C)	235 (113)

Electric System - DC	**Standard**		**Optional**	
System Voltage (Nominal)	12		24	
Battery Capacity for Ambients Above 32°F (0°C)				
Voltage (Nominal)	12	[C07633]	24	[C07634]
Qty. Per Battery Bank	1		2	
SAE size per J537	8D		4D	
CCA @ 0°F (-18°C)	1400		1050	
Reserve Capacity - Minutes	430		290	
Battery Cable Circuit, Max Resistance - ohm	0.0012		0.0012	
Battery Cable Minimum Size				
0-120 in. Circuit Length[2]	00		00	
121-160 in. Circuit Length[2]	000		000	
161-200 in. Circuit Length[2]	0000		0000	
Charging Alternator Maximum Output - Amp,	40	[C071363]	55	[C071365]
Starter Cranking Amps, Rolling - @60°F (15°C)	440	[RE69704/RE70404]	250	[C07819/C07820]

NOTE: This engine is intended for indoor installation or in a weatherproof enclosure. [1]Engine H_2O temperature is dependent on raw water temperature and flow. [2]Positive and Negative Cables Combined Length.

JU6H-UFADM8
INSTALLATION & OPERATION DATA (I&O Data)
USA Produced

Exhaust System	**1760**
Exhaust Flow - ft.³/min (m³/min)	1100 (31.1)
Exhaust Temperature - °F (°C)	1000 (538)
Maximum Allowable Back Pressure - in H_20 (kPa)	30 (7.5)
Minimum Exhaust Pipe Dia. - in (mm) [3]	5 (127)

Fuel System	**1760**
Fuel Consumption - gal/hr (L/hr)	10.4 (39.4)
Fuel Return - gal/hr (L/hr)	15.4 (58.3)
Fuel Supply - gal/hr (L/hr)	25.8 (97.7)
Fuel Pressure - lb/in² (kPa)	3 (20.7) - 6 (41.4)
Minimum Line Size - Supply - in.	.50 Schedule 40 Steel Pipe
Pipe Outer Diameter - in (mm)	0.848 (21.5)
Minimum Line Size - Return - in.	.375 Schedule 40 Steel Pipe
Pipe Outer Diameter - in (mm)	0.675 (17.1)
Maximum Allowable Fuel Pump Suction Lift with clean Filter - in H_20 (mH_20)	80 (2)
Maximum Allowable Fuel Head above Fuel pump, Supply or Return - ft (m)	6.6 (2)
Fuel Filter Micron Size	2

Heater System	**Standard**	**Optional**
Engine Coolant Heater		
Wattage (Nominal)	1500	1500
Voltage - AC, 1 Phase	120 (+5%, -10%)	240 (+5%, -10%)
Part Number	[C124948]	[C124949]

Air System	**1760**	
Combustion Air Flow - ft.³/min (m³/min)	360 (10.2)	
Air Cleaner	**Standard**	**Optional**
Part Number	[C03396]	[C03327]
Type	Indoor Service Only, with Shield	Canister, Single-Stage
Cleaning method	Washable	Disposable
Air Intake Restriction Maximum Limit		
Dirty Air Cleaner - in H_20 (kPa)	12 (3)	10 (2.5)
Clean Air Cleaner - in H_20 (kPa)	6 (1.5)	5 (1.2)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)[4]	130 (54.4)	

Lubrication System	
Oil Pressure - normal - lb/in² (kPa)	40 (276) - 60 (414)
Low Oil Pressure Alarm Switch - lb/in² (kPa)	30 (207)
In Pan Oil Temperature - °F (°C)	220 (104) - 245 (118)
Total Oil Capacity with Filter - qt (L)	21.1 (20)

Lube Oil Heater	**Optional**	**Optional**
Wattage (Nominal)	150	150
Voltage	120V (+5%, -10%)	240V (+5%, -10%)
Part Number	C04430	C04431

Performance	**1760**
BMEP - lb/in² (kPa)	190 (1310)
Piston Speed - ft/min (m/min)	1467 (447)
Mechanical Noise - dB(A) @ 1m	C133847
Power Curve	C133746

[3]Based on Nominal System. Back pressure flow analysis must be done to assure maximum allowable back pressure is not exceeded. (Note: minimum exhaust Pipe diameter is based on: 15 feet of pipe, on 90° elbow, and a silencer pressure drop no greater than one half of the maximum allowable back pressure.) [4]Review for horsepower derate if ambient air entering engine exceeds 77°F (25°C). [ ] indicates component reference part number.

JU4H & JU6H ENGINE MODELS
ENGINE MATERIALS AND CONSTRUCTION

Air Cleaner
Type………..………….. ..Indoor Usage Only
Oiled Fabric Pleats
Material……..………….. Surgical Cotton
Aluminum Mesh

Air Cleaner - Optional
Type…………………………Canister
Material…………………….Pleated Paper
Housing…………….…….Enclosed

Camshaft
Material…………………….Cast Iron
Chill Hardened
Location………..………….In Block
Drive………………….……..Gear, Spur
Type of Cam………..…….. Ground

Charge Air Cooler (JU6H-60,62,68,74,84, ADK0, AD58, ADNG, ADN0, ADQ0, ADR0, AAQ8, AARG, ADP8, ADP0, ADT0, AD88, ADR8, AD98, ADS0, ADW8, ADX8, AD98 only)
Type………………….Raw Water Cooled

Materials (in contact with raw water)
Tubes…… ………………… 90/10 CU/NI
Headers ………………… 36500 Muntz
Covers ………………… 83600 Red Brass
Plumbing ………………… 316 Stainless Steel/ Brass
90/10 Silicone

Coolant Pump
Type…………………………Centrifugal
Drive……. ………. ………. Poly Vee Belt

Coolant Thermostat
Type…………………………Non Blocking
Qty……………………………1

Connecting Rod
Type…………………………I-Beam Taper
Material…………………….Forged Steel Alloy

Crank Pin Bearings
Type…………………………Precision Half Shell
Number…………………….1 Pair Per Cylinder
Material…………………….Wear-Guard

Crankshaft
Material…………………….Forged Steel
Type of Balance……………Dynamic

Cylinder Block
Type…………………………One Piece with
Non-Siamese Cylinders
Material…………………….Annealed Gray Iron

Cylinder Head
Type…….. ………………… Slab 2 Valve
Material……………………. Annealed Gray Iron

Cylinder Liners
Type…….. ………………… Centrifugal Cast, Wet Liner
Material……………….…… Alloy Iron Plateau, Honed

Valves
Type……. ………………Poppet
Arrangement………… …..Overhead Valve
Number/Cylinder…………1 intake
1 exhaust
Operating Mechanism….. Mechanical Rocker Arm
Type of Lifter…………….. Large Head
Valve Seat Insert…………Replaceable

Fuel Pump
Type……… ………………Diaphragm
Drive……………………… Cam Lobe

Heat Exchanger (USA)
Type………………………Tube & Shell
Materials
Tube& Headers………… Copper
Shell……… ………………Copper
Electrode…………………Zinc

Heat Exchanger (UK)
Type………………………Tube & Bundle
Materials
Tube& Headers………… Copper
Shell……………… Aluminum

Injection Pump
Type………………………Rotary
Drive……………………… Gear

Lubrication Cooler
Type………………………Plate

Lubrication Pump
Type………………………Gear
Drive……………………… Gear

Main Bearings
Type………………………Precision Half Shells
Material……………………Steel Backed-Aluminum Lined

Piston
Type and Material……… Aluminum Alloy with Reinforced
Top Ring Groove
Cooling…………………… Oil Jet Spray

Piston Pin
Type………………………Full Floating - Offset

Piston Rings
Number/Piston……………3
Top………………………… Keystone Barrel Faced -
Plasma Coated
Second…………………… Tapered Cast Iron
Third………………………Double Rail Type
w/Expander Spring

APPENDIX B-14

Wet Cooling Tower Data Sheet

SPX

COOLING TECHNOLOGIES

JL Hermon & Associates, Inc.
7342 South Alton Way, Ste. H, Centennial CO 80112
P: 303-771-4045 F: 303-771-6657 E: jmick@jlhermon.com

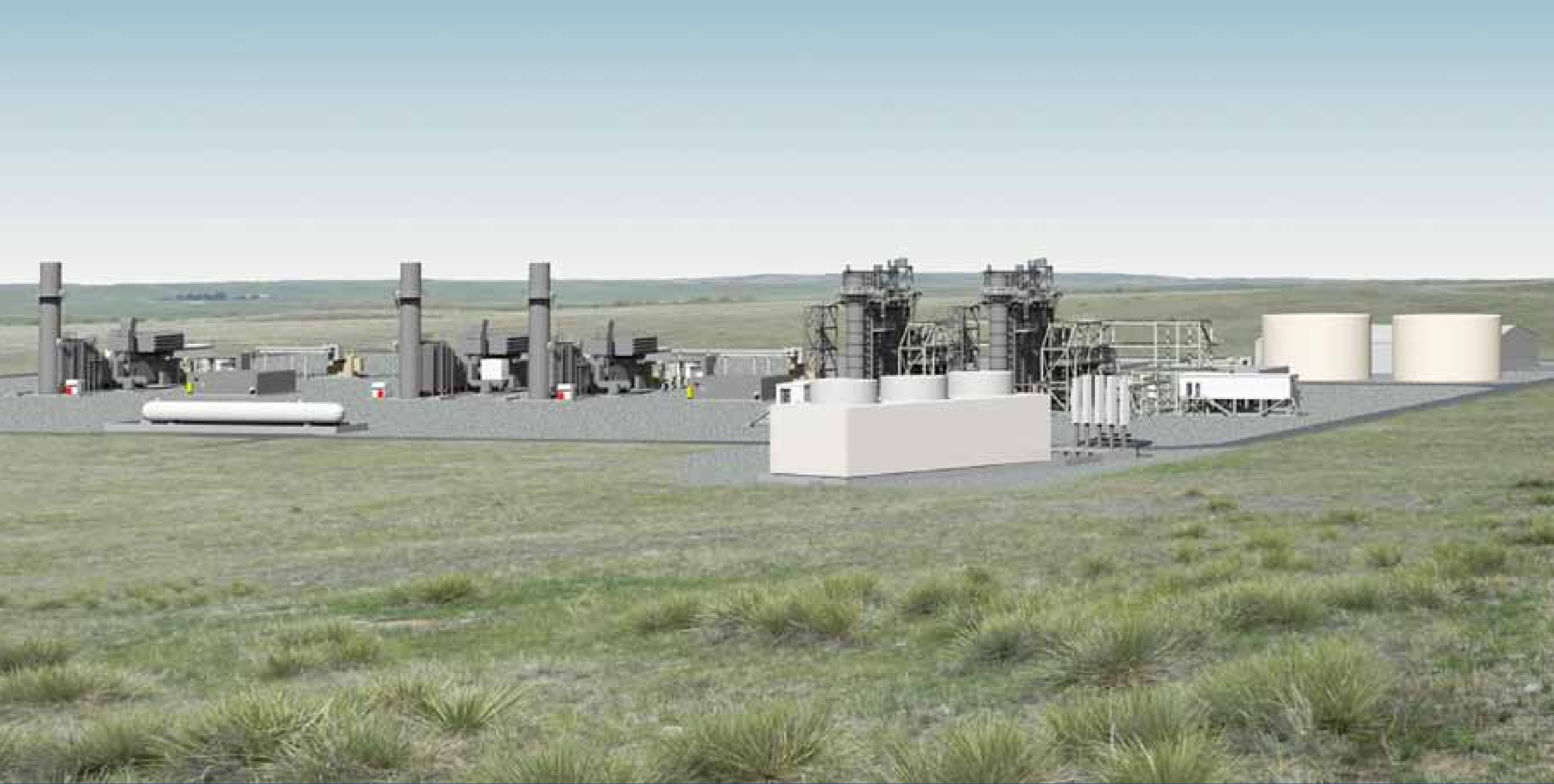
MARLEY FIELD ERECTED COOLING TOWER

TO:	Zachry Engineering	DATE:	June 30, 2011
ATTN:	Thomas Freeman – 303-928-4575	FROM:	Jim Mick
PROJECT:	Cheyenne 2 x 1 CC Project	JLH No.	Z01-11-5217

BUDGETARY SELECTION

DESIGN CONDITIONS:	Flow	28,000 gpm
	Hot Water	91 °F
	Cold Water	71 °F
	Wet Bulb	63 °F
	Plume Abatement	**None**
TOWER DESCRIPTION:	Model	F448A53C4.003A
	Number of Cells	3
	Pump Head	18.41 ft
	Fan Diameter	30 ft
	Motor Size	3 @ 150 Hp
	Brake Horsepower	3 @ 147.5 Hp
	Evaporation	608 gpm
	Drift Rate	0.0005 %
TOWER DIMENSION:	Tower Width	54 ft
	Tower Length	158.2 ft
	Tower Height	39.84 ft
	Fan Deck Height	26.09 ft
BASIN DIMENSION:	Basin Width	54 ft
	Basin Length	158.5 ft
BUDGET PRICE:	$1,546,000 USD	

This budget price is based upon a scope that includes engineering, prefabrication of materials, freight to jobsite and supervision and labor to field assemble the above field erected cooling tower. The following are not included, and should be provided by the purchaser: Sales and/or use taxes, concrete cold water basin, anchor bolts, fire protection sprinkler system (if required by Owner's insurance underwriter), pumps, piping, valves, water make-up, motor starter, disconnects, and controls.



Greenhouse Gas PSD Permit Application

Cheyenne Generating Station

Cheyenne, Wyoming

Submitted by

Black Hills Corporation
1515 Wynkoop Street, Suite 500
Denver, CO 80202

Submitted to

U.S. Environmental Protection Agency, Region VIII
Denver, CO

Prepared by

CH2MHILL

August 2011

Black Hills Corporation

Fred Carl
Director Environmental Services

409 Deadwood Avenue • PO Box 1400
Rapid City, South Dakota 57709-1400
P (605) 721-2219, F (605) 721-1338
fred.carl@blackhillscorp.com

August 5, 2011

Mr. Carl Daly
Director of Air Programs
EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

RE: Black Hills Corporation
Cheyenne Generating Station
Submittal of Greenhouse Gas PSD Construction Air Permit Application

Dear Mr. Daly,

Black Hills Corporation is submitting a Greenhouse Gas PSD Construction Permit Application for the Cheyenne Generating Station in the City of Cheyenne in Laramie County, Wyoming. Included in this submittal are five (5) copies of the permit application in 3-ring binders. As we discussed in the pre-application meeting for this project held in your offices on July 8, 2011, the application for the PSD permit for the criteria pollutant emissions will be submitted to the Wyoming Department of Environmental Quality.

The Cheyenne Generating Station (CGS) will be a nominal 220 MW gross electric generating facility that includes five (5) 40 MW combustion turbines. Two of the turbines will operate in combined cycle mode and three will operate in simple cycle mode. The planned start of construction is summer 2012.

Please contact Tim Rogers, Black Hills Corporation at (605) 721-2286 or Joe Hammond, CH2M HILL at (720) 286-5919 on any questions that EPA may have during the application review. We appreciate your assistance on this important project.

Sincerely,

Fred Carl
Director, Environmental Services
Black Hills Corporation

Cc Mark Lux, Tim Rogers; BHC
Chad Schlichtemeier,;Wyoming DEQ
Robert Pearson; CH2M HILL

Table of Contents

Appendices

Tables

Executive Summary

Black Hills Corporation (Black Hills) plans to construct a new nominal 220-megawatt (MW) gross simple- and combined-cycle natural gas-fired combustion turbine power plant in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located within the city limits of the City of Cheyenne, Wyoming, approximately 5 miles southeast of the downtown area.

Cheyenne Light, Fuel and Power Company (Cheyenne Light) is a wholly owned subsidiary of Black Hills. It was acquired from Xcel Energy on January 1, 2005, and provides electric utility service to Laramie County, Wyoming, including the City of Cheyenne.

Presently, electricity sold by Cheyenne Light is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is currently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The CGS project will include the following:

- Five 40-MW combustion turbine generators (CTGs) fired by clean-burning natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, Black Hills is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) from the CGS and contains a description of the project, a review of applicable federal regulations, a listing of the emissions, and a best available control technology analysis.

The CGS will have potential emissions of 963,874 tons per year (tpy) of GHGs expressed as carbon dioxide equivalent (CO_2e). This is comprised of 962,929 tpy of carbon dioxide (CO_2), 1.8 tpy of nitrous oxide (N_2O), and 18.2 tpy of methane (CH_4). Because the emissions of CO_2e exceed 100,000 tpy, this plant will be a major new source and will be subject to the Prevention of Significant Deterioration (PSD) rules.

Because the emission rate of GHG exceeds the 100,000-tpy limit specified in the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule), a best available control technology (BACT) analysis was performed. The BACT analysis concludes that the CGS project operating at its design energy conversion efficiency is BACT for GHGs.

Acronyms and Abbreviations

BACT	best available control technology
Black Hills	Black Hills Corporation
CAA	Clean Air Act
CatOx	Catalytic Oxidation
CEM	continuous emissions monitor
CFR	Code of Federal Regulations
CGS	Cheyenne Generating Station
CH_4	methane
Cheyenne Light	Cheyenne Light, Fuel and Power Company
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CTG	combustion turbine generator
°F	degrees Fahrenheit
EPA	U.S. Environmental Protection Agency
FIP	Federal Implementation Plan
FR	*Federal Register*
GHG	greenhouse gas
GWP	global warming potential
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kW	kilowatt
kWh	kilowatt-hour

LAER	Lowest Achievable Emission Rate
lb	pound
lb/hr	pound per hour
LHV	lower heating value
MACT	maximum achievable control technology
MRR	Final Mandatory Reporting of Greenhouse Gases Rule, or Mandatory Reporting Rule
MMBtu	million British thermal units per hour
MW	megawatt
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NO_X	nitrogen oxide
NSR	New Source Review
N_2O	nitrous oxide
O_2	oxygen
PFC	perfluorocarbon
PM_{10}	particulate matter less than 10 microns in diameter
ppm	parts per million
PTE	potential to emit
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SF_6	sulfur hexafluoride
SIP	State Implementation Plan
SO_2	sulfur dioxide
STG	steam turbine generator
tpy	tons per year
WDEQ	Wyoming Department of Environmental Quality
VOC	volatile organic compound

SECTION 1.0

Introduction

Black Hills Corporation (Black Hills) plans to construct a new nominal 220-megawatt (MW) gross simple and combined-cycle combustion turbine power plant located in Laramie County, Wyoming. The project, named the Cheyenne Generating Station (CGS), will be located in the City of Cheyenne approximately 5 miles southeast of the downtown area.

The facility will produce electrical power for Cheyenne Light, Fuel and Power Company (Cheyenne Light), a wholly owned subsidiary of Black Hills. Cheyenne Light provides electric service to Laramie County, Wyoming, and the City of Cheyenne, with more than 38,000 customers.

Presently, electricity sold by Cheyenne Light is generated elsewhere (primarily the Gillette, Wyoming, area) and is transmitted to Cheyenne for retail delivery. There is presently no local generation capability in the Cheyenne area. The CGS will provide a local source of electricity to increase the amount of available electricity and to improve reliability of power delivery in the Cheyenne area.

The power plant will include the following:

- Five 40-MW combustion turbine generators (CTGs) fired by clean-burning natural gas. Two of the turbines will be operated in combined-cycle mode and three will be operated in simple-cycle mode. Operating in combined-cycle will provide approximately 20-MW.
- One wet cooling tower for the combined-cycle steam turbine
- Three electric chiller units, each with cooling towers, for inlet air cooling for all of the CTGs
- Six natural gas inlet air heaters for inlet air heating for all of the CTGs
- Two fuel gas heaters, natural gas-fired
- One diesel emergency generator
- One diesel fire pump

In accordance with the terms of federal regulations, Black Hills is applying to U.S. Environmental Protection Agency (EPA) Region 8 for a permit to construct the CGS. The application is limited to requesting a permit for the emissions of greenhouse gases (GHGs) and contains a description of the project, a review of applicable regulations, a listing of the emissions, and a best available control technology (BACT) analysis.

Section 1.1 provides project contacts and an overview of the documentation being submitted with the application for a permit to construct the CGS.

1.1 Project Contacts

The following individuals may be contacted for additional information on this project:

Applicant	Tim Rogers Environmental Manager Black Hills Corporation 625 Ninth Street Rapid City, SD 57709 (605) 721-2286 TRogers@bh-corp.com
Permitting Consultant	Joe Hammond Senior Project Manager CH2M HILL, Inc. 9193 South Jamaica Street Englewood, CO 80112 (720) 286-5919 joe.hammond@ch2m.com

1.2 Document Overview

The following is an overview of the information included in this permit application.

- **Section 1.0 – Introduction.** This section provides an overview of the project and describes the application organization.
- **Section 2.0 – Project Description.** This section includes a general description of the proposed project including equipment and operations of the project. Information regarding non-emitting processes and equipment is provided for a general understanding of plant operations.
- **Section 3.0 – Greenhouse Gas Emissions Summary.** This section provides a summary of emissions-related information.
- **Section 4.0 – Greenhouse Gas Regulatory Review.** This section contains a detailed regulatory review of federal GHG air regulations that may impact the permitting, construction, or operation of the proposed project.
- **Section 5.0 – BACT Analysis.** This section includes a BACT analysis for GHG pollutants. This analysis follows the EPA-prescribed five-step top-down approach. Requested permit limits are also included in this section.
- **Appendix A – Location Map and Plot Plan.** This appendix includes a location map, plot plan, and general equipment arrangement drawing for the proposed project.
- **Appendix B – Greenhouse Gas Supporting Documentation.** This appendix contains the calculations used to determine the GHG emissions for this permit application.

SECTION 2.0

Project Description

Black Hills proposes to construct and operate the CGS in Cheyenne, Wyoming. A plot plan of the facility and a map detailing the location of the proposed facility can be found in Appendix A. The facility will be a nominal 220-MW gross output power plant that will produce electrical power for the Black Hills-owned Cheyenne Light, Fuel and Power (CLFP) electric retail service territory in Laramie County, Wyoming, including the City of Cheyenne and Black Hills Power (BHP) service territory in Wyoming and South Dakota. Facility output varies with ambient temperature, with higher output at lower ambient temperatures. A general arrangement of the turbine layout and associated equipment can be found in Appendix A.

The CGS facility configuration was selected based upon the needs identified in the CLFP *Integrated Resource Plan* (IRP).[1] The CLFP Certificate of Public Convenience and Necessity (CPCN) was filed with the Wyoming Public Service Commission (August 1, 2011 – Docket Number 20003-112-EA11) and was based upon CLFP IRP that identified three simple-cycle combustion turbines (nominally 120 MW gross output). The CLFP CPCN further identifies the potential build-out of the site to accommodate future generation needs. Black Hills plans to submit a BHP CPCN in fall 2011 and will be based upon the BHP IRP that tentatively (plan has not been finalized) identifies the need for two simple-cycle combustion turbines configured in combined cycle mode (nominally 100 MW gross output). The Black Hills' Integrated Resource Plans will show the public need for increased capacity requirements in the CLFP and BHP service areas, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking with base-load capability and further enable renewable generation (wind, solar, and other renewable resources).

The proposed CGS facility will consist of five combustion turbines. Combustion turbines CT01A and CT01B will operate in a 2 X 1 combined-cycle design consisting of two 40-MW CTGs with one heat recovery steam generator (HRSG) for each CTG with no duct burners. Steam from the HRSGs will be combined to flow to a steam turbine that will produce additional electricity. The total generating capacity of the combined-cycle configuration will be approximately 100 MW. Combustion turbines CT02A, CT02B, and CT03A, will each be high-efficiency 40-MW CTGs, operating in simple-cycle mode.

Inlet air chillers with wet cooling towers will be provided for each CTG to cool the combustion air, which will enhance overall plant output during times of higher ambient temperature. Inlet air heaters will also be provided for each CTG to heat the combustion air, which will prevent icing during times of lower ambient temperature.

The proposed CGS facility will also have fuel gas pre-heaters, an emergency generator, and a fire pump.

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[1] The IRP determines the capacity expansion, which takes into consideration the size of the electrical systems' demand, and further defines the size of combustion turbines selected.

2.1 Power Generation

Power will be produced in the plant by a total of six generators, one for each of the five 40-MW CTGs plus one steam turbine generator (STG). All other facility operations ancillary to the primary generation function are described below.

2.2 Emission Sources

2.2.1 Combined-Cycle Combustion Turbine Generators

The CGS will use two 40-MW combustion turbines CT01A and CT01B will be operated in a 2 X 1 combined-cycle design with two CTGs and one steam turbine. The combustion turbines will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines will be equipped with unfired (no duct burner) HRSGs to extract heat from each combustion turbine exhaust to make steam. The steam will be used in an STG to produce more electricity. The combined-cycle configuration will consist of two CTGs, two HRSGs (one for each CTG), and one STG.

2.2.2 Simple-Cycle Combustion Turbine Generators

The CGS will use three 40-MW combustion turbines operated in simple-cycle mode, without heat recovery from the turbine exhaust. These combustion turbines, designated as CT02A, CT02B, and CT03A, will be fired exclusively with pipeline-quality natural gas and are very similar to large aircraft jet engines in function and design. The combustion turbines have the capability to reach full-load operation quickly after initiation of startup, thereby reducing overall startup emissions.

Each combustion turbine consists of a compressor, combustor, and expansion turbine. After filtration, air passes through the compressor before combining with the fuel and entering the low nitrogen oxide (NO_X) combustor. The combustion products and compressed air pass through the expansion turbine, which drives both the compressor and the generator. Up to approximately 40 MW of gross electrical power are produced by each CTG over and above the work required by the compressor. The exhaust gas from each combustion turbine enters the Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CatOx) catalysts at high temperature (approximately 850 degrees Fahrenheit [°F] at full load).

2.2.3 Wet Cooling Towers

2.2.3.1 Inlet Chiller Cooling Towers

An inlet air chilling system will be installed at the compressor inlet of each CTG, downstream of the inlet air filter. The inlet air chilling system serves to enhance the overall output of the plant by lowering the temperature of the ambient air entering the CTGs during periods of high air temperature. The cooling process takes place at the cooling coils where air is cooled before entering the compressor section of the turbine. At low temperatures, the air becomes denser and, therefore, more air flows though the CTGs. The net increase in airflow results in higher power output for each of the CTGs at high ambient temperatures. Three inlet chiller cooling towers will be used to serve the inlet chilling system at CGS.

2.2.3.2 Unit 1 Cooling Tower

One wet cooling tower will be installed to provide cooling to condense the steam that is exhausted from the steam turbine on the combined cycle configuration. The steam condensers will have circulating cooling water flow through tubes that will absorb the heat from the condensing steam that is exhausted from the steam turbines. The warmed circulating water is then pumped to the cooling tower where it flows down through the tower and is cooled through evaporation, in a manner similar to other cooling towers. The cooled circulating water then flows back to the steam condensers to pick up more heat.

2.2.4 Inlet Air Heaters

An inlet air heating system will be installed at the compressor inlet of each CTG, upstream of the inlet air filter. The inlet air heating system **raises** the temperature of the ambient air entering the CTGs during periods of low air temperature to prevent icing.

2.2.5 Fuel Gas Heaters

A fuel gas pre-heat system will be utilized on each CTG to raise the temperature of the natural gas above the saturation temperature. Natural gas fired fuel gas heaters will be used on the five combustion turbines.

2.2.6 Diesel Fire Pump

One diesel fire pump will be used to provide fire protection water for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the fire pump are 250 hours per year or less.

2.2.7 Emergency Generator

One diesel emergency generator will be used to provide emergency power for the plant. This engine will fire only ultra-low-sulfur diesel fuel, and will operate only during testing that is anticipated to occur once per week. Total operating hours for the emergency generator are 250 hours per year or less.

2.2.8 Storage Tanks

Storage tanks at the site will include diesel tanks for the fire water pump and emergency generator, aqueous ammonia storage tanks for the SCR NO_x emissions control unit, and several water storage tanks.

2.3 Non-Emitting Major Facility Components

2.3.1 Ancillary Facilities

Other facilities used to support power generation at the CGS will include the following:

- Water treatment system to remove solids and hardness from plant makeup water
- Wastewater treatment system to allow recycle of cooling tower blowdown and other plant wastewater
- Plant and instrument air compressors (electric-driven) and auxiliary equipment

- Plant sumps, sump pumps, and oily water separator
- Miscellaneous fire protection equipment
- Septic system for sanitary waste
- Steam and water sampling systems
- Administration and warehouse/maintenance buildings

2.4 Emission Controls

The CGS will include the following emission controls:

- Dry low NO_X burners on the CTGs, and a SCR system to reduce NO_X emissions on all CTGs
- An oxidation catalyst to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CTGs
- Good combustion design and operation to reduce particulate matter of 10 microns in diameter (PM_{10}) emissions from the CTGs
- Use of pipeline-quality natural gas to minimize sulfur dioxide (SO_2) emissions from the CTGs
- High-efficiency drift eliminators on the steam condenser cooling towers to reduce PM_{10} emissions in the cooling tower drift

2.5 Emissions Monitoring

As required by Title 40 of the Code of Federal Regulations (CFR) Parts 60 and 75, the CGS will use continuous emissions monitors (CEMs) for NO_X, CO, and oxygen (O_2) for all five CTGs. These CEMs will average and record data on frequencies consistent with state and federal acid rain rules. The plant will also monitor and record the natural gas flow rate and will analyze natural gas fuel quality as required by the acid rain rules.

2.6 Operating Schedule

The exact annual operating schedule of the CGS will be dependent on the demand for electric power within Cheyenne Light's electric system. Thus, the exact operating schedule cannot be accurately predicted at this time.

For this reason, the permit limits requested in this application, and the resulting assumptions used in the ambient impact analysis and BACT analysis, are as follows:

- Up to 8,760 hours per turbine per year of CTG operation (both simple and combined cycle) at 100 percent load or at any lesser load rate
- Up to 600 startups for each simple-cycle combustion turbine per year
- Up to 600 startups for each combined-cycle combustion turbine per year

- Up to 5,330 hours per tower per year of inlet chiller cooling tower operation
- Up to 8,760 hours per year of combined-cycle cooling tower operation

These hours could be based on continuous short-term or long-term operation. In other words, the plant could operate up to 8,760 hours per year (counting startup episodes) and could operate 24 hours per day, 7 days per week, and 365 days per year.

2.7 Permitting and Construction Schedule

The planned permitting and construction timeline is shown in Table 2-1.

TABLE 2-1
Permitting and Construction Schedule

Event	Date
Air Permit Application Filed with EPA	August 5, 2011
Air Permit Application Filed with WDEQ	September 1, 2011
Air Permits Issued by EPA and WDEQ	Summer 2012
Begin Purchase Major Pieces of Equipment	Summer 2012
Start of Construction	Summer 2013
Commercial Operation	Summer 2014

SECTION 3.0

GHG Emissions Summary

GHG emission estimates were prepared for all point emissions sources from the CGS, including the combustion turbines and auxiliary equipment. The annual carbon dioxide (CO_2) equivalent (CO_2e) emissions were estimated based on 100 percent capacity factor (full-load operation for 8,760 hours per year) for each of the combustion turbines. More detailed GHG emission calculations are provided in Appendix B.

3.1 Combustion Turbines

The CGS project consists of two nominal 40-MW combustion turbines operating in a 2 X 1 combined-cycle configuration, designated as CT01A and CT01B. There will also be three nominal 40-MW combustion turbines operating in simple cycle identified as CT02A, CT02B, and CT03A. Each combustion turbine has a separate stack, which will be a separate emission point.

3.2 Auxiliary Equipment

In addition to the five combustion turbines planned for the CGS project, there are several other small GHG combustion sources associated with auxiliary equipment that will operate at the CGS:

- (6) Natural gas-fired inlet air heaters (nominal 16-million-British-thermal-units-per hour [MMBtu/hr] air heater with estimated emissions of 4,117 CO_2e tons/year each)
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year each)
- (1) Diesel-fired fire pumps (nominal 327-BHP engine with estimated 51 CO_2e tons/year each)

3.3 GHG Emission Summary

The GHG emission sources for the project are shown in Table 3-1, along with estimated annual CO_2e emissions.

TABLE 3-1
GHG Emission Source Summary

Source Number	Emission Point	Estimated Annual CO_2e Emissions
EP01 and EP02	(2) Nominal 40-MW Combined-Cycle Combustion Turbines CT01A and CT01B	374,635
EP03, EP04, and EP05	(3) Nominal 40-MW Combined-Cycle Combustion TurbinesCT02A, CT02B, and CT03A	561,953
EP06 through EP11	Six (6) Inlet Air Heaters	24,703
EP18 and EP19	Two (2) Fuel Gas Heaters	2,306
EP16	One (1) Diesel Fire Pump	51
EP15	One (1) Diesel Standby Generator	226

SECTION 4.0

Regulatory Review

This section provides a regulatory review of the applicability of federal air quality permitting requirements for GHGs and GHG air pollution control regulations for the CGS project proposed by Black Hills. The purpose of this section is to provide appropriate explanation and rationale regarding the applicability of these regulations to the CGS project. The review is limited to federal regulations for GHG because there are no State of Wyoming regulations for GHG that apply to the permitting of CGS. Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Both agencies have agreed to work together to process these two air permits for CGS.

4.1 Federal Regulations

The proposed project was evaluated to determine compliance with applicable federal GHG air quality regulations. Potentially applicable federal GHG regulations include the following:

- Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) – 40 CFR 51.166, 52.21, as published in the *Federal Register* (FR) June 3, 2010 (75 FR 31514)
- Federal Implementation Plan (FIP) for State of Wyoming GHG – 40 CFR 52.37, as published in the *Federal Register* December 30, 2010 (75 FR 82246)
- New Source Review (NSR) – 40 CFR 51 and 52

On April 2, 2007, the U.S. Supreme Court found that GHGs are air pollutants under Clean Air Act (CAA) section 302(g) (*Massachusetts* v. *EPA,* 549 U.S. 497 [2007]). GHG includes the six gases of CO_2, nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Of these, the first three will be emitted from the CGS. These gases have different potential to affect global warming, termed the global warming potential (GWP). The GWP of the three emitted gases are CO_2 (1), N_2O (310), and CH_4 (21).

Based on the series of legal and regulatory actions that culminated in the Tailoring Rule, regulation of major increases of GHG emissions through the Prevention of Significant Deterioration (PSD) permit program was required. EPA recognized that the major source threshold levels for the criteria pollutants for PSD pollutants of 100 or 250 tons per year (tpy) would make virtually every new project a major source. Accordingly, in June, 2010, EPA adopted the Tailoring Rule to raise the major source thresholds for GHG to 75,000 or 100,000 tons of GHG per year.

The State of Wyoming has an approved State Implementation Plan (SIP) based program for the criteria pollutants for the PSD permitting of new major sources. However, Wyoming has decided to not include GHG in the state PSD permitting program. Accordingly, the GHG PSD program is being implemented by the EPA for major sources of GHG within the State of Wyoming through the federally approved FIP.

4.1.1 Greenhouse Gas Tailoring Rule

On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed the phasing in of the PSD permitting process for new major sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with the potential to emit (PTE) greater than 100,000 tpy of CO_2e (including the statutory threshold of 100 or 250 tons on a mass basis) comply with PSD and Title V requirements. All references to "tons" are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

As shown in Table 4-1, under the Tailoring Rule, the CGS will be a major source subject to PSD permitting because the total emissions of CO_2e exceed 100,000 tpy. The CGS project will result in an increase in CO_2e emissions of 963,874 tpy, and more than 100 tpy in certain criteria pollutants. Therefore, the project is classified as a major source for PSD applicability determination.

TABLE 4-1
GHG Pollutants Expected to be Emitted, Annual Emission Rates, Global Warming Potential, and Annual Emissions Rates Adjusted for Global Warming Potential

Pollutant	Proposed Facility GHG Emissions (TPY)	Global Warming Potential (GWP)	GHG Emissions Adjusted for GWP (TPY)
Carbon Dioxide (CO_2)	962,929	1	962,929
Nitrous Oxide (N_2O)	1.82	310	564
Methane (CH_4)	18.17	21	381
Total GHG as CO_2e	----	----	963,874

4.1.2 Federal Implementation Plan for Wyoming

EPA has determined that the Wyoming SIP is deficient for purposes of the PSD permitting of GHG. Accordingly, EPA adopted a FIP in which it retains the authority to issue a PSD permit for GHG. Thus, this application is being filed with EPA Region 8 for the sole purpose of obtaining a PSD permit for the emissions of GHG from the CGS. The permit for the emissions of the criteria and hazardous pollutants from CGS will be obtained from the State of Wyoming.

EPA has not adopted ambient air quality standards or new source performance standards for GHG. Accordingly, this application only contains a BACT analysis for GHG.

4.1.3 New Source Review

PSD is the portion of NSR that applies to pollutants that are in attainment of National Ambient Air Quality Standards (NAAQS). Because there are no ambient air quality standards for GHG, all portions of the United States are in attainment for GHG. Major new or modified air emission sources locating in Laramie County are, therefore, potentially subject to PSD review for these GHG pollutants.

The first step in PSD review is determining whether the proposed facility is a major PSD source. As noted above, the CGS will be a major source. Therefore, CGS is subject to PSD review for GHG. The primary elements of PSD requirements are as follows:

- Application of BACT to emissions of GHG

SECTION 5.0

Greenhouse Gas BACT Analysis

5.1 Background

Black Hills plans to build a natural gas-fired combustion turbine generating facility in the southeast section of the City of Cheyenne in Laramie County, Wyoming, pursuant to its approved *Integrated Resource Plan* filed before the Wyoming Public Service Commission (described in Section 2.0, Project Description). The proposed site is immediately west of the Dry Creek Water Reclamation Facility, which is located approximately 5 miles southeast of the downtown area.

The CGS will consist of a total of five natural gas-fired CTGs sized at a nominal 40-MW capacity each. Two CTGs will be configured for combined-cycle operation and will each be equipped with dry-low NO_x combustors and a HRSG without duct burners, with steam flowing from the two HRSGs to one condensing STG with condenser in a "2x1" configuration. The combined-cycle generation capacity is nominally 100 MW. All of the CTGs will be equipped with SCR for NO_X control and Catalytic Oxidation for CO and VOC control. Three CTGs will operate in simple cycle. CGS auxiliary equipment includes one mechanical draft condenser wet cooling tower, three electric inlet air chiller units with mechanical draft cooling towers, six natural gas-fired inlet air heaters, two natural gas-fired fuel heaters, one diesel-fired fire pump, and one diesel-fired emergency generator.

5.1.1 CGS Business Plan and Combustion Turbine Selection

The Cheyenne Light CPCN and associated IRP (Docket Number 20003-112-EA11), were filed August 1, 2011, with the Wyoming Public Service Commission, and present the business plan in detail. The Black Hills Power CPCN and associated IRP will be submitted to the Commission in fall 2011. Generally, Black Hills' CPCN and associated IRP show the public need for increased capacity requirements, reserve generation requirements, and generation within the service area of Cheyenne for reliability reasons. The necessary generation will be primarily peaking with baseload capability and further enable renewable generation (wind, solar, and other renewable resources). Black Hills identified natural gas simple-combined-cycle gas turbines to be the best-suited generation source to meet this CGS business plan.

While Black Hills has determined the nominal output of each combustion turbine to be 40 MW, the combustion turbine manufacturer has not been selected. Table 5-1 lists potential combustion turbine manufacturers and a comparison of estimated performance efficiency at the CGS site conditions.

TABLE 5-1
Combustion Turbine Comparison

Turbine[1]	Production (kW)	Gross Heat Rate (Btu/kWh) HHV	Efficiency
Dresser-Rand			
DR-63G PC	35,150	9,095	37.5%
GE Energy Aeorderivative			
LM6000PC	39,253	9,487	36.0%
LM6000PC Sprint	40,605	9,419	36.2%
LM6000PD	34,612	9,103	37.5%
LM6000PD Sprint	38,079	9,091	37.5%
LM6000PF	34,612	9,103	37.5%
LM6000PF Sprint	38,649	9,079	37.6%
LM6000PG	42,995	9,556	35.7%
GE Energy Oil & Gas			
LM6000PD	33,964	9,283	36.8%
IHI Power Systems			
LM6000PC	34,306	9,198	37.1%
LM6000PC Sprint	37,129	9,228	37.0%
LM6000PD	33,800	9,231	37.0%
LM6000PD Sprint	37,236	9,213	37.0%
LM6000PG	40,084	9,157	37.3%
Pratt & Whitney Power Systems			
FT8 TwinPac	41,267	9,898	34.5%
SwiftPac 50 DLN	41,175	9,914	34.4%
Rolls-Royce			
Trent 60 DLE	41,537	9,064	37.7%
Trent 60 DLE ISI	46,612	8,913	38.3%
Siemens Energy			
SGT-800	37,772	10,126	33.7%
SGT-900	39,781	11,626	29.4%

[1] Specifications for production output at 59ºF, 5,950-Foot Altitude, Gross Output, HHV.

Black Hills will select a combustion turbine that best meets its business plan, its system, and operational criteria, with possible selection of any combustion turbine from Table 5.1. A key consideration is that installation of combustion turbines from only one manufacturer is desired, and both simple-cycle and combined-cycle operational considerations must be evaluated. Due to differences in exhaust temperatures and other factors, turbines with lower efficiency than others in simple-cycle operation may actually have higher efficiency than those others in combined-cycle operation. As will be demonstrated below, Black Hills proposes to establish annual GHG mass and output-based limits assuming use of a turbine from the top of the possible efficiency range, and will agree to comply with those limits regardless of actual turbine selection. Black Hills will perform a complete competitive bidding process to select the combustion turbine for the CGS project, and the selected combustion turbine will be subject to the GHG BACT permit limits established by EPA as part of this permitting process.

Therefore, Table 5-2 below lists the assumed combustion turbine attributes to be used within the GHG BACT analysis, and represents high-efficiency operation in both simple- and combined-cycle operation.

TABLE 5-2
Efficient Combustion Turbine Definition

Combustion Turbine Criteria	Assumed Value[1]
Simple-Cycle Combustion Turbine Gross Output (MW)	37
2x1 Combined-Cycle Combustion Gross Turbine Output (MW)	97
Simple-Cycle Gross Heat Rate (Btu/KWh) HHV	9,300
Combined-Cycle Gross Heat Rate (Btu/KWh) HHV	7,200
Heat Input (Btu/hr) HHV	366

[1] 60^0 F at site elevation.

5.2 Regulatory Basis

GHGs have become subject to emission permitting through PSD and Title V programs. On June 3, 2010, EPA issued the final Tailoring Rule (75 FR 31514), which allowed phasing in the PSD permitting process for new sources of GHGs such as the CGS project. Step 2 of the Tailoring Rule requires that beginning July 1, 2011, all new sources with PTE greater than 100,000 tpy of GHGs on a CO_2e basis, and with a GHG PTE of 100 or 250 tpy, depending on source type, on a mass basis will become subject to PSD and Title V requirements. All references to tons within the table and in this BACT analysis are provided in terms of short tons (2,000 pounds/ton) instead of metric tonnes, in accordance with EPA GHG PSD permitting guidance.

The CGS project will be a new source with a GHG PTE of greater than 100,000 tpy CO_2e and greater than the 100-tpy mass basis for listed sources, and will also have a PTE of greater than 100 tpy for certain criteria pollutants. Because the Wyoming Department of Environmental Quality (WDEQ) has a SIP-approved PSD program for all criteria pollutants but has not adopted regulations under the Tailoring Rule, WDEQ is the permitting authority for the CGS non-GHG pollutants (other regulated NSR pollutants), while EPA Region 8 is the permitting authority for the CGS GHG pollutants. Therefore, this GHG BACT analysis was prepared for presentation to EPA Region 8 as part of the CGS permit application process.

5.3 Emissions Summary

Per EPA Tailoring Rule definitions, GHGs consist of the following gases:

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)

To determine CO_2e emissions, mass flows of each individual gas are multiplied by the appropriate GWP as referenced to the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report, and the results are summed.

The combustion turbines, inlet air heaters, and fuel gas heaters will be fired with pipeline-quality natural gas, and complete combustion will result in water and CO_2 byproducts. However, incomplete combustion will result in some unburned natural gas or CH_4 emissions. Additionally, due to the presence of nitrogen in the combustion air, some small quantities of N_2O will also be emitted. The standby generator and fire pump engines will be fired with diesel fuel, again resulting in CO_2 emissions from oxidation of the fuel and with minor quantities of CH_4 emissions resulting from incomplete combustion and N_2O emissions from conversion of nitrogen from the atmosphere and fuel.

Table 5-3 represents potential sources and estimated quantities of GHG emissions from CGS project equipment.

TABLE 5-3
CGS Estimated GHG Emissions by Equipment Category

Equipment	Description	Total CO_2e Emissions (t/yr)
Two (2) Combustion Turbines in Combined-Cycle Operation with no HRSG Duct Burner	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	374,635
Three (3) Simple-Cycle Combustion Turbines	Maximum Heat Input Each 366 MMBtu/hr Higher Heating Value (HHV)	561,953
Two (2) Fuel Gas Heaters	Maximum Heat Input 4.5 MMBtu/hr each	2,306
One (1) Diesel Fire Pump	Maximum Heat Input 2.5 MMBtu/hr	51
One (1) Diesel Standby Generator	Maximum Heat Input 5.52 MMBtu/hr	226
Six (6) Inlet Air Heaters	Maximum Heat Input 16.07 MMBtu/hr each	24,703
Total		**963,874**

5.3.1 GHG BACT Analysis Assumptions

During the completion of GHG BACT analysis, the following assumptions were made:

1. Table 5-3 above presents estimated CGS GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, and N_2O. The CGS is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents. SF_6 is also a man-made gas that may be used as an insulating gas for high-voltage equipment and circuit breakers; however, Black Hills does not plan to install electrical equipment containing SF_6 at the CGS. Therefore, only CO_2, CH_4, and N_2O will be included in CO_2e totals.
2. From the GHG emissions inventory presented in Appendix A, the relative quantities of CH_4 and N_2O total only approximately 20 tpy, or less than 0.002 percent of total CO_2e emissions. Due to the extremely small contribution of CH_4 and N_2O emissions to the total, the CGS GHG BACT analysis only included the five-step process for CO_2 emissions.
3. Completion of the BACT analysis for criteria pollutants will result in the installation of an SCR system for NO_x emissions reduction, and an oxidation catalyst for control of CO and VOCs for each turbine.
4. During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule or MRR) (40 CFR 98) factors for estimating CO_2e emissions from the combustion of natural gas assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the MRR factors and included in the CO_2e totals.
5. Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the GHG emissions inventory, the estimated N_2O emissions from all combustion turbines total only 1.5 tpy. Therefore, even if there were an order–of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. The combustion turbine SCR systems will be designed to reduce NO_x from the combustion turbine low-NO_x burners (LNBs) from 25 parts per million (ppm) to 3 ppm. Similarly, the oxidation catalyst systems have the benefits of reducing both CO and VOCs. The oxidation catalyst reduces CO and VOC emissions from 70 ppm to 6 ppm, and from 8.4 ppm to 3 ppm, respectively.

While elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Thus, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 due to other environmental impacts. Therefore, we have not considered omission of these controls within the BACT analysis.

5.4 Top-Down BACT Process

The EPA has developed a recommended process for conducting BACT analyses, referred to as the "top-down" method. The following steps to conducting a top-down analysis are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, has been conducted for GHG emissions for the CGS project. The following top-down BACT analysis for CO_2e has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990). A top-down BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology.

5.5 Combustion Turbine BACT for GHGs

Step 1: Identify All Control Technologies

The combustion turbines will be nominal 40 MW machines that utilize the latest emissions control technology. There are two basic alternatives identified to limit the GHG emissions of this project. These options include

- Carbon Capture and Storage (CCS)
- Electrical Generation Efficiency

Black Hills' CGS Business Plan and IRP have determined that the proposed mix of natural gas combined-cycle and simple-cycle power generation is the only alternative that meets all of the CGS requirements for economic and reliable power 24 hours per day and in all weather conditions. As such, other generation technologies such as coal, wind, and solar were not evaluated in this BACT analysis. This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26) Nonetheless, it should be noted that the CGS is intended to provide supplemental and backup generation for solar and wind projects, and renewable generation is not an adequate supplement and backup for other renewable generation; a fuel-based alternative is required.

The only identified alternatives are post-combustion CCS and energy efficiency of the proposed generation facility.

Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

CCS systems involve use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery.

The concentration of CO_2 is required because injection of exhaust streams containing high levels of nitrogen, oxygen and dilute CO_2 is not technically feasible. Research into technically and economically feasible capture systems is ongoing and is the focus of many large-scale grants from the U.S. Department of Energy (DOE). Adequate techniques for compression of CO_2 exist, but such compression systems require large amounts of energy. Furthermore, the capture process is energy intensive. It is estimated that a significant portion of power plant output would be required for CO_2 capture and subsequent compression. As stated in the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*, "For a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture."

Research into geologic storage requirements is also ongoing. DOE research programs are investigating the reliability, permanence, risks, required monitoring, verification, and other issues to be addressed before geologic storage can proceed on a large commercial scale. Many regulatory issues remain to be resolved, such as pore space ownership, financial responsibility requirements, long-term risk following closure of the sequestration site, and issues regarding CO_2 purity and potential contamination of aquifers.

CCS systems are not currently available on a commercial basis. Large-scale demonstration projects are currently being planned or are in early stages of development, but no company or vendor currently offers a commercially available turn-key, integrated CCS system.

The Interagency Task Force on Carbon Capture and Storage consists of 14 executive departments and federal agencies, co-chaired by the DOE and EPA. As detailed in its August 2010 report, one goal of the task force is to bring five to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available.

In the EPA PSD GHG permitting guidance, it is acknowledged that, "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (italics added). "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases." As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard.

The Interagency Task Force report notes the lack of demonstration in practice: "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

Therefore, the CCS alternative is not considered technically feasible for the CGS project, and is eliminated from further consideration. While it is being eliminated based on technical feasibility in Step 2, it should be acknowledged that even if carried forward for further analysis, it would undoubtedly be eliminated in Step 4 based on cost effectiveness. The technical risks associated with the technologies would make the project un-financeable. The energy requirements for the capture and compression systems alone would dramatically increase the overall cost of generation for the project, and the cost of capture and compression systems, pipelines, development of storage reservoirs, and monitoring systems is very high as well.

Electrical Generation Efficiency

EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA, 2011) identifies three categories of control technologies (p. 25):

1. Inherently lower-emitting processes/practices/designs
2. Add-on controls, and
3. Combinations of lower-emitting process/practices/designs and add-on controls

Because there are no demonstrated add-on controls, only those processes, practices, and designs that result in lower GHG emissions are applicable for this BACT analysis. As noted above, the project includes both simple-cycle and combined-cycle generation in this phase of the project, and possible but unplanned future expansion of the facility could include build-out of the simple-cycle combustion turbines into combined-cycle systems. The CGS project as proposed will utilize a high-efficiency, state-of-the-art, combustion turbine and HRSG design. Operation will use good combustion practices and result in energy efficient operation to provide steam to a new steam turbine generator.

In addition, installation of two combustion turbines in a combined-cycle configuration results in a lower resultant plant heat rate as compared to only simple-cycle combustion turbines. In some cases, the turbine which is most efficient in simple-cycle mode will result in a less efficient turbine for combined-cycle operations.

Furthermore, inlet air chillers will be used to prevent loss of turbine efficiency that results during hot weather. The following analysis will demonstrate that the overall generation efficiency meets or exceeds that of other recently implemented projects.

The permit limits proposed in this application are based on assumed use of a combustion turbine of 37 MW gross output and a gross heat rate of 9,300 Btu/kWh (HHV) for simple-cycle operation. This results in an estimated net output of approximately 97 MW at a net heat rate of 7,200 Btu/kWh (HHV) for the 2x1 combined-cycle system. The combined-cycle system will not have duct firing. All noted performance information is based upon CGS site conditions at 60ºF; the high altitude of the area results in marginal decreases to turbine efficiency compared to other locations. The CGS project will utilize all new equipment.

Combustion Turbine Generator Comparable Permitted Emissions

A search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) was performed for simple- and combined-cycle projects with combustion turbines similar to those proposed for the CGS project. No GHG permit information was found in searching the RBLC for comparable units. Information from other recent combustion turbine projects was researched for this BACT analysis, even though this information has not yet been posted to the RBLC.

Efficiency Review

An efficiency review of the proposed CGS project was completed with two metrics: 1) RBLC comparable unit heat rates and 2) comparison of CO_2e emission rates.

RBLC Efficiency Comparison

The RBLC information presented in Table 5-4 below provides a comparison of efficiencies for projects with combustion turbines in the same nominal 40-MW size range as the CGS project. The information presented is for combustion turbines operating in simple cycle. No information was found for comparable 40-MW combined-cycle units without duct burning.

TABLE 5-4
RBLC Efficiency Information – Simple Cycle

Facility	State	Description	Heat Capacity MMBtu/hr (HHV)	Net MW	Heat Rate Btu/kWh (HHV)
Arvah B. Hopkins Generating Station	Florida	GE LM6000PC Simple Cycle	489.5	50	9,790
Lambie Energy Center	California	GE LM6000PC Simple Cycle	500	49.9	10,020
Creole Trail LNG	Louisiana	Combustion Turbine Simple Cycle	290	30	9,667
Western Farmers Electric	Oklahoma	Combustion Turbine Simple Cycle	462.7	50	9,254
El Colton, LLC	California	LM6000 (Enhanced Sprint)	456.5	48.7	9,374
Indigo Energy Facility	California	LM6000 (Enhanced Sprint)	450	45	10,000
Bayonne Energy Center	New Jersey	Rolls Royce Trent 60WLE	603	64	9,422

Notes: Used 1.108 for HHV/LHV conversion factor.

The combustion turbines compared above are similar in size to those planned for the CGS project. As noted above, this analysis and resulting CGS proposed permit limits are based on use of a turbine with simple-cycle gross heat rate of 9,300 Btu/kWh (HHV). An exact comparison cannot be made between the CGS combustion turbines and those listed in Table 5-1 above because each project has unique equipment and site conditions, primarily elevation and temperature. However, the CGS heat rate compares very favorably with all of the reviewed comparable projects listed above, which demonstrates the high-efficiency attributes of the CGS project.

CO_2e Emission Rate Comparison

In simple-cycle operation, the CGS turbines are estimated to produce 1,102 pounds of CO_2e/MWh at average ambient conditions and full-load operation. Considering the range of normal operating loads (50 to 100 percent generator output), and ambient temperature (0ºF to 108ºF), GHG output for the CGS simple-cycle combustion turbines range from 1,072 to 1,603 pounds of CO_2e for new and clean combustion turbine prior to any degradation.

Table 5-5 below presents operating information from the EPA Acid Rain database, and was developed using actual comparable operating unit information from 2010.

TABLE 5-5
CGS Comparable Unit GHG Emissions

State	Facility Name	Unit ID	Operating Time (Hr)	Net Load (MWh)	CO_2 Tons	lb CO_2/MWh
CA	El Cajon Energy Center	1	242	9450	5652	1196
OK	Horseshoe Lake	10	710	29293	18142	1239
OK	Horseshoe Lake	9	174	6851	4248	1240
CA	Orange Grove Project	CTG1	632	25017	15734	1258
CA	Orange Grove Project	CTG2	654	24954	15847	1270
FL	Arvah B Hopkins	HC4	903	27627	17623	1276
FL	Polk	**2	249	27652	18500	1338
FL	Arvah B Hopkins	HC3	662	18283	12529	1371
FL	Polk	**5	476	51662	36111	1398
FL	Polk	**4	563	60221	42443	1410
FL	Polk	**3	204	23176	16600	1432
NJ	Bayonne Plant Holding, LLC	2001	1055	35582	28385	1595
NJ	Bayonne Plant Holding, LLC	1001	1208	39061	32004	1639
NJ	Bayonne Plant Holding, LLC	4001	1134	36629	30200	1649
NE	C W Burdick	GT-3	24	426	399	1871
NE	C W Burdick	GT-2	33	606	579	1912
CA	Escondido Energy Center, LLC	CT1A	28	345	466	2702
CA	Escondido Energy Center, LLC	CT1B	28	345	468	2718

Notes:

Net load 5% lower than gross load.
Data as per EPA Clean Air Markets – Data and Maps.
Based on 2010 data.

The CGS combustion turbine GHG output compares favorably with the facilities shown Table 5-5 above. It is recognized that in establishing any permit limit, allowance must be given for load variances, impact of ambient conditions, startup and shutdown, and equipment degradation over time. This is exemplified by reviewing the information from Table 5-5, because all of these units can be considered as "peaking" due to the low number of annual operating hours. The resultant wide variance in pounds of CO_2e/MWh may likely be attributed to the significant proportion of time in startup and shutdown and/or reduced load operation, as well as lower thermal efficiency for older units.

Note that, based on the combustion turbine defined above, and considering the range of normal operating loads (50 to 100 percent output), and ambient temperature (0ºF to 108ºF), GHG output for the CGS 2x1 combined-cycle system ranges from 833 to 985 pounds of CO_2e for a new or clean combustion turbine prior to any degradation.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible GHG control technology for the CGS project is the electrical generation efficiency. This option is presented in Table 5-6 based on their energy efficiencies expressed in terms of heat rate.

TABLE 5-6
CGS Project GHG Control Technology Ranking

Configuration	Gross Plant Heat Rate (HHV) (Btu/kWh)[1]
Electrical Generation Combined-Cycle Efficiency (without duct firing)	7,200
Electrical Generation Simple-Cycle Efficiency	9,300

Note: [1]At CGS site conditions.

Step 4: Evaluate Most Effective Controls and Document Results

The proposed CGS electrical generation efficiency is determined to be the most effective GHG control technology. From a review of the three evaluation metrics presented above, the CGS combustion turbine net heat rate was found to favorably compare with other combustion turbines and projects.

Step 5: Select BACT

The only remaining option is the "Electrical Generation Efficiency" option, which, therefore, is selected as BACT. This option determined to consist of the CGS project as proposed with new state-of-the-art combustion turbines. Consistent with the review criteria presented above, the CGS project evaluated combustion turbine exhibits comparable efficiency with most of the evaluated alternative combustion turbines, and superior efficiency over the Pratt & Whitney and Siemens machines. Therefore, Black Hills proposes that CGS GHG BACT consist of installation of combustion turbines from any manufacturer with a rating of nominal 40 MW. However, the annual CO_2 emissions limit for the five new combustion turbines will be based upon the BACT emission limits proposed below, which are based upon a combustion turbine from the top of the efficiency range shown. The proposed permit limit of annual total tons of CO_2e and lb/MWh would remain fixed regardless of the combustion turbine selected.

The estimated total annual CO_2e emissions from the combustion turbines are 936,588 tpy, and this value is proposed to be the annual CO_2e permit limit for the five combustion turbines.

EPA's PSD permitting guidance for GHGs suggests use of output-based BACT emission limits and longer-term averaging periods for GHGs. Based on Black Hills' analysis of conservative scenarios for number of turbine startups and shutdowns, partial load operation, and ambient temperature during operations, and considering the range of normalized GHG emissions noted above and eventual turbine degradation, proposed BACT permit limits are 1,100 lb/MWh for each combined-cycle combustion turbine and 1,600 lb/MWh for each simple-cycle combustion turbine on an annual average basis. If the averaging time is less than 1 year, these permit limits should be increased accordingly.

5.6 Small Combustion Sources BACT for GHGs

In addition to the five combustion turbines planned for the CGS project, there are several other small combustion sources associated with auxiliary equipment which will operate at the plant. The GHG calculations for these small combustion sources are located in Appendix B.

- (6) Natural gas-fired inlet air heaters (nominal 16-MMBtu/hr air heater with estimated emissions of 4,117 CO_2e tons/year each)
- (2) Natural gas-fired fuel gas heaters (nominal 4.5-MMBtu/hr gas heater with estimated emissions of 1,153 CO_2e tons/year each)
- (1) Diesel-fired emergency generator (nominal 839-BHP engine with estimated emissions of 226 CO_2e tons/year each)
- (1) Diesel-fired fire pumps (nominal 327-BHP engine with estimated 51 CO_2e tons/year each)

The total GHG emissions from the above small combustion sources are very minor as compared to the emissions from the combustion turbines. However, for completeness, these minor GHG emission sources were evaluated in aggregate below.

Step 1: Identify All Control Technologies

The available control technologies for the CGS minor GHG sources are identical to those identified for the combustion turbines. These options include

- Carbon Capture and Storage Systems (CCS
- Small Combustion Source Efficiency
- Efficient Use of Energy

Step 2: Eliminate Technically Infeasible Options Effectiveness

Carbon Capture and Storage Systems

As discussed above, CCS for GHG control is not considered a technically feasible control option. Therefore, CCS is eliminated from further consideration for auxiliary boiler GHG reduction.

Small Combustion Source Efficiency

This small combustion sources for the CGS project will incorporate a high-efficiency design.

Efficient Use of Energy

The small combustion sources will not be operated continuously, but only during conditions when they are needed. For example, the inlet air heaters and fuel gas heaters will be operated only when required for safety reasons to protect against icing of the turbines or fuel lines. Therefore, energy will be utilized in an efficient manner.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies are equally important toward minimizing GHG emissions.

Step 4: Evaluate most effective controls and document results

The remaining technically feasible GHG control technologies for the CGS project are "Small Combustion Source Efficiency "and "Efficient Use of Energy." Both technologies will be implemented for the CGS project.

Step 5: Select BACT

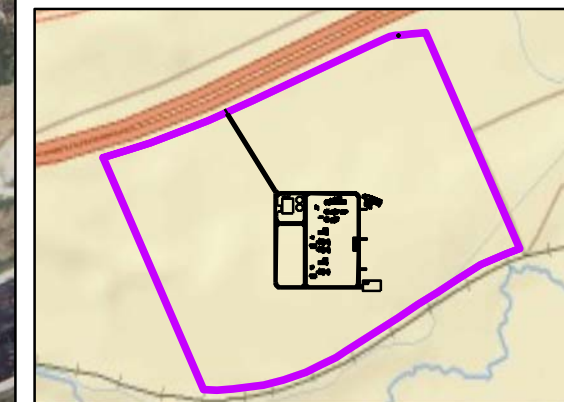
GHG BACT for the CGS small equipment are "Small Combustion Source Efficiency "and "Efficient Use of Energy." All auxiliary equipment will be selected with consideration for high design efficiency, and will be operated in an efficient manner. Due to the estimated minor CO_2e emissions contribution from these small combustion sources, no GHG permit limit is recommended for the CGS auxiliary equipment.

APPENDIX A

Location Map and Plot Plans

APPENDIX A-1

CGS Site Location and Fenceline Map



LEGEND

- Buildings in Analysis
- General Arrangement
- Project Boundary

N

0 250 500 1,000
Feet

FIGURE A-1
Cheyenne Generating Station
Fenceline and Power Block

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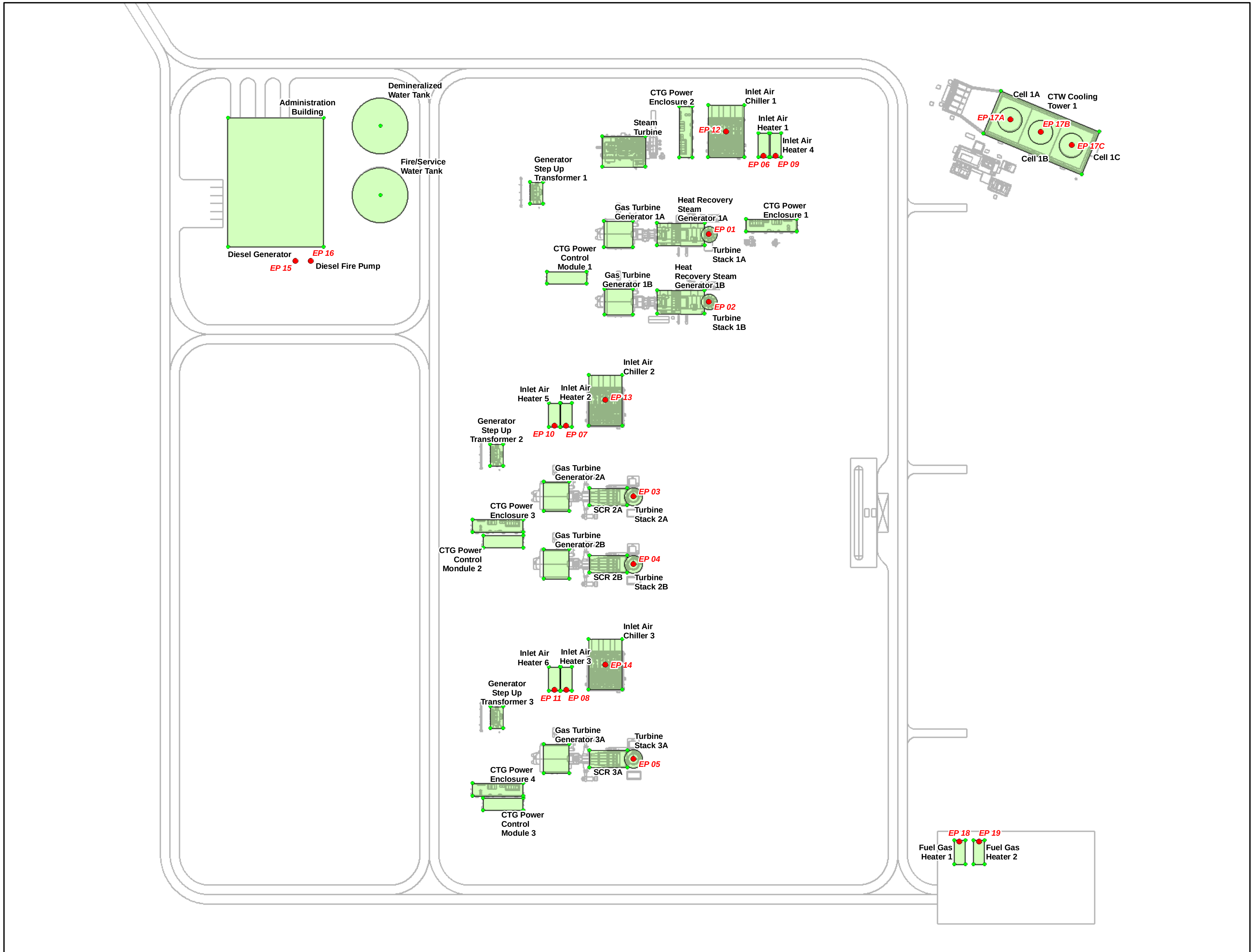
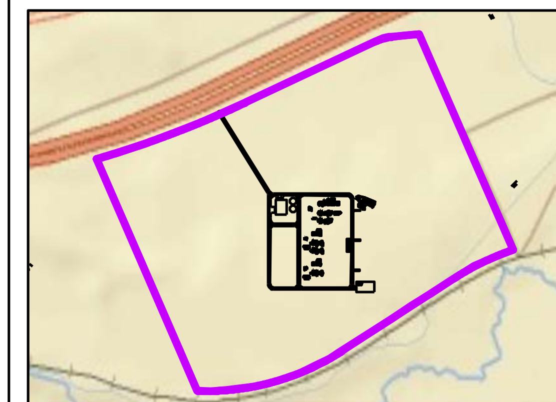
APPENDIX A-2

CGS Structures and Emission Points





LEGEND

- Structure Corner
- Emission Point
- Buildings in Analysis

Emission Point	Description
EP01	Combined Cycle Combustion Turbine CT01A
EP02	Combined Cycle Combustion Turbine CT01B
EP03	Simple Cycle Combustion Turbine CT02A
EP04	Simple Cycle Combustion Turbine CT02B
EP05	Simple Cycle Combustion Turbine CT03A
EP06	Inlet Air Heater 01
EP07	Inlet Air Heater 02
EP08	Inlet Air Heater 03
EP09	Inlet Air Heater 04
EP10	Inlet Air Heater 05
EP11	Inlet Air Heater 06
EP12	Inlet Air Chiller 01
EP13	Inlet Air Chiller 02
EP14	Inlet Air Chiller 03
EP15	Diesel Generator
EP16	Diesel Fire Pump
EP17	Combined Cycle Wet Cooling Tower
EP18	Fuel Gas Heater 01
EP19	Fuel Gas Heater 02

0 50 100 200
Feet

N

FIGURE A-2
Cheyenne Generating Station
General Arrangement

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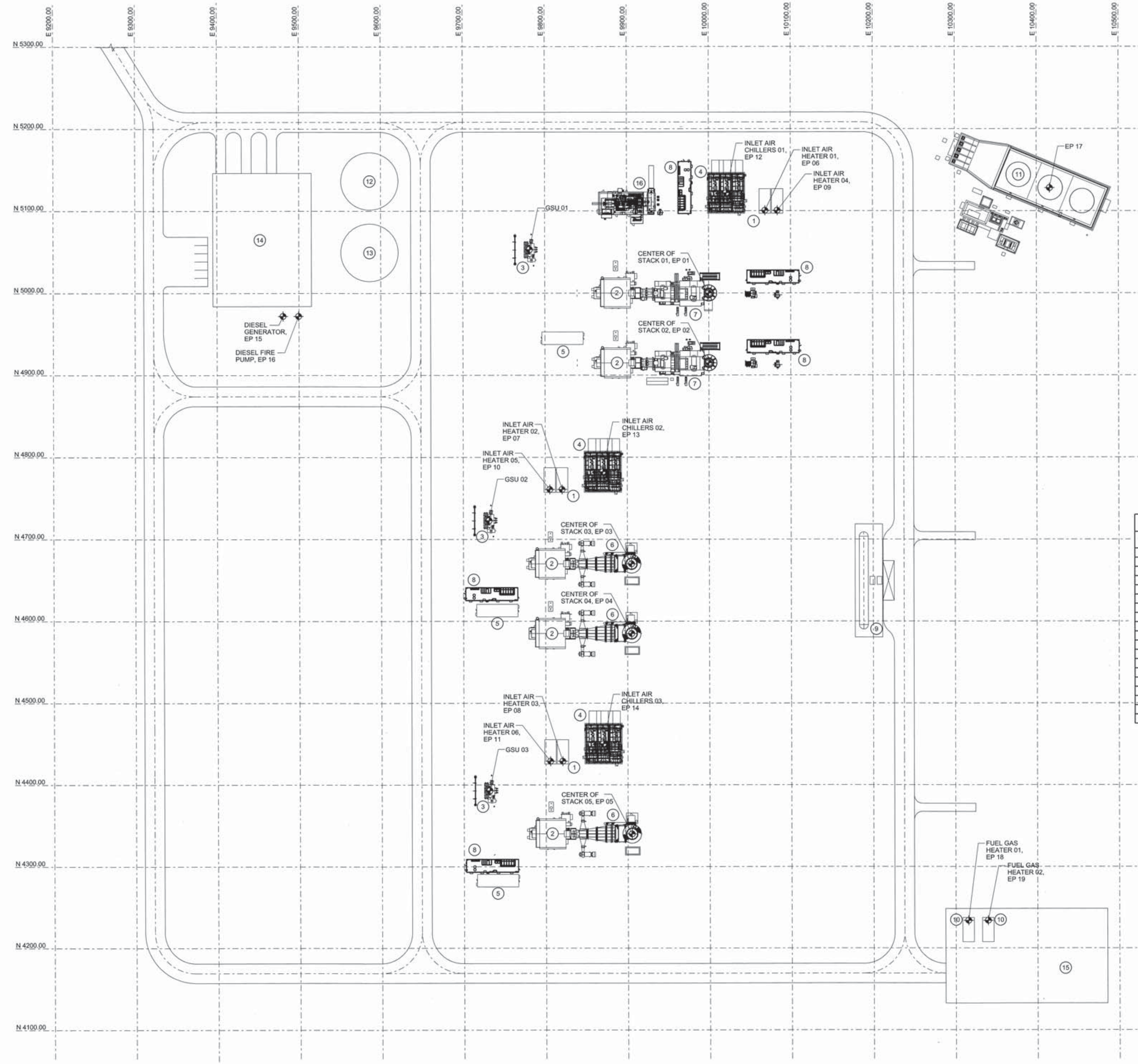
APPENDIX A-3

Zachry CGS Site General Arrangement



SCALE
IN FEET

GENERAL NOTES

1. HORIZONTAL CONTROL WILL BE BASED ON THE MODIFIED WYOMING STATE PLANE COORDINATE - WYOMING (NAD 1983) SYSTEM.
2. PLANT COORDINATES N 5000.00, E 10000.00 = MODIFIED WYOMING STATE PLANE (NAD1983) COORDINATE N 779204.00, E 227517.00.

EQUIPMENT LEGEND

1. INLET AIR HEATER
2. GAS TURBINE GENERATOR & AUXILIARIES
3. GENERATOR STEP UP TRANSFORMER (GSU)
4. INLET AIR CHILLERS
5. CTG POWER CONTROL MODULE
6. SELECTIVE CATYLIST REDUCTION
7. HEAT RECOVERY STEAM GENERATOR
8. CTG AUXILIARY POWER ENCLOSURE
9. AMMONIA TANK
10. FUEL GAS HEATER
11. CTW COOLING TOWER
12. DEMINERALIZED WATER TANK
13. FIRE/SERVICE WATER TANK
14. ADMINISTRATION BLDG
15. GAS YARD
16. STEAM TURBINE & AUXILIARES

LEGEND

EMISSION POINT (EP), SEE SURVEY CONTROL CHART FOR LOCATION.

EMISSION POINT SURVEY CONTROL

EMISSION POINT	LOCATION	PLANT COORDINATES (FEET)		MODIFIED STATE PLANE COORDINATES (FEET)		STATE PLANE COORDINATES (FEET)	
01	CENTER OF STACK 01	N 5000.00	E 10000.00	N 227517.00	E 779204.00	N 227442.34	E 778949.97
02	CENTER OF STACK 02	N 4915.00	E 10000.00	N 227432.00	E 779204.00	N 227357.34	E 778949.97
03	CENTER OF STACK 03	N 4670.00	E 9905.00	N 227187.00	E 779109.00	N 227112.34	E 778854.97
04	CENTER OF STACK 04	N 4585.00	E 9905.00	N 227102.00	E 779109.00	N 227027.34	E 778854.97
05	CENTER OF STACK 05	N 4340.00	E 9905.00	N 226857.00	E 779109.00	N 226782.34	E 778854.97
06	INLET AIR HEATER 01	N 5100.50	E 10068.75	N 227617.50	E 779272.75	N 227542.84	E 779018.72
07	INLET AIR HEATER 02	N 4761.00	E 9820.50	N 227278.00	E 779024.50	N 227203.34	E 778770.47
08	INLET AIR HEATER 03	N 4429.00	E 9820.50	N 226946.00	E 779024.50	N 226871.34	E 778770.47
09	INLET AIR HEATER 04	N 5100.50	E 10083.75	N 227617.50	E 779287.75	N 227542.84	E 779033.72
10	INLET AIR HEATER 05	N 4761.00	E 9805.50	N 227278.00	E 779009.50	N 227203.34	E 778755.47
11	INLET AIR HEATER 06	N 4429.00	E 9805.50	N 226946.00	E 779009.50	N 226871.34	E 778755.47
12	INLET AIR CHILLERS 01	N 5122.00	E 10021.50	N 227639.00	E 779225.50	N 227564.34	E 778971.47
13	INLET AIR CHILLERS 02	N 4782.50	E 9870.25	N 227299.50	E 779074.25	N 227224.84	E 778820.22
14	INLET AIR CHILLERS 03	N 4450.50	E 9870.25	N 226967.50	E 779074.25	N 226892.84	E 778820.22
15	DIESEL GENERATOR	N 4972.00	E 9480.50	N 227489.00	E 778684.50	N 227414.34	E 778430.47
16	DIESEL FIRE PUMP	N 4972.00	E 9499.50	N 227489.00	E 778703.50	N 227414.34	E 778449.47
17	COOLING TOWER	N 5128.00	E 10416.00	N 227645.00	E 779620.00	N 227570.34	E 779365.97
18	FUEL GAS HEATER 01	N 4234.00	E 10315.50	N 226751.00	E 779519.50	N 226676.34	E 779265.47
19	FUEL GAS HEATER 02	N 4234.00	E 10339.50	N 226751.00	E 779543.50	N 226676.34	E 779289.47

GSU SURVEY CONTROL

LOCATION	PLANT COORDINATES (FEET)		MODIFIED STATE PLANE COORDINATES (FEET)		STATE PLANE COORDINATES (FEET)	
GSU 01	N 5053.00	E 9781.50	N 227570.00	E 778985.50	N 227495.34	E 778731.47
GSU 02	N 4723.00	E 9731.50	N 227240.00	E 778935.50	N 227165.34	E 778681.47
GSU 03	N 4393.00	E 9731.50	N 223910.00	E 778935.50	N 226835.34	E 778681.47

NO.	REVISION	DATE	DRWN	DSND	CHKD	CHKD
A	ISSUE FOR PERMITTING					

Black Hills Corporation

ZACHRY

BHC CHEYENNE GENERATING STATION
SITE RELATED WORK
GENERAL ARRANGEMENT
2x1 COMBINED CYCLE & 3 UNIT SIMPLE CYCLE

D014255-SRWL00005 | SHEET 01 | REV A

APPENDIX B

GHG Support Documentation

APPENDIX B-1

CGS GHG Emission Calculations

Black Hills Corporation
Cheyenne Generating Station
Potential to Emit Facility Wide Greenhouse Gas
Revision 07-28-11

Emission Point	Description	Consumption (MMBtu/hr)	Emission Factors (kg/MMBtu)			Emissions (tons/year)			
			CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2-equivalent
EP01	Combined Cycle Combustion Turbine CT01A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP02	Combined Cycle Combustion Turbine CT01B	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP03	Simple Cycle Combustion Turbine CT02A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP04	Simple Cycle Combustion Turbine CT02B	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP05	Simple Cycle Combustion Turbine CT03A	366	53.02	0.001	0.0001	187,134.03	3.53	0.35	187,317.56
EP06	Inlet Air Heater 01	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP07	Inlet Air Heater 02	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP08	Inlet Air Heater 03	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP09	Inlet Air Heater 04	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP10	Inlet Air Heater 05	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP11	Inlet Air Heater 06	16.0680	53.02	0.001	0.0001	4,113.13	0.08	0.01	4,117.17
EP15	Diesel Generator	5.52	73.96	0.003	0.0006	225.01	0.01	0.00	225.77
EP16	Diesel Fire Pump	2.5	73.96	0.003	0.0006	50.95	0.00	0.00	51.13
EP18	Fuel Gas Heater 01	4.5	53.02	0.001	0.0001	1,151.92	0.02	0.00	1,153.05
EP19	Fuel Gas Heater 02	4.5	53.02	0.001	0.0001	1,151.92	0.02	0.00	1,153.05
Total PTE for Facility						**962,928.74**	**18.17**	**1.82**	**963,873.80**

Notes:

(1) CO_2 Emission Factors from Table C-1 of the EPA's Mandatory Reporting Rule.
(2) CH_4 and N_2O Emission Factors from Table C-2 of the EPA's Mandatory Reporting Rule.
(3) Global Warming Potentials are:

CO_2	1
CH_4	21
N_2O	310

(4) Combustion Turbines (hr/yr operation per turbine)	8760
(5) Inlet Air Heaters (hr/yr operation per turbine)	4380
(6) Diesel Emergency Generator (hr/yr operation per turbine)	500
(7) Diesel Fire Pump (hr/yr operation per turbine)	250
(8) Fuel Gas Heaters (hr/yr operation per turbine)	4380